TRANSMISSION OPTIONS FOR OFFSHORE WIND FARMS IN THE UNITED STATES

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Abstract

While offshore wind farms have been installed in Europe for over a decade, developers in the United States are only beginning to look toward the offshore resource. This paper provides an introduction to transmission issues for offshore wind farms in North America, aimed towards non-electrical engineers in the windpower industry. Topics include cable terminology and installation, and factors involved in choosing a voltage and between AC and DC. Specific issues related to offshore wind farm development in the United States include the lack of a domestic manufacturer of medium and high voltage insulated submarine cables, as well as a shortage of domestic equipment and experience in large-scale submarine cable laying. A project in the US must take into consideration the cost of transporting cables and equipment from overseas manufacturers.

Introduction

The European wind power industry is increasingly turning to the offshore wind resource, and the United States will draw on the Europeans' experience as we begin to plan offshore wind farms. Short of generating hydrogen, or otherwise using or storing the energy offshore (see for instance, Altmann 2001), it must be conducted to the on-shore load centers by submarine cables. Offshore transmission has proved to be challenging and costly in Europe, and will present additional challenges in the US because of the lack of domestic manufacturers of high-voltage, high-capacity submarine cable, and lack of equipment for and experience in installing this type of cable.

Submarine transmission cables are common in the US for other applications, but this experience has a limited applicability to wind farms. The offshore gas and drilling industry uses lower power levels and low (under 10 kV) to medium voltage (10-100 kV), whereas the trend in offshore wind power is toward high voltage transmission. A number of medium and high voltage transmission cables have been installed in the US to power islands but submarine transmission *from* generation offers different problems than transmission *to* a load. For instance, windfarms usually have high reactive current demands, since most wind turbines employ induction generators. This can cause resonance with the capacitance of the cables.

Economies of scale are driving up the size of offshore windfarms. Larger farms will both allow and demand more sophisticated electrical transmission systems, as wind power makes a greater impact on the onshore electrical grid. As power electronics are being developed, we may expect to see them play a greater role in offshore windfarm transmission and distribution designs, including the introduction of high voltage direct current (HVDC) transmission.

Anatomy of a submarine cable

The following is a brief introduction to cable types and components as it pertains to offshore wind installations.

Insulation – Three types of cable insulation are in common use for submarine transmission for long distances (at least several kilometers.) While insulation construction and thickness vary based on voltage, all three types discussed here are used for both medium and high voltages. Insulation is characterized by their insulation material, their construction, and whether the dielectric (i.e. insulation) is lapped or extruded.

Low-pressure oil-filled (LPOF), or fluid-filled (LPFF) cables, insulated with fluid-impregnated paper, have historically been the most commonly used cables in the US for submarine AC transmission. The insulation is impregnated with synthetic oil whose pressure is typically maintained by pumping stations on either end. The pressurized fluid prevents voids from forming in the insulation when the conductor expands and contracts as the loading changes. The auxiliary pressurizing equipment represents a significant portion of the system cost. LPFF cables run the risk of fluid leakage, which is an environmental hazard. Fluid-filled cables can be made up to about 50 km (30 mi.) in length. They are rarely used for DC applications, which are generally longer than practical for pressurizing. While LPFF cables are widely installed worldwide, the cost of the auxiliary equipment, the environmental risks, and the development of lower-cost alternatives with lower losses, have all contributed to the reduced use of LPFF cables in recent years.

Similar in construction are the solid, mass-impregnated paper-insulated cables, which are traditionally used for HVDC transmission. The lapped paper insulation is impregnated with a high-viscosity fluid and these cables do not have the LPOF cable’s risk of leakage.

Extruded insulation is replacing lapped installation as the favored options in many applications. Cross-linked polyethylene (XLPE, also called PEX) is lower cost than LPOF of a similar rating and has lower capacitance, leading to lower losses for AC applications. XLPE can be manufactured in longer lengths than LPFF (Gilbertson 2000.) Until recently XLPE was not an option for DC transmission, since it broke down quickly in the presence of a DC current, but recent improvements allow its use for DC as well. Figure 1 shows an example of an XLPE cable.

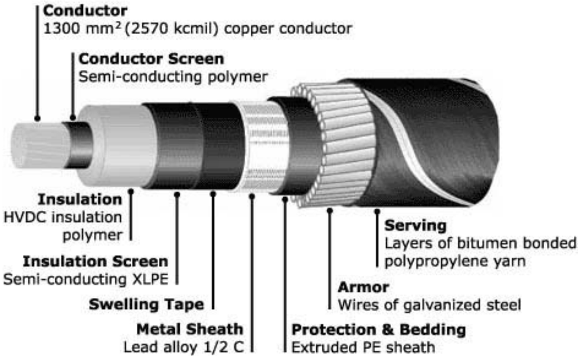

Figure 1: Anatomy of a single-core XLPE cable (from ABB’s Long Island Cross Sound cable)

Another extruded insulation used in submarine cables is ethylene propylene rubber (EPR), which has similar properties to XLPE at lower voltages, but at 69 kV and above, has higher capacitance (Gilbertson, 2000).

High-voltage submarine XLPE cable is not manufactured in the North or South America. LPOF cables are manufactured here but are not available in the sizes and lengths that will be required for an economically sized offshore wind farm. Currently any offshore windfarm in the US (or anywhere else in the Western Hemisphere) will have to import cables from Europe or Japan. With cables that may weigh more than 75 kg/m (50 lbm/ft), the transportation costs will be a significant portion of the cost of the cable.

Conductors – The conductor in medium- and high-voltage cables is copper, or less commonly aluminum, which has a lower current-carrying capacity (ampacity) and so requires a greater diameter. Ampacity increases proportionally with the cross-sectional area, which can range up to about 2000 mm^2 (3 in^2, i.e. 50 mm (2 in) in diameter) before the cable becomes unwieldy and the bending radius is too great. Large cables may have a bending radius as large as 6 m (20 ft). The design amperage is a function not only of the voltage and the power to be carried, but also the cable length, insulation type, laying formation, burial depth, soil type, and electrical losses. Gilbertson (2000) offers a thorough technical reference on these subjects. The issues of length and losses are discussed in more detail below.

Number of Conductors – When possible in AC-cable applications, all three phases are bundled into one "three-core" cable. A three-core cable reduces cable and laying costs. It also produces weaker electromagnetic fields outside the cable and has lower induced current losses than three single core cables laid separately. As the load requirements and conductor diameter rise, however, a three-core cable becomes unwieldy and no longer feasible. One advantage of single-core cables is that it is easier and cheaper to run a spare, fourth wire. Another advantage is that longer lengths can be made without splices or joints. Figure 2 shows a three-core cable.

Screening – a semiconductive screening layer, of paper or extruded polymer, is placed around the conductor to smooth the electric field and avoid concentrations of electrical stress, and also to assure a complete bond of the insulation to the conductor. Figure 1 shows screening on a single-core cable, and Figure 3 shows a three-core cable with screening on both the individual conductors and the three-core bundle.

Figure 2: Three-core cable (Nexans)

Sheathing – Outside the screening of all the conductors is a metallic sheathing, which plays several roles. It helps to ground the cable as a whole and carries fault current if the cable is damaged. It also creates a moisture barrier. In AC cables, current will be induced in this sheath, leading to circulating sheath losses; various sheath-grounding schemes have been developed to reduce circulating currents that arise in the sheath. Unlike other cable types, EPR insulation does not require a metal sheath.

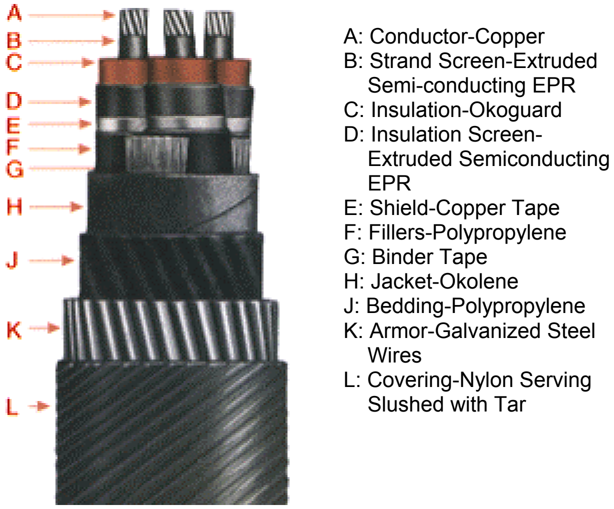

Figure 3: Three-core cable (Okonite)

Table 1: Capacities of high voltage cable (Häusler, ABB, 2002)

System	AC 3 single-core cables		DC bipolar operation, 2 cables		
Cable insulation type	XLPE polymer	LPOF: Oil- filled paper	LPOF: Oil- filled paper	Mass imp. Paper	XLPE polymer
Maximum Voltage	400 kV	500 kV	600 kV	500 kV	150 kV
Maximum Power	1200 MVA*	1500 MVA*	2400 MW	2000 MW	500 MW
Max. length, km (mi.)	100 (62)	60 (37)	80 (50)	Unlimited	Unlimited

* Losses may be excessive at these powers

Armor – An overall jacket and then armoring complete the construction. Corrosion protection will be applied to the armor; this may include a biocide to inhibit destruction by marine creatures such as marine borers that are present in Southeast US waters, and have recently been reported in the Northeast (Fox Islands, 2001).

Fiber optic cables for communications and control can be bundled into the cables. Note the bundled fiber optic line in Figure 2.

Table 1 summarizes the current availability and limitations of AC & DC cables.

AC or DC?

The most significant difference between AC and DC, in the context of submarine transmission, is that AC cables have a high capacitance and so generate considerable reactive current. (Capacitance is the ability of an insulating material between conductors to store electricity when there is a voltage difference between the two conductors. One of the "conductors" is in this case the sea and soil, as well as the armoring and sheathing. The air surrounding overhead lines does not allow an electro-magnetic field to develop enough to create this issue in overhead lines, which *consume* reactive power) The buried cable itself acts as a long capacitor, and charging current is produced along its entire length, so the longer the cable, the more kVAR's are generated. Typical amounts of kVAR generation are in the range of 100-150 kVAR/km for 33 kV XLPE cable and 1000 kVAR/km for 132 kV XLPE cable (Grainger, 1998)

The additional reactive current not only reduces the active current-carrying capacity of the cable, but also requires a scheme to absorb the reactive current. For any length over about 10 km (6 mi.), some form of reactive power compensation will be required. The transmission system must be designed to avoid resonance between the cable's capacitance and the reactance of the generators, any overhead lines on shore, and any power electronics in the wind farm or the on-shore grid. Induction generators must be prevented from self-exciting. These other components that are required for compensation are discussed in more detail below.

AC cable systems are a well understood, mature technology and are currently the more cost-effective transmission method unless the voltage is high (over about 175 kV), or the distances are long. What constitutes a "long" distance depends primarily on the cable's losses, which depends on the voltage and cable type. As a rule of thumb, economic cut-off points have been estimated to be between 30 and 250 km (20 and 155 mi) (see, for instance, Rudolfson (2002) for the high end.)

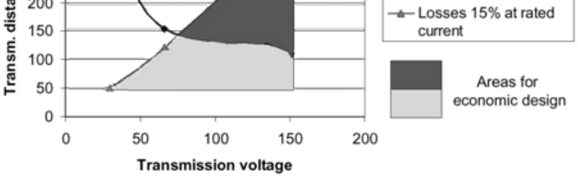

Figure 4: Economic limits of submarine XLPE cables (Häusler, ABB, 2002)

AC is usually the more economic choice as long as the charging current is less than the active current (i.e. the current associated with the power being transferred.) and the losses and voltage drop are kept under an acceptable limit. For example, Figure 4 shows the applicability of ABB's AC XLPE cables, based on limiting losses to 15% (Häusler, 2002).

When the charging current and losses of an AC cable are no longer acceptable, the only other option is high voltage direct current (HVDC). Offshore-wind-compatible HVDC is still under development and currently costs considerably more than AC transmission. With the development of power electronics, however, HVDC is becoming more feasible. The cables themselves are less expensive for DC than for AC, because for a given amount of insulation they can be operated safely at higher current, so they allow more power per cable. However, the overhead costs of the power converters at either end of the transmission line are considerable.

Although HVDC's converters lead to electrical losses on either end, the DC system has lower overall losses. The losses in the cable are significantly lower for DC cables because of the lack of both the charging currents in the main conductor, and the induced current in the shielding.

For systems large enough to warrant a DC transmission system, DC will offer a number of advantages:

- Asynchronous connection – i.e. the frequency at either end can differ. This decoupling allows for variable speed wind turbines, and more advanced control schemes. It also allows a greater choice in wind turbines.
- The AC voltage at either end can also differ, possibly saving a transformer
- Distance of transmission is not limited by losses, since HVDC losses over distance are almost negligible. Cable cost, laying cost, and manufacturability are more likely to be the limiting factor in length for a given application.
- Avoids the resonance between the cable capacitance and the inductive reactance of the grid
- The direction and magnitude of the power flow can be controlled
- HVDC does not transfer short circuit current. This is a benefit on both ends, since it limits the disruption caused by faults on the other end.
- Since a given cable can carry more power in DC than AC, a set of cables that now feeds a medium-sized AC wind farm could later be used for a windfarm four times the size if a converter is added along with more wind turbines. (Weatherill, 2000)
- If the onshore substation is at some distance, the transmission cables might have to be buried onshore as well, since permits for new overhead lines are becoming more difficult to obtain. This added distance might in some cases eliminate the possibility of AC cables.
- The large-scale power electronics allow greater control of the active and reactive power. As wind turbines contribute a greater percentage of a grid's power, they will increasingly be required to provide support to the grid, as do traditional power plants. This will include having the ability to ride through transmission faults, i.e. short periods of very low voltage, and providing kVAR & voltage support or even frequency regulation. Denmark is already stiffening interconnection requirements (Eltra, 1999) and other European countries are following suit. US interconnection requirements vary by utility or regionally, and are in some respects not as stringent as the Eltra requirements for small generation facilities, but as wind farms become more prevalent in the US, the same issues will have to be addressed. Recent developments in HVDC will inherently meet some of the new requirements.

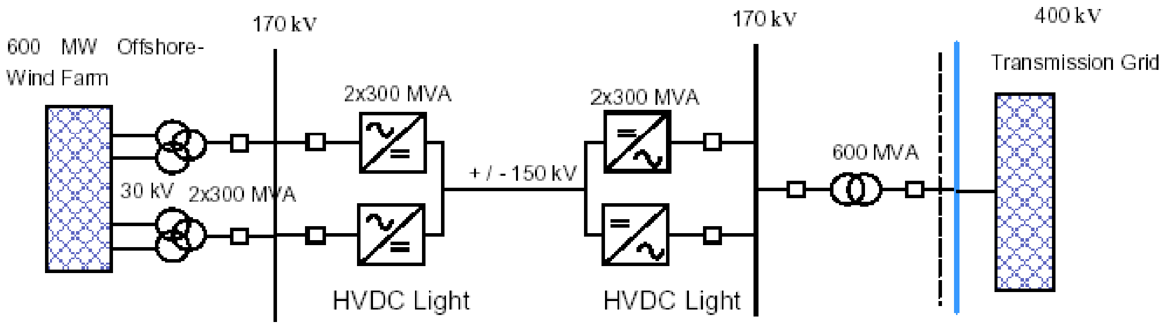

Figure 5: ABB's "HVDC Light" VSC technology: DC connection of a large offshore windfarm (Häusler, 2002)

HVDC developments

Two types of HVDC systems are available, conventional thyristor-based current-source converters, and the newer voltage-source converters (VSC) systems. Neither has yet been used for offshore wind farms, but the latter is being tested on land-based farms, and both have been used in non-wind applications for powering islands from the mainland.

Conventional HVDC is a well-established technology, but is not well suited to use on an offshore wind farm. First, it requires an AC current source for commutation and a source of reactive current on the windfarm end. Consequently either a smaller AC cable must be run to the wind farm, or synchronous rotating machinery or power electronics is required at the wind farm site. Second, the conventional converter itself is typically quite large and not appropriate for an offshore platform.

With recent advances in power electronics, VSC is a new HVDC option. These converters use isolated gate bipolar thyristors (IGBT's) and allow independent control of both active and reactive current. These systems have somewhat higher losses but are more compact and also more flexible due to the reactive power capabilities and the fact that they do not require an independent AC source for commutation on the windfarm end.

ABB offers this under the name of HVDC Light; Siemens calls their version of HVDC Plus. Alstom also offers HVDC technology targeted for offshore wind installations. Figure 5 illustrates the major components of a VSC-based HVDC transmission system.

A DC transmission system can consist of one cable (single pole) or two cables (bipolar). A single pole system uses electrodes for sea or ground return. While reducing the cable and laying costs, single pole transmissions have a few disadvantages:

- Greater electromagnetic field creation
- emissions of gases generated at the electrode, and
- other environmental problems.

Bipolar is the more common design, but often includes sea electrodes for temporary backup use in the case of damage of one of the cables. One manufacturer has developed a bipolar coaxial cable, with the return conductor being surrounding the inner conductor.

While HVDC is not cost effective at this time for offshore windfarms in the scale presently being developed, we can expect for a number of reasons that it will become a good candidate in the near future. First, it is still a new technology and will most likely drop in price over time as the semiconductors are developed further. Second, windfarms are growing, and HVDC has significant economies of scale in both size and distance, while AC transmission becomes less feasible over about 200 MW and 50-100 km.

Third, inter-regional offshore HVDC networks are being planned in the United States as well as elsewhere in the world. For instance the 1200-MW "Neptune" link between eastern Canada and the US northeast is planned and the New York section is in the permitting phase (see, for instance, PJM press release (Hewett, 2001)). This will not only promote the technology but also may eventually provide offshore "substations" to which wind farms can be linked.

What Voltage?

For AC transmission the choice of voltage is a balancing between the cost of the cables and their associated losses, vs. the cost of placing transformers at sea. Intra-farm collection voltages are now typically in the medium voltage range of 24-36 kVAC, with transformers in the base of the tower for converting from the generator's voltage. For smaller wind farms the power can be transmitted back to the onshore substation, in one or more medium voltage 3-core cables. Three-core AC XLPE cables at 33 kV can carry about 25-30 MW (Grainger, 1998).

When more than about three cables would be required at medium voltage, a transformer at sea will be warranted, bringing the transmission up to high voltage to reduce losses. A 3-core cable at a high voltage such as 150 kV can carry up to 150 or 200 MW. This is the strategy used at Horns Rev, the world's first high-voltage offshore transformer. The transformer requires too much space to fit on a wind turbine's foundation, and will require its own platform.

Raising the transmission voltage to the onshore voltage can also eliminate the need for a transformer onshore.

These transmission capacities are approximate. The ampacity (current-carrying capacity) of a submarine cable depends on a number of criteria including the thermal resistivity of sediments, which is usually assumed to be lower than dry soil onshore, in the range of 0.5-0.7 K·m/W, but could in a specific case be higher (Gilbertson, 2000). It is necessary to take core samples at a given site.

Cable separation also affects ampacity. Gilbertson (2000) offers a detailed description of ampacity calculations. Figure 6 shows a summary of submarine cable options as a function of the distance and the power to be transmitted. The largest offshore wind farm to date, Horns Rev (150 MW, 150 kVAC) is marked with an asterisk. While all the ranges are of course approximate, the economic and technical limits dividing HVAC and HVDC are even more variable and are not indicated as a distinct line.

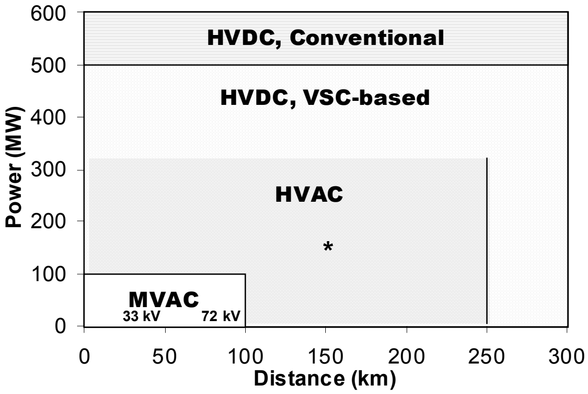

Figure 6: Approximate ranges for voltage options as a function of power and distance.

Cable Installation

The installation of submarine cables can be 1-3 times the cost of the cables themselves. It is usually performed by a specialized cable-laying vessel, which must have an integral turntable or reel for storage, equipment for proper tensioning of the cable, dynamic positioning for precision maneuvering, a trencher, and a crew with experience in cable laying. For lengths of cable that cannot be manufactured and shipped in one piece, a clean room is required as well in which to perform the splices. Figure 7 shows a specialized cable-laying vessel.

A few of these vessels are in use in Europe and Japan but none is currently stationed in the US. For instance, for the HVDC New York – Connecticut Cross Sound cable that is being put down this year (2002), a cable-laying vessel was brought from the Netherlands. For high-voltage

Figure 7: Skagerrak laying vessel (Nexans)

cable lengths up to a few dozen kilometers, the cable may be transported from the manufacturer on the laying vessel, which reduces the amount of handling.

Nexans cable-laying vessel, the Skagerrak, has a draft of 8 m (27 ft) including the propellers, so it cannot operate in shallow waters. Windfarms are likely to be installed in shallow water outside of shipping lanes, where a full-scale cable vessels cannot operate, necessitating the use of general purpose vessels with a shallower draft.

Submarine cables have had a high failure rate in the past (Gardner, 1998), primarily due to damage from fishing trawlers and anchors. Today they are usually trenched and back-filled at a depth of 1- 4 m (3-13 ft), to reduce this risk. In areas where waves move deep sands, the greater depths are necessary to keep the cable from rising back to the surface. Trenching is done with equipment such as a cable plow (Figure 8) or a jet plow like "CapJet" in Figure 9. The remotely operated CapJet uses a water jet to fluidize most sea-bottom surfaces, and simultaneously buries the cable. The fluidized material falls back into the trench, covering the cable. For hard rock bottoms, there are remotely operated vehicles that use rock-cutting chainsaws to excavate a trench.

Standard submarine cable trenchers may be difficult or impossible to use at the shoreline and in shallow waters around wind turbine foundations. Depending on shipping and fishing activity in the area, the short intra-farm cabling may not be buried, and might be able to be pulled from one turbine to the next by barges or winches.

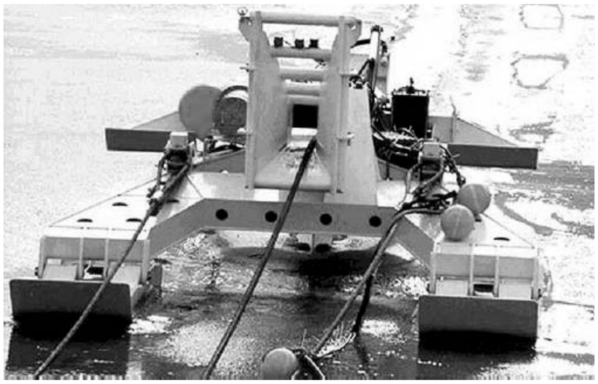

Figure 8: Cable Plough: One of Global Marine's many cable trenchers

Short sections of unburied cables can be laid simultaneously, but usually each cable requires a separate pass with the laying vessel and again with the cable trencher. If field splices are required, cable sections must be spliced in a clean room on board which can take 1-2 days per splice.

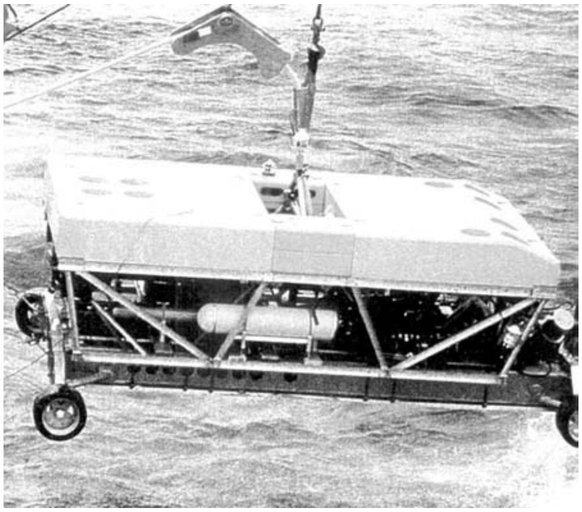

Figure 9 Nexans' CapJet cable-burying ROV being lowered into the water

Whenever more than one cable is needed, cable spacing is an important issue. Electrically it is preferable to place AC cables near one another, since induced currents rise as separation increases. DC cables should also be installed as close as possible to reduce the generation of magnetic fields. (Even bipolar DC cables will affect magnetic compasses but they are rarely used any more). On land, AC cables are usually rated based on losses induced by a 1-m separation. However, logistically submarine cables must be spaced at least 20 m (65 ft) or the water's depth apart, whichever is greater. The former requirement comes from the difficulty of laying the cable precisely and the need for the cables not to cross. The latter requirement arises from repair considerations. When a cable is repaired, the damaged cable is removed, along with the waterlogged lengths of cable to either side. A longer section of cable is spliced into it, forming a loop with a diameter approximately equal to the water's depth. The loop is dropped back to the bottom and must not cross the other remaining lines.

At landfall the cable must be buried to avoid damage as well as corrosion, which is greater in the presence of both air and water. Directional drilling may be an option here, or else trenching and filling with selective backfill.

Assessing the structural requirements of a cable requires knowledge of the tides, currents, seabed stability, potential for biological decomposition, and earthquake activity of the area. A detailed seabed survey must be performed before specifying the cable.

A study of the environmental impact of the trenching will be required, particularly where it passes through shellfish beds or other sensitive habitat. Accommodation for marine habitat may be necessary, such as postponing installation until winter when the sea life is less active. Additionally, permitting for the cable will be required from the same bodies that are permitting the farm as a whole, such as the Army Corps of Engineers and the Coast Guard. Even if the farm itself is outside of state-controlled waters, local planning and environmental protection bodies that are not otherwise concerned will be involved in the cable laying route and process.

Case Studies and Costs

Tables 2 and 3 list the cables that were used in a number of recent submarine transmission projects. The first lists wind farm experience in Europe. Offshore wind power has so far used AC transmission; Horns Rev will employ the first offshore transformer used to raise the voltage from the intra-farm voltage of 36 kV, to a higher transmission voltage of 150 kV. Table 3 lists a few recent medium- and high-voltage North American submarine cables. These examples indicate a transmission cost range of \$10,000 - \$40,000/MW·km.

A rule of thumb used in the US is \$1M/mile (\$0.62M/km) for lower medium voltages such as 33 kV, or about twice that for higher medium voltages such as 72 kV. This includes cable, installation, permitting, and the connection on either end (Fredericks, 2002).

The cables themselves cost between US\$90/m and \$130/m for medium voltage cables, and in the range of \$200/m for 145 kV, not including transportation from Europe to the US. Cable laying costs 1-3 times the cost of the cable, depending on the site, depth, length, etc. Permitting costs will vary locally.

Transmission equipment can be expected to cost in the range of 10-20% of the total offshore wind farm costs (see, for instance, Weatherill (2000)). With only a few offshore wind farms in operation worldwide, and much of the technology under development, it is difficult to estimate transmission costs in the US or anywhere else. Some costs for actual and proposed systems are shown in Table 2, 3, and 4.

Martander (2002) points out that the bulk of the cost of DC transmission lies in the power semiconductors, which are being developed quickly and can be expected to reduce in cost rapidly in the coming years. He estimated that based on current development rates, by 2011 the cost of DC transmission would be as low as high-voltage AC transmission.

Table 2: Wind Power Submarine Transmission

Site	Year	MW	kV	AC, DC	Length, km (mi.)	Cable Type Notes
Blyth	'00	4	11	AC	1.9 (1)	EPR
Middelgrunden	'01	40	30	AC	3 (2)	XLPE, 2 parallel cables. 690V/30 kV transformers in tower bases Approx $4.8M for transmission ($40,000/MW·km) (Weatherill 2000 & Barthelmie, 2001)
Horns Rev (under construction)	'02	150	150	AC	18-20 (12)	Nexans XLPE. One, 3-core cable. 36 kV-XLPE cables between turbines. Transformer on an offshore platform. The cable is the world's largest three-conductor XLPE cable designed for 150 kV.

Table 3: Non-Wind Submarine Transmission, in North America

Site	Year	MW	kV	AC, DC	Length, km (mi.)	**Approx** .US$/ MW·km	Cable Type & Manufacturer, Notes
Juneau, Alaska	'99	130	138	AC	5 (3)	$17,500	LPOF, Nexans (formerly Alcatel). 4, single-core cables. $11.4 million -for Project Management, Engineering, Materials, Shipping and Installation Labor
Galveston, TX	'01	200	138	AC	6.3 (4)	NA	XLPE, Nexans 3-core cables
Long Island Sound, NY- CT	'02	330 + 16 loss	+/- 150	DC	39(24)	$9,700	XLPE. ABB. Weight >75 kg/m (50 lb/ft) $125M for installed cables, converters & interconnection
Nantucket, MA	'96	35	46	AC	42(26)	$20,000	One, 3-core cable, Pirelli. ~$30M including installation, permitting and substations

Table 4: Estimated Costs of Transmission for Proposed Submarine Cables

Site	MW	kV	AC, DC	Length, km (mi.)	**Est'd** US$/ MW·km	Notes
Block Island, RI	10	35	AC	24(15)	44,000	Plus 1 km (¾ mi.) on land. Rocky shores and archeological areas
Fox Islands, ME	~45	33	AC	14 (9)	9,500	EPR. Okonite $6M for proposed replacement, ~50% material, 50% installation.
Viking HVDC Light, (Germany)	70	HV	DC	100(62)	4,300*	(Weatherill, 2000)
HVDC Light	400	HV	DC	100(62)	2,800*	1/3 cables, 2/3 converters. (Weatherill, 2000)

**Installation not included.*

Note that all prices listed may reflect dissimilar scopes of supply and are given for rough comparison only.

Conclusions

Wind power is moving offshore in Europe and although land limitations are not as severe on this side of the Atlantic, this trend will eventually reach the United States. Not only will we draw on European experience for transmission design; we will be using their cable and their cable laying equipment, until these are manufactured in the United States. When offshore wind power becomes more prevalent in the US, we may expect that cable companies will respond to a growing industry by manufacturing cables domestically.

With transmission costing as much as 20% of the total farm costs, the choice of transmission voltage and technology is an important one. Europe has now begun to use high-voltage AC transmission, with Horns Rev boasting the first offshore high-voltage transformer. HVDC is not a feasible transmission option for the scale of offshore wind farms today, but we expect that it soon will be. As economies of scale drive up the size of the offshore windfarm, the sophistication of the transmission system will have to rise to meet the electrical stability needs of the offshore wind farm as well as the onshore grid.

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