Transporting Renewables: Systematic Planning for Long-Distance HVDC Lines

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***Abstract*—The planning and operation of high voltage direct current (HVDC) lines within synchronous alternating current (AC) transmission networks has become an important topic, particularly with the integration of remote renewables into the grid. The optimal dispatch of particular fixed AC-DC networks has already been studied in the literature; we focus in this paper on optimizing the initial positioning of the DC network within the AC network and how it should be optimally sized. The problem is challenging because the optimization criteria (such as reducing congestion, overloading and losses) are non-linear while the optimization space of possible connection points of the DC terminals is discrete. Techniques are presented here based on a linearized version of the AC load-flow equations known as power transfer distribution factors (PTDFs). Examples are calculated for Germany in the year 2030 and for the European network up to the year 2050, with renewable power plants built out to provide 90% of electrical energy.**[1]

Keywords: HVDC, HVDC planning, PTDF, optimization, AC/DC interaction

1. Introduction

The integration of large amounts of renewable energy into the power system requires new power corridors to transfer the energy to where it is needed. For example, good wind resources are often geographically remote, on coastlines or in the sea, and thus can be far away from load centres; in addition, the balancing effects of aggregating multiple wind sites can best be leveraged when very wide areas are interconnected.

For the transmission of power over long distance high voltage direct current (HVDC) has several advantages over high voltage alternating current (HVAC): lower losses over long distances and therefore lower costs; higher power transmission for the same mast height and ground clearance; no need for reactive power compensation along the line; as a result, it is feasible to put underground or in the sea; much better controllability and hence greater ease of allocating the cost of the transmission assets; and, in the case of voltage source converter (VSC) HVDC technology, the stabilization of weak grids (see for example [1]).

A further advantage of HVDC is the ability to connect different synchronous AC networks and thus enable power transfers between them. The majority of HVDC lines that have thus far been built have been between grids that are not synchronous; exceptions are mostly lines under bodies of water, such as Fenno-Skan between Finland and Sweden and the connection between Italy and Greece. However this is now changing, as the need for long distance power transmission, particularly to accommodate renewables, has lead to plans for HVDC lines within meshed synchronous AC zones. Examples in Europe include the currently under construction Inelfe line between Spain and France [2] and planned lines between Belgium and Germany [3] and within Germany itself [4].

A high voltage DC network running parallel to an AC network presents several challenges, many of which have been tackled in the literature. The effects on stability and voltage control during disturbances have been widely studied for different technologies (see for example [5] and [6] for recent operation and control strategies). Interactions between several nearby HVDC systems where the subject of, for example, [7]. From a more economic perspective, optimal power flow strategies for mixed AC-DC systems with fixed topology were considered in [8] and [9], while hourly scheduling of HVDC with VSC was discussed in [10].

From a planning point of view, the optimal expansion of AC transmission systems is already a highly developed field, with various strategies being employed depending on the size of the network, the time horizon, whether generation assets are also included in the optimization and what kind of objective function is used. The optimization problem is non-linear because the load-flow equations and computation of losses are non-linear; it is constrained by the various characteristics of the assets; it is in general non-convex; and it is a mixed integer problem, since transmission and generation assets can only be built out in discrete steps. Usually the topology of the network is assumed to be fixed. To enable computation in reasonable times simplifications are often made, such as the linearization of the load-flow equations, neglecting losses, forcing convexity of the solution space or allowing expansion of the network in arbitrarily-sized steps. Literature surveys can be found in [11], [12], [13].

Some optimal planning studies have also incorporated HVDC systems alongside AC networks [14], [15] but they assume that the location and topology of the HVDC line is fixed and only optimize its capacity. DC lines are built out in preference to the AC grid to enable longer distance power flows and thus cheaper

[1] Presented with peer review at EWEA 2013 in Vienna.

generation technologies to be dispatched. By allowing more controllable power transfers, they can also relieve large parts of the AC grid, although they may require the AC grid to be strengthened at the connection points. Overdimensioning of the DC line must also be avoided, to prevent parallel flows in the opposite direction on the AC network.

In this paper we introduce and investigate some algorithms for choosing not just the size but also the optimal placing of HVDC lines within an AC network. They can be located to relieve congestion in the AC network, to reduce overloading of AC lines, to reduce power losses or to reduce overall network expansion costs. To simplify the problem we linearize the load-flow equations using Power Transfer Distribution Factors (PTDFs), a strategy already used in other studies [16], [17]. However the optimization problem remains non-linear since the objective functions are non-linear. The problem is also by nature discrete, since particular nodes must be selected for attaching the DC network.

Case studies are presented for the European transmission system, with a particular focus on Germany. An aggregated grid model is used for the power flow calculations, while the scenario for installed capacities and dispatch of generation technology is taken from the SmoothPV project [18], in which generation and transmission assets were jointly optimized for social welfare up to the year 2050 with a 90% reduction in CO_2 emissions. Germany was chosen as the main focus because the need for HVDC links within Germany is already known (to carry wind from the North to the South of the country to replace shut-down nuclear capacity) and because studies already exist against which we can compare our results, such as the German Network Development Plan 2012 [4].

The remainder of the paper is structured as follows: Section II presents the methodology. The algorithms are applied to Germany in Section III. Section IV expands the analysis to the rest of Europe. Section V concludes. In the Appendix a flow-allocation algorithm for detecting long distance flows in AC networks is presented which is related to the other algorithms presented here.

2. Methodology

The basic methodology is to minimize an objective function which gives each HVDC configuration within the AC network a score based on how much it reduces losses, congestion, costs or overloading in the AC network. Load-flow equations are incorporated into the objective function so that the effect of the HVDC network on every AC line is taken into account. Each different HVDC configuration (i.e. the different connection points, including simple multiterminal examples) is optimized separately and then the results are compared.

2.1. The PTDF representation of the load-flow equations

To simplify the problem, linearizations of the load-flow equations are used called Power Transfer Distribution Factors (PTDFs), which are essentially the same as what is known as a 'DC load flow' calculation. It is a linearized relation between the net power imbalances at each node and the active power flows on the lines, based only on series reactances of the lines and the voltage angles.

The non-linear AC load-flow equations can be linearised if we assume that: all voltages are set to 1 p.u.; reactive power is neglected; losses are neglected; line series reactance is always bigger than the resistance $X >> R \approx 0$; voltage angles between busses are small enough to make the approximation $\sin(\delta_i - \delta_j) \approx \delta_i - \delta_j$.

If $i, j \in \{1, \dots n\}$ label the nodes, then let P_{ij} represent the real power flow along the branch between nodes i and j, δ_i the voltage angle at each node with respect to some reference and x_{ij} the reactance of the branch. Then the load-flow equation for each branch simplifies to

$$P_{ij} = \frac{1}{x_{ij}}(\delta_i - \delta_j) \tag{1}$$

Combining this equation with the fact that that the power transfers in each branch incident at each node must add up to the power balance at that node, the branch flows can be related linearly to the nodal balances

$$\mathbf{P}_{\text{branch}} = \mathbf{PTDF} \cdot \mathbf{P}_{\text{nodal}} \tag{2}$$

The elements of the matrix $\mathbf{PTDF}$ are the power transfer distribution factors, constituting the linear relationship between the load flows on the lines and nodal power balances. They can also be calculated by choosing a slack bus within the network and measuring the change in power flow on each line for an additional power transfer between a chosen node in the network and the slack bus (this is where the name PTDF comes from).

2.2. Optimization and objective functions

A variety of different objective functions were tested, each with different advantages and disadvantages that should be taken into account when planning an HVDC line.

For each topology (e.g. single HVDC line, two HVDC lines, multiterminal configurations) the different possible locations of the connection nodes were enumerated and then the power flow for each configuration was optimized separately. The optimization space is the power transfers $\{\mathbf{x}\}$ between nodes connected by the HVDC network, represented as power injections at the nodes. For a single line connecting two nodes there is one variable; for three nodes in a multi-terminal configuration there are two variables.

For the non-linear optimization the quasi-Newton algorithm of Broyden, Fletcher, Goldfarb and Shanno (BFGS) as implemented in the Python library SciPy [19] was used, which offered good performance for the problems under consideration.

The optimization is highly dependent on the generation dispatch data, which determines the power flows in the AC network. The data will be discussed shortly. The optimization was performed separately for each dispatch snapshot and then the scores were summed across the snapshots to get the optimal configuration for a variety of load flow situations.

The objective functions considered here were:

1) Power losses reduction: The power-loss objective function optimizes for the reduction in losses in all branches b of the AC network with and without the HVDC lines

$$f_{\text{losses}}(\mathbf{x}) = \sum_b \left[P_{b,\text{before}}^2 - P_{b,\text{after}}^2(\mathbf{x}) \right] * \frac{R_b}{V_b^2} \quad (3)$$

This is only an approximation of the actual losses on the line, since by simplifying the load flow equations we have neglected reactive power flows and losses, but it serves as a reasonably accurate proxy, where R_b is the resistance of the line and V_b the (constant) voltage. The losses incurred in the HVDC lines, assuming a rate of 3% for every 1000km [20], are small in comparison to the losses reduction on the AC network, so we neglect them here.

2) Congestion reduction: The congestion reduction function measures the reduction in power flow on each line multiplied by its length ℓ_b

$$f_{\text{MWkm}}(\mathbf{x}) = \sum_b \left[|P_{b,\text{before}}| - |P_{b,\text{after}}(\mathbf{x})| \right] * \ell_b \quad (4)$$

This function is particularly sensitive to parallel loop flows in the AC network where power spreads out in the network, travelling over long indirect routes to get to where it is used. It is also useful for deciding how much power to dispatch in the DC network $\{\mathbf{x}\}$ so that it doesn't cause backward flows in the reverse direction in the AC network (which would worsen the score).

3) Cost reduction: The congestion function can be adapted to optimize the cost of building the DC network versus the AC network

$$f_{\text{Cost}}(\mathbf{x}) = \sum_b \left[|P_{b,\text{before}}| - |P_{b,\text{after}}(\mathbf{x})| \right] * \ell_b * c_{\text{OHL}} - \sum_h |x_h| * (\ell_h * c_{\text{OHL}} + c_{\text{Converter}}) \quad (5)$$

The first term is the cost saved by reduced flows on the AC lines, while the second term is the cost of the DC lines h and converters. c_{OHL} is the cost per MW per kilometre of overhead lines (assumed to be the same for AC and DC) and $c_{\text{Converter}}$ is the cost per MW of the AC-DC converters required at the connection points of the DC network to the AC grid. We have taken cost values c_{OHL} = €400/MW/km and $c_{\text{Converter}}$ = €150,000/MW from [18], but neglected the terrain factors used there.

This function is not perfect, since one would only build out transmission capacity in discrete parts. It also gives positive scores to power reductions within the thermal limits of existing infrastructure, which wouldn't provide a cost benefit. In addition, it does not take into account costs incurred by the higher losses and reactive power compensation in the AC network, so it must be treated with caution.

4) Loading reduction: For the loading reduction the score is weighted according to whether the DC lines helps reduce the loading on AC lines which are already loaded over 70% of their thermal limit (70% was chosen as a safety margin following n-1 security criteria and also to allow flexbility for future increases in load and generation)

$$f_{\text{thermal}}(\mathbf{x}) = \sum_b \left[\text{reduction of loadings above } 70\% \right] * \ell_b \quad (6)$$

Let the loading be $L_b = P_b / P_{b,\text{thermal limit}}$. If the loadings before and after the introduction of the HVDC system are below 70%, the score is zero. If the loading before is less than 70% but the HVDC system has increased the loading above 70% then the score is the negative of the difference between the new loading and 70%. If the loading before is more than 70% then the score corresponds to how much the HVDC system has decreased (positive score) or increased (negative score) the loading. Reductions below 70% are ignored.

This function is perhaps more relevant than the congestion MWkm function from a planning perspective, since it is sensitive to reductions only on overloaded AC lines. The MWkm function may reward configurations that reduce loading on lines that are already well below their thermal limits, which are not of concern to planners.

2.3. Network model

To analyse the power flows in the European transmission network, a detailed model of the high voltage grid is used. This model was developed with DIgSILENT's power system calculation tool PowerFactory and covers all ENTSO-E members. It consists of over 200 nodes, representing generation and load centers within Europe, 450 high voltage AC (HVAC) lines and all the high voltage DC (HVDC) lines within the ENTSO-E area (see Figure 1 for the German part of the network). The grid model is built for AC load flow calculations, but in this paper only DC load flow was used.

The model includes load and generation allocation keys, which distribute generation per technology across the nodes within each market region. The network and distribution keys were validated by comparing cross-border flows in the model against publicly available data from ENTSO-E, after which the impedances and allocation keys were optimized to ensure good agreement across several snapshots of the network.

The model covers four points in time: 2011, based on the current network; 2020, including all mid-term planning projects from ENTSO-E's Ten Year Network Development Plan [3] (constituting 82 GVA of extra AC and 13 GW of extra DC capacity comparated to 2011); and 2030 and 2050 based on the optimal generation and transmission expansion taken from the SmoothPV project [18]. The 2030 and 2050 networks include a fixed HVDC overlay grid which connect the major load centres in each market region (see Figure 4). The initial motivation for the study presented in this paper was to determine where HVDC lines should be placed in the SmoothPV network, since the linear optimization algorithms used for that project needed fixed line topologies before they could optimize for the size of the transmission assets.

For the Germany case study the 2020 network was used with the 2030 dispatch data, so that the stresses on the network in 2030 could be seen from the perspective of a present-day planner.

For the European case study a slightly different approach was used: the overlay grid in 2030 and 2050 was assumed to be in fixed locations (but the capacity was free to be optimized), while HVDC lines were then optimized in each country but forced to be connected to the overlay grid landing point in each market region.

2.4. Generation dispatch scenario to 2050

The load, generation and transmission system expansion scenario up to 2050 was taken from the SmoothPV project [18], which jointly optimized generation and both AC and DC network infrastructure using similar PTDF-based methods (the methodology is discussed in [17]) based on a 90% CO_2 reduction target compared to 1997. The grid model was the same as that presented above; the electricity market model was developed at the Institute of Energy Economics in Cologne [22].

For the years 2011, 2020, 2030 and 2050 the dispatch was calculated for eight typical days per year on an hourly basis, representing variations in electricity demand as well as in solar and wind resources [23]. Extreme events that particularly stress the power system, such as periods of low wind and high demand, were also covered. For the case studies in this paper we have focused on snapshots with high wind, to model situations when the network is put under strain by large wind power inflows.

For the study of Germany, 42 GW of onshore wind were installed by 2030 along with 44 GW of offshore wind (28 GW in the North Sea and 16 GW in the Baltic Sea), assuming cost-optimal development. (In the Network Development Plan of 2012 by contrast, 64 GW of onshore wind and only 28 GW of offshore are foreseen in the lead scenario by 2032.) All the nuclear plants are assumed to have been taken off-line.

For the entire ENTSO-E area the installed capacities for onshore wind were 264 GW in 2030 and 266 GW in 2050, and for offshore wind 166 GW in 2030 and 497 GW in 2050. Big cost reductions were assumed and predictions this far ahead should obviously be treated with caution.

2.5. Simplifications and assumptions

The use of DC load flow, a simplification necessary to reduce computation complexity, means that we cannot take account of reactive power flows, voltage stability or reactive power compensation in the AC network.[2] No account was taken of fault behaviour either.

We have made no assumptions about the HVDC technology used; the HVDC line is modelled with a static generator taking up active power in one place and another delivering it somewhere else. We assume by 2050 VSC or similar technology will be available for large power transfers and will be favoured due to its ability to provide reactive power and hence contribute towards system stability.

3. Test Case: Germany in 2030

Germany was chosen as a test case for these algorithms both because the aggregated network model is most detailed for Germany and because there are already existing plans for HVDC capacity in Germany [4] with which we can compare our results.

For each topology all possible nodes within Germany were considered in the optimization for the connection of the HVDC terminals. For the changes in power flows on the network measured by the objective functions, all branches in Germany and the bordering countries were included. The network capacities from 2020 were used with the dispatch data predicted for 2030, as explained above. This means that in the base case, without HVDC lines, there are already a significant number of AC lines which are overloaded (see Figure 2).

For each optimization we have taken an average across 8 winter snapshots with high wind levels; a maximum score is also included for comparison. The nodal dispatch in the windiest snapshot is indicated graphically in Figure 1.

3.1. Optimizing for a single line

The results for a single HVDC line are displayed in Tables I to IV. The highest scoring lines for losses reduction and congestion reduction are in agreement: a line with capacity around 20 GW is recommended from Hamburg (DE03), in between the offshore wind parks in the North and Baltic seas, and load centres in the very south of Germany, around Ulm (DE34), Augsburg (DE30) and Munich (DE35). With such a line one can save around 4 GW of losses in the AC network under windy winter conditions, around 14000 GWkm of loading on the AC network and reduce the number of overloaded lines by a factor of 3. The line between Hamburg and Ulm is marked on the map in Figure 1.[3]

The graphic in Figure 1 shows the extent to which the loading on the AC network is reduced by the introduction of the HVDC line. All routes going from north to south have their burden reduced, including loop flows that go through the Netherlands, Belgium and France and on the other side through Poland and the Czech Republic. Some lines near the connection points have increased loading, particularly in the south, as the connection point stresses the network locally delivering the power.

These capacities agree broadly with the German Network Development Plan 2012 (NEP) [4], which foresees capacity of 20 GW from the North Sea to southern Germany in its scenario for 2032. In the NEP strain

[2] A study of these issues for several HVDC configurations in the network of the German TSO Amprion can be found in [21].

[3] The background image in this figure and others is courtesy of ENTSO-E.

on the AC network is avoided by splitting the capacity into four separate corridors[4] across the country with multiple terminals in each corridor, although one must bear in mind that this also increases the costs by adding converter stations. We will explore simpler versions of such multiterminal solutions in the next section.

The avoided losses in Table I appear quite high, but there are several reasons for this. Firstly, the 2020 version of the network was used for this study, so the capacities of the AC lines are under-sized; as you can see from Figure 2 many of the lines are overloaded, so their losses will be higher than in a properly-dimensioned network. Secondly, there is a very large amount of power (50 GW including Denmark) being injected in the north, enough to cover most of Germany's demand at its lowest point and around 60% of its peak demand, therefore a significant amount of power is being transported over long distances. From Figure 1 it is clear that many lines, including those far away, are affected by this power flow. And thirdly, since the losses go quadratically with the power, reducing the power from higher values has a very large effect on the losses reduction.

The scores in saved costs from Table III are roughly in agreement for location, with the exception of a high-scoring line going from North (DE03, Hamburg) to the East (DE18, Chemnitz), which appears because of a lack of West-East capacity dating back to the Reunification of Germany and because the shorter length of the HVDC line leads to a lower cost.

The optimized capacities are noticably lower than for the other objective functions, between 3 GW and 8 GW. For reasons discussed before, the cost savings for the AC network are most likely a significant underestimate, since it doesn't take account of the discrete steps in which transmission capacity is built out and it doesn't take account of the cost of losses and reactive compensation in the network.

The scores for reducing overloading on lines loaded over 70% can be found in Table IV. In contrast to the losses and congestion scores, the highest scoring are delivering power to the East. This is because around half the overloaded lines are in this eastern region, so there is a strong bias towards reducing the loading there. Because the distances there are not so great and the losses in the AC network correspondingly lower, it may be better to build out the AC network here, and then use HVDC for the longer routes.

An example of the change in loading profile for the AC network is depicted in Figure 2 for a 17 GW line from DE03 to DE32. The single DC line has reduced the number of overloaded lines by a factor of three, reducing the total which are over their thermal capacity from 39% to 13%. (That so many lines are overloaded shouldn't be alarming, since we've used the 2020 network.)

Given the discrepancies between the other scores, it is surprising that the losses and congestion scores

[4]The line DE03 to DE34 most resembles Corridor C in the NEP.

TABLE I
SCORES FOR LOSSES REDUCTION

Line	**Averaged score** (MW)	**Averaged power** (GW)	**Max score** (MW)	**Power max** (GW)
DE03 → DE34	4458	18	6250	21
DE03 → DE30	4362	17	6005	20
DE03 → DE35	4268	17	5829	20
DE03 → DE32	4122	16	6046	20
DE03 → DE18	3957	20	5263	23
DE03 → DE33	3876	15	5639	18
DE03 → DE31	3791	15	5183	17

TABLE II
SCORES FOR CONGESTION REDUCTION

Line	**Averaged score** (GWkm)	**Averaged power** (GW)	**Max score** (GWkm)	**Power max** (GW)
DE03 → DE34	13864	19	18123	23
DE03 → DE30	13495	19	17402	23
DE03 → DE35	13326	20	17065	23
DE03 → DE18	12347	22	14916	26
DE03 → DE31	12287	19	15823	22
DE03 → DE29	12126	19	15529	22
DE03 → DE32	12082	18	17336	22

TABLE III
SCORES FOR REDUCED COST

Line	**Averaged score** (million €)	**Averaged power** (GW)	**Max score** (m€)	**Power max** (GW)
DE03 → DE18	362	8	495	11
DE03 → DE35	201	3	209	5
DE03 → DE31	136	2	112	3
DE03 → DE34	128	4	289	8
DE03 → DE30	118	2	178	2
DE07 → DE35	109	3	93	3
DE03 → DE23	98	4	203	8

TABLE IV
SCORES FOR REDUCING OVERLOADED LINES

Line	**Averaged score** (%)	**Averaged power** (GW)	**Max score** (%)	**Power max** (GW)
DE03 → DE18	3116	19	3992	22
DE03 → DE19	2871	18	3670	21
DE03 → DE32	2617	15	3855	17
DE03 → DE30	2569	14	3393	16
DE03 → DE11	2567	18	3309	21
DE03 → DE35	2564	14	3344	16
DE03 → DE34	2535	15	3397	18

are in such close accord. They show good agreement on recommended locations and for the recommended capacities the congestion method recommends lines about 10% bigger. A possible explanation is that the length of each line ℓ_b in equation (4) is a good enough proxy for the resistance in (3) and for large currents the quadratic relation of losses to current is flat enough that it is sufficient to model the losses as linearly dependent on the power.[5] The congestion method is significantly faster computationally, so presents a good compromise when the size of the potential solution space grows large.

[5]In equations, we are saying that for large I, we can approximate the loss function $P = RI^2$ with $P = A + BI$. Since the losses score (3) is a subtraction of losses, the constant A disappears.

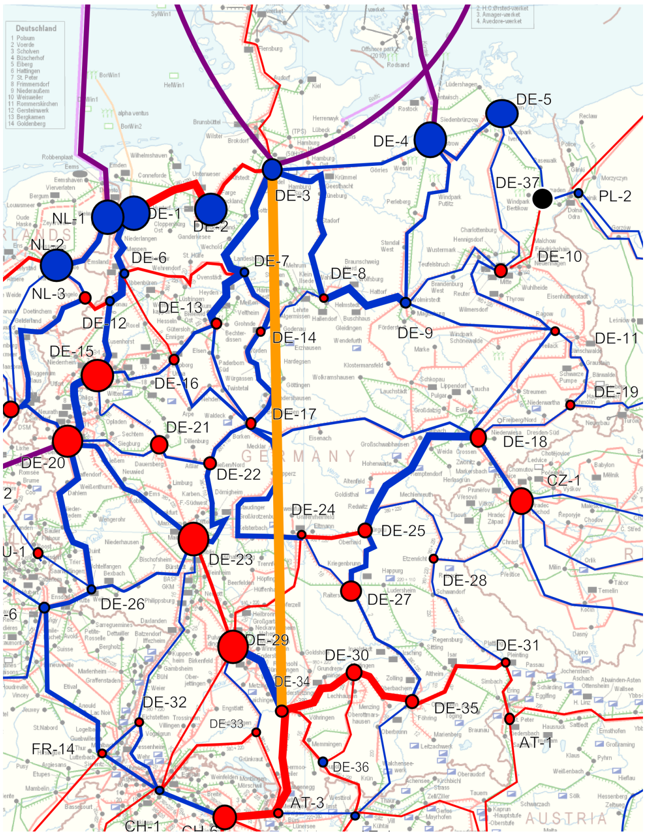

Fig. 1. The aggregated network model for Germany. For this windy winter snapshot, blue nodes have net generation, red net load, while their radii are in proportion to their power. The orange line is the HVDC, carrying 20 GW. Blue AC lines have their loading reduced by the HVDC line; for red lines the loading increases (in both cases proportional to the width of line).

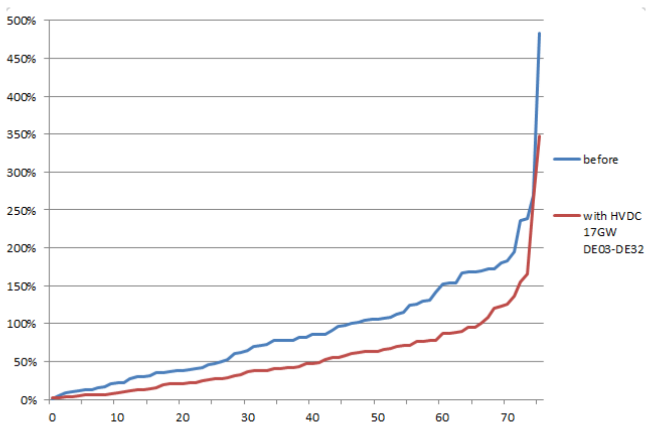

Fig. 2. Loading as a percentage of the thermal limits of the 76 lines in Germany on a windy winter day, with and without an HVDC line carrying 17 GW from Hamburg (DE03) to Freiburg (DE32).

3.2. Optimizing for a multiterminal three-node network

In this section we consider a multiterminal topology which connects three nodes with HVDC lines. To simplify the problem we treat this configuration as two HVDC lines with a common connection node, although in reality the lines would split at a fourth point, see the examples drawn in Figure 3. Results are calculated for the losses-reduction and congestion objective functions in Tables V and VI, since these methods gave the

TABLE V
LOSSES SCORES FOR THREE-NODE NETWORK

Lines	Averaged score (MW)	Averaged power (GW)	Max score (MW)	Power max (GW)
DE03→DE18	5299	10	6817	11
DE03→DE34		12		15
DE01→DE34	5269	11	6997	13
DE03→DE34		13		16
DE03→DE32	5052	9	6835	12
DE03→DE35		10		11

TABLE VI
CONGESTION SCORES FOR THREE-NODE NETWORK

Lines	Averaged score (GWkm)	Averaged power (GW)	Max score (GWkm)	Power max (GW)
DE03→DE18	16425	12	20760	12
DE03→DE34		13		16
DE01→DE34	15296	12	21196	16
DE03→DE34		15		19
DE03→DE32	14847	12	19941	16
DE03→DE35		9		8

best indications in the previous section for long-distance power transfers. For interest's sake and to save space, we have left out some configurations which were very similar to the others.

The three highest scoring configurations are a line from North to South that branches off to the East (DE18, Chemnitz), a line from the North that splits when it gets to the South, and lines from the Northwest (DE01) and the North (DE03) that join and then go down to the South. Two of these configurations are show in Figure 3.

Compared to single line configurations, the amount of losses that can be avoided in such configurations rises by around 24% and the congestion score by 18%. The amount of power being transported away from the coast has also been increased by just over 20%, which is enabled because the power is able to be dispatched more evenly around the network, avoiding strain around the connection points.

3.3. Optimizing for two HVDC lines

From the previous multiterminal solutions it is clear that HVDC lines connecting the big power injection points in the Northwest (DE01) and North (DE03) are prefered. Therefore in this section we consider two lines, one from each of these points, and optimize for the positions of the other ends of the two lines. The results for the losses-reduction and congestion metric are in Tables VII and VIII (again we have not repeat configurations that are very similar).

The optimal connections are from the North-East to the South and then from the North to Chemnitz in the East. The top-scoring result is drawn in Figure 3. Comparing the optimal solutions with the three-terminal case, the losses avoided increases only 7% and the congestion reduction by 10%. However the amount of power transferred increases by 41%, which is significant. This increase in power is because the two lines

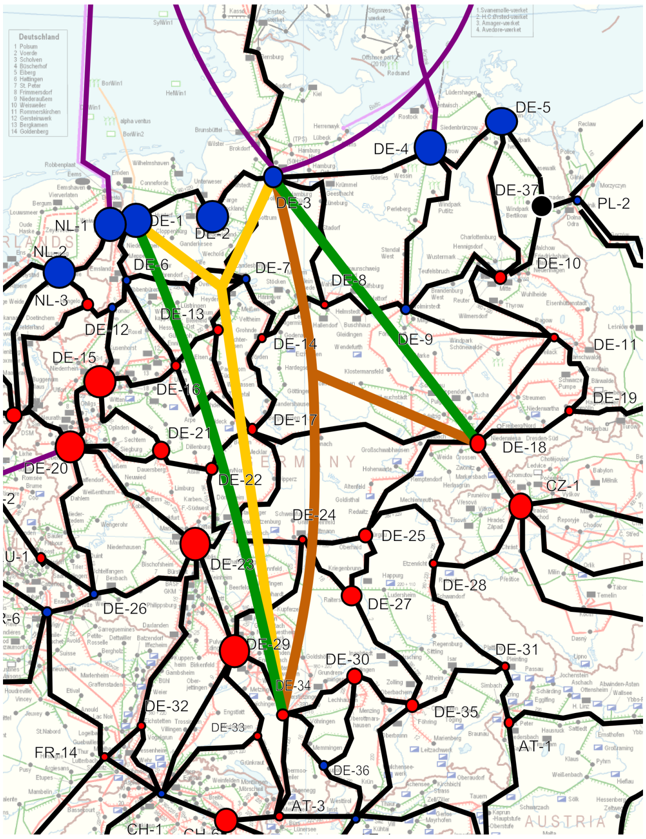

Fig. 3. Two different 3-node multiterminal solutions (in yellow and brown) and one two-line solution (in green). The branching points in the middle for the 3-node solutions are indicative only and have not been optimized.

TABLE VIII
MWKM SCORES FOR TWO LINES

Lines	Averaged score (GWkm)	Averaged power (GW)	Max score (GWkm)	Power max (GW)
DE01→DE34	18141	16	22870	20
DE03→DE18		17		20
DE01→DE32	17433	15	23404	19
DE03→DE18		18		21
DE01→DE34	17059	17	21737	24
DE03→DE28		15		16

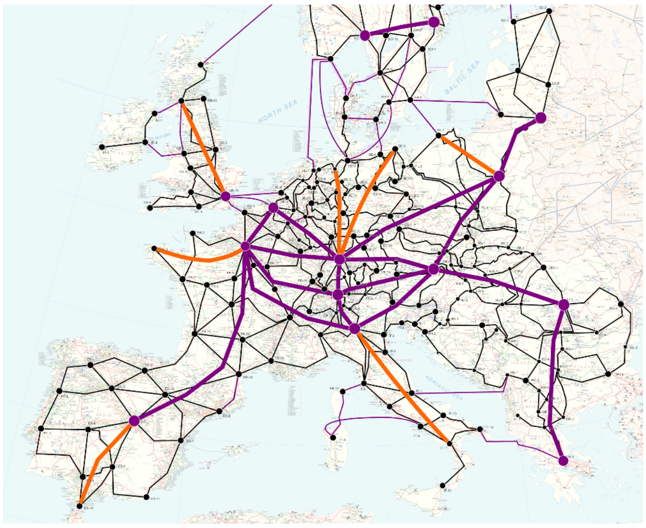

Fig. 4. European model with an overlay HVDC grid between regional load centres in purple and internal HVDC lines in orange.

TABLE VII
LOSSES SCORES FOR TWO LINES

Lines	Averaged score (MW)	Averaged power (GW)	Max score (MW)	Power max (GW)
DE01→DE34	5666	16	7594	19
DE03→DE18		15		18
DE01→DE32	5550	13	7653	17
DE03→DE18		16		19
DE01→DE32	5471	12	7692	15
DE03→DE30		14		16

can be far enough apart that the strain induced at the connection points is spread out.

It's also interesting to note that these results are not fully in accordance with the NEP, in which all the HVDC lines bring power to the South and not to the East. An explanation is that the NEP assumes more onshore wind expansion in the East, which would cover the load there, while from Figure 3 it is clear that there is a big load centre in the Czech Republic being served.

Also interesting is that the single HVDC line solution from DE03 to DE34 doesn't appear high in the list. This means if we'd taken the single solution and then tried to add a second line separately, we would have missed the optimal two-line solution. Solutions with multiple terminals need to be considered jointly for optimal results.

4. Europe to 2050

In this section we present results computed for the SmoothPV project [18], a project to optimize generation and transmission capacity for the whole of Europe up to 2050 with 90% CO_2 reductions. For computational reasons it was decided to first fix the topology of an overlay HVDC grid connecting the major load centres (in purple in Figure 4), whose capacities were set by the main optimization algorithm along with the AC transmission capacities and the generation distribution. The HVDC lines internal to each market region (in orange in Figure 4) were then selected using the algorithms presented above, with the condition that they connect directly to the overlay grid.

The resulting locations and capacities of the internal lines are presented in Table IX. With the exception of Spain, every line was necessitated by the development of offshore wind. Very large installed capacities far from load centres meant that such lines scored highly.

Note that the capacities in Germany for 2030 are lower than those presented above, since the locations on the coast were fixed based on the 2050 dispatch, which sees a proportionally bigger expansion of offshore wind in the Baltic Sea. In addition the other ends of the lines were forced to connect to the overlay grid landing point in the load centre of Stuttgart.

TABLE IX
DOMESTIC HVDC LINES CONNECTING TO THE OVERLAY GRID

Country	**From** (Optimized)	**To** (Fixed)	**Capacity 2030** (GW)	**Capacity 2050** (GW)
DE	Bremerhaven	Stuttgart	13	25
DE	Greifswald	Stuttgart	3	10
ES	Algeciras	Madrid	4	7
FR	Cherbourg	Paris	2	6
GB	Glasgow	London	3	6
IT	Naples	Milan	1	8
PL	Gdansk	Warsaw	2	16

5. CONCLUSIONS

In this paper we have developed four algorithms to optimize the placement of HVDC networks within AC transmission systems. They allow HVDC lines to be planned in a systematic way in a variety of configurations, which we hope will be useful not just for roadmap studies with aggregated network models, but also for real-life network planners.

In a case-study for Germany we found our predictions for necessary HVDC capacity agreed broadly with the scenario for 2032 from the German Network Development Plan [4], which calls for significant capacity in a North-South direction, although we also found a need for lines connecting to the central eastern part of the country. Results for a European HVDC supergrid were also presented.

From a methodological point of view the losses- and congestion-reducing objective functions worked well in identifying the need for long-distance power transfers. Since they largely agreed and the congestion function was computationally quicker, for larger studies we would recommend the congestion function for quick and accurate results. We also found that for more complicated topologies, multiple lines and terminals must be optimized jointly to obtain the best results.

For future studies it would be very interesting to increase the scope of the optimizations by working with network models that have not been aggregated, and to consider more complicated topologies. It would also be useful to incorporate planning for the entire network, including generation assets and AC capacity built out in discrete steps. Some of the simplifications outlined in Section II-E could be avoided, but at the expense of significantly higher computation times.

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Appendix: Detecting Long-Distance Flows with Marginal Participation

In this section we present a method to allocate the power flow on a particular line to the different producing and consuming nodes in the network. There is *a priori* no unique way to do this allocation; we borrow a method called Marginal Participation that has been suggested for calculating the compensation to transmission system operators owed for the use of each other's assets [25] (it has also been used in South America). By allocating flows to particular nodes, we can detect whether power is flowing over long distances through the network, and therefore whether there is a need for long distance HVDC transmission.

We use a variant of Marginal Participation using a 'virtual' slack bus, as described in [25]. Th PTDF in equation (2) already defines an allocation of flows to the nodes, but the results depend very strongly on the choice of slack bus. We can get around this problem by adding a constant to each row of the PTDF (corresponding to each branch), which has the effect of distributing the slack 'virtually' around the network. This might seem arbitrary but we can choose the constant with a particular goal in mind: in our case, following [25], we choose the constant so that for each branch the contribution to the flows from generators and loads is equal (we could have chosen any ratio between the contributions of generators and loads, but we want to detect when consumers and producers are far away from each other, so 50-50% makes sense). In this way the results are completely independent of the choice of slack bus.

With this allocation in place we can take any line we suspect is overloaded due to long-distance power transfers and see whether this is indeed the case. For example, in a windy snapshot the line DE18 $\rightarrow$ DE25 in eastern Germany from Chemnitz to Bamberg was loaded at 113%. The decomposition of this flow into contributions from specific nodes is in Table X along with the distance of the nodes from the line.

TABLE X
Marginal Participation algorithm for line DE18→DE25

Node	**Type**	**Fraction of flow** (%)	**Distance** (km)
DE01	producer	2	569
DE02	producer	3	568
DE03	producer	4	443
DE04	producer	9	300
DE05	producer	12	420
DE09	producer	6	100
DE18	producer	12	0
DE25	consumer	3	0
DE27	consumer	3	93
DE32	consumer	6	603
DE33	consumer	8	449
DE34	consumer	10	449
DE35	consumer	14	280
DE36	consumer	6	536

The biggest contributors are indeed far away: the coastal nodes where there is a lot of wind injection (particularly on the Baltic sea at the node DE05 nearest to Chemnitz) and the load centres in the far south (particularly DE35, Munich). The average distance to the producers is 343km and to the consumers is 344km, so it would make sense to build a DC link between these two groups given the likely losses over such a distance.