Automated grid connection design process for offshore wind farm clusters

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Summary

An automated grid connection design process for offshore wind farm clusters that takes into account the variability of wind and power demand/prices is demonstrated on a 7200 MW case study inspired by Dogger Bank, using the Net-Op planning tool. Two modelling approaches for demand, generation and prices are outlined and compared for this case study. Both approaches result in the same optimal offshore grid and clustering of wind farms.

The design process is done in several steps. Based on a relatively modest amount of user input, the design tool generates a set of potential connections and formulates the problem mathematically as a mixed integer linear programming (MILP) problem. This problem is then solved with an external solver, and the result is the grid layout that minimises socio-economic costs. The solution specifies which nodes and connections to realise, and the number of cables and total capacities of these.

In the presented case study, the resulting optimal offshore grid consists of a meshed cluster grid including both AC and DC connections, and DC connection to the two onshore connection points in Great Britain. No connections to Germany or Norway are included in the optimal solution.

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1 Introduction

Many offshore wind farms are planned in the proximity of each other and in regions where it is relevant to consider wind farm grid connection in tandem with power exchange links between different countries. With long transmission distances to onshore connection points and expensive subsea cables, it is likely that considerable reductions in cost of energy can be achieved through sharing of grid infrastructure. The most beneficial grid design is a solution that balances the cost of the infrastructure with the system's ability to exploit the cheapest means of generation.

The ultimate objective is to identify grid connection solutions for offshore wind farm clusters that are beneficial from a socio-economic point of view. In order to achieve this, the Net-Op planning tool [1, 2] tool has been created for and is suitable for providing design assistance for early stage planning with minimal need for input data, in a way that accounts for the variability in wind power, power prices and power demand, and the offshore grid's potential utilisation both for wind power transmission and inter-area power trade

The European EERA-DTOC project is currently integrating Net-Op and other tools for offshore wind farm design into an integrated *Design Tool for Offshore wind farm Clusters* (DTOC) [3, 4].

Two different ways to represent onshore generation and demand are explored and compared in this study. The fist is the "price driven" approach where onshore generation is represented by a single generator per price area, with a variable generation cost that is set equal to the electricity market spot price. In this case the variability of the demand is only important insofar as it constrains the amount of wind power that can be absorbed onshore. The second is the "demand driven" approach where a portfolio of generators is included with different capacities and generation costs, and with variable demand for each area. In this case, demand and power inflow determines which generators are needed, and therefore the overall cost of generation. These two approaches are applied on the same case study and the results are compared. The "price driven" approach is simpler to set up, but requires power price time series, and does not include the feedback from wind on the price. This is inherent in the "demand driven" approach, which, however, requires demand time series as an input and more detailed modelling of the generation portfolio.

2 Approach

Grid connection of offshore wind farms differs from grid connection of onshore wind farms in several significant ways. Firstly, the offshore location means that power transmission has to be through subsea cables, something which adds costs and constraints. Secondly, there is in most cases no pre-existing offshore electricity grid that offshore wind farms can connect into. And thirdly, the long distances to onshore connection points for many planned wind farms brings with it technological challenges, but also new possibilities regarding grid layout; when distances are large it is increasingly relevant to consider the wind power grid connection in tandem with power trade possibilities.

These considerations are at the core of the Net-Op design approach. It takes into account the possibility of trade with different prices at onshore connection points, and optimises the grid from a socio-economic benefit point of view. The optimisation finds the solution whereby the demand is covered by the cheapest possible mode of production. The comparison between investment costs of electrical infrastructure and the operational costs of generation for the other generation sources in the system determines the cost-beneficial production output of the offshore wind clusters.

The Net-Op tool takes a high-level perspective, avoiding technical and financial details. It is aimed at long-term planning at a high-level by users such as government and government agencies, transmission grid operators and academia. It is fairly easy to use and requires a relatively modest amount of input data.

2.1 Description of automated design procedure

The design procedure has previously been described in refs. [1, 2], but is summarised here for accessibility.

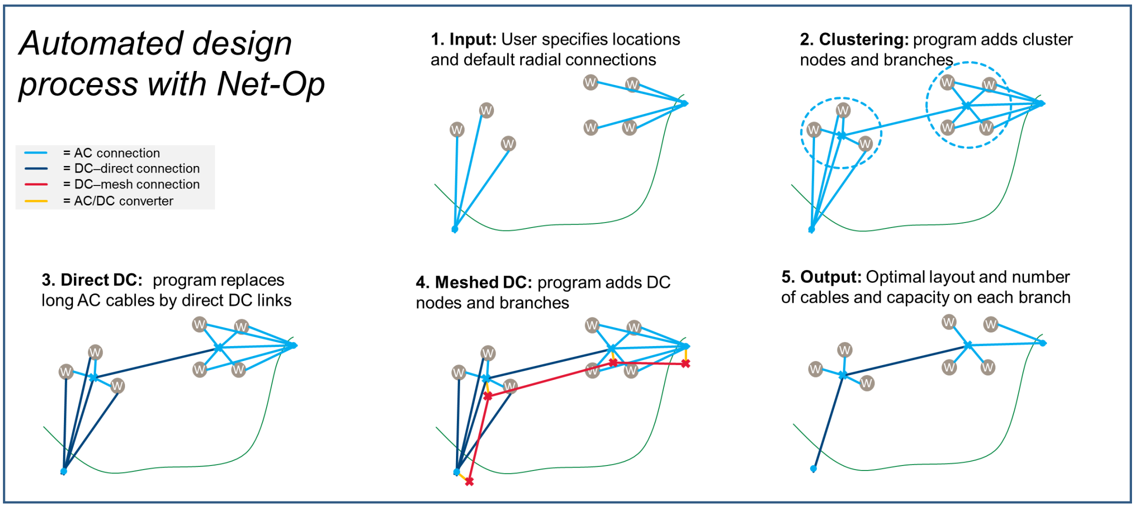


Figure 1: Overview of automated design process

The problem is formulated in terms of a number of nodes representing wind farms and potential clusters and onshore connection points, and a number of branches representing potential connections (cables and converters) between the nodes. Based on a linear cost function, an optimisation algorithm then determines which connections to realise, and what their power capacities should be.

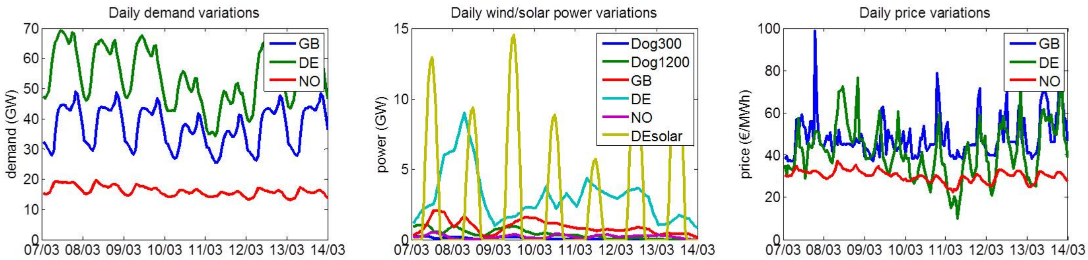
Potential nodes and branches are assigned an investment cost that depends on the distance (which in turn may be computed from the location of the nodes), the power rating, and the type of node or branch, e.g. whether it is a HVAC or HVDC cable. It is reasonable to approximate this cost using a linear model where power rating and number of units are independent variables. These variables are continuous and integer variables respectively.

A linear cost function is appropriate for three reasons: 1) it gives a reasonable approximation to the real costs; 2) it requires a limited amount of input data; and 3) it simplifies the computational complexity of the problem. The first point is important to get realistic results. And for the coarse level of analyses that Net-Op is intended for, the linear cost model is believed to be sufficient. The second point is important for the usability of the tool: It is often a difficult task to collect representative cost data, and the more complex the model, the more data has to be included. If this data is not available, a more detailed model is likely to add only to the uncertainty of the results rather than to improve it. On the other hand, if detailed cost data is available, these can be used to derive the appropriate linear cost parameters before these are fed into the model. The third point is important because of limited computational power. There are well-defined algorithms for optimisations with linear and quadratic cost models, but anything more complicated gives a much more non-standard and computationally difficult problem. Since computation time is already a limitation of this type of problem, added complexity is likely to render the problem practically unsolvable.

Mathematically, this optimisation problem is a mixed integer linear programming (MILP) problem. The number of possible combinations of cables grows exponentially with the number of potential branches, and the number of potential branches grows quadratically with the number of nodes. This means that even for small problems it is practically impossible to consider all possible branches. To overcome this problem, the Net-Op tool includes a pre-processing step that selects a subset of *allowable branches*, in order to reduce the size of the MILP problem.

The automated design process is done in several steps as illustrated with a hypothetical example in Figure 1. Step 1 is the user input, which specifies wind farm substations and onshore connection points, and a set of "default" radial AC connections.

Step 2–4 is an optional, automated pre-processing phase that generates the full set of allowable branches and nodes. First, in step 2, the substations are clustered together using the k-means algorithm together with given constrains on the size of each cluster. For each cluster, a cluster node is added, as well as AC connections from each substation to its associated cluster



(a) demand (b) generation (c) prices

Figure 2: Daily variations in demand, generation and electricity prices. Example showing one week in March 2012.

node, from cluster nodes to onshore connection points, and the nearest neighbour connections between all cluster nodes. Secondly, in step 3, long AC branches are replaced by direct DC branches, including a converter at each end. Thirdly, in step 4, DC nodes are added for all clusters and DC meshed connections between clusterers and between clusters and onshore points. Converters are added between AC and DC nodes.

The next step is the optimisation, which is performed using an external MILP solver of choice. The program chooses a statistically representative sample from the timeseries to properly represent the variabilies in demand, generation and prices, and the correlations between them. A sample of e.g. 30 states is used instead of the whole time series (of e.g. 8760 hourly values for a whole year) simply to reduce the size and computation time of the problem.

Step 5 is the result of the optimisation and the output of the process: The optimal offshore grid.

2.2 Cost model

Costs of branches, nodes and generation (operational cost) are specified by the following linear cost functions.

$$\text{cost of branches} = \sum_{\text{branches}} \Big[(B + B_d \cdot D + B_{dp} \cdot D \cdot P) + \sum_{i=1,2} (C^{b_i} + C_p^{b_i} \cdot P) \Big], \tag{1}$$

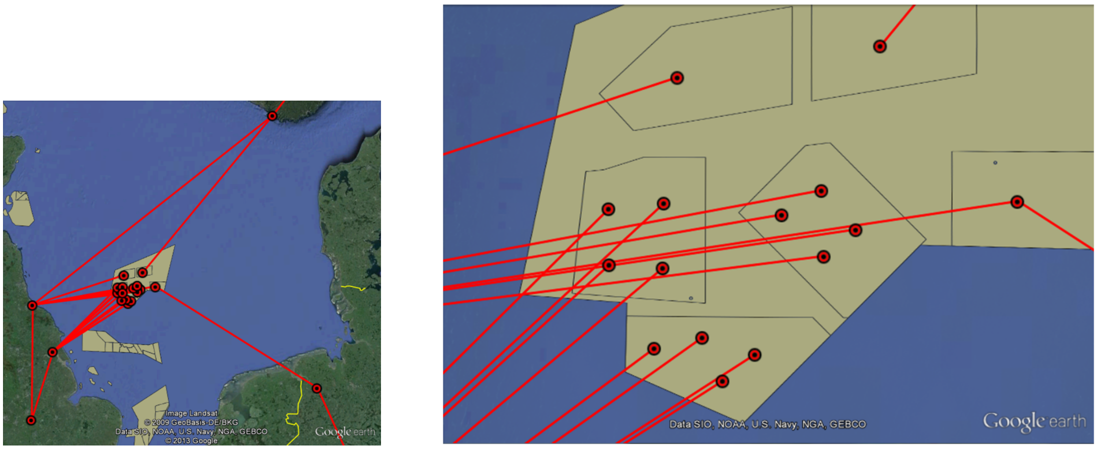
$$\text{cost of nodes} = \sum_{\text{nodes}} C^n_{\text{node}}, \tag{2}$$

$$\text{cost of generation} = \text{NPV}\Big\{ \sum_{\text{generators}} P_g(t) \cdot c_g(t) \Big\}. \tag{3}$$

Here, D is branch distance, P is branch power capacity; B, B_d and B_{dp} are cost parameters that describe branch costs; and C and C_p are cost parameters associated with each branch endpoint. Branch endpoint costs may depend on whether the endpoint is onshore or offshore, which is indicated by the superscripts $b_i \in \{\text{offshore}, \text{onshore}\}$. The node cost C^n_{node} is a fixed value that may depend on whether the node is onshore or offshore, $n \in \{\text{offshore}, \text{onshore}\}$. The parameter $c_g(t)$ is the marginal cost of a generator at sample time t, and $P_g(t)$ is its power output. NPV refers to the *net present value* function. Total costs are obtained by summing costs for all branches, nodes and generators. Different types of branches, nodes and generators have different values for these cost parameters, as shown in Table 1.

2.3 Assumptions

The case considered in this study is inspired by the planned Dogger Bank wind farm cluster in the British part of the North Sea. The total wind power capacity is 7200 MW, divided between six projects of 1200 MW each. Three of them (Creyke Beck A and B, and Teeside A) are represented in more detail with four substations of 300 MW each, whereas the other three (Teeside B, C and D)



(a) overview

(b) detailed

Figure 3: Nodes and connections entered as user input

are represented by a single lumped node with the full capacity of 1200 MW. Potential connections to shore are two sites in Great Britain (Creyke Beck and Teeside) as well as to Norway and Germany. Connections to Norway and Germany are included to explore the Potential connections to Great Britain (Creyke Beck and Teeside), Germany and Norway.

The year 2012 has been used as basis for demand, generation and price input. Time series for wind power production have been estimated based on Reanalysis weather data[1] using power curves representative of wind farm clusters. Time series for electricity prices have been obtained from Elexon[2], Nordpool[3], and EEX[4]. Power demand time series have been obtained from ENTSO-E[5]. The hourly variation in these time series are illustrated in Figure 2 for a week in March 2012. A map showing the location of the Dogger Bank cluster and the "default" radial connections is shown in Figure 3.

Power generation capacities for 2012 have also been obtained from ENTSO-E[6]. Generation costs for different generator types are based on 2010 numbers obtained in the OffshoreGrid project[5]. Generation costs and capacities are shown in Table 2. The cost for hydro is non-zero to capture more realistically the behaviour with limited resource and large storage capacity. The value given is similar to the average system price.

Costs for electrical infrastructure are based on information provided through the Windspeed project [6, 2]. Values are shown in Table 1, with references to symbols used in the cost model, equations (1) and (2).

Note that costs for converters are entered per endpints (to allow different values for onshore and offshore converters). The full converter costs is therefore 210 k€/MW. For direct DC connections, each end-point includes a DC node, a converter and AC protection, so the endpoint costs equal the sum of these costs.

Other important parameters are given in Table 3.

3 Results

The case study with the price-driven modelling gave an MILP problem with 4375 variables of which 80 integer ones, and 9875 constraints. Execution time was 56 minutes on a normal laptop computer, using the open source COIN-OR Symphony solver. With the demand-driven modelling

[1] NCEP Reanalysis data provided by the NOAA/OAR/ESRL PSD, Boulder, Colorado, USA, from their Web site at `http://www.esrl.noaa.gov/psd/`

[2] Data downloaded from `http://www.geog.ox.ac.uk/~dcurtis/neta_ALL.html`

[3] Nordpool spot historical data, `http://www.nordpoolspot.com/Market-data1/`

[4] EPEX spot intraday, `http://www.epexspot.com/en/market-data/intraday/`

[5] ENTSO-E consumption data, `https://www.entsoe.eu/data/data-portal/consumption/`

[6] ENTSO-E net generation capacities, `https://www.entsoe.eu/data/data-portal/miscellaneous/`

Table 1: Cost parameters for branches and nodes

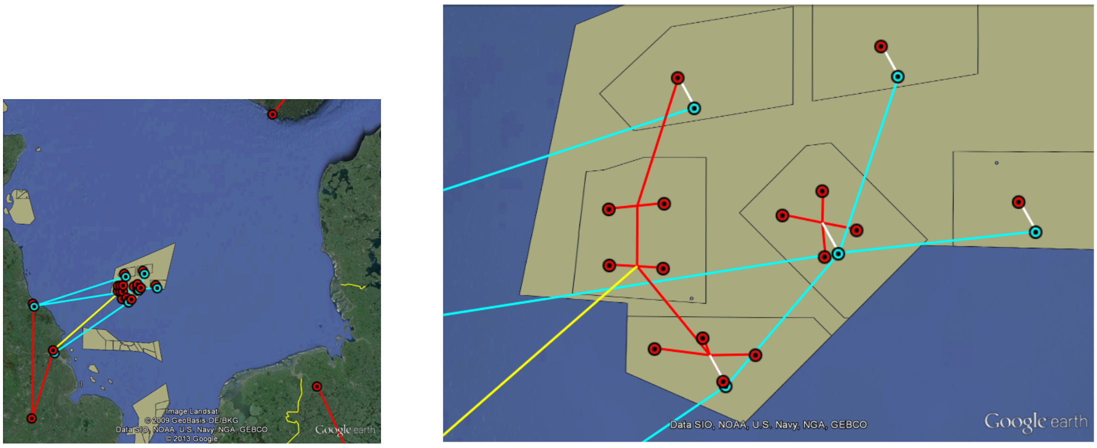
Type	B_d	B_{dp}	B	C_p^L	C^L	C_p^S	C^S
	k€/km	k€/kmMW	k€	k€/MW	k€	k€/MW	k€
AC	0	4.1	5 000	11.8	0	11.8	0
DC–mesh	0	1.27	5 000	70.0	0	70.0	0
DC–direct	0	1.27	5 000	221.8	0	221.8	27 600
converter	0	0	0	105.0	0	105.0	0
AC node					0		18 700
DC node					0		27 600

Table 2: Generation capacity (MW) and costs (€/MW)

Type	Cost	GB capacity	DE capacity	NO capacity
hydro	45	3 889	10 800	30 164
wind	0	5 111	31 300	730
solar	0	0	33 100	0
nuclear	11	9 726	12 068	0
hard coal	32	0	21 178	0
coal	48	23 576	28 056	0
gas	66	30 871	27 284	1 166
oil	111	3 876	5 427	0
other	120	804	6 500	0

Table 3: Constraints and other parameters

Constraint	Value	Units
Maximum branch capacity, AC	373	MW
Maximum branch capacity, DC direct	1302	MW
Maximum branch capacity, DC mesh	1148	MW
Maximum branch capacity, converter	1148	MW
Maximum cluster size, distance	20	km
Maximum cluster size, power	1200	MW
Maximum AC branch distance	65	km
Economic lifetime	30	years
Discount rate for NPV	8	%
Relative power losses for cables	0.003	%
Relative power losses for converters	1.6	%
State sampling method	latin hypercube	
State sample size	30	



(a) overview

(b) detailed

Figure 4: Optimal solution. (red=AC, yellow=DC direct, cyan=DC mesh, white=converter)

the problem had 4705 variables of which 80 integer ones, and 10535 constraints. The larger number of variables and constraints is due to the larger number of generators included. Execution time, with the same solver, was in this case 24 minutes. It has not been checked whether this significant difference in execution time is more or less a coincidence or a systematic difference for the two modelling approaches.

The resulting optimal grid turned out the same in both cases. The input is shown in Figure 3, and the resulting, optimal grid is shown in Figure 4. These results show that:

- There is in this case no significant difference between the results based on price-driven and demand-driven modelling approaches.
- The optimal grid does not include any connectsion to Norway or Germany.
- The optimal grid includes both direct DC connections and meshed DC connections.
- Wind farms are interconnected via both an offshore AC grid and via a meshed DC grid

When considering these results, it is important to keep in mind that they are sensitive to the input parameters, in particular maximum capacity on cables, and the assumed costs of DC protection. In this case, DC protection costs were assumed to be 70 k€/MW, compared to 210 k€/MW for a converter (costs for two end-points), see Table 1. Higher costs for DC protection would eliminate meshed DC grid in the solution.

4 Conclusions

The case study represents the planned Dogger Bank cluster, with 7200 MW wind farm capacity included. An optimal offshore grid is found with a meshed cluster grid including both AC and DC connections, and DC connection to the two onshore connection points in Great Britain. No connections to Germany or Norway are included in the optimal solution. These results should be interpreted cautiously, as they are very dependent on assumptions regarding cost parameters and capacity limits on cables and converters. Further work remains to assess such sensitivities.

The presented case study demonstrates the use of the Net-Op planning tool for offshore wind farm clustering and grid connection. Two modelling approaches for demand, generation and prices are discussed and compared for this case study. Both approaches yield similar results: An optimal offshore grid and clustering of wind farms that take into account variability of the wind and demand/prices.

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