MOTT MACDONALD

Elia Future Grid 2030

Stevin-Avelgem & Avelgem-Center Power Corridor
Comparison of Technology Options

05 March 2019

Elia Engineering SA

Mott MacDonald
Victory House
Trafalgar Place
Brighton BN1 4FY
United Kingdom

T +44 (0)1273 365000
F +44 (0)1273 365100
mottmac.com

Elia Engineering SA
Leon Monnnoyer 3
B-1000 Brussels

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Mott MacDonald Limited. Registered in England and Wales no. 1243967. Registered office: Mott MacDonald House, 8-10 Sydenham Road, Croydon CR0 2EE, United Kingdom

Elia Engineering SA

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Contents

1 Introduction

Elia Engineering has commissioned Mott MacDonald to carry out a review of technology options for high voltage electricity power corridors.

This report compares technology options against the specific requirements of the Elia Future Grid 2030 project.

Mott MacDonald is a global engineering, management and development consultancy with our registered head office in the UK. One of our areas of specialism is power generation, transmission and distribution where we offer a complete range of engineering services required for the development and implementation of high voltage power systems.

2 Context and Background

2.1 Introduction to Elia

Elia owns and operates the Belgian high voltage electricity transmission grid. Assets include all Belgian 150 kV, 220 kV and 380 kV electricity grid infrastructure, and almost 94% of the grid infrastructure between 30 kV and 70 kV. Elia's grid is made up of 3,000 km of overhead line, 5,500 km of underground cable and 800 substations.

Elia's main activities:

- Managing infrastructure: Maintaining and developing the grid, as well as connecting electrical installations to the grid;
- Operating the electricity system: Granting access to the grid in a straightforward, objective and transparent way, providing full services for transporting electricity, monitoring flows on the grid to ensure that electricity runs smoothly and managing the balance between electricity consumption and production 24 hours a day;
- Facilitating the market: Developing initiatives to improve how the electricity market operates and making its infrastructure available to all market players in a transparent, non-discriminatory way. Elia develops services and mechanisms allowing the market to trade on different platforms, which promotes economic competitiveness and wellbeing.

2.2 Future Grid 2030 needs case

2.2.1 A power system in transformation

The Belgian power system is going through a transformation.

Like many power systems across the world it has traditionally been dominated by a small number of very large, centralised thermal power plants.

Today's power system must incorporate energy produced from many power generation sources and technologies and there is increased international energy exchange. Elia's grid is a key link between France, Europe's largest electricity exporter, and markets in Northern Europe.

At the same time, Elia is facing the challenge of achieving an energy system which is sustainable, affordable and reliable. This is known as the "energy trilemma".

Substantial expansion and reinforcement of the Belgian grid is required to face today's challenges, and to support an increasing amount of generation from renewable sources in line with policy targets.

2.2.2 Elia's Federal Development Plan

Elia's Federal Development Plan covers a period of 10 years and is adapted and published every 4 years. It is developed in collaboration with the Federal Public Service Economy and the Federal Planning Bureau.

The 2020-2030 Federal Development Plan identifies capacity needs for the Belgian high voltage grid (150 kV, 220 kV and 380 kV) for the period between 2020 and 2030 and describes the investment program required to achieve this.

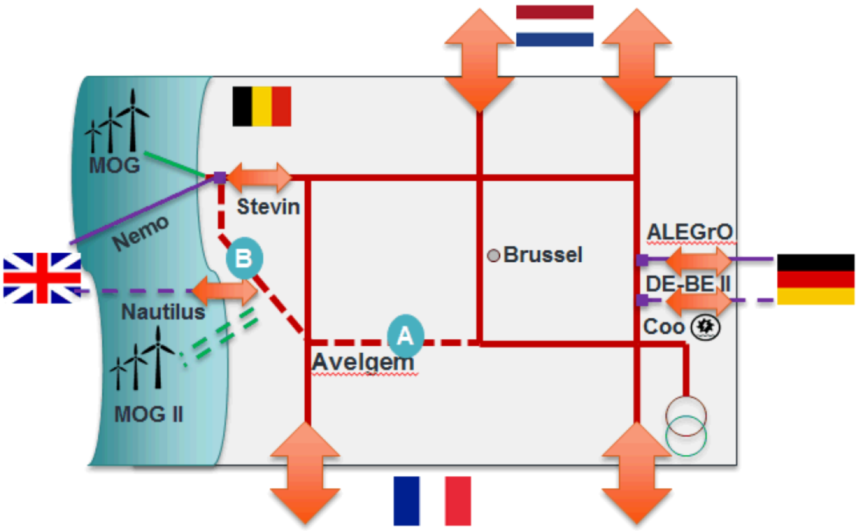
The plan includes the strengthening of the 380 kV transmission grid, the integration of additional offshore wind generation and the development of interconnections with other countries.

2.2.3 Future Grid 2030 project

The Future Grid 2030 project is included in the 2020-2030 Federal Development Plan:

- Creation of a new 6 GW (2 x 3 GW) connection between Stevin and Avelgem, the Stevin-Avelgem corridor
- Creation of a new 6 GW (2 x 3 GW) connection between Avelgem and the centre of the country, the Avelgem-Centre corridor

Figure 1: Future Grid 2030



Source: Elia

2.3 Elia's obligations

Each technology option should be considered in the context of Elia's statutory and regulatory obligations. The following obligations are considered for all new developments:

1. Safety – Compliance with all relevant safety standards
2. Environment – Compliance with all environmental standards and policies
3. Reliability and availability – The extent to which the grid is available for operation, considering downtime for planned and unplanned outages.
4. Robustness and flexibility – The capability of the grid to withstand non-standard operating conditions and grid faults without loss of supply, and the provision for future grid connections and reinforcements.
5. Economic efficiency – Provision of a cost-effective solution which meets the project requirements whilst managing the lifetime cost of the development.

3 Power Corridor Technology Options

3.1 Technology options

This report considers the following high voltage power corridor technology options:

- Overhead lines
- Underground cables
- High voltage direct current (HVDC) as an alternative to high voltage alternating current (HVAC)

3.2 Power corridor technical requirements

The Future Grid 2030 power corridor has the following technical functionality requirements:

Table 1: Basic technical requirements

Criteria	Requirement
Power capacity	6 GW
Redundancy	50% availability after a single grid fault (i.e. the requirement is for at least two independent 3 GW circuits, or 2 x 3 GW capacity)
Length	50-100 km
Provision for future additional connections to the new lines	Required

4 Methodology for Comparing Technology Options

Power corridor technology options have been compared against the following technical criteria:

Table 2: Criteria for comparison of technology options

Criteria	Notes
Safety	The technologies discussed in the report are capable of compliance with all relevant safety standards. They can be made safe in any area, including publicly accessible areas. Safety is therefore not considered in detail in the report.
Technical performance	To include: • Maturity of technology • System complexity • Electrical impact on the grid • Provision for additional future connections • Operation & maintenance
Environmental impact[1]	To include environmental, ecological and societal impact. See note 1.
Planning, permitting and construction programme	-
Whole life cost	-

1 Separate and more detailed environmental, ecological and social impact assessments and studies into public acceptance are being carried out by others.

The key technical risks associated with the application of each technology for the Elia Future Grid 2030 project are identified and discussed.

Each technology is considered against the following scoring criteria:

Table 3: Scoring criteria

Score	Description
++	Very low risk / significant advantage
+	Low risk / moderate advantage
-	Moderate risk / moderate disadvantage
- -	Significant risk / significant disadvantage
X	Does not meet the minimum requirements

5 AC Overhead Line

At present Elia operates the transmission grid at 150 kV, 220 kV and 380 kV.

380 kV is considered the most appropriate AC operating voltage for the Future Grid 2030 power corridor to meet the required power transmission capacity. Increasing the voltage decreases the current flowing in the lines, which consequently decreases power loss.

A 380 kV double circuit overhead line will meet the Future Grid 2030 technical requirements.

5.1 380 kV overhead line installation

The required 6 GW capacity can be provided via a double circuit overhead line, i.e. 2 x 3 GW circuits supported on a single tower structure.

The tower design will be selected as part of the route design. Standard steel lattice tower designs include vertical and triangular (also known as Donau) conductor arrangements. Vertical towers are taller and narrower than Donau towers, which are shorter and wider.

Figure 2: Double circuit steel lattice tower (vertical conductor arrangement)

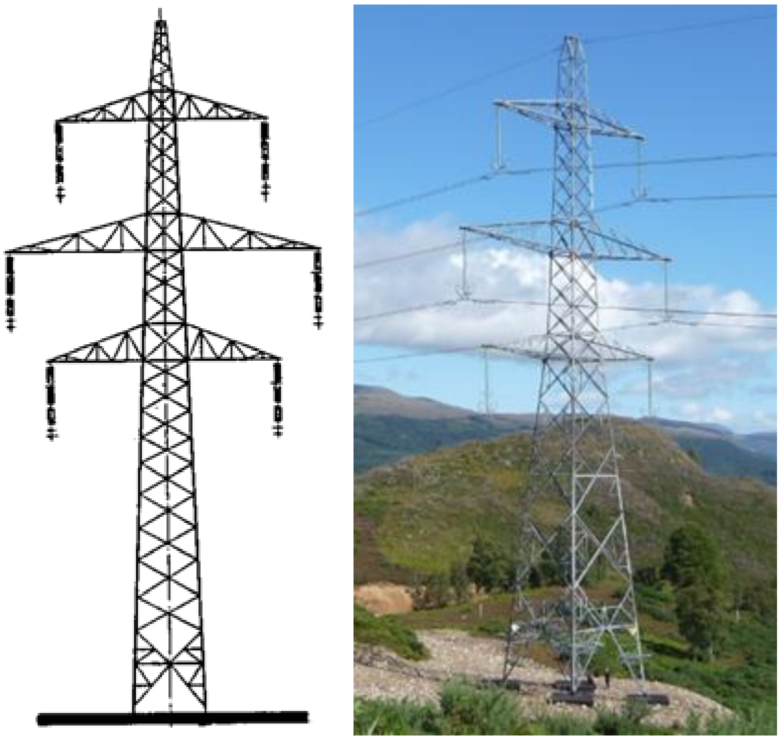
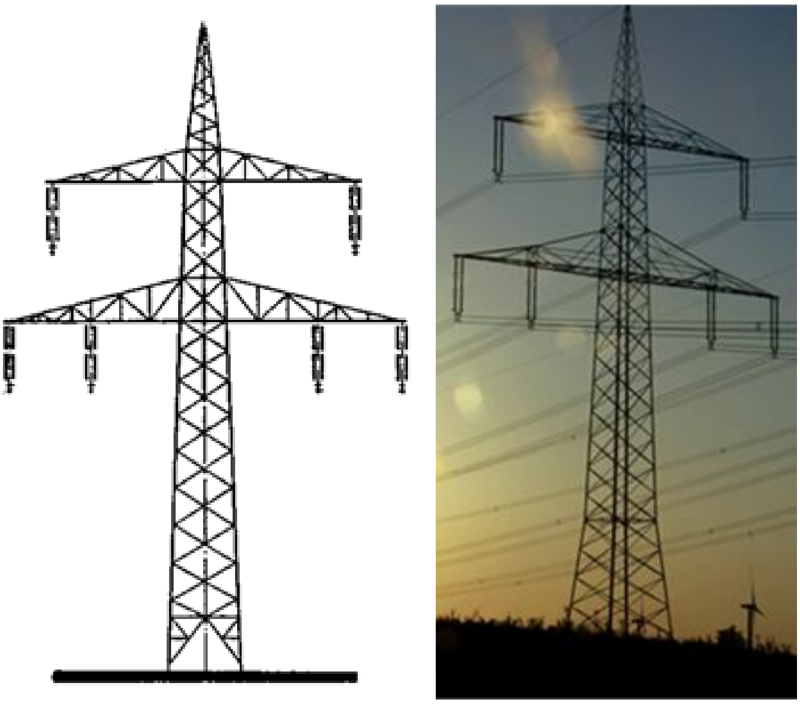


Figure 3: Donau double circuit overhead line tower



Tower height and the spacing between towers are selected so that a minimum safe conductor height above ground is maintained. Standard spacing of 380 kV towers is at 350-400 m intervals. Tower heights vary based on tower type and position; 380 kV towers for vertical conductor configurations are typically 50 m high with a base dimension of around 8 m whilst Donau towers are around 40m in height.

5.2 Overhead line safety

Overhead lines are constructed to national standards to ensure they are designed for the local environmental conditions whilst maintaining adequate ground clearance with the conductor at its maximum sag.

5.3 Overhead line technical performance

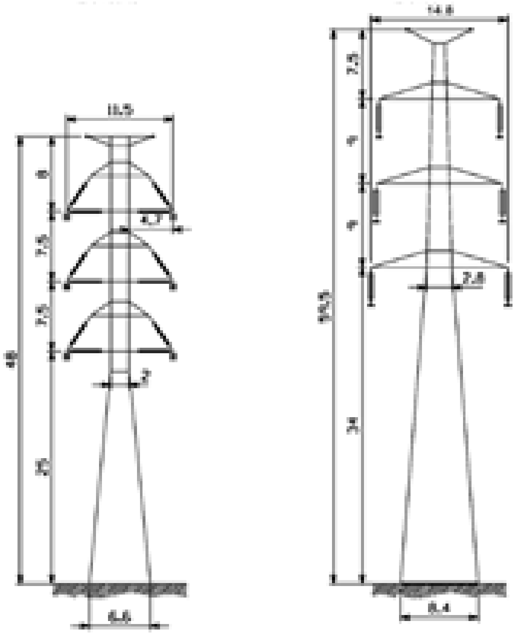
A standard 380 kV overhead line installation can achieve the technical requirements of the Future Grid 2030 project.

5.3.1 Maturity of technology

Overhead line is a mature technology which has remained largely unchanged for over 50 years.

There are variations to the standard steel lattice tower designs, for example the more compact insulated cross arm constructions (see Figure 4 and Figure 5) and folded steel structures which may be considered more visually pleasing (see Figure 6).

Figure 4: Compact (insulated cross arm) tower compared to a conventional tower



Source: Elia

Figure 5: Compact 380 kV tower

Source: Elia

Figure 6: 380 kV folded steel structure

Source: National Grid UK

5.3.2 Electrical impact on the grid

Overhead line has a low electrical impact on the system in which it is connected and hence will not have a significant adverse effect on the transmission grid.

5.3.3 System complexity

Overhead line is relatively simple in construction and operation.

5.3.4 Provision of future connections

It is straightforward to provide future connections to an existing AC overhead line via standard connection arrangements.

5.3.5 Availability and reliability

Overhead line is a robust technology and has high availability and reliability. For temporary faults the line is usually returned to service automatically within seconds of an incident with minimal disruption to customer supply. However, when damage leads to a sustained fault, automatic re-energisation will be unsuccessful, and the line must be taken out of service. Physical damage can be readily identified by visual inspection. Damage tends to be minor and can usually be repaired within a few days.

Table 4 shows 380 kV fault statistics for Nordic countries.

Table 4: 380 kV OHL fault statistics for Nordic countries

Country	Lines (km) in 2016	Number of faults in 2016	Number of faults per 100 km	
			2016	1996-2016
Denmark	1419	2	0.14	0.32
Finland	6086	7	0.12	0.25
Norway	3266	30	0.92	1.14
Sweden	10564	25	0.24	0.36

Source: ENTSO-E Nordic Grid Statistics 2016

Most overhead line faults are temporary. Typically less than 10% are categorised as ‘permanent’ and require immediate intervention to carry out repairs.

Due to the low electrical impact on the system, overhead line can be energised from a relatively weak system and provide feed into previously dead systems such as in a black start scenario.

5.3.6 Operation and maintenance

Planned maintenance activities of overhead lines include route patrols and inspection, vegetation management, tower painting, and other work needed to retain the serviceability of the overhead line.

Many maintenance inspections can be carried out without taking an outage, using helicopter inspection or remote inspection techniques using drones. These inspections are carried out every year or two depending on the owner’s policy.

Climbing inspections of overhead line towers are generally possible without an outage, provided the safety clearances to the live conductors are maintained.

When it comes to accessing the insulators or the conductor to carry out repairs, an outage is usually required. Some utilities adopt live line working using ‘hot stick’ or ‘bare hand’ methods to carry out repairs to insulators and conductors without an outage. This requires specialist equipment and training.

5.4 Overhead line environmental impact

Overhead lines are large linear developments that affect visual and other environmental aspects of the landscape they cross to varying degrees.

Routeing of new overhead lines needs to follow defined guidelines and rules to minimise the effect on the environment and includes consultation with stakeholders. The routeing of overhead lines is a complex process. A balance is required between statutory obligations, engineering requirements, economic viability, land use and the environment.

Overhead lines may not be suitable for some urban regions or areas of high environmental sensitivity. Underground cables are an alternative in some cases.

5.4.1 Land use

Overhead line routes may be required to cross agricultural, urban, industrial or environmentally sensitive areas.

Overhead lines do not prevent normal operations on agricultural land, however precautions may need to be taken with the use of some types of farming machinery.

The use of overhead lines in urban areas will lead to restrictions on future land use.

In industrial areas, overhead lines would not normally impose any significant land use issues.

Route planners must identify environmentally sensitive areas so that overhead lines can be routed away from these areas where possible.

5.4.2 Ecology

Ecological concerns include vegetation clearance and ground excavation works during construction, and bird mortality due to collision during operation.

Vegetation clearance includes the removal of trees and plants from the overhead line corridor and access roads. Clearing of line corridors should be done with special care to minimise damage to the original natural landscape and to allow the natural habitat under and around the lines to flourish. Ongoing vegetation management is required during operation.

Excavation works are required for construction of access tracks and foundations.

The use of bird flight diverters attached to conductors is effective in reducing the number of collisions.

5.4.3 Audible noise

Overhead lines are designed to minimise audible noise caused by electrical discharge and wind generated sound. Electrical discharge results in a crackle and low frequency hum and increases in some wet weather conditions.

5.4.4 Electric and magnetic fields

We are exposed to electric and magnetic fields wherever we live. Natural electric and magnetic fields include the earth's geomagnetic field and electric fields from storm clouds. Other sources include radio waves, TV signals and visible light.

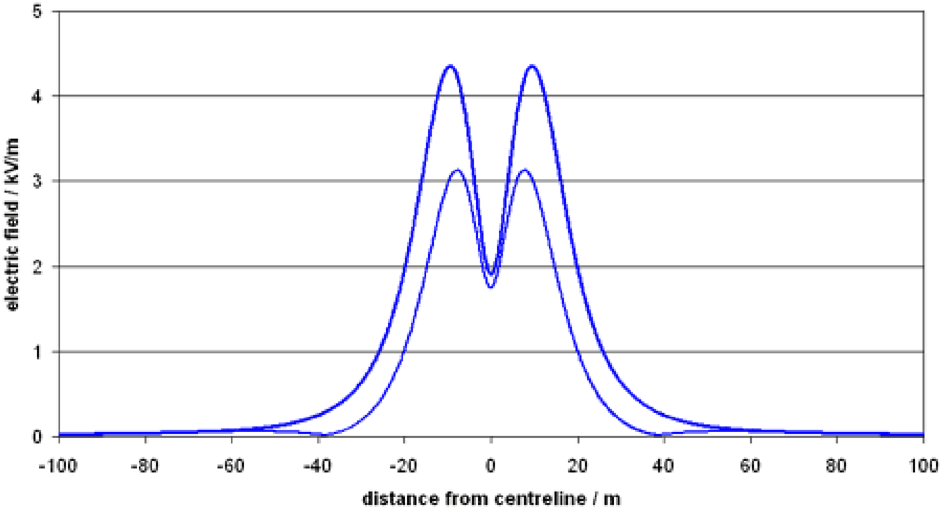
When electricity flows, both electric and magnetic fields are produced. The magnitude of the fields depends on a number of factors including the voltage, current, geometry and configuration of the line.

Overhead lines are a source of two fields – the electric field produced by the voltage and the magnetic field produced by the current.

The electric and magnetic fields from overhead lines and underground cables must comply with relevant exposure limits.

Figure 7 shows typical electric fields for two types of 380 kV vertical tower type overhead lines with transposed phasing

Figure 7: Typical electric fields for two 380 kV overhead line installations

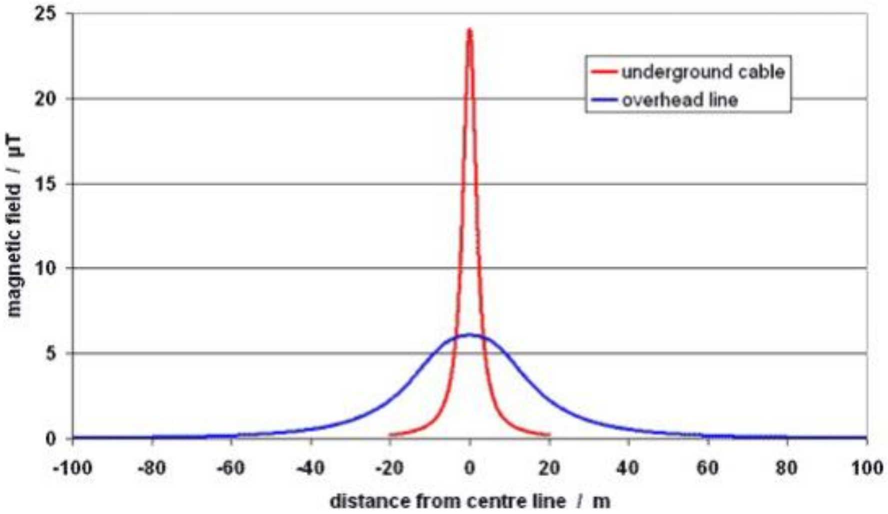


Source: http://www.emfs.info/

A metal sheath around underground cables eliminates the electric field, but cables still produce magnetic fields.

Figure 8 shows magnetic field against distance from equivalent overhead and underground circuits for a particular case.

Figure 8: Typical magnetic fields for a particular overhead line and the equivalent underground cable



Source: http://www.emfs.info/

As the source of a magnetic field is approached the field gets higher. Cables are typically installed 1 m below ground, whereas the conductors of a 380 kV overhead line are typically more than 10 m above ground. This means that the magnetic field directly above a cable is usually higher than that which is directly below the equivalent overhead line.

As individual cables can be installed much closer together than the conductors of an overhead line, the result is that the magnetic field from cables falls more quickly with distance than the magnetic field from overhead lines.

Overall, directly above the cable and for a small distance to the sides of the cable, the magnetic field is larger. At larger distances to the sides, the cable produces a lower field than the overhead line.

5.5 Overhead line planning, permitting and construction programme

A typical overhead line development, from concept to completion, takes several years. The development is an iterative process which has to consider both public amenity and engineering feasibility.

To develop a new power corridor, constraints are mapped between the start and end points and a preliminary route and design is identified. Stakeholders including land owners and the general public are then consulted which often leads to the modification of preliminary routes and changes to the design.

New overhead lines may face opposition from the public due to the visual impact of the line and other environmental concerns. It is likely that this opposition may add time to the planning and permitting process.

The environmental permitting process requires selection of the type of tower to be employed. Use of a new tower design may add time to the process. The use of an existing design of overhead line may therefore offer benefit to the overall programme.

Consent and land rights must be granted by land owners for equipment to be located within their land and for access for maintenance. Access is required periodically to each tower position to maintain the conductor and insulation systems, as well as the tower structure. Generally this access can be planned, however in some circumstances emergency intervention may be necessary to carry out repairs. Between towers, depending on the land use, periodic access may be required for tree cutting. Tree growth can lead to electrical clearances from the line conductors being compromised with the consequent risk of line failure, thus in forested areas regular tree felling must be carried out so as to maintain a clear corridor.

Fewer, taller towers can be used to increase the span length and thus reduce the disturbance to landowners. However, these structures must be designed to withstand the resulting additional conductor loads and are generally of heavier construction than a typical tower and, due to the additional height and strength, can be more visually intrusive. Planning authorities generally prefer lower structures whilst landowners generally prefer longer spans. The final design will always be a compromise.

5.6 Overhead line whole life cost

Many factors affect the cost of an overhead line, including its capacity and length, the tower design, the terrain and ground conditions along the route.

It is estimated that material costs represent approximately 65% of total line cost.

Overall construction costs include:

- Site mobilisation
- Foundations
- Tower materials
- Conductors, earth wires and communications
- Insulators and fittings
- Erection of towers and stringing
- Access roads
- Engineering and safety (including construction wayleaving and access permissions, site-based engineering, management, safety arrangements to protect contractors and the public)
- Project launch and management (early designs, application for consent, project management)

Operating costs include:

- Electrical losses in the conductor
- Operation and maintenance activities

A 2012 costing study[1] commissioned by the UK government calculated a whole life cost of 4.9 million EUR[2] per km for a 380 kV overhead line of the capacity and length required by the Future Grid 2030 project.

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[1] Electricity Transmission Costing Study, Parsons Brinckerhoff, 2012

[2] 4.0 million GBP converted to EUR using 2012 exchange rate of 1.233 EUR/GBP

Unit cost information produced by National Grid[3] in 2015 gives a cost of 2.7-3.5 million EUR[4] per km. This value does not include the cost of electrical losses and operation and maintenance activities.

5.7 Overhead line summary

High voltage overhead line technology provides a robust and cost-effective solution for transmission of large volumes of electricity over long distances.

An overhead line has a high level of availability and most faults can be located and repaired easily and quickly.

Overhead lines are a flexible technology that can be routed and constructed across a wide range of geophysical and topographical environments. They have a relatively low physical impact on the land.

Overhead lines may not be suitable for some urban regions or areas of high environmental sensitivity.

The main risks associated with an overhead line connection usually occur at the design stage where prudent design is required to ensure that the overhead line meets the expected reliability and performance requirements during its operational life. These include areas such as lightning performance, constructability, operability and maintainability.

Prior to and during construction, route access, ground conditions and the environmental risks are also major considerations.

During the lifetime of the overhead line it will experience faults due to the environment, third parties and wear and tear. Robust maintenance and inspection procedures minimise this risk. Catastrophic failures of overhead transmission lines can occur, but these are rare.

[3] Electricity Ten Year Statement, National Grid, 2015

[4] 2.0-2.6 million GBP converted to EUR using 2015 exchange rate of 1.359 EUR/GBP

6 AC Underground Cable

Underground cables play an important role in transmission grids by providing an alternative solution to overhead lines for transmitting electricity where overhead line cannot be used. Underground cables are most often installed in urban or environmentally sensitive areas.

As stated in section 5 of the report, 380 kV is considered the most appropriate AC operating voltage for the Future Grid 2030 power corridor to meet the required power transmission capacity.

380 kV underground cables make up less than 2% of the 380 kV AC land transmission systems in western Europe, with over 98% using overhead lines.

Table 5: 380 kV AC overhead and underground circuit lengths* in Western Europe

Country	Overhead Line (km)	Underground Cable (km)	% Cable
Belgium**	1,490	40	2.61%
Denmark	1,508	371	19.7%
Finland	4,331	0	0.00%
France	21,364	3	0.01%
Germany	20,307	70	0.34%
Ireland	439	0	0.00%
Italy	10,327	466	4.32%
Netherlands	2,091	30	1.41%
Norway	8,355	442	4.80%
Portugal	2,236	0	0.00%
Spain	19,622	55	0.28%
Sweden	10,708	8	0.07%
Switzerland	1,788	8	0.45%
UK	11,979	229	1.86%

Source: ENTSO-E Statistical Yearbook 2011

* ENTSO-E defines the above as “Lengths of circuits in km”.
** Updated to include Brabo and Stevin projects which were commissioned after 2011.

6.1 380 kV underground cable installation

To transmit 2 x 3 GW for a distance of 50-100 km via 380 kV underground cable would require two circuits, each with three cables per phase, or 18 cables in total.

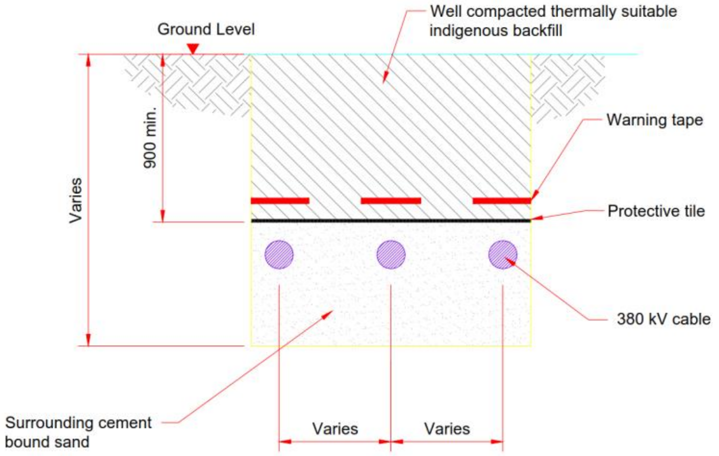
Various installation methods may be employed along the cable route. The installation methods would be determined following route selection and identification of obstructions. Most of the route is likely to be direct buried. Other installations may include surface troughs, ducts, horizontal directional drilling and deep bore or ‘cut and cover’ tunnels.

Typical installation and construction details for a 2 x 3 GW 380 kV direct buried underground cable development are given below.

Groups of three cables (one per phase) are laid in trenches excavated in the ground and surrounded with sand (or a sand/cement mixture) to improve heat transfer. Protection covers are placed above the cables and the trench is filled with excavated material, ensuring that topsoil is reinstated in the top layer.

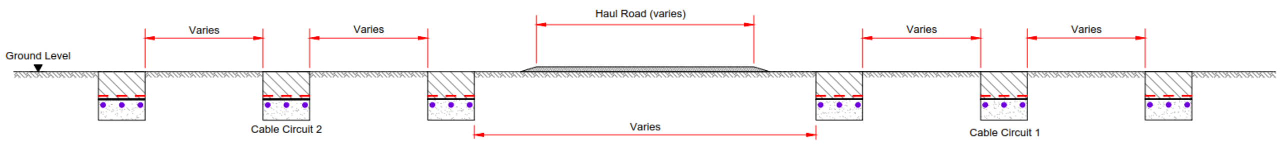
Communication cables are installed in the same trench as the power cables.

Figure 9: Indicative direct burial open trench arrangement



The installation would require six trenches to be excavated, three either side of a central road. A dedicated road is required to carry materials to and from site and to haul the cables.

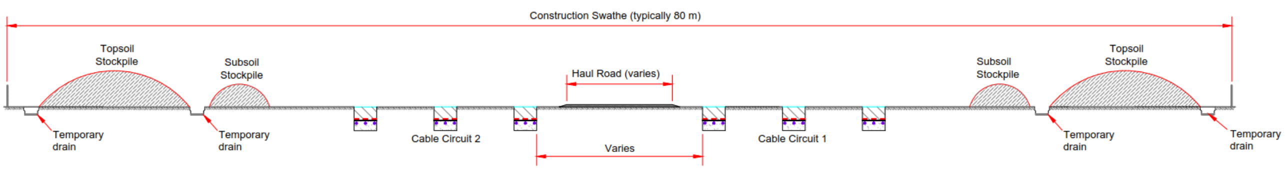
Figure 10: Indicative 2 x 3 GW 380 kV direct buried installation



Provision for construction activities further increases the corridor width. Sufficient space must be provided for the operation of excavation plant. Space for temporary placing of excavated material must be provided along the full length of the route.

For the period of construction activity this would result in a total corridor width of up to 80 m, with the completed installation width in the region of 30 m.

Figure 11: Indicative construction swathe



6.2 Underground cable safety

The main safety risk associated with buried cables is accidental contact by a third party, typically a contractor carrying out excavation works.

Cables are installed at varying depths depending on the land use and terrain. For example, cables installed in agricultural land are typically buried at 0.9 m depth to allow for the use of farm machinery above.

This risk of accidental contact is reduced by ensuring the position of the cable route is marked with warning tape and is recorded on record drawings. Tiles are installed above the cable to provide mechanical protection. The warning tapes and protective cover tiles act as a caution notice during excavations

The installation of underground cables requires the removal of large volumes of material which requires mechanical excavation. Excavations must be designed and managed carefully to ensure the safety of all personnel.

6.3 Underground cable technical performance

6.3.1 Maturity of technology

Modern underground cables use a high-performance insulating material called cross-linked polyethylene (XLPE).

XLPE cable technology has been used since the late 1990s so is a fairly mature technology with around 20 years of data.

6.3.2 Electrical effect on the grid

As a result of the extra insulation around a cable, AC cables hold and store some of the energy they carry. The longer the cable is, the more energy it holds. This effect is known as ‘capacitance’. Both overhead line and underground cable adds capacitance to the grid; however, due to the physical construction and installation of a cable the effect is much greater in underground cable systems.

Cable capacitance results in a constant flow of charging current proportional to the length of the cable and the voltage of the system. The ability of the cable circuit to transmit useful power is restricted due to capacity being used by the charging current and this charging current can also cause undesirable voltage changes on the transmission grid. The energy stored is proportional to the square of the operating voltage, therefore the impact of these currents is far more significant for 380kV cables than at lower voltages.

Due to these effects, long lengths of underground cable can cause technical issues and there are limitations on the maximum length of cable that can be practically installed in a transmission grid. The maximum length is dependent on the specific network and cable system parameters and will vary for each particular case.

When considering long underground cable systems, the following technical performance issues need to be considered at an early stage of planning and design.

6.3.2.1 Future upgrade of capacity

Increasing the capacity of an underground cable circuit is costly as it requires the installation of additional cables in the ground as well as the associated civil works. In comparison, for the upgrade of an overhead line, a conductor can be replaced with a larger size or different formation allowing the line to be in some cases reconfigured relatively easily.

6.3.2.2 Balancing of power flow

Underground cable circuits tend to carry a greater proportion of the power flow than a parallel overhead line. Additional equipment may need to be installed to control the imbalance. Special equipment such as reactors or phase shifting transformers can be used to manage the power flow through the parallel circuits.

6.3.2.3 System fault level

Installation of underground cable circuits may result in an increase in the transmission grid energy level, or fault level. When this happens, equipment on the grid may face energy levels beyond its safety threshold. This may require the installation of additional equipment to limit the energy level or the replacement of existing equipment affected by the change.

6.3.2.4 Reactive power compensation

As previously discussed, underground cable circuits have higher capacitance than equivalent overhead line circuits. To balance this effect, and to preserve the useful power capacity of the circuit, special equipment known as reactive compensation is sometimes required.

The requirement for reactive compensation is dependent on the electrical characteristics of the installation and the system into which it is being installed.

6.3.2.5 Voltage profile and temporary overvoltages

Reactive power generated by a cable system affects the voltage profile along it. Switching long cable circuits on and off can cause significant step changes in voltage. These step changes must be limited to reduce the disturbance to consumers. Reactive compensation is sometimes required to maintain the voltage within limits.

6.3.2.6 Harmonic distortion

An increase in the proportion of underground cable in a grid increases the risk of a power quality issue known as harmonic distortion. The resulting distortion of power may affect the quality of supply to customers.

The risk associated with this power quality issue is difficult to quantify. The level of distortion is difficult to study because it requires detailed information of the existing transmission grid and requires prediction of future network developments which may exacerbate the distortion effect.

Special equipment known as harmonic filters may be required to reduce the levels of distortion.

6.3.2.7 Switching of circuits

Capacitive charging currents which flow in cable circuits impose an onerous condition on circuit breakers which are used to switch the circuit on and off.

Care must be taken to ensure that the cable system does not cause conditions which exceed the rating of the circuit breakers and associated equipment.

6.3.2.8 Black start

Consideration must be given to the potential requirement to energise a relatively weak system via a long cable circuit, such as in a black start scenario. Due to the electrical impact of the cable on the transmission system this is likely to lead to a temporary overvoltage outside the allowable limits.

6.3.3 System complexity

The complexity of the cable system is largely dependent on the requirement for corrective equipment such as reactive compensation and harmonic filters, and the extent to which either is required.

Corrective equipment may not be required for short lengths of cable, or where cable is installed in very strong systems.

Where reactive compensation and/or filters are required, the most straightforward solution is to install the equipment at the substations at each end of the circuit.

For longer circuits the equipment may be required at the midpoints of the circuit, or at several locations along the route. Special compounds would be required to house the equipment.

For very long cable circuits, where large-scale midpoint compensation and filtering is required, the complexity of the system is significantly increased. Special control systems may also be required to control the equipment operation based on the real time status of the grid.

6.3.4 Provision of future connections

As with AC overhead lines, it is straightforward to provide future connections to an existing AC underground cable via standard connection arrangements.

6.3.5 Availability & reliability

In general, XLPE cable circuits are reliable and have a low rate of unplanned faults. However, there may be occasions where a circuit fails and requires repair. Cable fault repairs require the damage to be located, the faulted portion of the cable to be removed and a replacement section to be added (requiring new joints to be made). For 380 kV cable systems, repairs can be a costly and time-consuming exercise and can have a significant effect on circuit availability.

There are two main causes of cable faults:

- Failure of a component within the insulation system due to a manufacturing or installation defect
- Damage by a third party, typically a contractor carrying out excavation works in connection with another project

Cables can also be damaged by sustained electrical overloading, although cases occur infrequently.

The risk of these events occurring is not easy to control and the resilience of the transmission network can be affected.

Repairs to cable require excavations and clean and dry conditions for jointing. Wet weather may restrict access to the cable and affect cable repair times.

Operational performance data for installed cable systems is not widely available. Cable system failure statistics published were by CIGRE in 2009 and were updated by JICABLE in 2011 for 380 kV systems.

Table 6: Failure rates of cables and accessories

	CIGRE failure rate[5]	JICABLE Minimum failure rate[6]	JICABLE Maximum failure rate[2]
	Per 100 accessory years or 100 circuit km years	Per 100 accessory years or 100 circuit km years	Per 100 accessory years or 100 circuit km years
Cable	0.133	0.079	0.120
Joint	0.026	0.016	0.035
Termination	0.032	0.092	0.168

These figures are significantly lower than would be expected for a comparable overhead line, i.e. cables are less likely to suffer a failure. However, cable faults are rarely temporary and it takes longer to locate and repair a fault in an underground cable than in an overhead line. Repair duration for an on-land 380 kV cable is likely to be in the between two weeks and one month depending on the location of the fault.

A further point to note is that fault rates are expressed as per 100 accessory years or per 100 circuit km years, thus where a cable system requires multiple cores per phase the failure rates must be adjusted accordingly. For example, if a circuit is installed with three conductors per phase then the route km must be multiplied by three to obtain the appropriate circuit km figure. Similarly, the number of joints and terminations to be considered must also be multiplied by three to establish the failure rate to be considered.

6.3.6 Operation & maintenance

Planned maintenance of an underground cable route includes management of vegetation along the route and inspection and testing of cable system components.

6.4 Underground cable environmental impact

The installation of transmission cables has a significantly reduced visual impact when compared to overhead lines; however, underground cables have their own environmental and landscape considerations.

6.4.1 Land use

Where land is used for agricultural purposes, or open heathland and moorland habitats, there is not likely to be any significant restriction once restoration is complete.

The use of native backfill material allows shallow rooted vegetation to be re-established over the route and, in some cases, for land to be fully returned to its original condition and use.

The planting of trees above underground cables is not permitted due to the potential for deep root systems to cause cable damage.

Construction of buildings is not permitted above underground cables.

6.4.2 Ecology

As described in section 6.1, provision for construction activities can result in a corridor width of up to 80 m.

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[5] Update of service experience of HV underground and submarine cable systems, TB 379, Working Group B1.10, CIGRE 2009

[6] Return of experience of 380kV XLPE landcable failures, paper A.3.7, JICABLE, 2011

As with overhead line construction, ecological concerns include vegetation clearance and ground excavation works during construction. Cable installation works can cause significant effects on the landscape resulting from the felling of trees, hedges, areas of woodland and other vegetation along the route. The disruption of habitat is more intensive for underground cable installations than for overhead lines.

During construction, large quantities of earth and soils are removed to facilitate burial of the underground cables. This can be many times the quantity removed for an equivalent overhead line.

6.4.3 Electric and magnetic fields

See section 5.4.4 of the report for a consideration of electric and magnetic fields of AC overhead lines and underground cables.

6.5 Underground cable planning, permitting and construction programme

The duration of a typical underground cable development is similar to an overhead line development and takes several years.

Underground cable developments are likely to face less opposition from the public. However, gaining land owner consent and land rights may be more onerous than for an equivalent overhead line due to the more extensive vegetation clearance and ground excavation works which are required along the full length of the cable route during construction. In comparison, access is required predominantly at tower locations for an overhead line. Furthermore, it may not be straightforward to amend the routing of a cable to accommodate landowner preferences, thus potentially making agreement more difficult.

Due to the electrical effects of installing long lengths of 380 kV cable (outlined in section 6.3.2) it is likely that extensive studies and simulations would be required to confirm the feasibility or otherwise of a cable installation, and to carry out a detailed engineering design. This process would need to be completed before the commencement of the permitting process and would add time to the pre-contract engineering programme.

Undergrounding of the Elia power corridor would require 18 km of single phase 380 kV underground cable per km of route. Procurement of the quantity of cable required for undergrounding a significant length of the route would therefore present a significant risk. Securing the services of the number of skilled cable jointing technicians required to install a significant length of underground cable would also present a risk to the project.

6.6 Underground cable whole life cost

The cost of operation, maintenance and power losses over the lifetime of an AC transmission circuit is broadly the same for overhead lines and underground cables.

Underground cables are always significantly more expensive to construct when compared to equivalent overhead lines.

The major elements of this cost differential are due to the relatively higher cost of the cable itself and the cost of the civil works required to install the cables in the ground.

Many factors affect the cost of an underground cable installation, including the capacity and length of the circuit, the terrain, land use and ground conditions along the route and natural and man-made obstructions.

Overall construction costs include:

- Cable terminal compounds (supply and erection of a cable sealing end compound at each end of the route)
- Cable terminations and testing (supply, erection and testing of outdoor terminations within the compounds at either end of the route)
- Cable system materials (all cables, joints, earthing and bonding equipment)
- Cable installation
- Reactive compensation
- Harmonic filters
- Project launch and management (routing surveys, soil samples, predesign/route feasibility, publicity, notifications, stakeholder consultation, land access and easement purchasing negotiations, on site supervision, site engineers)

Operating costs include:

- Electrical losses in the conductor
- Operation and maintenance activities

A 2012 costing study[7] commissioned by the UK government calculated a lifetime cost of 25.1 million EUR[8] per km for a 380 kV underground cable of the capacity and length required by the Future Grid 2030 project. This is approximately five times the cost of an equivalent overhead line.

Unit cost information produced by National Grid [9] in 2015 gives a cost per km of 7.3-8.9 million EUR[10] for supply and 4.7-7.7 million EUR[11] for installation, or 12.0-16.6 million EUR per km total. This estimate does not include the cost of electrical losses and operation and maintenance activities or the reactive compensation and harmonic filtering which would be required to install long lengths of underground cable as required by the Future Grid 2030 project, and thus underestimates the total project cost. Based on a dielectric capacitance of 0.23 µF per cable per km, the project would require approximately 67 MVAr of reactive compensation per km for full compensation of the cable capacitance. Assuming a cost of 6 million EUR per 200 MVAr reactor gives an additional cost of close to 2 million EUR per km for reactive compensation. The cost of harmonic filtering would be in addition to this.

6.7 Underground cable summary

Underground cables offer a reduced visual impact when compared to overhead lines and may therefore be suitable for environmentally sensitive areas. In some cases, underground cables are the only feasible solution, for example through urban areas; however, 380 kV cable installation requires a wide corridor and can lead to a significant and permanent effect on the landscape and significant disruption during construction.

There are a number of technical challenges in connecting long lengths of cable in transmission grids. Many of these challenges can be overcome through the installation and control of additional equipment, such as reactive compensation and harmonic filters. The introduction of

[7] Electricity Transmission Costing Study, Parsons Brinckerhoff, 2012

[8] 20.4 million GBP converted to EUR using 2012 exchange rate of 1.233 EUR/GBP

[9] Electricity Ten Year Statement, National Grid, 2015

[10] ((0.896-1.095) x 6) million GBP converted to EUR using 2015 exchange rate of 1.359 EUR/GBP

[11] ((0.58-0.95) x 6) million GBP converted to EUR using 2015 exchange rate of 1.359 EUR/GBP

this equipment, however, leads to increased system complexity, risk of reduced availability and increased cost.

The increase of harmonic distortion resulting from the installation of cable is difficult to quantify and therefore presents a significant risk.

Procurement of the quantity of cable and skilled cable jointing resource required for undergrounding an extensive proportion of the route would present a significant risk.

An underground cable solution would be significantly more expensive than an equivalent overhead line.

Undergrounding of the full length of the Stevin-Avelgem and Avelgem-Centre corridors is therefore not considered a feasible solution.

7 Partially Undergrounded AC Overhead Line

As discussed in section 6, there are a number of technical performance, programme, procurement and resource issues associated with very long 380 kV underground cable systems. Total undergrounding of the Stevin-Avelgem and Avelgem-Centre corridors is therefore not considered a feasible solution.

The term partial undergrounding refers to an overhead line circuit where a short section or sections are undergrounded. Partial undergrounding is technically feasible and could be considered in specific areas that would be significantly affected by construction of an overhead line.

Refer to sections 5 and 6 for discussion of overhead line and underground cable safety, technical performance, environmental impact, planning, permitting and construction programme, and whole life cost which would apply to a partially undergrounded solution.

Determination of the maximum length of underground cable that would be technically feasible requires studies and simulations. It is therefore not possible to state the maximum allowable length of partial undergrounding at this stage. A recent international study[12] considering a specific case in the Danish transmission grid concluded that the maximum length of 380 kV underground cable in the overhead line circuit must not exceed 15% of the total circuit length. The Danish cable design was for two cables per phase and was therefore less onerous than the Future Grid 2030 project in that respect. As stated in section 6.3.2, the maximum length for a particular case will vary based on the specific network and cable system parameters.

Gas insulated line is discussed in section 8.1. While experience of gas insulated line over long distances is not available, the use of gas insulated line for undergrounding short sections of a partially undergrounded solution (particularly where one end is terminated in a substation) would be technically feasible and could be considered.

Where overhead line transitions to cable, the overhead line is terminated at each end of the underground cable section. A large compound is required to accommodate the cable terminals together with other equipment required to facilitate the connection between the overhead and underground systems. A typical 380 kV cable terminal compound is 45 m x 65 m.

[12] Technical Issues Related to New Transmission Lines in Denmark, Energinet, Doc. 18/04246-24

8 Alternative Underground Technologies

8.1 Gas insulated line

In some cases, gas insulated line represents a viable alternative to overhead lines and underground cables. Most applications of gas insulated line have been over short distances and are installed above ground in areas with no public access such as power plants or substations.

Gas insulated lines can be installed above ground, buried below ground or installed in trench or tunnel installations and are thus an alternative to conventional cables. In comparison with cables, they offer the following advantages:

- Lower electrical losses
- Higher power ratings per ‘cable’, potentially reducing the width of the power corridor.
- Energy storage in the internal capacitance is much lower than an equivalent cable, thus much longer lengths can be applied before system technical limits are exceeded (also helped by the reduced number of ‘cables’ required).
- Risk of harmonic amplification are significantly reduced.

However, there are no gas insulated line projects with significant route lengths in service or under construction, with a maximum installed route length of approximately 3.25 km (the Japanese Shinmeika – Tokai project).

The most extensive installation of buried gas insulated line is a 380 kV installation at Frankfurt Airport in Germany which comprises two circuits, each with a route length of 900 m and a power rating of 1800 MVA.

Although technically capable of providing a transmission capacity of 3GW per circuit, experience of gas insulated line over long distances is not available. As such, a 100 km route length may face previously un-encountered technical and construction challenges. The technology is therefore not considered sufficiently mature to be deployed as part of a critical grid reinforcement project and therefore long-distance gas insulated is not considered further in this report.

The use of gas insulated line for undergrounding short sections of a partially undergrounded solution would be technically feasible and could be considered.

The 2012 costing study[13] commissioned by the UK government calculated a lifetime cost of approximately 20.0 million EUR[14] per km for short lengths of direct buried gas insulated line, although this estimate is for a smaller capacity than is required for the Future Grid 2030 project.

8.2 Superconducting cable

The resistance to the flow of electricity in a conductor increases with temperature. If a conductor is cooled the resistance falls. If a copper conductor is cooled to near absolute zero (-273 ºC), the electrical resistance falls close to zero. This means that high currents can flow without generating any significant electrical resistive losses, and the requirement to

[13] Electricity Transmission Costing Study, Parsons Brinckerhoff, 2012

[14] 16.2 million GBP converted to EUR using 2012 exchange rate of 1.233 EUR/GBP

dissipate the heat generated by these losses is virtually eliminated. This condition of virtually lossless transmission is generally described as 'superconductivity'.

It is not practical to maintain the temperature of a cable close to absolute zero, and for many years researchers have been developing high-temperature superconducting materials that can provide very low levels of resistance at viable temperatures. The construction of a superconducting cable is similar to that of a conventional cable, but copper or aluminium wires are replaced by tapes manufactured from these high-temperature superconductor materials for the current transport. The superconducting tapes consist of a metallic substrate and an oxide ceramic material which displays virtually perfect electricity conducting properties if cooled to temperatures below -180 °C. A superconducting tape of this kind can transmit current densities that more than a hundred times exceed the current carrying capacity of a copper conductor of the same cross section. The conductors are sheathed with low temperature proof high voltage insulation and surrounded by a superconducting screen which provides electromagnetic shielding. Liquid nitrogen cools the cable core to its operating temperature of approximately -200 °C.

Maintaining an electrical transmission system at such a low temperature requires special cryogenic plant which is challenging to operate and maintain and would add significantly to the complexity of a cable system.

Advances in the application of high-temperature superconductors to cables has allowed the construction of some short length pilot projects. One of the most significant is the 'AmpaCity' project in Essen, which provides a 1 km cable system rated to carry 40 MVA (2310 A) at 10 kV. These pilots fall far short of the circuit length & power capacity required for the Elia future grid project.

Whilst superconducting technology is still in development and, although there are a number of small-scale trials in distribution networks, it is still some way from implementation in an operational transmission grid. The technology is therefore not considered further in the report.

9 HVDC as an alternative to HVAC

The existing grid in Belgium is a high voltage alternating current (HVAC) system. Any new transmission project utilising HVAC would therefore be an extension of the existing technology.

HVDC offers technical advantages when compared to HVAC for the following cases:

1. Transmission between power systems which are not synchronised
2. Very long distances high power transmission
3. Use of subsea cables, or facilitation of the undergrounding of a transmission circuit
4. Where complete and variable control of power flow is required, i.e. for interconnection between grids

9.1 HVDC configuration

In general, the converter used for HVDC transmission can be classified as current source or voltage source.

The most recent regulations covering new HVDC systems in Europe demand smooth voltage control. Consequently, all new HVDC interconnectors in Europe are expected to be voltage source converter (VSC) type. Only VSC technology will be considered in the report.

In the context of the Future Grid 2030 project, the use of HVDC would only be considered to facilitate undergrounding the full length of the power corridor. Hence only HVDC underground cable will be considered.

HVDC systems can be configured in three ways:

- Point-to-point configuration
- Back-to-back configuration
- Multi-terminal configuration

9.1.1.1 Point-to-point configuration

Most HVDC systems are point-to-point configuration. Power is transmitted between two points in a HVAC grid. Almost all installed HVDC interconnectors have only two terminals.

9.1.1.2 Back-to-back configuration

HVDC with back-to-back configuration has two converters located at the same site in a single building and there is no overhead DC line or underground DC cable. Back-to back schemes are generally used for connection of HVAC systems operating at different frequencies or for connecting unsynchronised systems. This configuration is not suitable for the proposed power corridor and is not considered further in the report.

9.1.1.3 Multi-terminal configuration

HVDC with multi-terminal configuration has more than two terminals.

9.2 HVDC topology

HVDC topologies include:

- Monopolar
- Bipolar
- Symmetrical monopolar

Most installed VSC HVDC systems around the world are symmetrical monopolar. This topology is designed to operate with a total transmission voltage double the line-earth voltage rating of the lines or cables. For example, for a line-earth capability of 500 kV the transmission voltage is 1000 kV since one line is operated at +500 kV and the other at -500 kV.

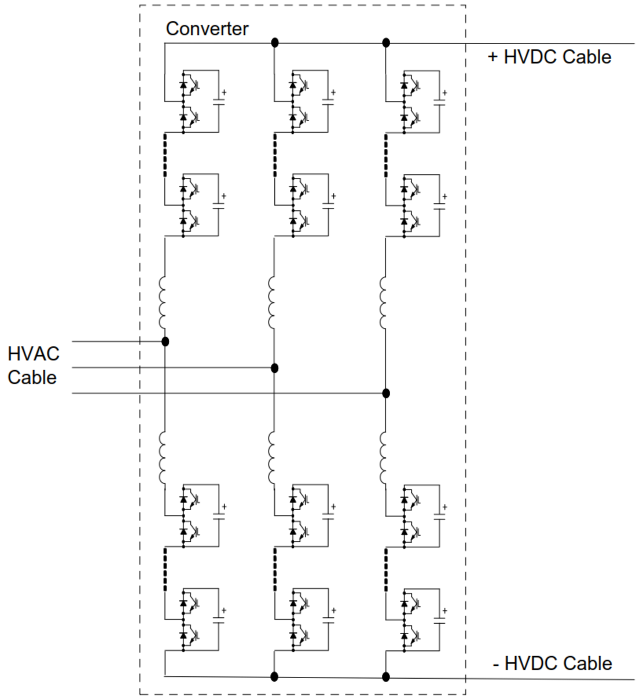
A monopolar topology only operates with one line at high voltage (the return line is at earth potential). Thus for a line-earth capability of 500 kV, the transmission voltage is limited to 500 kV. In some circumstances it is possible to construct monopolar links using the ground or sea as the return conductor; there are a number of technical limitations associated with links of this type and they are not considered suitable for application in developed areas.

A bipolar topology adds some additional technical complexity (in comparison with a symmetrical monopolar design) but provide a level of redundancy in the event of equipment failure. In view of the power ratings required for the Elia future power grid, the benefits of this additional redundancy may not justify the greater technical complexity.

Only symmetrical monopolar topology will be discussed in the report (although adoption of a bipolar topology would only impact on the converter station design).

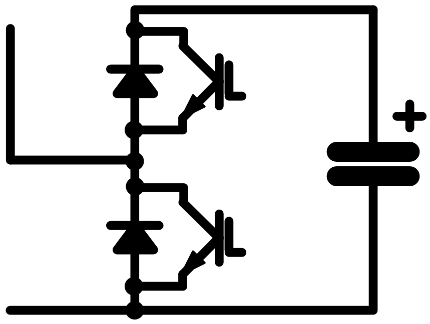
The current generation of high-power VSC converters are based on a multilevel design, as shown in Figure 12.

Figure 12: Symmetrical monopolar VSC modular multilevel converter



Each arm of modular multilevel converter consists of many units (submodules or cells) shown in Figure 13 below:

Figure 13: Modular multilevel converter unit



Each unit can be controlled independently. The DC voltage is selected by controlling the number of units switched into the circuit.

9.3 HVDC installation

To meet the 6 GW capacity required by the Future Grid 2030 power corridor the highest available proven DC voltage is likely to be selected. Today there are two HVDC links rated at 500 kV under construction with others being considered. It is likely that this technology will be proven in time for consideration for the Future Grid 2030 project.

The largest power rating of a single symmetrical monopole in service is 1 GW but higher ratings are under construction. Two 500 kV schemes under construction are rated at 1400 MW and expected to go into service in the next year or so. This maximum power limit is determined by the maximum permitted single circuit failure in Scandinavia, not by the HVDC technology. Suppliers are currently quoting single interconnector ratings of up to 2 GW.

The Future Grid 2030 project requires an overall redundancy in connections so that at least 3 GW can be achieved with one HVDC link out of service.

The 6 GW capacity can therefore be achieved by either 4 x 1.5 GW or 3 x 2 GW links operating at 500 kV DC.

It has been reported that VSC Converters with a capacity of up to 5 GW at 800 kV (equivalent to 3 GW at 500 kV) are under construction in China. These higher ratings have been discounted due to the limited range of Suppliers able to achieve this capacity.

9.3.1 HVDC converter station

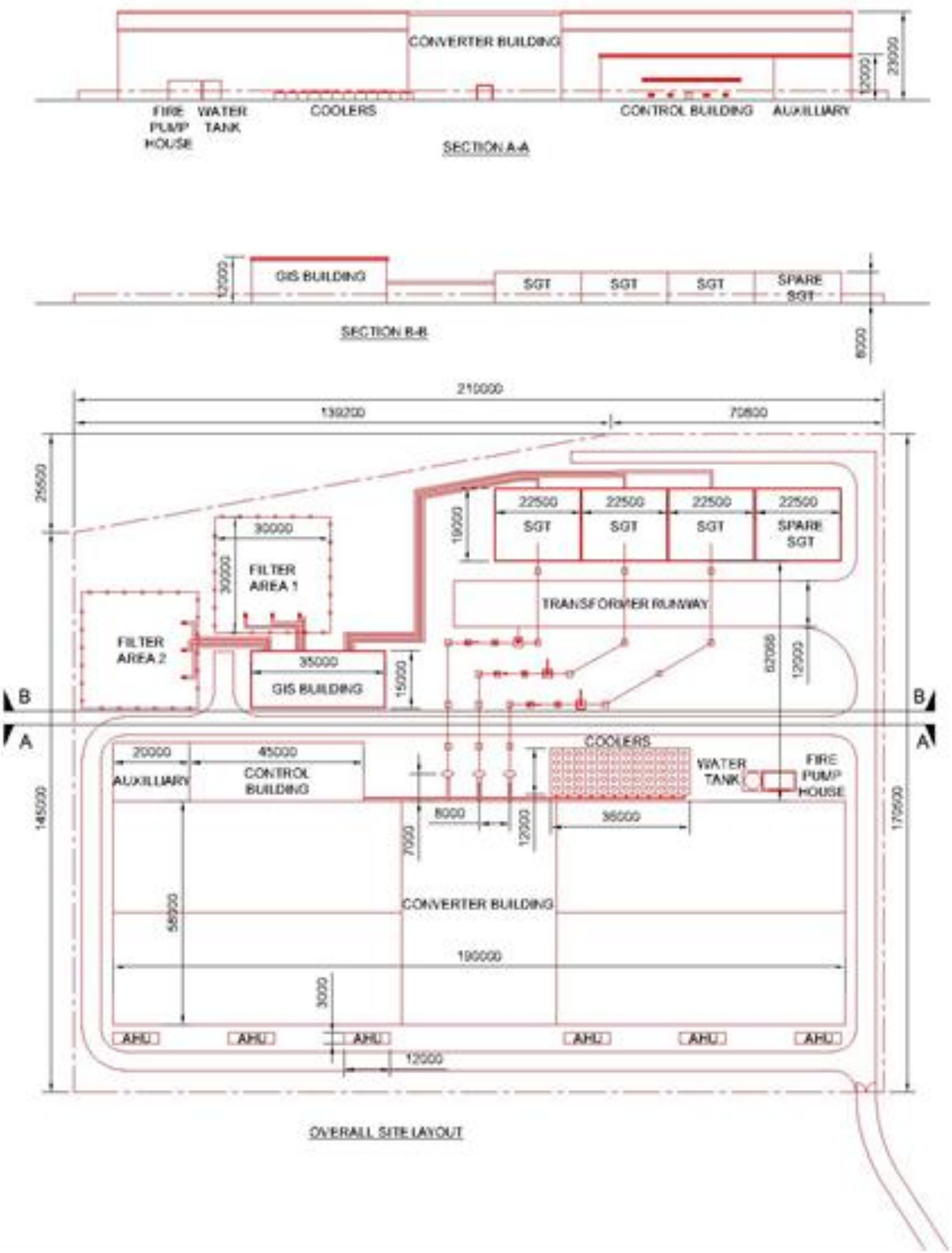
The design of an HVDC converter station is project specific and is determined by individual scheme requirements.

There are several suppliers of VSC HVDC systems each with their own converter station designs but each design is based on the same fundamental principles.

The DC operational voltage is the dominant factor in determining the converter station size and cost. All electrical equipment with exposed live parts require a safe distance to other objects. The distance increases with voltage and can be several metres, hence the higher the voltage the larger the footprint. The converter valves are constructed of modules each with a maximum voltage rating; the higher the total voltage, the more modules are required. Modules are stacked vertically so the height also increases with voltage.

A single 500 kV DC converter station would be approximately 210 m by 175 m. Buildings would cover approximately 50% of the land with a maximum height of approximately 23 m. These dimensions would vary based on land and access issues and supplier variations.

Figure 14: Indicative 500 kV HVDC converter station layout



The main components are introduced below.

9.3.1.1 AC switchgear and converter transformer area

AC switchgear and converter transformers control and transform the AC power.

AC switchgear may be air or gas insulated. Air insulated switchgear is cheaper but requires a larger area. Gas insulated switchgear is more compact, so the footprint of the converter station is reduced.

As gas insulated switchgear is more expensive it is largely used in projects which have a requirement to minimise footprint or reduce visual impact.

9.3.1.2 Filter area

Harmonic filters may be required to reduce harmonic distortion and ensure the HVDC system does not adversely affect other transmission grid users and stakeholders. The requirement for filtering varies. In some cases, where limited filtering is required the equipment may be included within the converter buildings. Larger filters may require large outdoor compounds. The filters are controlled by switchgear, hence increased numbers of filters add to the AC switchgear requirements.

9.3.1.3 Reactor hall

AC reactors are commonly added in series with VSC converter transformer on the converter side. The main function of the reactors is reducing DC energy levels (fault current and peak switching current) in the system. Reactors are usually located indoors adjacent to the converter valve halls. This limits the magnetic field and audible noise impact.

9.3.1.4 Valve hall and DC area

Power electronic converter modules and DC components are in this area. The converter valves are built of many modules connected together which convert AC to DC at the sending end and DC to AC at the receiving end. The number of modules depends on the DC operating voltage plus the number of additional modules required to provide redundancy and hence improved availability and reliability. DC components include reactors, devices for measuring current and voltage used for protection and control, surge arresters which are used to protect the converters from excessive voltage, DC cable terminations and switchgear for isolating and making safe the systems to allow maintenance.

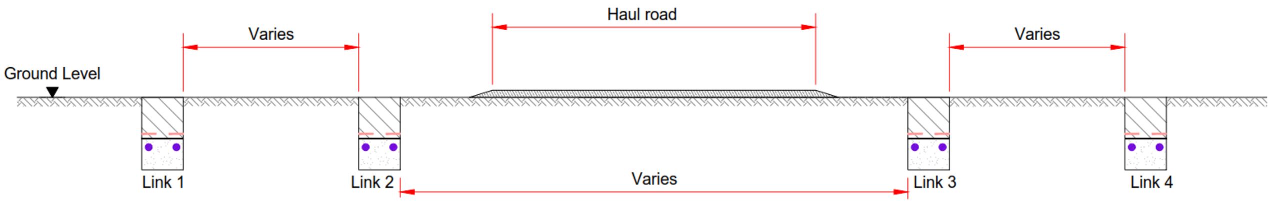
9.3.1.5 Other rooms and buildings

In addition to the major areas described above, a converter station requires several other smaller areas most of which can be included within the large building housing the valve hall. These include rooms for control, protection and communications equipment, a control room for operators, auxiliary supplies including batteries and battery chargers, air conditioning equipment, converter valves cooling plant, fire fighting systems, store rooms and domestic services.

9.3.2 HVDC underground cable installation

To transmit 4 x 1.5 GW via 500 kV DC underground cable would require four HVDC links, each with two cables per link, or 8 cables in total.

Figure 15: Indicative 4 x 1.5 GW 500 kV DC direct buried installation with two cables per link



To transmit 3 x 2 GW via 500 kV DC underground cable would require three HVDC links. Two cables per link could achieve the required rating in a standard direct buried installation but four cables per link may be required depending on the route specifics, including obstructions faced along the route.

Figure 16: Indicative 3 x 2 GW 500 kV DC direct buried installation with two cables per link

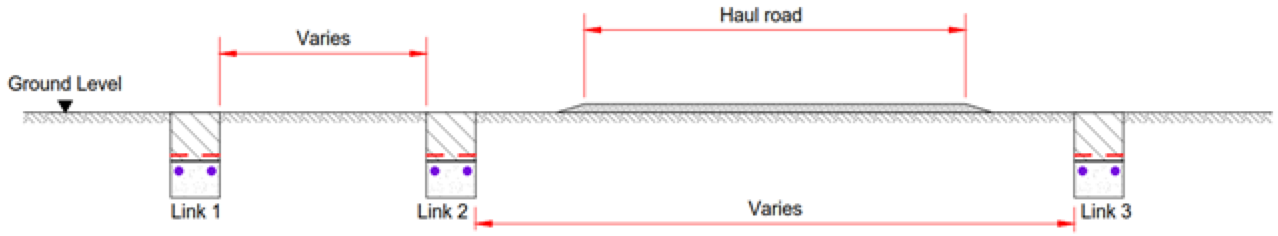
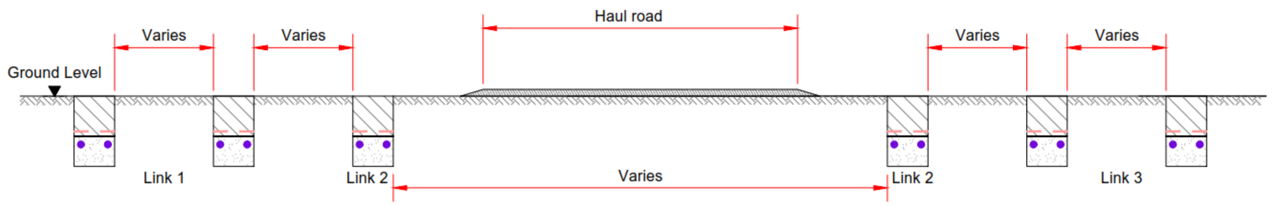


Figure 17: Indicative 3 x 2 GW 500 kV DC direct buried installation with four cables per link



9.4 HVDC safety

HVDC technology can comply with all relevant safety standards. Safety issues in relation to DC overhead and underground installations are similar to the AC equivalents and are discussed in sections 5.2 and 6.2 of the report.

9.5 HVDC technical performance

9.5.1 Maturity of technology

VSC technology has more than 20 years' service history and is therefore considered to be a proven technology. It is noted that the service history does not include experience of 500 kV and 2000 A VSC operation. Based on experience to date there is confidence that planning for operation at this voltage and current rating would not present a significant risk.

9.5.2 Electrical effect on the grid

The maximum length of AC underground cable is limited for the reasons described in section 5.3.2. DC underground cable does not suffer the same technical performance issues as AC cable. Thus, in the context of the Future Grid 2030 project, the use of HVDC would facilitate undergrounding the full length of the power corridor.

However HVDC converters can present other operational problems.

The manner in which power electronic systems interact with the AC transmission network is inherently non-linear, thus converters can generate harmonic distortion. This is a particular issue with thyristor controlled LCC converters which require extensive provision of harmonic filters. On the other hand, modern VSC converters are designed to limit their harmonic contribution and may not require any mitigation measures.

HVDC converters require complex control systems which may interact dynamically with other network equipment. These may represent a performance risk to the system, although these risks can generally be mitigated by carrying out comprehensive electrical studies at the design stage.

In operation, HVDC converters interact with the AC network through software algorithims and thus do not perform in the same way as conventional AC plant which responds to network disturbances in real time by virtue of physical laws. Whilst the controls have been developed to replicate, as far as possible, the desired characteristics of an AC network, they can be considered as adding some degree of fragility to the network performance.

Voltage source converters can operate in weak systems and provide feed into previously dead systems such as in a black start scenario.

9.5.3 System complexity, availability and reliability

Guarantees on reliability and availability are given by suppliers. Owners monitor operations to confirm the guarantees are achieved. Where guarantees are not achieved suppliers are required to improve their systems and pay penalties.

HVDC systems are complex with many sub-systems and components. The greater the complexity and component count, the greater the risk of failure. Operators of transmission grids demand very high reliability. Redundancy is built in to allow the converter station to continue normal operation during and after a fault occurs, thereby providing improved availability and reliability.

Control and protection systems are perhaps the most complex sub-systems within a converter station and are therefore the most likely to develop faults. They too can be duplicated so that in the event of a failure the standby system comes immediately and seamlessly into service. The faulty system can then be repaired, often without need for an outage. They are rigorously factory tested, however, the software in the main and backup systems are identical hence in the event of a software fault both systems would fail at the same time.

VSC converter modules are also complex with a significant component failure rate. Redundancy in the converters is provided via the installation of extra modules so that in the event of failures the overall converters continue to operate until a scheduled outage when the faulty modules can be replaced. These faulty modules can then be repaired ‘off-line’ and retained as spares.

Valve and transformer cooling systems have a risk of failure particularly as they include most of the few moving parts in a converter station. Again, redundancy is built into these systems such as standby pumps and fans. Most failures can be repaired without need for outages.

Auxiliary power supplies are duplicated and taken from more than one source. This may include emergency diesel generators or taking power from the converter transformers, so that loss of the local distribution supplies does not lead to an unplanned outage.

For details of underground cable reliability see section 5.3.5 of the report.

9.5.4 Provision of future connections

To provide future connections to the HVDC link, the original point-to-point scheme would need to be extended to create a multi-terminal scheme. Adopting a multi-terminal HVDC solution increases the technical risk when compared to an AC solution where providing additional connections is routine.

Each terminal of a multi-terminal scheme would require a converter station. This would add significant cost to each new connection.

9.5.5 Operation and maintenance

For the multiple connections required for the Future Grid 2030 Power Corridor it is likely that a single operation centre would be required to be manned 24/7.

Some routine maintenance can be carried out at any convenient time without need for outages whilst other work requires access to areas not possible whilst the interconnector is in service. Maintenance staff are not required to be present at the converter stations 24/7 but, if availability is to be optimised, technicians should be on call to provide technical support to the operating team. These technicians would carry out the routine maintenance during normal office hours. Each of the links would undergo scheduled maintenance when the others are fully available. It is normal to outsource scheduled maintenance activities. Some of this work is specialised but there are also cleaning tasks of lesser skill levels.

HVDC requires greater operational resource than an equivalent AC development due to the relatively higher complexity of the converter stations.

9.6 HVDC environmental impact

As discussed above, the use of HVDC would only be considered to facilitate undergrounding the full length of the power corridor. This may be required for environmental or social reasons. See section 6.4 of the report for discussion on the environmental impact, land, planning, consents and rights issues of underground cables.

An HVDC underground cable installation would result in a narrower corridor, with fewer cables and reduced excavation, hence a lesser environmental impact than an AC cable installation.

HVDC converter stations are significantly larger than conventional AC substations and therefore increase the visual impact of an HVDC solution at the terminal points.

9.7 HVDC planning, permitting and construction programme

Starting at the date when a decision to use HVDC technology is confirmed, a programme to put the scheme into service would include:

- Owners system studies, data collection, preparation and issuing of specifications for converter stations and cables: 1 year
- Supplier bidding, bids review, placement of orders: 1 year
- Supply of first pair of converter stations (2 GW), cables and commissioning: 3-3.5 years
- Supply of each subsequent pair of converter stations 1 year

9.8 HVDC whole life cost

The 6 GW capacity is likely to be provided by either 4 x 1.5 GW or 3 x 2 GW at 500 kV DC. The cost and size of a converter station is dependent on the rated DC voltage, with only a small variation due to power capacity.

Overall construction costs include:

- Converter project launch and management
- Converter engineer, procure, construct contract cost
- Cable terminal compounds (supply and erection of a cable sealing end compound at each end of the route)
- Cable terminations and testing (supply, erection and testing of outdoor terminations within the compounds at either end of the route)
- Cable system materials (all cables, joints, earthing and bonding equipment)
- Cable installation

Operating costs include:

- Electrical losses in the converters
- Electrical losses in the cables
- Operation and maintenance activities
- Converter refurbishment and replacement parts following failures
- Loss of income due to failures in the links
- Insurance costs
- Replacement of major systems due to age and obsolescence

A 2012 costing study[15] commissioned by the UK government calculated a lifetime cost of approximately 700 million EUR[16] for the converter stations at each end of a 1-1.5 GW link.

Unit cost information produced by National Grid [17] in 2015 gives a cost of 285-307 million EUR[18] per converter, or 570-614 million EUR for converter stations at each end of the link.

Recent discussions with suppliers suggests that prices have fallen (as would be expected due to the wider application of the technology), with estimates for 500 kV HVDC in the region of 500 million EUR for the converter stations at each end of a 1.5 GW interconnector and 600 million EUR for the converter stations at each end of a 2 GW interconnector.

The cost of the DC cables is likely to be somewhat reduced from the 25.1 million EUR per km estimated for a 380 kV AC underground cable due to the reduced number of cables and

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[15] Electricity Transmission Costing Study, Parsons Brinckerhoff, 2012
[16] 565 million GBP converted to EUR using 2012 exchange rate of 1.233 EUR/GBP
[17] Electricity Ten Year Statement 2015, National Grid, 2015
[18] 210-226 million GBP converted to EUR using 2015 exchange rate of 1.359 EUR/GBP

associated civil installation works and the elimination of the requirement for reactive compensation and harmonic filtering along the route.

Unit cost information produced by National Grid in 2015 gives a cost per pair of DC cables per km of 0.95-1.2 million EUR[19] for supply and 0.54-0.88 million EUR[20] for installation, or 1.5-2.1 million EUR per pair of cables per km total (i.e. 4.5 – 8.4 million EUR per km for a 6GW power corridor). This estimate does not include the cost of electrical losses and operation and maintenance activities.

500 kV DC cable is not widely available and the cable material cost may vary significantly depending on market conditions.

It can be assumed that at each converter station approximately 1% of the transmitted power is lost within the station. This includes not only energy lost as heat within the major components, converter valves, transformers, reactors etc but also auxiliary power used for cooling systems, protection & control systems and other secondary systems. In addition, losses of around 1% per 100km of cable can be expected.

As part of the initial purchase spare parts would be provided based on calculated failure rates and to cover an initial period, typically 5 years. Major items as spares would also be purchased at this time, particularly transformers, reactors and converter modules. These costs are included in the initial capital costs. Subsequent spare parts purchases are often reassessed after a few years' experience but an allowance of 0.1% of initial capital cost per year should be adequate.

It is normal to purchase an HVDC link with a life expectancy of 30-40 years. Typically, the HVDC control and protection system is considered obsolete after about 20 years and a replacement programme is carried out. This not only incurs capital cost but also an outage of two months or so is required to install and commission the new system. A new control and protection system for both ends of an interconnector could cost in the region of 20 million EUR.

It is difficult to assess if a replacement set of converter valves would be required in the first 30 years. This would be dependent on the reliability and availability of spare parts but also in that time new technology offering improved efficiency and/or reliability might make a refurbishment cost effective.

9.9 HVDC summary

HVDC can facilitate the undergrounding of long circuits where the maximum length of AC underground cable is limited. It is technically feasible to utilise HVDC technology to underground the full length of the Future Grid 2030 power corridor.

The additional cost of HVDC would be significant and HVDC technology would not offer the operational flexibility and resilience of an HVAC solution.

An HVDC solution offers several technical risks and disadvantages when compared to a HVAC equivalent.

New connections can more easily be provided using an AC circuit. Future connections to a HVDC link are possible, but each new connection along the route would require a converter station and hence large capital cost.

[19] (0.70-0.85) million GBP converted to EUR using 2015 exchange rate of 1.359 EUR/GBP

[20] (0.40-0.65) million GBP converted to EUR using 2015 exchange rate of 1.359 EUR/GBP

Control systems for multi-terminal HVDC are complex and there are technical risks of low reliability and availability of a multi-terminal HVDC link.

Significant land area is required for converter stations at each terminal point.

A typical HVDC system requires at least four years to bring it into service. In this case, with more than one interconnector required, it would probably take a further year or more before the full scheme is operational.

There are two main options to achieve 6 GW capability; 4 × 1.5 GW or 3 × 2 GW links. Currently 1.5 GW is a normal rating for s single system VSC project. This can be achieved by several suppliers. Due to the cable voltage limit and the current limit of power electronic modules, 2 GW for one system is less easy to achieve and there are currently no VSC links of this capacity in operation. A 3 × 2 GW system therefore has a higher technical risk than 4 × 1.5 GW system.

10 Summary of Technology Comparison

The technology scoring and final positions are summarised in Table 7.

Table 7: Summary of technology comparison

Criteria	HVAC					HVDC
	Overhead Line	Underground Cable	Partially Undergrounded Overhead Line	Gas Insulated Line	Superconducting Cable	Underground Cable
Safety	+	+	+	x	x	+
Technical performance	++	x	+	x	x	- -
Environmental impact	-	-	+	x	x	-
Planning, permitting and construction	-	-	+	x	x	-
Whole life cost	++	- -	-	x	x	- -
Overall position	1	x	2	x	x	3

An AC overhead line is the preferred solution. Partial undergrounding of the AC overhead line is technically feasible and could be considered in specific areas that would be significantly affected by construction of an overhead line.

While HVDC can facilitate the undergrounding of long circuits, the additional cost of HVDC would be significant and HVDC technology would not offer the operational flexibility and resilience of an HVAC solution. It is therefore ranked in third place.

There are significant technical performance issues associated with the installation of long lengths of AC cable in transmission grids. Mitigation of these technical issues leads to increased system complexity, risk of reduced availability and significantly increased cost. Undergrounding a 100 km route length would require 1,800 km of cable which would present a significant procurement risk to the project. An underground cable solution would be significantly more expensive than an equivalent overhead line. Undergrounding of the full length of the Stevin-Avelgem and Avelgem-Centre corridors therefore does not meet the requirements of the project.

Although technically capable of providing a transmission capacity of 3 GW per circuit, experience of gas insulated line over long distances is not available. As such, a 100 km route length may face previously un-encountered technical and construction challenges. The technology is not considered sufficiently mature to be deployed as part of a critical grid reinforcement project and therefore long-distance gas insulated does not meet the requirements of the project.

Superconducting technology is still in development and is some way from implementation in an operational transmission grid. Superconducting cable therefore does not meet the requirements of the project.

11 Glossary of technical terms and acronyms

Table 8: Technical terms and abbreviations

Term	Abbreviation	Description
Alternating current	AC	A type of electrical power where the electric charge reverses direction at regular intervals
Availability		The amount of time the circuit is available for the purpose it was designed, i.e. to transmit its rated power. This is influenced by planned maintenance activity and unplanned faults.
Black start		Energisation of a previously dead system
Capacity		The amount of electricity that can be safely and reliably transmitted on the grid or a circuit
Circuit		The overhead line or underground cable linking two substations
Conductor		The part of the overhead line or underground cable that carries the electrical power
Converter station		A station that converts direct current to alternating current or vice versa
Corridor		The strip of land of a particular width where the electricity line or cable will be routed
Current		The flow of electric charge in a circuit, analogous to the flow of water in a water system. Measured in units called Amps.
Demand		The amount of electrical power that consumers take from the grid
Direct current	DC	A type of power where the electric charge is constant in direction.
Distribution grid		A lower voltage grid which delivers power to households and businesses. The equivalent of a regional minor road networks in a country's road system
Electric and magnetic field	EMF	Invisible areas of energy which occurs naturally, When electricity flows, both electric and magnetic fields are produced.
Electrical losses		See losses
Faults		A failure of equipment requiring a circuit to be switched off and therefore to become unavailable for use
Generator		A unit that produces power in the form of electricity
Grid		A network or 'energy motorway' made up of high voltage overhead lines, underground cables and substations. The grid links energy users with energy producers. It is designed so that power can flow freely to where it is needed.
Giga-Watt	GW	A unit of power (see power). 1 GW is equal to 1000 MW.
Harmonic distortion		A phenomenon which affects the quality of supply to customers.
Insulator		A component used in electrical equipment to support and separate electrical conductors.
Interconnector		A large circuit connecting two countries
kV	kV	A unit of voltage (see voltage). 1 kV is equal to 1000 V.
MW	MW	A unit of power (see power). 1 MW is equal to 1000 W.
Power Plant		A facility made up of generators that produce power in the form of electricity
Power system		The overall system which produces, transmits and distributes electricity as soon as it is needed
Reactive power		Energy held and stored in cable capacitance
Reactive power compensation		Special equipment to neutralise energy held and stored in cable capacitance and balance the associated effects

Term	Abbreviation	Description
Redundancy		The inclusion of additional capacity in case of failure of other circuits
Reliability		The ability of the circuit to perform consistently well
Renewable generation		The generation of electricity using renewable energy such as wind and solar
Substation		A set of electrical equipment used to control power flows and change the voltages between the transmission and distribution grids
Transmission grid		A physical network that links generators of electricity to the distribution grid. The transmission grid is the equivalent of the national motorway network in a country's road system
Voltage	V	A measure of electric potential, analogous to the pressure in a water system. Measured in units called volts.
Voltage source converter	VSC	A type of HVDC converter technology
Watt	W	This is a measure of electrical power. Measured in units called Watts. An electric kettle consumes about 2 kW

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