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Expansion planning of the North Sea offshore grid: Simulation of integrated governance constraints

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A B S T R A C T

The development of offshore transmission and wind power generation in the North Sea of Europe is advancing fast, but there are significant barriers to an integrated offshore grid in the region. This offshore grid is a multi-level, multi-actor system requiring a governance decision-making approach, but there is currently no proven governance framework for it, or for the expansion planning of the European power system in general. In addition, existing offshore expansion planning models do not endogenously include governance considerations, such as country vetoes to integrated lines. We develop a myopic Mixed-Integer Linear Programming model of offshore generation and transmission expansion planning to study the effect of integrated governance constraints. These constraints limit investments in integrated lines: non-conventional lines linking offshore wind farms to other countries or to other farms. Each constraint affects the system (including the main transmission corridors), transmission technologies and welfare distribution differently. We apply our model to a long-term case study of the 2030–2050 offshore expansion pathways using data from the e-Highway2050 project. Results confirm that the offshore grid is beneficial to society. Integrated governance constraints induce a modest loss of social welfare, but do not change significantly the existing welfare distribution asymmetry between countries and actor groups. They do strongly affect the interaction of line technologies and types (conventional or integrated), so the impact of the integrated governance constraints is more visible on the grid topology than on welfare levels and distribution. We highlight the need to consider technology and type interactions in expansion planning, especially between multiterminal HVDC and integrated transmission lines. Also, an offshore governance framework should address the use of multiterminal HVDC in a non-integrated grid, but this is a second-best option compared to an integrated grid.

1. Introduction

We study the impact of integrated governance constraints on the generation and transmission expansion planning of the European North Sea offshore grid from 2030 to 2050. Governance is a main barrier to the expansion of the grid using integrated transmission lines (Dedecca et al., 2017a; Flament et al., 2015; Konstantelos et al., 2017), but was generally not addressed in the formulation of expansion planning models. In this introduction, to justify our research gap and objective we first present the following concepts: the integrated offshore grid, expansion planning, and governance.

1.1. The integrated North Sea offshore grid

A major driver for the offshore grid are the recent significant cost reductions for offshore wind, apparent in several competitive offshore auction results. Turbine technology and scale, innovation in supply chain processes, business models which reduced risks to developers and reduced financing costs all drove these cost reductions (IEA RETD TCP, 2017; WindEurope, 2017a). We define the North Sea offshore grid as the power system in the North Sea combining offshore power generation (particularly from renewable sources), offshore loads and transmission lines of different technologies.

Offshore conventional generation from fossil fuels and offshore loads (especially oil and gas platforms) may participate but are not as important a driver for the offshore grid as offshore generation from renewable sources (WEC, 2017). Thus, the focus of this study is the expansion of the latter, particularly offshore wind power. Offshore wind and transmission expansion bring economic, environmental and security of supply benefits to the European power system.

The North Sea offshore grid has two main functions: to interconnect offshore wind power plants to onshore systems, and to interconnect these national power systems among them (Dedecca and Hakvoort, 2016). Traditionally, conventional lines perform these functions separately: they either connect offshore farms to an onshore system, or

interconnect two onshore power systems. In contrast, an integrated line performs both functions simultaneously. We define it as a line that directly connects an offshore wind farms to another wind farm or to an onshore node belonging to another country. While many studies use this nomenclature, these lines can also be called hybrid in the literature (EC and North Seas Countries, 2017; Konstantelos et al., 2017; PROMOTioN, 2017; PwC et al., 2016).

Fig. 1 presents illustrates offshore conventional and integrated lines between two countries. Using the concept of integrated lines, we define an integrated grid as a grid where the generation and transmission expansion planning considers both conventional and integrated lines, leading to the deployment of the two types.

An integrated offshore grid was recently supported by multiple European actors (Belet et al., 2016; EC and North Seas Countries, 2017). Several studies have demonstrated that this may be beneficial to society (Dedecca and Hakvoort, 2016; Konstantelos et al., 2017). Potential benefits include increased system reliability, more efficient generation dispatch, better exploitation of renewable resources, reduced environmental impacts, and reduction of onshore congestions. However, governance aspects such as regulatory differences, the distribution of costs and benefits and the planning of integrated lines are central barriers to an integrated grid (Dedecca et al., 2017a; Flament et al., 2015; Konstantelos et al., 2017).

Since the Dedecca and Hakvoort (2016) review, new studies appeared on the offshore grid, on offshore wind and on HVDC transmission, including Houghton et al. (2016), Konstantelos et al. (2017) and Kristiansen et al. (2017b). Rodrigues et al. (2015) overview the status of offshore wind worldwide, while WindEurope (2017b, 2017a) provide updated statistics and forecasts for offshore wind development. The European Network of Transmission System Operators for Electricity (ENTSO-E, 2016a) has published its latest European development plan, with an analysis of offshore grid projects. Finally, Van Hertem et al. (2016) review the aspects of planning, operation and modelling of HVDC grids.

1.2. Governance in expansion planning models

The expansion planning of power systems is defined as the process of identifying the most adequate investments in generation and

transmission to guarantee the future system reliability given certain energy and climate policy objectives.

Lumbreras and Ramos (2016) list liberalization, increased penetration of renewable energy sources (RES), large-scale generation projects, long permitting times, and increased market integration and regional planning as new challenges to transmission expansion planning in Europe. To Conejo et al. (2016), the generation and transmission expansion planning in liberalized markets are conducted separately, being the responsibility of different actors. Nonetheless, 'generation and transmission expansion plans are clearly interrelated', which has spurred a number of works on joint expansion planning in liberalized markets.

These aspects and challenges of joint expansion planning make a new paradigm of decision-making necessary: governance (Scott and Bernell, 2015). We define governance as the combination of heterarchical (non-hierarchical) and possibly hierarchical institutions (formal and informal) that guide decision-making in a networked multi-level, multi-actor system, following Bevir (2011).

This form of decision making is also necessary for the expansion planning of the offshore grid, for the offshore grid is also a dynamic, multi-level, networked multi-actor system. Currently, offshore generation and transmission expansion planning is an individual prerogative of European countries, being conducted mainly at the national level (Saguan and Meeus, 2014; Tangerås, 2012). Regional transmission investment plans are non-binding and based on national transmission expansion plans. Moreover, neither the Energy Union nor cooperation initiatives in the North Seas alter this significantly or in a binding manner (EC, 2016a; EC and North Seas Countries, 2017).

One of the main barriers to an integrated grid is the distribution of costs and benefits among countries and actors, as for power systems in general. Thus, Konstantelos et al. (2017) identify "significant imbalances" in the distribution of benefits among consumers and producers and of investment costs among North Sea countries. To Delhaute et al. (2016) 'the distribution of costs and benefits is seen as one of the largest barriers for the development of multi-national assets like interconnectors in meshed structures'.

De Clercq et al. (2015) also indicate the distribution of costs and benefits as a major building block to a governance framework, indicating there is still not an agreed-upon redistribution methodology. Moreover, an integrated European planning process is best suited to assess the interaction and impact of multiple transmission lines, but may increase the complexity of the planning process and face the resistance of national authorities.

Hence, while governance at the regional and European levels of expansion planning is beneficial, the current governance frameworks are not adequate to address it. The distribution of costs and benefits and the complexity of the expansion planning process are particular issues for the North Sea offshore grid, but the majority of studies on offshore grid models of Dedecca and Hakvoort (2016) do not address these governance barriers endogenously. That is, these barriers constrained the models externally (e.g. through investment candidate portfolios) and not internally, through the models' formulation.

1.3. Integrated governance constraints

In summary, European expansion planning mainly occurs at the national level and does not consider integrated lines. The networked, multi-level and multi-actor aspects of European expansion planning argue for decision-making through governance, but there is no specific and tested governance framework for the offshore grid. Moreover, modelling studies have largely left the governance barriers for integrated lines unaddressed.

These barriers are modelled using integrated governance constraints, which represent governance barriers to the expansion planning of integrated lines. We include two types, the novel Pareto welfare and integration constraints described in Section 2.2. This is the first application of integrated governance constraints on a more detailed system
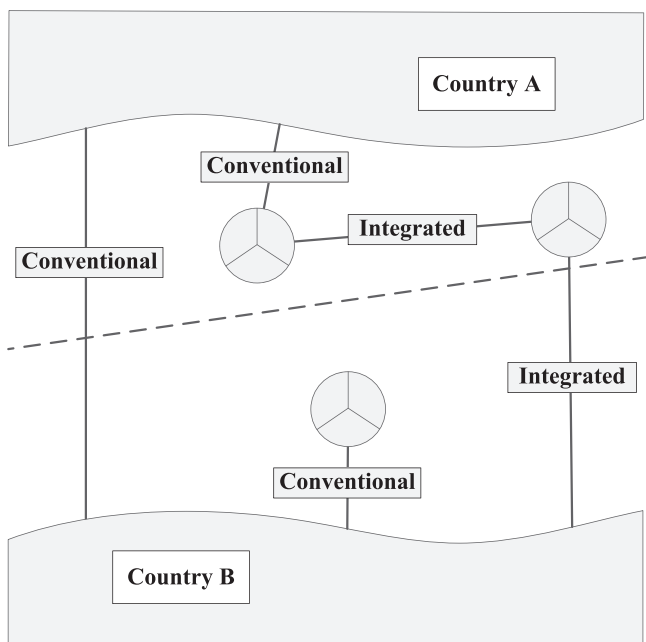

Fig. 1. Integrated and conventional offshore transmission lines.

than that of Dedecca et al. (2017a) and to include the co-planning of generation and transmission. To address long-term uncertainty we incorporate the five scenarios of the e-Highway2050 (2015) project for the European power system expansion.

The contributions of our research are thus the following: first, we develop integrated governance constraints in an expansion planning model. Our Pareto welfare and complex integration constraints were not existent in any previous offshore grid expansion model; second, we analyze the impact of these integrated governance constraints on unconstrained expansion pathways of the offshore grid in the different scenarios of the e-Highway2050 project. Particularly, the constraints lead to (limited) European welfare losses, affect transmission corridors unevenly depending on their line type and technology, and reduce the participation of integrated and multiterminal HVDC lines, while increasing the path dependence; third, our verifiable and open-source model uses transparent input and output data, facilitating the further utilization of data and the governance constraints approach by other researchers. Our study will be of interest to energy analysts and policy makers working with the expansion planning of the North Sea offshore grid and other multi-level, multi-actor power systems.

This article is structured as follows: Section 2 presents the methodology and data (a full model formulation can be found in the supplementary material, and the data and source code are public). Then, Section 3 presents a comparative analysis of the unconstrained and constrained offshore expansion pathways, discussing the effect of the integrated governance constraints. Finally, we conclude in Section 4, deriving principles for the design of offshore expansion planning governance frameworks.

2. Methodology

Our model optimizes offshore transmission and generation investments and the operation of the European power system for sequential expansion planning periods. It is a deterministic sequential-static (myopic) Mixed-Integer Linear Programming (MILP) model. We modify the myopic expansion planning approach of Dedecca et al. (2017a) following its recommendations, by also optimizing investment and by including generation expansion.

Thus, we first present in Section 2.1 the overarching structure of myopic optimization through sequential expansion periods, and then present the formulation of each expansion period in Section 2.2. The integrated governance constraints are the main contribution of our model, and we cover them in detail in Section 2.3. Finally, the case studies data are presented in Section 2.4, while Sections 2.5 and 2.6 cover verification and validation, respectively.

2.1. Myopic approach

The expansion pathway for the offshore grid is composed of sequential period expansions, each lasting ten years, and the approach is myopic because each optimization considers only the current period. Myopic or short-sighted optimization considers only a subsection of the time horizon of the complete problem, as opposed to perfect-foresight optimization. Our myopic expansion planning complements the perfect foresight and robust optimization approaches of current offshore grid models by providing non-optimal and path-dependent expansion pathways which realistically represent decision-making by considering governance constraints and lock-in effects. The myopic approach also reduces the problem size compared to a dynamic optimization problem, helping to maintain problem tractability even when introducing governance constraints.

On the other hand, this approach does forfeit the benefits of dynamic generation and transmission expansion planning, which by considering the inter-period interaction of the generation and transmission expansion would lead to different expansion pathways with higher benefits (Munoz et al., 2013; Pozo et al., 2013; Sauma, 2009; Sauma and Oren,

2006). We chose the myopic approach to complement existing expansion models on the offshore grid, for computational tractability, and for an exploratory rather than prescriptive approach.

We implement the full model formulation of the supplementary material through a mixed-integer modification of the Python for Power Systems Analysis (PyPSA) toolbox (Brown et al., 2018). We add selected candidate transmission lines in each period as existing lines in the following period, and the initial system for 2030 is based on the e-Highway2050 project.

For each expansion period we run the model represented by Eqs. (1)–(23) three times. Each run represents investment decisions in the 2030, 2040 and 2050 decades (each modelled by a representative year), as in Fig. 2. First, a full-year (8760 snapshots) system operation optimization is conducted, without any candidate line (step 1), so in this case each snapshot represents 1 h of operation in a specific system state. This establishes the baseline system operation to calculate the net benefits of the offshore expansion.

Before optimizing the expansion of the offshore system, we reduce the number of snapshots (step 2) to make the expansion optimization computationally tractable. To select representative snapshots we cluster snapshots using a k-medoids algorithm with marginal prices for all system nodes as input data. This means snapshots are grouped in order to reduce the within-cluster nodal price differences. The time series representing load and renewables availability are then scaled, so that the reduced-snapshot time scales are equivalent to the full-snapshot ones. Load is scaled by an average factor considering mean and peak load, while renewables are scaled by the peak availability. More information on clustering and scaling techniques can be found in Nahmmacher et al. (2016), Härtel et al. (2017a) and Kristiansen et al. (2017a).

Also, since the order of snapshots is lost with the clustering, the dispatch of storage units from the first optimization is fixed. We thus do not optimize the investment in storage technologies, and thus do not analyze the possible substitutability or complementary interactions of transmission and storage expansion, such as in Bustos et al. (2017).

We then solve the investment and operation optimization problem with the one hundred clustered, representative snapshots (step 3). This provides the generation and transmission investments for the current expansion period.

This investment selection is fixed and storage units unfixed in the intermediary step 4 in order to run a full-year operation optimization model including these selected offshore candidate lines and wind farms (step 5). This allows us to compare the operation of the expanded system against the baseline system of the first optimization, to calculate the net benefits of the expansion.

2.2. Formulation

Fig. 3 presents the main decision variables and the conceptual formulation of the expansion model for a single period, while the exact variables and formulation are available in the supplementary material.

Eqs. (1)−(21) represent the expansion problem for a single period, with the optional integrated governance constraints (21)−(22). The objective function minimizes the sum of investment and operation costs, and we impose a balance constraint for every node considering transmission, demand, generation and storage (Eq. (2)). We apply linearized power flow constraints for HVAC and multiterminal HVDC lines due to voltage constraints (Eqs. (3)–(6)) and thermal capacity limits for all transmission technologies (Eqs. (7)–(9)). Offshore generation investment is modelled through continuous variables. Additional constraints comprise generation and storage capacity and energy limits (Eqs. (12)–(19)).

The three possible offshore transmission technologies are HVAC, point-to-point HVDC and multiterminal HVDC (Van Hertem et al., 2016). While HVAC and HVDC point-to-point cables are connected to AC nodes, HVDC multiterminal cables are connected to DC nodes as in Fig. 4, with AC/DC converters between AC and DC nodes (Dedecca
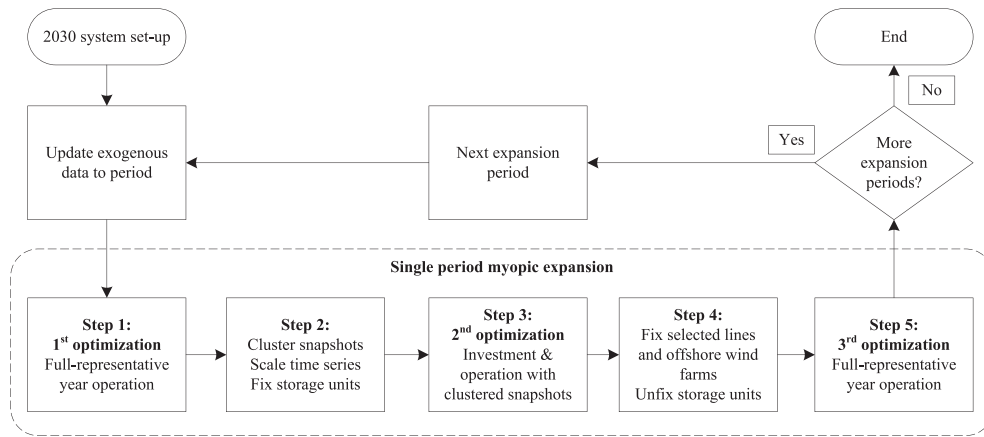
Fig. 2. Sequential expansion planning model flowchart.

Decision variables

Operational

- generation dispatch
- storage dispatch
- storage states of charge
- transmission line flows
- AC/DC converters dispatch

Investment

- offshore wind investment
- offshore transmission lines investment
- AC/DC converters investment

Formulation

$$
\begin{aligned}
minimize \quad & generation\ costs \hspace{4cm} (1)\\
& + load\ curtailment\ cost\\
& + offshore\ wind\ investment\\
& + offshore\ transmission\ lines\ investment\\
& + AC/DC\ converters\ investment
\end{aligned}
$$

subject to:

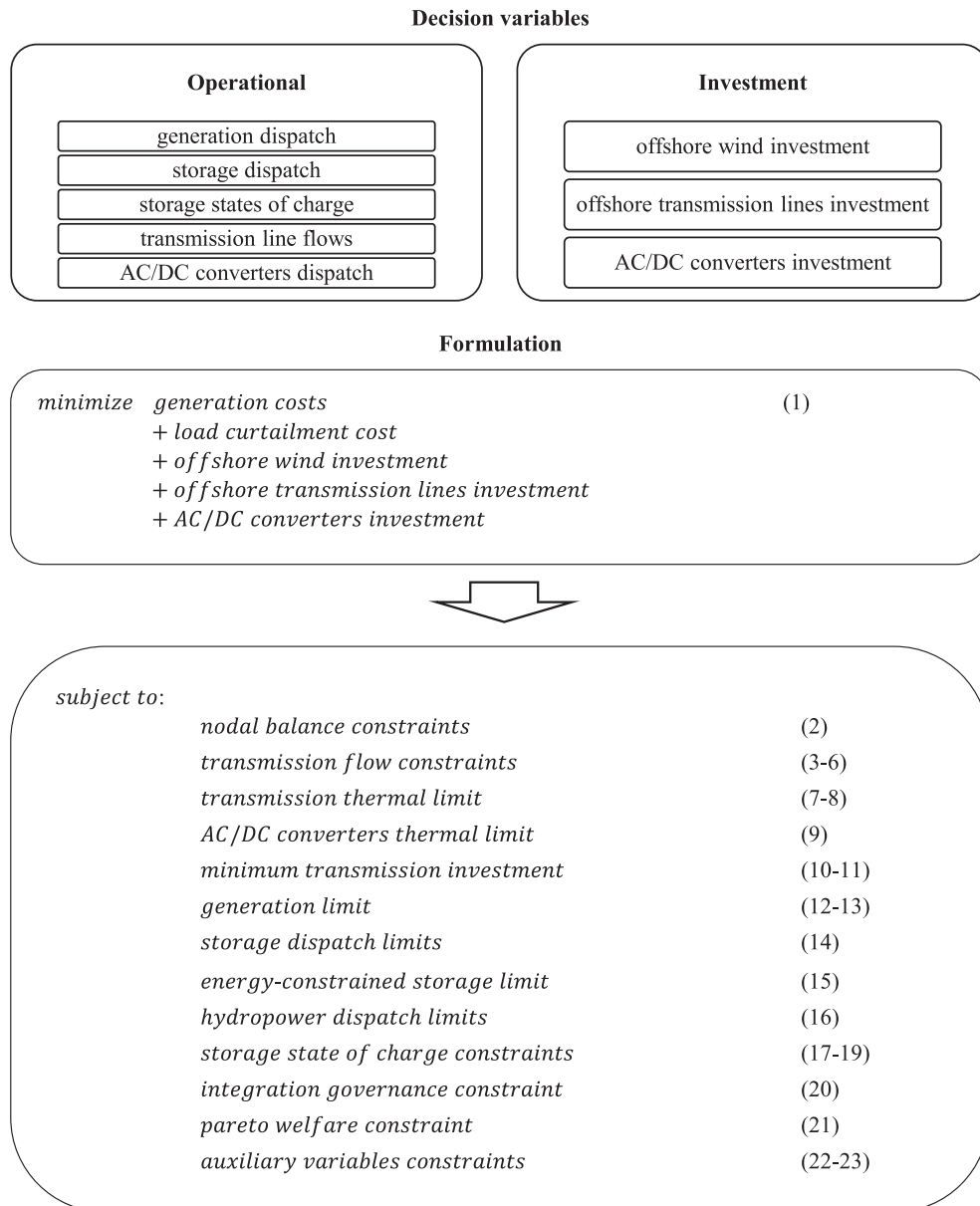|	
nodal balance constraints	(2)
transmission flow constraints	(3-6)
transmission thermal limit	(7-8)
AC/DC converters thermal limit	(9)
minimum transmission investment	(10-11)
generation limit	(12-13)
storage dispatch limits	(14)
energy-constrained storage limit	(15)
hydropower dispatch limits	(16)
storage state of charge constraints	(17-19)
integration governance constraint	(20)
pareto welfare constraint	(21)
auxiliary variables constraints	(22-23)

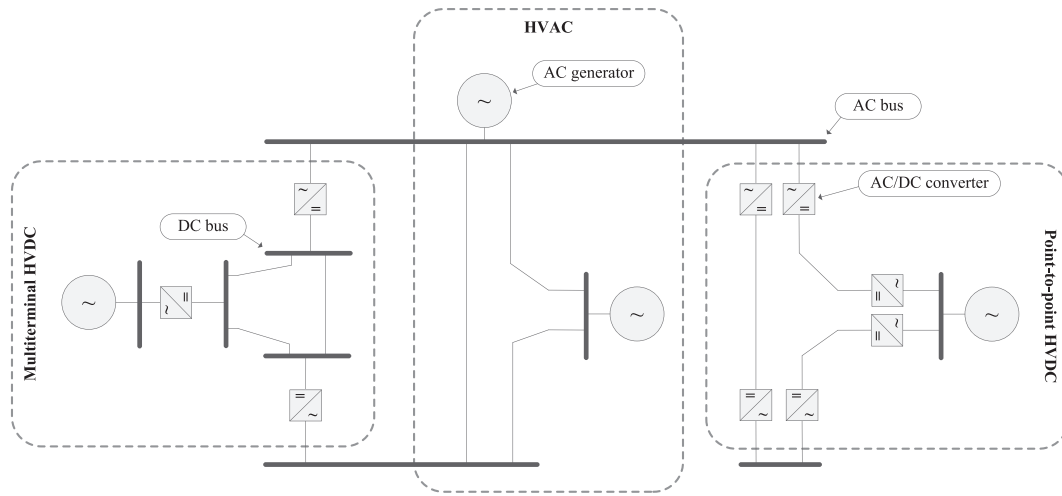**Fig. 3.** Single period expansion model formulation.

Fig. 4. Transmission line technologies.

et al., 2017a). Hence, on the one hand multiterminal HVDC investment costs may be lower than for an equivalent point-to-point HVDC grid, since converters are needed only in nodes withdrawing and injecting power. On the other hand, multiterminal HVDC flows are limited by the power flow equations just as for HVAC, while point-to-point HVDC is limited only by the transmission thermal capacities. Thus, the disadvantage of additional flow constraints counterbalances the multiterminal HVDC advantage of converter investment savings. Moreover, submarine HVDC transmission technologies (cables, converters and breakers) will require innovation to increase maximum transmission capacities, voltage levels and installation depths, and still face uncertainty regarding the technical performance, cost, and standardization and compatibility (Vafeas and Peirano, 2015).

2.3. Integrated governance constraints

As indicated in the introduction, the integrated governance constraints represent governance barriers to integrated transmission lines. To analyze the effect of the integrated governance constraints, we use a comparative structure, comparing the constrained expansion pathways against the unconstrained ones. Every expansion pathway (constrained or not) uses the methodology of Figs. 2 and 3, and for constrained pathways we activate a single integrated governance constraint at a time.

The integration constraint (Eq. (20)) represents the planning complexity by limiting the number of integrated lines built for any node in a given expansion period to a certain limit $\in \{0,1,\infty\}$.

For each node
$$: \sum_{incoming\ offshore\ line} binary\ invesment\ variable \leq integration\ limit \quad (20)$$

The particular value of this limit leads to two types of integration constraint. First, the complex integration constraint limits expansions to one integrated line per node per expansion period. Then, the disintegrated constraint prohibits any integrated line being built at all. This limit does not constrain the investment in conventional offshore transmission lines.

Then, the Pareto welfare constraint (Eq. (21)) represents distribution of costs and benefits by modelling the veto of a North Sea country to investments in integrated lines in their territory. When it is active, any country whose welfare decreases relative to the base welfare does not invest in any integrated lines (Dedecca et al., 2017a). The cooperation variable of Eq. (23) indicates for each North Sea country whether it invested in any integrated line or not.

For each North Sea country:

$$\sum producer\ surplus + \sum storage\ surplus + \sum congestion\ rent$$
$$+ \sum consumer\ surplus - \sum offshore\ lines\ investment$$
$$- \sum AC/DC\ converters\ investment - \sum offshore\ wind\ investment \quad (21)$$
$$+ disjunctive\ parameter * (1 - cooperation\ variable) \geq 0$$

Here, the welfare components are the producer surplus (including of storage units), consumer surplus and congestion rent as in Hogan (2011), always compared to a case without offshore expansion. Hence, welfare stems from system operation gains due to offshore expansions, while net benefits amount to the total welfare gains minus investment costs for all expansion periods.

2.4. Data

All non-confidential input, output and figures and annexes data is available in Dedecca et al. (2017b), with large files available upon request. The code is also open-source (Dedecca, 2017).

2.4.1. Scenarios for the onshore power system

To address uncertainty we utilize the five scenarios of the e-Highway2050 project. They were selected in the project to form alternative, representative futures to achieve the almost complete decarbonization of the European power system, as indicated in Table 1. These scenarios define the exogenous expansion of the onshore power system, while the offshore generation and transmission expansion is determined endogenously by our model. The scenarios differ in macro-economic and technological aspects (growth, demographics, fuel costs, carbon capture and storage maturity), preferences (regarding nuclear and distributed generation) and policies (towards renewable energy sources and regional and national energy independence). This results in different levels of demand, onshore interconnection and deployment of carbon capture and storage, and nuclear and renewable energy sources technologies. Annex 1 indicates the 2050 merit order curve for each scenario, with clear differences in the cost and capacity of generation technologies, and load levels.

2.4.2. System

The clustered European grid model of e-Highway2050 has 103 onshore and 11 offshore nodes, using HVAC and point-to-point HVDC transmission lines. Fig. 5 presents the 2030 initial system, including any initial offshore wind farms and their point-to-point connectors. All figures can be found in color in the electronic version of this article.

Table 1
e-Highway2050 onshore scenarios.

Scenario	Description	Demand	Nuclear	Fossil fuels with CCS	Onshore interconnection	Onshore renewables
Large-scale RES	High RES deployment with interconnection and nuclear	Very high	High	None	Very high	High
100% RES	Highest RES deployment with interconnection and only combined cycle gas as conventional generators	High	None	None	Very high	Very high
Big & Market	Medium RES deployment with nuclear and some CCS	High	High	Medium	Low	Medium
Small & Local	High local RES deployment with little interconnection	Medium	Low	None	Low	Very high
Fossil & Nuclear	Medium RES but high nuclear and CCS deployment	Very high	Very high	Very high	Low	Medium

Table 2 presents the assumed component cost and useful lives. We annuitize all investment costs, with no asset residual value, and discount all costs and benefits to 2030 using a 4% discount rate. This is the rate adopted in the ENTSO-E (2016b) cost-benefit analysis methodology and on multiple European Commission guidelines. It is also within the range recommended in the discount rate analysis of Hermelink and Jager (2015). The total net benefits of the offshore generation and transmission expansion is thus computed as the welfare gains from the expansion when compared to a no-expansion case, minus the offshore wind and transmission investment costs, for all expansion periods, up to the lifetime of the assets.

The storage technologies are concentrated solar power and pumped hydropower storage. The first has an energy inflow from solar radiation, while the latter has no hydropower inflow but may store energy with a round-trip efficiency of 75% as in the e-Highway2050 project.
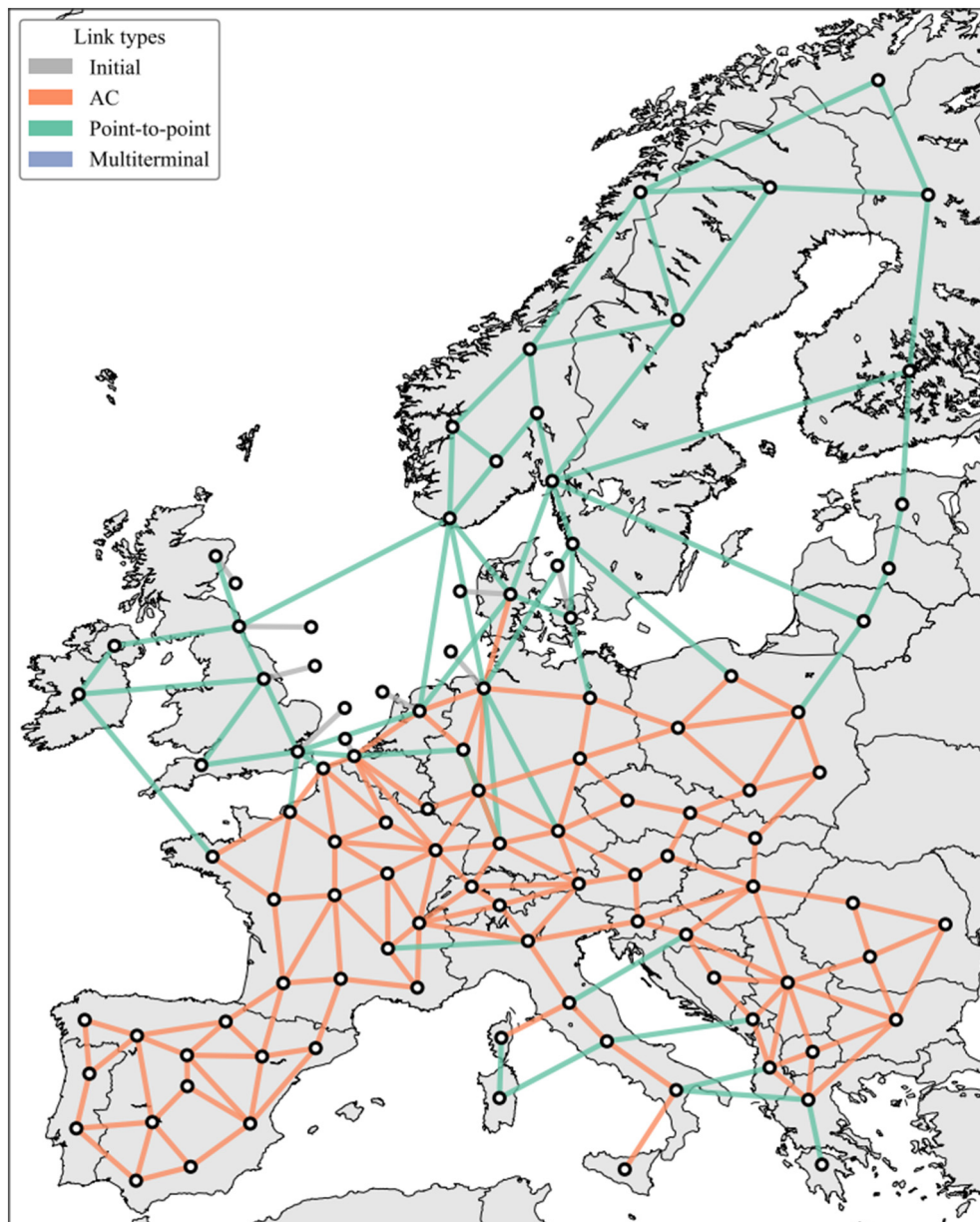

Fig. 5. 2030 initial system. (For interpretation of the references to color in this figure, the reader is referred to the web version of this article.)

Table 2
Component cost and lifetime data.

Component		CAPEX		CAPEX reference	OPEX	Lifetime (years)
Offshore wind farm	Nearshore	1,800,000.0	€/MW	(Weise and Bauer, 2013)	2% of CAPEX	25
	Farshore	2,200,000.0	€/MW		(Flament et al., 2015)	
HVDC multiterminal cable		1765.7	€/MW·km	(Vafeas et al., 2014)		40
AC/DC converter		123,000.0	€/MW			
HVAC cable		2895.6	€/MW·km			
HVDC breaker		16,666.7	€/MW	(CIGRE, 2013)		

Assumptions were required, partly due to data availability restrictions. First, exact impedances for onshore lines are distributed in the impedance ranges indicated by the e-Highway2050 project (inversely to line capacities), since exact values are unavailable. Second, differently from the e-Highway2050 project, the offshore wind farm potential (increasing linearly from 2030 to 2050) and starting installed capacity is the same for all scenarios. We analyze a higher offshore wind starting capacity and potential in the sensitivity analysis. Third, we model load curtailment for inelastic demand using a long run value of loss load of 1500 €/MWh (IIT, 2012). This is lower than the e-Highway2050 value but more adequate for long-term expansion planning. Fourth, marginal costs for generators in 2030 were derived from parameters of the ENTSO-E (2016c). Finally, the onshore Nordic and British Isles transmission grid uses point-to-point HVDC lines, as in e-Highway2050.

The e-Highway2050 node locations minimize the distance between the network clusters. Hence, the location of onshore nodes bordering the North Sea would penalize investments in offshore transmission, due to increased cable lengths. Therefore we relocate these bordering clusters to nearby coastal substations identified in the ENTSO-E transmission system map (ENTSO-E, 2017). This does not affect the onshore system operation and there are no endogenous onshore transmission investments.

Our model focuses on the long-term expansion planning of generation, and thus we do not address some short-term aspects of power systems. These include especially unit commitment constraints, intra-day and balancing markets, and renewable generation forecast errors. These are important aspects for the operation pillar of an offshore grid governance framework (Van Hertem et al., 2016), but impact less the planning and cost and benefit distribution governance pillars.

2.5. Verification

To ensure that the 'that the computer program of the computerized model and its implementation are correct' (Sargent, 2013) we compared the results with the e-Highway2050 project, and conducted extreme input testing.

The largest differences to the e-Highway2050 project are lower generation from biomass (due to a high marginal cost) and higher generation from nuclear (driving down biomass and fossil-based generation) in some scenarios. However, generally generation and load shedding levels of the results are consistent with the e-Highway2050 results, with the assumptions detailed in Section 2.4 explaining the differences.

Finally, for the extreme input testing we applied null and extreme values for generation marginal costs and installed capacities, and transmission and generation investment costs. We also removed the energy constraints and storage round-trip losses. This allows us to observe if the model behaves accordingly, and to observe which extreme inputs affect results the most. For example, generally extreme costs have the largest effect: null investment cost values for transmission or generation may double the net benefits and lead to investments orders of magnitude higher than normal. Also, very high generation marginal costs (equal to the value of loss load) lead to large negative net benefits (more than a hundredfold original positive net benefits). It also eliminates all producer surplus due to the marginal cost homogeneity.

2.6. Validation

To ensure that 'within its domain of applicability [the model] possesses a satisfactory range of accuracy consistent with the intended application' (Sargent, 2013) we compared the results to the e-Highway2050 project. While transmission expansion in the e-Highway2050 project happens primarily onshore, our model focuses on offshore expansion. Thus, we find increased levels of offshore expansion, especially in the corridor to Britain and Denmark, while corridors to Norway are underinvested. With integration constraints this underinvestment in Nordic corridors is not as pronounced. This could indicate that the integrated lines and co-investment in generation and transmission of OGEM provides greater opportunity for shorter, integrated connections, which affect the long Nordic interconnections negatively.

Since the offshore wind potentials of our input data are higher than in the e-Highway2050 project, our model results in higher offshore wind installed capacities for all scenarios except the 100% RES. Again, the larger offshore portfolio (including integrated lines), the consideration of multiple transmission technologies and the co-expansion of generation and transmission make offshore wind expansion more attractive, and more in line with current developments. For example, the original Small & Local scenario forecasted a 14.9 GW offshore wind installed capacity, while the North Sea already has almost 10 GW installed and 20 GW consented (WindEurope, 2017a).

These observations corroborate the adequacy of our approach to address the impacts of integrated governance constraints on the North Sea offshore grid expansion, providing more insights for the region than the e-Highway2050 project.

3. Results

The left side of Fig. 6 presents observations regarding the unconstrained offshore expansion pathways, that is, without any active integrated governance constraint. The effect of the integrated governance constraints is indicated on the right, with each line of the figure discussed in detail in the following subsections. Full indicators and the expansion pathways can be found in the annexes.

3.1. Scenarios determine offshore expansion and welfare gains

In unconstrained expansion pathways we find that scenarios strongly determine offshore expansion and welfare gains. Then, as we discuss in Section 3.1.1, the integrated governance constraints lead to limited welfare losses in absolute terms. Moreover, the constraints affect the specific transmission corridors unevenly, that is, they impact the transmission corridor technologies and types differently.

The first observation on the unconstrained expansion pathways concerns the central role of differences between scenarios as drivers of offshore expansion and its associated welfare gains, especially the load levels and the cost and capacity of generation. The Fossil & Nuclear and Small & Local scenarios have the cheapest and largest reserve margins (i.e. the gap between average available generation capacity and load), leading to lower needs for offshore investments.

Section	In unconstrained expansion pathways ...		... and integrated governance constraints ...
3.1	Scenarios strongly determine offshore expansion and welfare gains	⇨	Lead to limited welfare losses in absolute terms
			Affect specific transmission corridors unevenly
3.2	There is a high welfare distribution asymmetry for actor groups and countries	⇨	May bring limited benefits to certain countries at the cost of European welfare
			Affect little the welfare distribution symmetry for actor groups and countries
3.3	Line types and technologies strongly affect each other	⇨	Reduce the participation of integrated lines and multiterminal HVDC
			Increase the effect of path dependence on multiterminal HVDC

Fig. 6. Effect of integrated governance constraints on offshore expansion pathways.

On the other hand, the 100% RES scenario has a particularly tight and expensive margin, leading to higher investments levels and higher load shedding. This low margin is visible in Fig. 7, which presents the cumulative capacity contribution of each generation technology prior to any offshore wind investment, together with the onshore load (median and 80% interval in grey). Here the average available capacity is slightly above 600 GW and is not even sufficient to meet the 80% percentile load. This indicates significant load shedding would happen in the absence of further offshore wind investments. In the Fossil & Nuclear scenario, on the other hand, the average available generation capacity reaches almost 900 GW and can easily deal with the 80% percentile load level.

Thus, reserve margins strongly determine the general level of investments in offshore transmission and generation. For all scenarios and governance constraints, the initial offshore wind capacity in 2030 is 25.3 GW, in line with the 2016 European Commission reference scenario (EC, 2016b). Endogenous investments in offshore wind lead to total installed capacities between 51.4 and the maximum potential of 114.9 GW in 2050 for the unconstrained case (up to 172 B€$_{2030}$ in investments). The highest deployment levels are observed in the 100% and Large-scale RES scenarios. By 2050 offshore wind and transmission investments lead to low nodal prices (below 60 €/MWh) in most of Europe. Total transmission investments range from 6.5 to 24.0 TW·km for the unconstrained case (up to 55.7 B€$_{2030}$ in investments), which represents an addition by 2050 of up to 11% in TW·km to the 2030 grids of the e-Highway2050 project.

Capacity margins between scenarios also determine the welfare gains of expansions. The 100% RES presents the highest net benefits (24.4 B€/year for 226.4 B€ in investments) and the Fossil & Nuclear the lowest (1.5 B€/year for 77.8 B€ in investments). This is in line with the corresponding generation capacity margins and costs. As a comparison, the estimate of the 2016 North Sea regional planning of the ENTSO-E (2016a) for the offshore grid benefits reach 2.6 B€/year for 24.8 B€ in investments. However, this estimate covers only 2030 and just transmission expansion, while here three expansion periods are considered including generation expansion, and thus welfare gains are logically higher.

The low-benefit scenarios assume the availability of low-cost nuclear and fossil-based generation with carbon capture and storage, or low demand levels. Thus, there are large benefits in deploying offshore wind and transmission given tighter and more expensive generation capacity driven by a lack of carbon capture and storage, which seems the more probable future.

Finally, common national reserve margins across scenarios lead to some common transmission corridors, namely Germany-Denmark and three corridors from Great Britain to France, Belgium and Netherlands (Annex 6). In the 100% RES scenario they are driven by insufficient generation in continental Europe, while for the other scenarios the continental merit order curve is more expensive than in the British Isles and Scandinavia. A Norway/Sweden corridor to continental Europe is not common to all scenarios because in the nuclear and fossil fuel-based scenarios the Scandinavian capacities are much smaller.
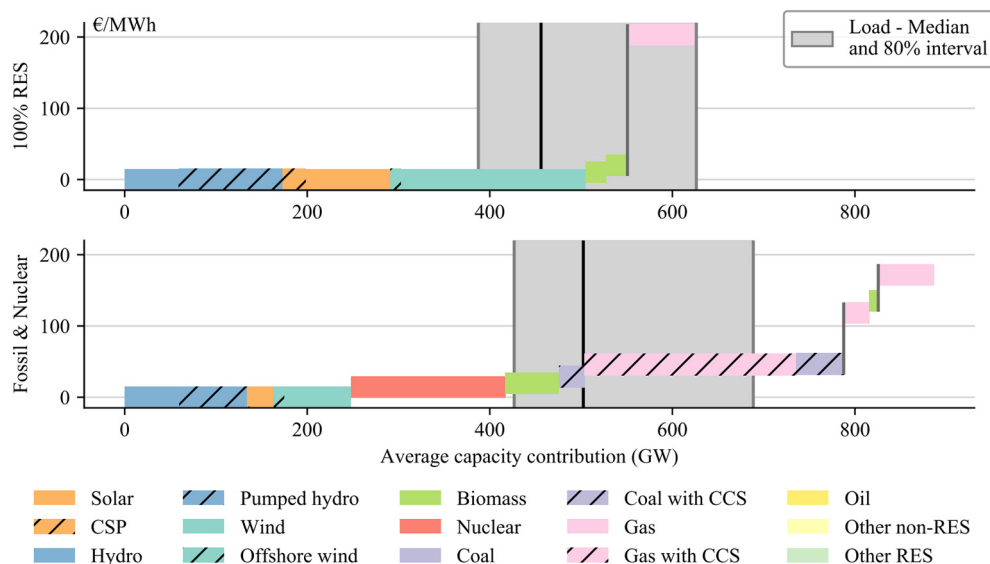

Fig. 7. 2050 merit order curves without offshore wind investments. (For interpretation of the references to color in this figure, the reader is referred to the web version of this article.)

3.1.1. Constraints lead to limited welfare losses in absolute terms and affect specific transmission corridors unevenly

While scenarios strongly determine the welfare gains of the unconstrained offshore expansions, integrated governance constraints reduce these regardless of the scenario. Thus, the complex cooperation, disintegrated planning and Pareto constraints may represent welfare losses of 15% or more, but in absolute terms remain limited to under 0.5 B€/year for all scenarios and constraints.

Moreover, integrated governance constraints do not necessarily have a negative impact on offshore generation or transmission investment levels, although the same cannot be said for specific line types or technologies, as discussed in Section 3.3. Offshore investments can be independent from generation investments when subsequent periods leverage the pre-existing offshore system, expanding offshore wind or transmission capacity separately. Nonetheless, this decoupling is limited: usually the scenario characteristics drive both the expansion of offshore transmission and generation. Thus, the ratio of transmission and generation investments is stable across scenarios, with or without constraints.

Concerning common transmission corridors across scenarios, the complex planning constraint maintains more similar levels of investment. The effect of the Pareto constraint is mixed, sometimes building the integrated lines of the common transmission corridors, but often not. Then, there is no investment in the Germany-Denmark corridor under the disintegrated planning, while Great Britain-Netherlands sees its capacity generally reduced. The effect of each constraint is directly related to the participation of integrated lines in these corridors. Hence rather than substituting prohibited integrated lines for conventional ones, the constraints may shift the expansion to conventional domestic wind connections.

3.2. High welfare distribution asymmetry for actors and countries

In unconstrained expansion pathways the distribution of costs and benefits per actor and country is strongly asymmetric, a common feature of power systems – see for example Pudjianto et al. (2016). Then, as we detail in Section 3.2.1, the integrated governance constraints may bring limited benefits to certain countries at the cost of European welfare. Moreover, the constraints affect little the welfare distribution asymmetry for actor groups and countries.

Regarding the distribution of total costs and benefits, Annex 4 presents the data for all actors, countries and scenarios. The 100% RES and Large-scale RES scenarios present the largest costs and benefits per actor and country in accordance with their higher European investment levels (Annex 2).

Generally, the largest and most stable net benefits occur to Belgium, Germany and the Netherlands, reaching up to 16 B€/year for Germany (8% of its operational cost in 2050). Consumer surpluses arising from price reductions are the main contributor, and can be traced back to an increasing offshore wind and transmission capacity (Fig. 8). On the other hand, generally Norway and Sweden lose out due to negative surpluses for their hydro producers caused by price reductions, though usually net losses are small. Since in the unconstrained pathways these countries cannot constrain the transmission expansion, they still cooperate to develop integrated lines despite their losses.

A major winner from offshore investment are offshore wind producers themselves, who exhibit significant surpluses in all high-investment scenarios. Nonetheless, since investments are optimized at the system level, at country level surpluses may not be sufficient to cover investment costs. Also, pre-existing offshore wind may lose due to price reductions from subsequent investments. Finally, onshore intermittent renewables producers generally lose with the introduction of offshore wind due to price decreases, just as conventional onshore generators. This is more pronounced for onshore wind than solar PV generators, due to the higher availability correlation with offshore wind and to a lesser scale to the higher onshore wind installed capacity.

3.2.1. Constraints may bring limited benefits to certain countries at the cost of European welfare losses and affect little the welfare distribution symmetry for actor groups and countries

The literature indicates that the asymmetric distribution of costs and benefits is a central barrier to the development of an integrated offshore grid. Our study confirms this by studying the effect of the integrated governance constraints on line types and technologies, as discussed in Section 3.3.

But the impact of the integrated governance constraints on the welfare of individual countries is small. When countries do not cooperate in welfare-reducing periods with the Pareto constraint, this only leads to a slight reduction in losses for them (and consequently for national actor groups). Thus, the capacity of countries to limit their losses by not cooperating is limited. Individual countries can cause welfare losses to Europe which are not compensated by their individual gains.

Hence, the effect of the constraints is stronger regarding the effect on the deployment of specific transmission corridors, types and technologies, as discussed in the Sections 3.1 and 3.3. Also, the effect on the profitability of individual offshore transmission and wind farm assets deserves further attention.

3.3. Line types and technologies strongly affect each other

In the unconstrained expansion pathways there is a strong interaction between the line types (conventional or integrated) and the three transmission technologies: HVAC and point-to-point and multiterminal HVDC. As we detail in Section 3.3.1, the integrated governance constraints on their turn reduce the participation of integrated lines and multiterminal HVDC. They also increase the effect of path dependence on multiterminal HVDC.

We first present the analysis for the unconstrained expansion pathways. Fig. 9 presents the resulting transmission expansion capacity classified by technology. In the high-investment Large-scale RES scenario, multiterminal HVDC lines are the main technology, accounting for over 48% of the total TW·km. Multiterminal HVDC can form regional multiterminal grids but also local ones, involving only some North Sea countries, such as the French-Dutch grid of Fig. 10. The path dependence identified in Dedecca et al. (2017a) leads to the reinforcement of pre-existing multiterminal grids, through new investments in multiterminal HVDC lines and/or converters. An example is Scandinavia in the unconstrained Large-scale RES case, which invests in HVDC converters in 2050 without any significant new multiterminal HVDC lines.

Point-to-point HVDC remains an important technology, especially in high-investment scenarios, where it can provide an exclusive connection between two nodes, most often through integrated lines. Hence, it is central to the 100% RES scenario, even in the 2040 and 2050 periods, partly crowding-out multiterminal investments.

HVAC is the least used technology for scenarios with large investments, especially due to its length limitation to 200 km, which restricts the candidate portfolio almost exclusively to conventional lines. However, it is the technology of choice for early projects and its investment levels are more stable, which is coherent with it being more attractive for near-to-shore projects.

Regardless of integrated governance constraints, there is significant intra-country transmission capacity investments, especially in Germany, Denmark, Great Britain and the Netherlands, which have the highest offshore development. While cross-border transmission corridors make extensive use of integrated HVDC lines, intra-country connections often leverage HVAC lines. In this way, there can be a complementarity of technologies and line types. For example, in 2030 the conventional HVAC connection of the German wind farm complements an integrated line to Denmark (Fig. 10). In this way, the offshore wind expansion, national merit order curves and loads interact with the integrated offshore grid expansion. Low or expensive generation reserve margins drive offshore wind development and specific transmission corridors, while the offshore node locations influence integrated lines. Finally, the offshore grid
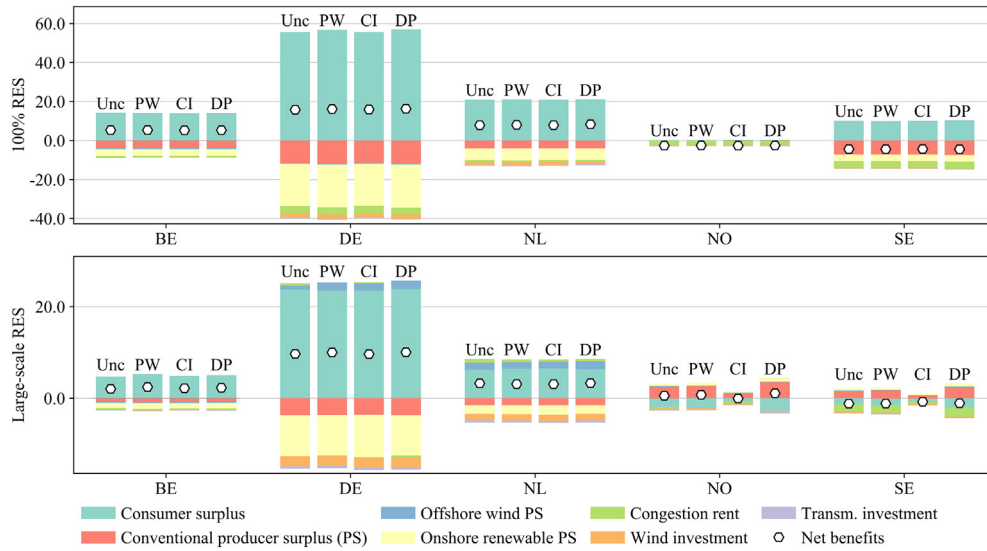
Fig. 8. Selected annualized costs and benefits (B€/year). Constraints: Unc - unconstrained; PW - Pareto welfare; CI - complex integration; DP - disintegrated planning. (For interpretation of the references to color in this figure, the reader is referred to the web version of this article.)

can combine technologies to avoid HVAC and multiterminal HVDC loops and consequently the load flow constraints of Eqs. (3)–(6). Thus, complementary transmission technologies can eliminate single-technology loops in grids.

Since we do not model the expansion of storage technologies (we take it as an exogenous input as well as onshore generation

technology – taking both quantities from the scenarios in e-Highway), we do not analyze the interaction of transmission and storage expansion such as in Bustos et al. (2017). The possible expansion of storage technologies could significantly alter the main transmission corridors by increasing the importance of Scandinavian hydropower storage or by other factors.
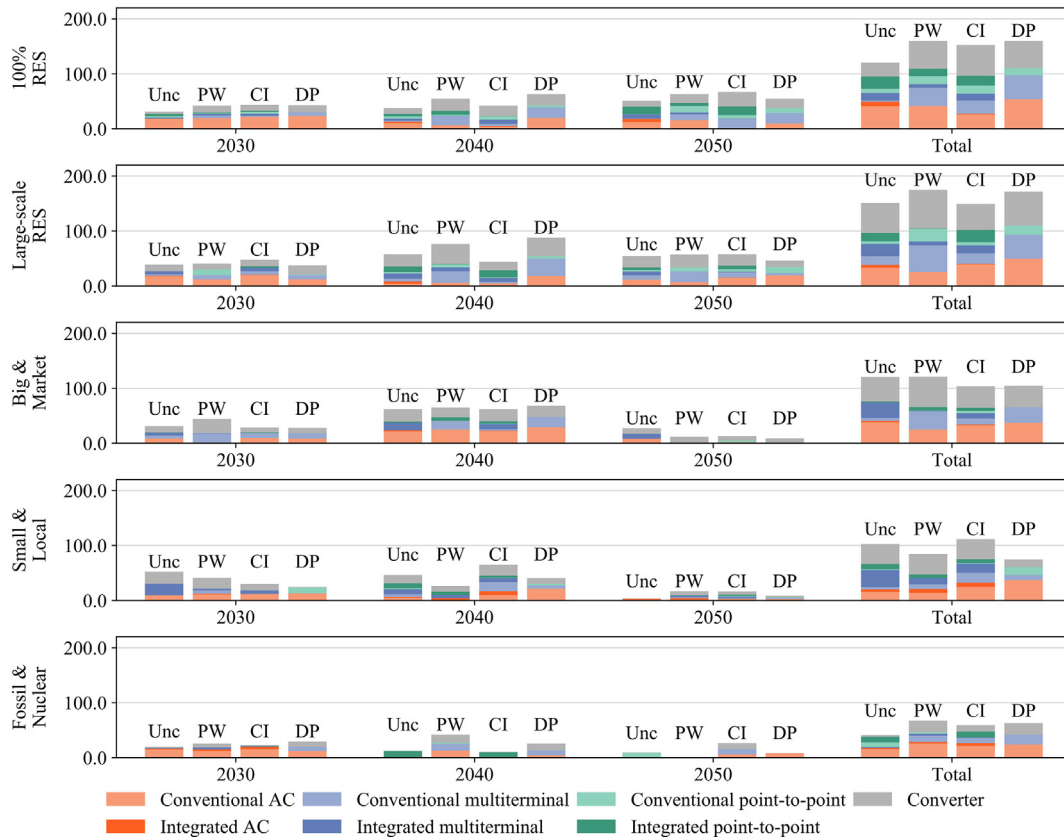

Fig. 9. Results for transmission capacity expansion pathways (GW). Constraints: Unc - unconstrained; PW - Pareto welfare; CI - complex integration; DP - disintegrated planning. (For interpretation of the references to color in this figure, the reader is referred to the web version of this article.)
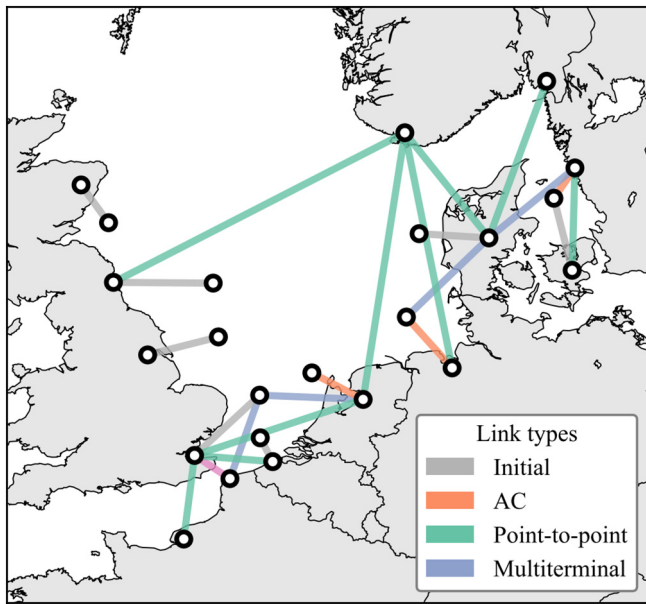
Fig. 10. Unconstrained Large-scale RES scenario grid in 2030. (For interpretation of the references to color in this figure, the reader is referred to the web version of this article.)

3.3.1. Constraints reduce the participation of integrated lines and multiterminal HVDC, and increase the effect of path dependence on the latter

The ability of each constraint to build multiple, separate or no integrated lines affects more the multiterminal than the point-to-point

HVDC. This is sensible since the potential benefits of multiterminal HVDC are greater when it is possible to build multiple integrated lines simultaneously. In low investment scenarios, the share of HVAC increases as investment in integrated lines decreases, accompanying the reduction in investments in integrated cross-border transmission corridors. In high-investment scenarios the capacity of HVAC remains constant, for then there is significant investment in cross-border corridors, albeit different ones than under the unconstrained case. Nonetheless, the transmission technologies keep their observed complementarity under any governance constraint.

Moreover, path dependence influences the deployment of transmission technologies, as further similar investments in a technology are more likely after its initial deployment. For example, after a certain transmission corridor uses multiterminal HVDC, or a complementary technology to avoid transmission loops.

The disintegrated planning constraint blocks any kind of integrated grid. This partially shifts investments from wind farms located closer to load centers to eastern wind farms. Accompanying this, central nodes of the unconstrained multiterminal grids shift from offshore to onshore ones, especially in Denmark. Thus, the disintegrated planning constraint does not impede multiterminal grids but changes the interaction of offshore wind and transmission expansion significantly.

The complex integration constraint is more subtle, reducing the participation of integrated lines (Fig. 9). Furthermore, although by 2050 there are multiple integrated lines per offshore node in high-investment scenarios, these lines are added sequentially, one per investment period. For example, in the Large-scale RES scenario, by 2040 complex planning still develops multiterminal grids. These are however focused on onshore nodes and leveraging multiterminal line investments made in 2030 (Fig. 11).
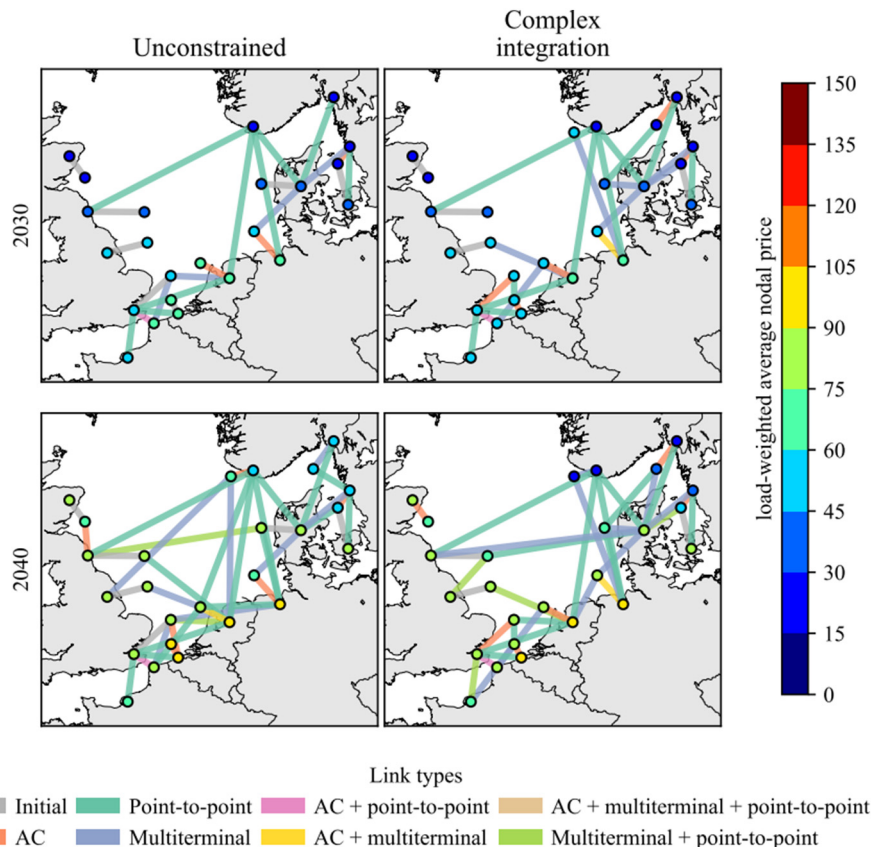

Fig. 11. Multiterminal HVDC expansions in the Large-scale RES scenario. (For interpretation of the references to color in this figure, the reader is referred to the web version of this article.)

Table 3
Sensitivity analyses values.

Sensitivity		Parameter values	Justification	Data source
Offshore wind capacity and potential	Initial capacity Potential	80.0 GW 147.3 GW in 2030 355.0 GW in 2050	Favorable cost reduction and deployment forecasts (WindEurope, 2017a)	ENTSO-E (2016a), Bruninx et al. (2015)
Transmission investment costs	HVDC cables HVDC converters	1324.3–2207.1 €/MW·km 92.3 to 153.8 M€/MW	Costs uncertainties (Härtel et al., 2017b; Wiser et al., 2016).	Vafeas et al. (2014)
Offshore wind CAPEX	Near-to-shore Far-to-shore	1350.0–2250.0 k€/MW 1650.0–2750.0 k€/MW	Values of e-Highway2050 compared to IRENA (2016)	Weise and Bauer (2013)
HVDC circuit breakers	Investment cost	16.7 k€/MW	Uncertainty in requirements and cost	CIGRE (2013)
Hydropower energy availability	Hydropower inflow	+/−25%	Analyze impact of wet and dry years	–
Discount rate		0–9%	Representation of social and private perspectives	Hermelink and Jager (2015)
Time series		Alternative realization for wind, solar and load	Impact of specific time series given deterministic approach	e-Highway2050 project

The Pareto welfare constraint has a similar effect as the disintegrated planning constraint, significantly reducing investments in integrated lines, despite not explicitly blocking them. In high-investment scenarios this actually leads to higher transmission investment costs despite stable investment levels in offshore wind, and possibly higher investment in conventional multiterminal HVDC lines. However, the number of lines built is higher than in the former constraint, which indicates a lower line average capacity.

3.4. Sensitivity analyses

In order to further understand the impact of uncertainties and modelling assumptions on results we conducted the sensitivity analyses indicated in Table 3.

Across, scenarios, decreases of 25% in investment costs for HVDC cables lead to increases of multiterminal and point-to-point HVDC investments of up to 52% in TW·km. Cost increases on their turn favor HVAC cables at the expense of point-to-point investments. Cheaper DC converters favor both HVDC technologies, while cost increases affect mainly point-to-point HVDC. The inclusion of DC breaker costs favors point-to-point HVDC at the expense of multiterminal HVDC, for only the latter requires them. Finally, a 25% offshore wind investment cost increase affects HVAC transmission the most, with a 34% reduction in TW·km investments.

These trends vary per scenario however, and there is no direct relationship between absolute investments in a certain transmission technology per scenario and the influence of investment cost changes. This lack of a clear relationship is compounded by the fact that the relative attractiveness of each transmission option may be more important than the absolute investment cost for any single technology. Thus, counterintuitively, investment cost increases which affect both HVDC technologies may lead to higher investments in one of them. This reinforces the conclusions of Dedecca et al. (2017a) regarding the importance of considering the relative cost and performance of the different transmission technologies.

Increases or decreases in hydropower energy availability inversely affect offshore wind investments and directly affect the interconnection of Scandinavia with continental Europe, at the expense of interconnection to Great Britain. Thus, these changes affect the main offshore transmission corridors, but do not have a clear effect on the general level of transmission investment nor in the chosen transmission technologies.

A higher offshore wind potential leads to significant more investments in offshore wind for the 100% RES and Big & Market scenarios, with a final 2050 installed capacity of 178.5 and 151.4 GW respectively. On the other hand, the higher starting installed capacity means that generation investments for the Small & Local scenario are actually lower, and remain stable for the remaining scenarios. Thus, given

adequate scenario characteristics with tight and/or expensive onshore reserve margins, higher offshore wind potentials can be very beneficial.

Discount rates changes affect especially the low-investment scenarios, while investment in the 100% and Large-scale RES scenarios are affected, but not as significantly. This indicates that the tight and expensive reserve margins of the latter scenarios are still determinant drivers for the offshore expansion despite the change in benefits provided (which are inversely proportional to the discount rate changes). Regarding the technologies, the stability of HVAC transmission to different investment levels already noted in Section 3.3 remains, while HVDC transmission technologies accompany the increase or decrease in investment brought by the discount rates. Also, there is no evidence that discount rate changes particularly affect the deployment of integrated lines.

Finally, the main impact of an alternative offshore wind time series is an increased multiterminal HVDC deployment in the high-offshore wind scenarios due to path dependence. Thus, a slightly higher investment in the technology in 2040 leads to significant further deployment in 2050. This indicates that path dependence can lead to significant differences in the offshore expansion pathway. This does not alter the exploratory model conclusions on the interaction of technology and topology, nor the principles for offshore governance frameworks. In this way the sensitivity analyses reinforce the importance of the interaction of transmission technologies, of generation and transmission expansion and the path dependency of offshore expansion.

4. Conclusions

Using a myopic model, we analyzed the impact of integrated governance constraints on the offshore generation and transmission expansion pathways. The novel Pareto welfare and integration constraints represent governance endogenously, a growing necessity given the importance of the governance decision-making approach in expansion planning.

The offshore grid expansion benefits are positive but highly dependent on the scenarios and asymmetrically distributed between countries and actor groups, and governance constraints affect benefits negatively: up to 0.5 B€/year can be forfeited. The e-Highway2050 scenarios succeeds in representing very different futures. Nevertheless, the high-renewables, high-offshore investment scenarios (where benefit losses from constraints are highest) seem more probable. This because of offshore wind cost reductions and the current difficulties nuclear and carbon capture and storage technologies face.

However, the novelty of the integrated governance constraints lies in more subtle insights. Constraints limit integrated lines and thus

influence the expansion pathways through different channels. First, in the Pareto constraint, losing countries do not cooperate, despite the potential being limited to reduce their own losses, at the cost of increasing societal ones. Second, the complex cooperation complicates the expansion planning by enhancing path dependence, thus demanding anticipatory measures and/or intertemporal coordination between expansion periods. Finally, the more traditional disintegrated planning constraint restricts but does not impede the deployment of multiterminal HVDC transmission, where the ability to build multiple integrated lines simultaneously is important.

Also, important offshore corridors are determined by scenario differences in generation reserve margins between countries. While corridors which leverage integrated lines are significantly affected by the governance constraints, conventional corridors may remain untouched. Thus, instead of replacing conventional for integrated lines, a governance constraint may shift transmission to completely different corridors. On the other hand, governance constraints have little effect on the net benefits distribution asymmetry observed.

Although a top-down decision-making paradigm is not adequate for Europe, there is currently no proven governance framework for expansion planning, especially for the offshore grid. Our results do confirm the importance of the design principles of Dedecca et al. (2017a) for a governance framework. First, expansion planning must consider all combinations of technologies and candidate lines, or risk forfeiting economic, environmental and operational benefits. Second, intertemporal considerations are pivotal to address path dependence and lock-in. Third, the

interaction of technologies must be considered, as well as technological innovation, which will change the relative attractiveness of each technology.
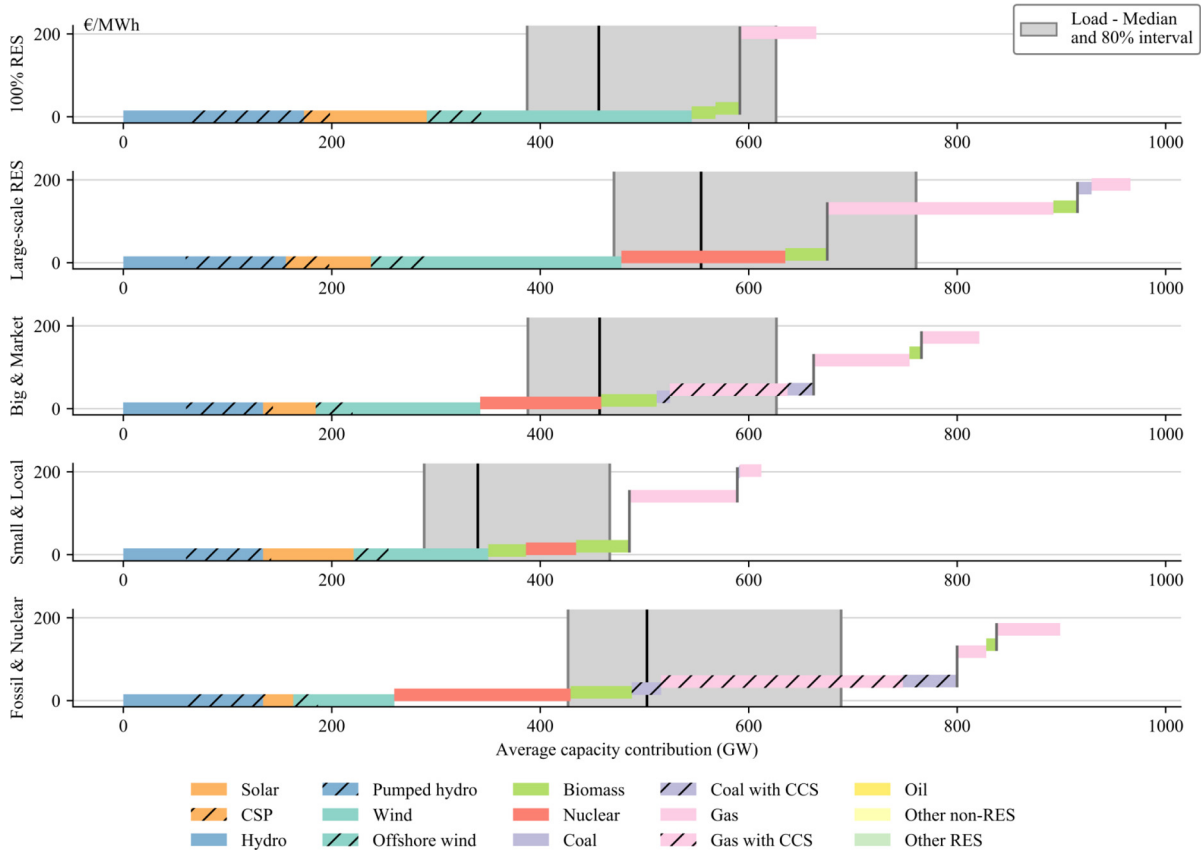
To these principles, we add a fourth: the deployment of multiterminal HVDC and integrated lines are partly independent. Hence, a governance framework must be capable to address the compatibilization and planning of multiterminal grids separately of the deployment of integrated lines. Nonetheless, a disintegrated grid leveraging multiterminal HVDC is a second-best solution - Europe should strive for an integrated offshore grid, with a corresponding governance framework.

Annex 1. 2050 merit order curve with offshore wind investments (unconstrained case)

Annex 2. Offshore grid expansion pathways measures

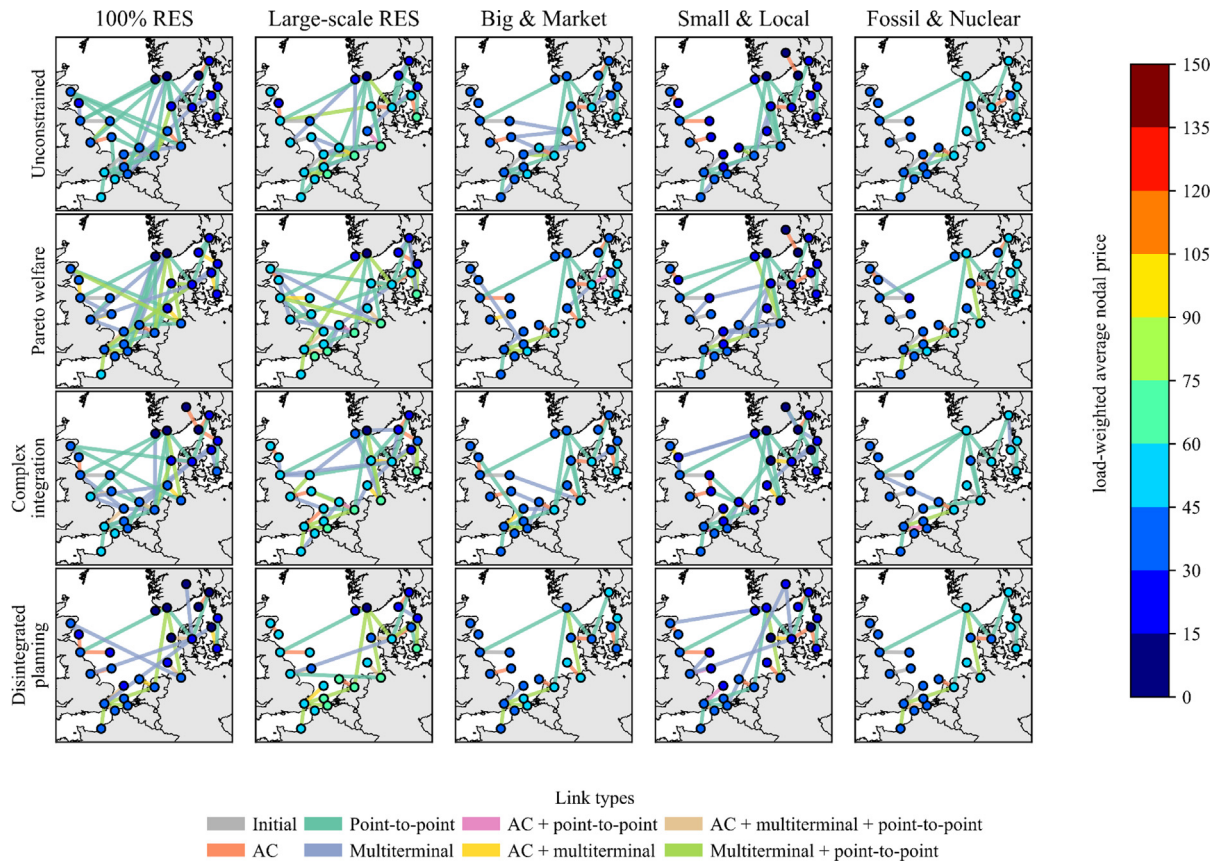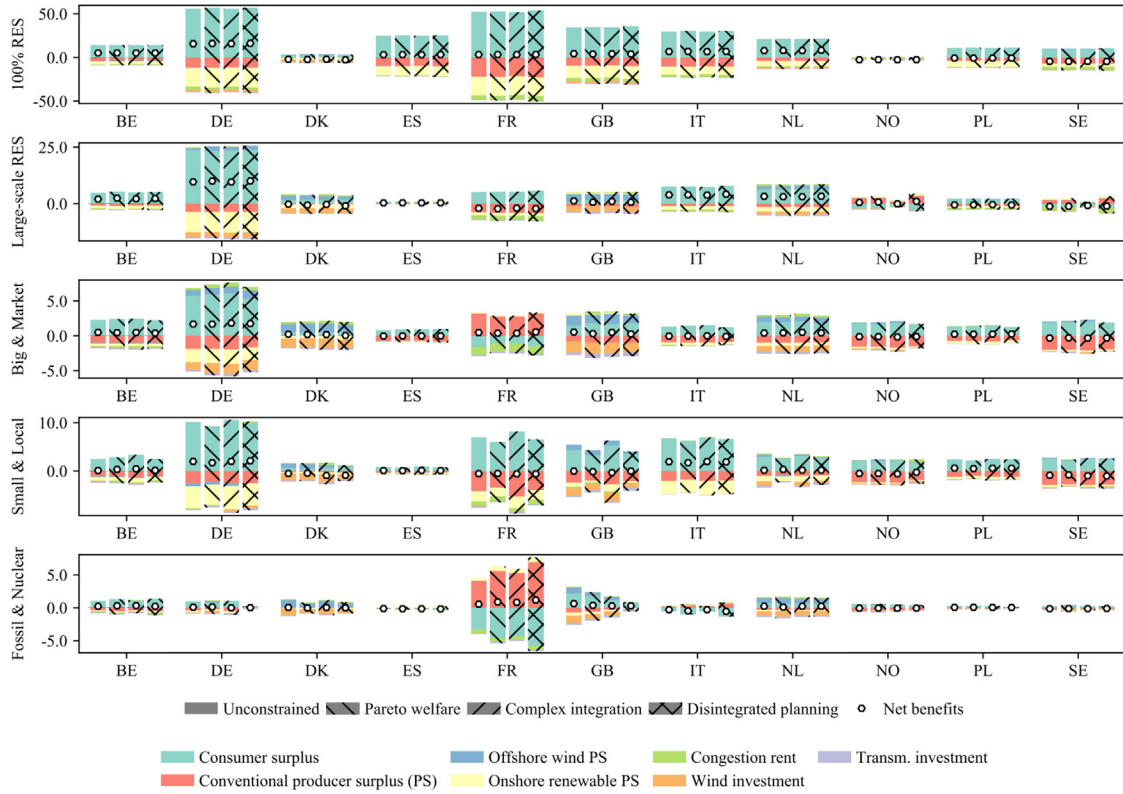| Scenario	Governance constraint	B€$_{2030}$		B€$_{2030}$/year						GW	TW·km		
		Investments		Net benefits	Surpluses					Offshore wind capacity	HVAC	Multiterminal HVDC	Point-to-point HVDC
		Offshore wind	Transmission		Consumers	Congestion rent	Conventional producers	Offshore producers	Renewable producers				
100% RES	Unconstrained	170.7	55.7	24.44	316.2	−28.3	−127.8	0.1	−124.7	114.9	5.98	4.74	13.36
	Pareto welfare	175.4	61.5	24.30	321.0	−28.6	−129.8	−0.2	−126.7	114.9	4.98	10.81	11.75
	Complex integration	173.6	57.9	24.40	314.2	−27.8	−126.8	0.3	−124.3	114.9	3.50	9.53	10.97
	Disintegrated planning	174.0	63.7	24.30	323.8	−28.3	−131.3	−0.9	−127.5	114.9	6.89	16.06	6.01
Large-scale RES	Unconstrained	172.4	48.7	13.60	57.9	−5.7	−17.4	7.9	−18.3	114.3	4.86	9.31	5.38
	Pareto welfare	172.6	60.2	13.32	58.7	−6.5	−17.2	8.1	−18.6	113.1	3.69	12.86	7.58
	Complex integration	177.1	50.1	13.30	60.2	−4.5	−19.8	8.3	−20.0	114.4	4.78	8.04	6.57
	Disintegrated planning	170.1	57.1	13.39	58.2	−6.9	−16.5	7.7	−18.1	114.9	6.23	12.40	4.69
Big & market	Unconstrained	103.5	30.5	3.24	22.4	−0.9	−11.4	4.4	−4.9	78.7	4.57	6.38	0.65
	Pareto welfare	113.7	34.6	2.89	23.8	−0.4	−12.3	4.4	−5.5	84.1	3.30	6.66	2.15
	Complex integration	117.9	31.5	3.24	24.7	−0.4	−12.8	4.5	−5.6	86.1	4.21	3.90	2.67
	Disintegrated planning	101.3	30.7	2.85	21.9	−0.3	−10.9	3.7	−5.2	77.3	4.84	6.51	0.00
Small & local	Unconstrained	88.2	33.3	1.38	54.5	−1.7	−30.6	1.8	−16.7	72.4	2.11	6.02	3.39
	Pareto welfare	67.1	27.7	1.37	49.0	−1.8	−27.7	1.2	−14.8	64.4	2.09	5.52	2.34
	Complex integration	108.1	31.9	0.90	58.6	−1.2	−32.8	1.4	−18.3	86.3	3.41	5.71	4.17
	Disintegrated planning	79.5	38.2	1.21	51.8	−0.9	−29.4	0.8	−15.4	68.8	4.54	4.09	5.40
Fossil & nuclear	Unconstrained	58.9	18.9	1.46	2.8	−0.7	1.2	2.7	−0.8	51.5	1.93	0.29	4.32
	Pareto welfare	59.4	21.9	1.34	0.0	−0.6	3.6	2.5	−0.4	54.2	3.14	4.27	0.36
	Complex integration	46.5	23.3	1.23	0.4	−0.6	3.0	2.1	−0.3	46.6	2.95	2.68	3.82
	Disintegrated planning	26.2	19.8	1.35	−4.0	−0.8	7.0	1.1	0.3	36.4	3.04	4.33	0.00

Annex 3. Offshore wind installed capacity (GW)
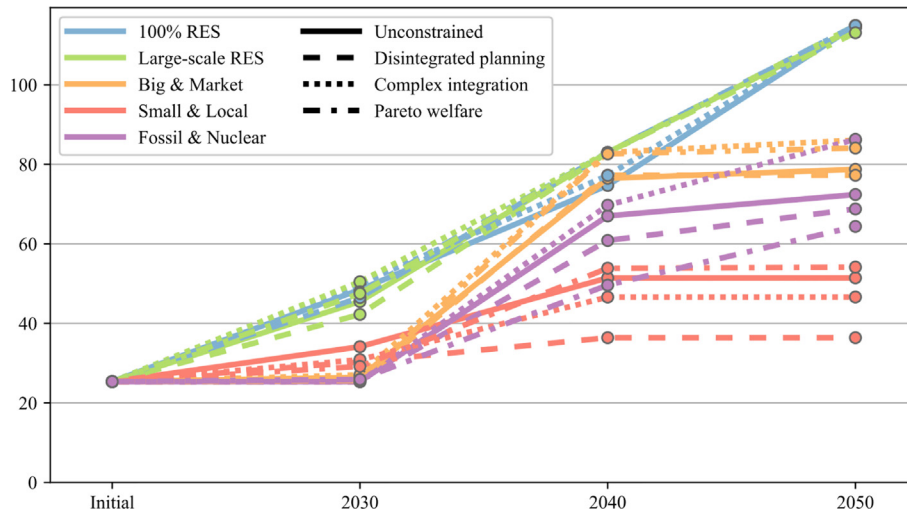
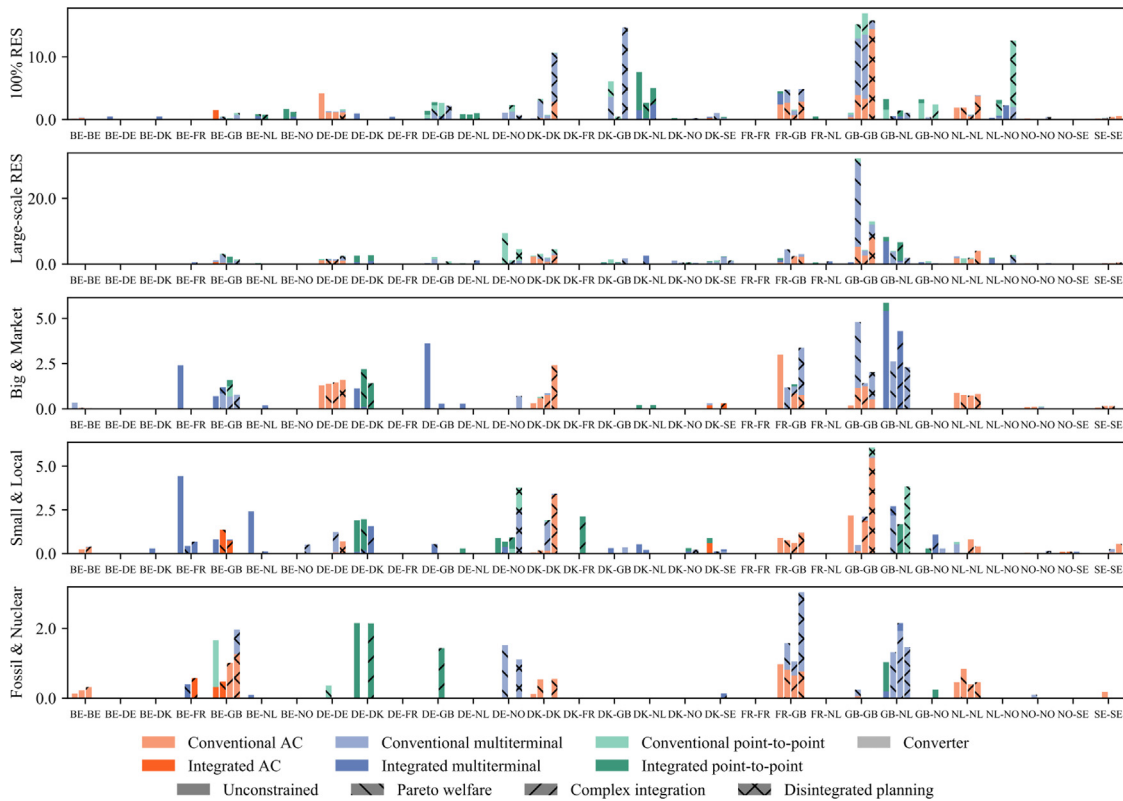**Annex 4. Unconstrained expansion pathways for the offshore grid**
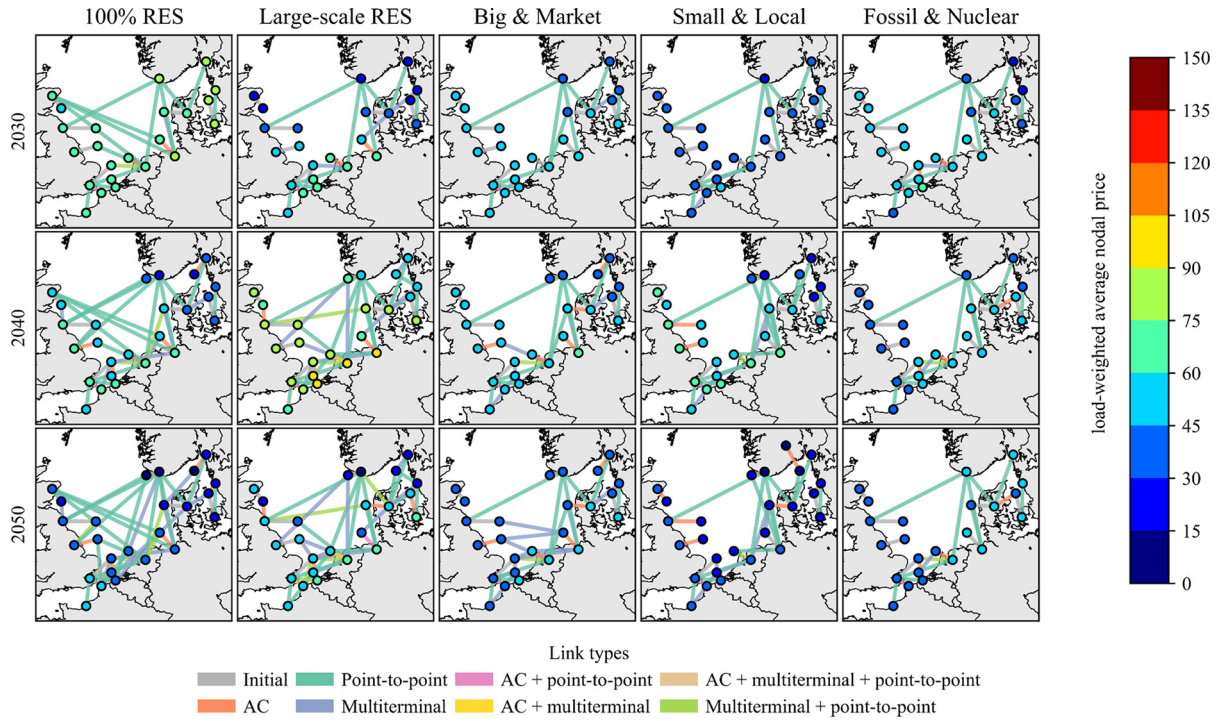
Annex 5. 2050 offshore grid for all scenarios and governance constraints

Annex 6. Annualized costs and benefits (B€/year)

Legend:
Unconstrained · Pareto welfare · Complex integration · Disintegrated planning · ○ Net benefits

Consumer surplus · Offshore wind PS · Congestion rent · Transm. investment
Conventional producer surplus (PS) · Onshore renewable PS · Wind investment

Annex 7. Transmission corridors and technologies (TW·km)

Legend:
Conventional AC · Conventional multiterminal · Conventional point-to-point · Converter
Integrated AC · Integrated multiterminal · Integrated point-to-point
Unconstrained · Pareto welfare · Complex integration · Disintegrated planning

Appendix 8. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.eneco.2018.04.037.

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