Delft University of Technology

Section: Intelligent Electrical Power Grids

Multi-Terminal Expansion

Identifying options for the multi-terminal expansion of the COBRAcable

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keywords: COBRAcable, cost benefit analysis, interconnector, long-term transmission expansion planning, Monte Carlo, multi-terminal expansion, North Sea grid, offshore HVDC, stakeholder analysis

2015 – 2016

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Identifying options for the multi-terminal expansion of the COBRAcable

by

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to obtain the degree of Master of Science
at the Delft University of Technology,
to be defended publicly on Monday 12 December, 2016 at 9:00 AM.

Student number:	4404505		
Project duration:	September 1, 2015 – December 12, 2016		
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An electronic version of this thesis is available at `http://repository.tudelft.nl/`.

Abstract

The European Commission envisions a power network that increasingly integrates national grids to support renewable energy integration, market coupling and security of supply. An important part of this future grid is the North Sea Offshore Grid corridor. The first steps towards such an offshore network include the expansion of point-to-point sub sea high voltage DC interconnectors with additional terminals to connect with further transmission systems or energy generation facilities such as offshore wind farms.

Traditional expansion planning involves a social cost benefit analysis to assess the economic and social impacts of an expansion. However, the interdisciplinary and multi-actor problem that arises due to the regional scope calls for a broader perspective that addresses the regulatory uncertainties and multiple stakeholder interests involved.

Objective

The objective of this research is to create a socio-economic framework that addresses these problems and identifies options for multi-terminal expansions of the COBRAcable. It consist of the development of time series and scenarios, an expansion portfolio, a social cost benefit analysis and a complementary stakeholder analysis. The COBRAcable is an interconnector between Denmark and the Netherlands that has started commissioning in late 2016. The case study is interesting since it is the first international interconnector to opt for expansion with renewable energy technologies. Moreover, this expansion would occur in the German North Sea area, leading to additional regulatory uncertainties and participation issues between stakeholders with different interests (see base case figure 1) as now three countries are involved and not all benefit equally from the project.

Approach

After the identification of main theories and modeling approaches in the field of expansion planning we developed our own socio-economic framework to address the interesting aspects of the COBRAcable.

Firstly, the time series and scenarios were created to address the stochastic nature and future demand and generation uncertainty. The time series consist of several cases of wind and solar output and demand that represent specific segments of a year. The scenarios define future development of demand profiles, generation mixes and exchange capacities, as well as input values for fuel emissions, and fuel and carbon prices on a 5 year periodical basis from 2020 up to the year 2050.

Second, the portfolio is build upon short-term (up to 15 years from 2020) and long-term transmission and generation projects (after 15 years) that have been found viable for

multi-terminal expansion. This was done based on a literature review. Eight expansions have been identified with differing timings and sizes, see figure 1.

Figure 1: The expansion candidate portfolio.

Third, a cost benefit analysis is performed and consists of several social costs and benefits in the areas of total costs, socio-economic welfare, sustainability, security of supply and network losses. Monte Carlo simulation is adopted to analyze the expansions under stochastic renewable energy generation input. The amount of Monte Carlo runs were determined on the basis of convergence of the cost benefit indicators by setting relative errors (95% confidence interval) of 5% for the main socio-economic indicators.

Lastly, we consider the stakeholder analysis framework that ought to complement the cost benefit analysis. We address several stakeholder criteria based on the governance model in the areas of: planning, ownership, financing, pricing and operation. Sub criteria were then identified in order to identify options and barriers in the implementation of our expansion project.

Results & Conclusions

We have provided a novel approach to address the problem of multi-terminal expansion. The research has exposed that our socio-economic framework is subject to a large amount of uncertainties and assumptions. Furthermore, we have shown the added value of a quantitative analysis looking into the distribution of costs and benefits among countries, and a complementary qualitative analysis to address the effects of regulations and interests on this distribution of costs and benefit. Next to that, our analysis of TEP approaches and the case study have provided insights and recommendations to address the shortcomings of current approaches and our own framework, and the regulatory issues that arise due to the multi-lateral expansion problem.

The main conclusions regarding the case study are presented below.

- All expansions typically improve total socio-economic welfare, sustainability and reliability indicators. Sensitivity analysis on fuel and carbon prices showed similar results, but also indicated that caution must be taken in making assumptions about these variables.
- Our scenarios provided useful insights in different outcomes that exist in possible alternative futures. In terms of total socio-economic welfare, our high RES scenario provided the largest improvements compared to base case. However, we again see that there exist outliers which need further analysis to be explained in detail.
- For Denmark the benefits are most uncertain, exposing large variations between scenarios (shifting between positive and negative results). This indicates the need for mechanisms that ensure the cooperation of Denmark. Again, consideration on the choices of marginal costs values is necessary. Not only the values chosen but also the assumption of the same marginal costs for the same energy technologies in different countries.
- Total consumer surplus is increased and total producer surplus is decreased for all expansions and each scenario, due to the price reducing effect of low marginal cost wind farm integration. This is a consequence of our CBA model not taking into account regulatory and financial mechanisms. There are costs that will be socialized and hence moderate the results as benefits will be transferred from consumers to TSOs and wind farm developers. This outcome is supported by similar methodologies which therefore state that total socio-economic welfare is a more meaningful indicator. However, we adopted the stakeholder analysis to look a bit further in these effects.

The stakeholder analysis provided additional insights on the distribution of costs and benefits and the effect of regulatory uncertainties. The following issues should be addressed.

- Creation of standardized and harmonized planning procedures to reduce their costs and duration, and reduce the risk of parallel planning respectively. The latter is apparent mainly for expansions including wind farm hub.
- Economic regulation could be more harmonized to align TSO interests as currently different national regulations incentivize respective TSOs differently.
- Market coupling of participating countries via harmonized implicit auctions, super shallow connection charging regimes and wind farm feed-in tariffs to provide non-discriminatory choices for wind farm location.
- Providing non-discriminatory incentives for wind farms so that for example radial connection is not preferred over hub connection or vice versa.
- Flexibility mechanisms for support schemes that allow for subsidies to be allocated to a wind farm outside of the own territory should be developed further, or the appropriate tools for cost and benefit allocation to allow national support schemes to multi-lateral projects.
- The creation of appropriate tools to compensate countries or stakeholders that do not benefit from the expansion. In our model this country would be mostly Denmark.

For further conclusions, discussion and recommendations we refer to chapter 4.

Preface and Acknowledgments

This report is the result of a research executed at Delft University of Technology. I have performed this research under joint supervision by the faculty of Technology Policy and Management and the faculty of Electrical Engineering, Mathematics and Computer Science to obtain the degree of Msc. Sustainable Energy Technology.

The research was performed on behalf of the COBRAcable research team at the Intelligent Electrical Power Grids section of the faculty of Electrical Engineering, Mathematics and Computer Science, to complement the technical analysis of multi-terminal expansion with a broader economic scope, and on behalf of João Gorenstein Dedecca, PhD at the Energy and Industry section of the faculty of Technology Policy and Management, to give further insight in the techno-economic development of the future North Sea offshore grid. The approach was to develop a socio-economic framework that could address the wide scope of interests that are involved in the offshore grid development, while identifying the main options and barriers for the first steps to achieving this fully integrated North Sea offshore grid. The COBRAcable provided a very interesting case that illustrates well the complexities of implementing a more integrated electricity grid including large capacities of renewable energy generation.

I have experienced a very steep learning curve throughout the writing of this thesis, analyzing many technical, economic and regulatory aspects of the future power system. Being new to modeling, I acquired a decent amount of experience in the usage of tools like Matlab and Python. Moreover, I developed my professional and academic skills and a great deal of self-knowledge. Specifically, keeping focus and choosing the most relevant concepts to study, and planning the approach of the research were the main personal learning points.

I owe João Gorenstein Dedecca the most gratitude for making this learning experience possible and guiding me on an almost daily basis. His patience and criticism - illustrated by nightly hours of debugging a model that had no bugs - have allowed me to present the thesis in the form it currently is.

Furthermore, I would like to thank Arcadio Perilla for acquainting me with some of the major technical challenges involved in the COBRAcable project, the people in the Energy and Industry section for the input and support, and friends and family for their support when personal difficulties struck.

Last but not least, I want to thank thesis committee members Prof.dr.ir. Paulien Herder, Dr.ir.M.B. Zaaijer and Dr.ir. José Rueda Torres, who provided me with critical feedback on the approach, structure of the report and presentation. Specifically José, who was my supervisor and allowed me to zoom out and concentrate on the right things.

J.T.Pieper
Delft, December 5, 2016

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Nomenclature

ACER	Agency for the Cooperation of Energy Regulators
ACM	Authority Consumer and Market
ARMA	Auto Regressive Moving Average
BNetzA	Bundesnetzagentur
CAPEX	Capital Expenditures
CBA	(Social) Cost Benefit Analysis
CDF	Cumulative Distribution Function
CEER	Council of European Energy Regulators
CEF	Connecting Europe Facility
DERA	Danish Energy Regulatory Authority
DTEP	Dynamic Transmission Expansion Planning
EC	European Commission
EEPR	European Economic Recovery Programme
EIA	Energy Information Administration
ENTSO-E	European Network of Transmission System Operators for Electricity
HVDC	High Voltage Direct Current
LOPF	Linear Optimal Power Flow
MC	Monte Carlo
MCA	Multi-Criteria Analysis
NPV	Net Present Value
NREAP	National Renewable Energy Action Plans
NSOG	Northern Seas Offshore Grid
NTC	Net Transfer Capacity
OPEX	Operational Expenditures
PCI	Project of Common Interest
PDF	Probability Density Function
RAB	Regulated Asset Base
RED	Renewable Energy Directive
RES	Renewable Energy Source
SSRD	Surface Solar Radiation Downwards
STEP	Static Transmission Expansion Planning
TEP	Transmission Expansion Planning
TSO	Transmission System Operator
VSC	Volatge Source Converter

CHAPTER 1

Introduction

Renewable energy sources (RES) to mitigate greenhouse gas emissions and increase energy independence are generally intermittent, and rely on better planning and more complex supply networks than conventional energy sources. Expansion of the power grid across national borders is considered to be beneficial for future energy provision since it can partly overcome the problem of the intermittent nature of renewable energy sources by increasing system flexibility, and allows for a more integrated electricity market. While expectations for total offshore wind power capacity are an increase from 33-40 GW in 2020 to 83-114 GW in 2030 in the North Sea [Adeuyi et al. 2015; de España 2013], total needed transnational transmission capacity is anticipated to increase in the order of tens of GW by 2050 [Hewicker et al. 2011].

Currently, there is significant interest in developing a European Super grid: interconnecting different international regions by High Voltage Direct Current (HVDC) lines to facilitate the added wind power exploitation and international power trade. Several priority corridors have been assigned within Europe, including the Northern Seas Offshore Grid (NSOG) ranging from the Irish to the Baltic Sea, which have gained priority status for cross-border electricity exchange projects such as interconnectors. Increasingly, Transmission Expansion Planning (TEP) practices envision a meshed grid where interconnectors not only connect two on-shore converter stations in two different countries. These would be combined projects where additional intermediate terminals also (inter)connect with other international grids or offshore energy technologies.

Multiple international interconnections have been installed with varying degrees of success, all of which have two terminals. Around 15 interconnectors are currently in the conceptual or 'authorized' development stage, yet only few consider the possibility of a combined project [E3G et al. 2013]. The complexity of technical and social aspects, and different national energy policies and legislative environments make risk management and economical analysis difficult and generates high perceived risk [Eskandari Torbaghan et al. 2015]. Therefore, a different approach is required compared to common national TEP.

This research seeks to identify options for implementing multi-terminal interconnectors, where options relate to the trade-off between potential drivers and barriers. We do this from a broad perspective by addressing the problem socio-economically, taking into account (social) costs and benefits for both expansion planners and developers, and society as a whole. Moreover, this analysis will be done considering the impacts of important regulatory aspects that impact these costs and benefits.

Emphasis will put on a case study that is implemented and considers the COBRA cable, planned to be the first cable in the North Sea grid to implement multiple terminals [NSCOGI 2012]. This approximately 300 km submarine HVDC cable will directly interconnect the Netherlands and Denmark and has the possibility of connecting an offshore generation or transmission expansion project, where the connection of a wind farm seems the most probable installation. The COBRAcable provides a unique case study as the interconnector runs through German territory and hence expansion in this country is likely. The scope of this regional project therefore poses many barriers relating to the many stakeholders and interests involved, and the different national regulations that are currently not adequately equipped to address several problems stemming from expansions.

1.1 Problem Definition

Expansion of the North Sea grid is imminent. Large offshore wind energy capacities to be installed in the area require submarine HVDC interconnections across borders to cope with generation uncertainties. The implementation of multiple terminals in two-terminal transnational power cables is an interesting opportunity to realize this but requires extensive research in order to assess its feasibility and address all problems.

Firstly, RES technologies give rise to uncertainties in energy generation. The stochastic nature of RES complicates the decision making process regarding multi-terminal expansions (and any generation or transmission planning process in general) as the costs and benefits that arise are less predictable and stakeholders therefore face risks in the development. Planning issues such as correct sizing and siting, operational issues such as grid reinforcements or balancing to ensure reliable energy supply, and regulatory issues to address all of these issues in an unbundled environment are examples. An adequate method should be developed in order to assess these random uncertainties properly.

Tying in with the RES generation problem, there is also non-random uncertainty regarding the estimation of future developments in generation (e.g. installed capacity, efficiency and fuel prices), demand and exchange profiles. Especially in long-term planning, the outcomes of a feasibility study for multi-terminal expansions may vary significantly under different assumptions for future developments. This problem therefore relies on retrieving correct input data and making reasonable assumptions.

Third, there are ample opportunities for different technologies, capacities/sizes and configurations for expansion candidates to be connected to additional terminals. Expansion projects could consist of transmission, energy generation and energy storage facilities, or even loads or any combination of these technologies. Moreover, the configuration and location makes the amount of possible combinations of potential expansions even larger. Some approach to identify expansion portfolio candidates is required.

The main research problem stems from the allocation of costs and benefits. As stated by Torbaghan et al [Eskandari Torbaghan et al. 2015], in a large interconnected grid there will be both winners and losers in terms of the social and economic costs associated with the expansion investment. Hence, an international expansion project may improve overall benefits to society, but the costs to a specific country or producer may be larger than its benefits. Therefore, the interests of such an actor may impede the expansion. For the COBRAcable case study, the two-terminal interconnection is between the Netherlands and Denmark, but an additional terminal may well be implemented in German territory. Interests of German stakeholders are now also involved while they do not necessarily contribute to the implementation of the expansion.

Next to the costs and benefits that arise from an economic analysis of grid operation, for international multi-terminal expansions other challenges come into play that may affect the distribution of benefits. Stakeholders need to address challenges in planning procedures, project financeability and remuneration, uncertain power generation, operational constraints and potentially fair compensation of 'losing' stakeholders, among others. Many of these issues arise due to the different regulations in participating countries. Some European guidelines are available to address the regulatory differences, but legislation is still required as regional multi-terminal expansions are novel.

We focus on the case study but our analysis can be applied to other interconnectors as well. The scope of the research is confined to Europe, specifically the North Sea area, to reflect European energy policies and regulation, and the status of the NSOG as an innovative energy corridor when it comes to developing the regional offshore grid. Furthermore, we consider the expansion of point-to-point (two terminal) interconnectors with one or several terminals to focus on the first steps towards a truly meshed grid. Lastly, we focus on unbundled markets where the transmission system investors and operators are regulated entities that are incentivized to provide for socially beneficial investments. Merchant investors have other interests than regulated Transmission System Operators (TSOs) , as the former are inclined to only maximize their own profit, and require an alternative approach.

In the next section we address the research questions and objectives that are developed based on the research problems.

1.2 Research Questions & Research Objective

We address the identified problems by designing research questions and objectives. The main objective of this research is to test probable expansion projects for expanding the COBRAcable under different scenarios and design a socio-economical framework to do so. The final report provides insight in the COBRAcable expansion opportunities and a framework for any stakeholder to assess the impact of multi-terminal expansion of the COBRAcable. It will seek to establish feasible expansions in which all international stakeholders will have most interest. The main research question addressing the problem definition in section 1.1 and this objective is as follows:

Question: What is the socio-economic feasibility of expansion options of the COBRAcable from the perspective of the main stakeholders, and how to assess this?

Objective: Develop a socio-economic framework for assessing expansion options to connect to an additional terminal and the impacts of these expansions on the main stakeholders involved, apply the framework to the COBRAcable case study.

A set of sub questions is generated to address further questions that arise from the main research question. The first sub question refers to the theoretical background of TEP and the modeling and simulation methods that could be applied to develop our socio-economic framework as described in the main research question. The objective is to examine TEP theories and methods, such as cost benefit analysis and scenario development, and modeling and simulation methods used in similar projects and studies and identify those that are suitable for the COBRAcable case study.

Sub question 1: What modeling methods are currently applied in the field of expansion planning and what methods are suitable for the COBRAcable case study?

The second sub question addresses the selection of an expansion project portfolio. It will be necessary to select an exhaustive list of suitable expansion options, hence the objective is to develop an expansion portfolio by identifying expansion candidates based on a preliminary research. Expansion candidates can be both transmission and generation technology candidates. This preliminary research considers (future) energy technology developments or trends, grid configurations (topologies) and expansion project timing. Therefore, the following sub question is formulated:

Sub question 2: What projects are viable candidates for connection to an additional COBRAcable terminal, considering energy technology trends, and project timing, sizing and topology?

The third sub question relates to the calculation of social costs and benefits. The objective is building a model that will be able to analyze these social costs and benefits for the expansions in our portfolio, and the allocation among countries and stakeholders to identify winners and losers.

Sub question 3: What will be the social and economic benefits of the COBRAcable expansions, how are they distributed among involved countries and stakeholders?

Lastly, the complexity of regional expansions requires further analysis of the allocation of costs and benefits. The objective is to create simple methodology to identify drivers and barriers for cross-border expansions and gain insight in the effects of these drivers and barriers on the main stakeholders. It will be a more qualitative interpretation of the costs and benefits as calculated in sub question 2 and will provide a complementary analysis by addressing regulatory uncertainties.

Sub question 4: What are the drivers and bottlenecks for the main stakeholders involved in the COBRAcable expansions?

The results would lead to insights in the expansion of the COBRAcable and to a general socio-economic framework that assesses the costs and benefits of multi-terminal expansion of HVDC links on a national basis, and identifies the drivers and bottlenecks for the main stakeholders. This could help for instance planners to identify opportunities or possible losing strategies for particular expansions.

1.3 Research Approach

The sub questions refer to different stages in the research process and require different research approaches. The first sub question consists of literature review of existing theories. This will be the first step of the research and creates an overview of the simulation and modeling tools, and methods applied in expansion planning projects. A research framework will be developed so serve as a guideline to the remainder of the research.

A separate section is created in which the retrieval and creation of input data is discussed. This model input is not addressed directly in a research question but will be essential for our research as the uncertain environment of TEP relies on many assumptions. We analyze it separately as the methodology of model input creation will already address the COBRAcase study.

The other sub questions relate directly to the case study, therefore they will be partly addressed in literature reviews and partly in the results of our study. In chapter 2 we address the theoretical background of these sub questions by literature reviews. The answering of these sub questions will then be addressed later as they present the case study results.

Our model input section and the results of our qualitative portfolio development (sub question 2) are an input to our model. This model (sub question 3) is a purely quantitative analysis of costs and benefits that arise due to the expansions. Sub question 4 is then meant to give further insight in these results by addressing criteria mostly qualitatively again. Where possible however, some quantification of this complementary analysis could be given.

1.4 Report Structure

In Chapter 2 we develop the methodology for our research. We start with evaluating the modeling and simulation tools. We then address some of these topics with a literature research to get into the subject, elaborating on existing expansion planning approaches.

Secondly, we address the methodology and case study implications of model input. This entails taking into account the scale and scope of the research, gathering of input data and the creation of a grid model, scenarios and time series (section2.2).

Third, in section 2.3 the portfolio development approach will be introduced. The portfolio development comprises of identifying and analyzing different candidates for the connection to another terminal. Assessing the viability entails looking into the Dutch, Danish and German North Sea planning, current and expected trends on the power market and in energy policies, and identifying different expansion topologies.

Fourth, in section 2.4 we address the socio-economic indicators that will be assessed in the CBA. These consist of all costs involved for the project developers, the socio-economic welfare, system reliability indicators, sustainability related indicators and the network losses. Where possible these indicators will be monetized.

Lastly, we develop a stakeholder analysis framework. Here we identify the main stakeholders involved and create a framework for a qualitative analysis based on stakeholder criteria and sub-criteria. Results are expected to complement the cost benefit analysis of a multi-terminal system.

In Chapter 3 we will present the result of the COBRAcable case study. We apply our developed framework and model to this interconnector to assess options for the expansions. The COBRAcable will be interesting as it is considered to be the first project of its kind. Results are also meant to give some insights on the framework developed.

In the first section, we introduce the expansions that were chosen to evaluate in the model. We justify the choice of these expansions by looking into the Dutch, German and Danish energy system trends.

Next, we present the main results of the CBA for all expansions. Allocation of costs and benefits among different countries and in time are evaluated for all the indicators.

Lastly, we present the stakeholder analysis results. Here we have looked from the perspective of the expected main stakeholders in the COBRAcable expansion process.

In Chapter 4 we present the main conclusions and recommendations. We analyze the main drivers and bottlenecks of the expansions that are evaluated in the CBA and stakeholder analysis, on the basis of the different scenarios. A trade-off will be made between the risks as identified via the stakeholder criteria, the costs and benefits and division thereof to different stakeholders as identified by our MC model, and the different scenarios evaluated, in order to present the options for COBRAcable expansions as selected in our portfolio.

Apart from this case study perspective, we will also address the general research question as presented in section 1.2, to validate our framework and investigate its use to evaluate similar projects.

Lastly, we provide recommendations for further research. The main assumptions and potential shortcomings of this research will be identified and possible solutions will be presented. We address the importance of similar interdisciplinary frameworks and models.

CHAPTER 2

Methodology

This Chapter introduces the methods applied in the research project. In the first section (2.1) we identify the main theories of the research te be used as a guide and overview to the overall research approach and methods described in subsequent sections. The goal is to create a clear view on the theories and methods that are used in TEP and identify those that fit the objective of our research most.

Secondly, we will discuss our approach to input data creation, and address the data that is used in the COBRAcable case study. The input data creation relates to the grid model, the scenarios and the time series and is discussed in section 2.2.

Next, in order to assess the impact of an expansion in the North Sea, possible projects should be identified and selected. In section 2.3 a qualitative analysis of likely or interesting expansions is presented. The result of which will be an expansion portfolio to be assessed in the model.

After that, we address the choices for cost benefit indicators. For the results to address the impact of an expansion on many different stakeholders, many indicators are identified. Section 2.4 provides the choices and calculations of cost benefit indicators on which we base the results deemed valuable to the research.

Lastly, we will introduce the qualitative stakeholder analysis (section 2.5) that will complement the technical analysis. Here a large framework is presented, to try and grasp all aspects that could be critical to the expansion. This specifically addresses regulatory uncertainty that is not accounted for in the model.

2.1 Modeling Approach

In this section we will discuss the main underlying theories of TEP and the socio-economic framework. Next to that, we address the choices made on input for our model, addressing the COBRAcable case study. Its purpose is answering sub question 1.

What modeling methods are currently applied in the field of expansion planning and what methods are suitable for the COBRAcable case study?

This will provide an analysis of the theories and methods that can be applied in subsequent methodology sections. In section 2.1.1 we elaborate on TEP classifications. There are several main characteristics of TEP that help define which approach should be taken in the research of interest. We comment on these and analyze the desired features for our COBRAcable case study.

Secondly, we address the modeling and simulation methods used in TEP, providing an theoretical analysis of DC power flow, optimization methods and simulation methods and keeping in mind our analysis of TEP classifications in order to tailor the approach to our case study.

Third, in section 2.1.3 we analyze the tools to assess the costs and benefits that arise from multi-terminal expansion. We elaborate on the need for both quantitative and qualitative research approach and discuss commonly adopted assessment criteria and compare several well known methodologies. We end up with our socio-economic research framework.

2.1.1 TEP Classification

TEP requires the modeling of nodal grids, generation and load profiles and exchange patterns. After these inputs are generated, optimization can be applied to assess network and market behavior. Traditionally, such optimization has the purpose of cost reduction [Lee et al. 2006]. Network behavior relates to the technical aspects such as assessing grid reliability and security of supply and developing possible grid reinforcement projects. Market behavior addresses electricity pricing and attempts to predict economic aspects. The classification encountered in literature such as [Latorre et al. 2003; L'Abbate et al. 2011; Lee et al. 2006; Oloomi Buygi et al. 2003] describe three (or four counting optimization methods as well) pillars to distinguish between different TEP models which are important to have in mind when setting up our own models. We address the optimization methods separately in section 2.1.2.

- Static/dynamic
- Bundled/unbundled
- Deterministic/probabilistic

Static vs Dynamic

Depending on the time horizon definition a static or dynamic approach might be undertaken. When only focusing on the optimal expansion (e.g. transmission and generation topology and capacity) at a specific time horizon, and the investments occurs at the start, the approach can be considered static (STEP) . In this situation the unknown variables are the sizing, location and technology type of the expansion. When on the other hand attention is paid to the whole path towards the time horizon, taking into account the specific time at which the expansion is done, we speak of a dynamic approach (DTEP) [Latorre et al. 2003]. Hence, in DTEP the investment timing or planning schedule itself is optimized.

Most often a static or hybrid approach is adopted because the more complex DTEP is computationally heavy and sometimes has negligible effects for long time horizons [Lee et al. 2006]. The hybrid static-dynamic situation considers multiple points in time without the need of complex time consuming models that are often present in the dynamic approach. Usually TSO's adopt time horizons of 5, 10 or 20 years [ENTSO-E 2013; L'Abbate et al. 2011]. After such times uncertainties about various input variables become too large. However, long-term TEP is getting increasing attention due to new modeling tools and improved computational times. It is an interesting approach when one is also interested in the costs and benefits that arise after typical life times of the planned expansions.

Bundled vs Unbundled

In Europe the power market has experienced ownership unbundling since the 1970's. This market restructuring decreases vertical integration between transmission and generation services and has important consequences for TEP processes. In bundled environments, regulated entities have control over both transmission and generation systems. TEP usually formulates the optimization problem of cost minimization or most economical operation to benefit the costumers, while keeping a reliable system [Lee et al. 2006].

In unbundled environments the ownership of generation and transmission assets is divided and merchant generation owners now also have interests in maximizing their own profits from generation plants (and not so much in maximizing social welfare if it all) [Oloomi Buygi et al. 2006]. TSOs on the other hand rely on information of generation owners to maintain reliability and optimal market and network performance, creating uncertainty when there is no transparency between generation companies and TSOs. These different interests also give rise to the issue of choosing the right TEP criteria to include, least-cost criterion is no longer the only option as maximization of profits becomes an objective as well [Wu et al. 2006]. Actual market and regulatory conditions are usually not included in TEP methods [Lee et al. 2006] giving rise to more uncertainties in case of unbundled environments.

Deterministic vs Probabilistic

Models can also be distinguished based on a deterministic or probabilistic approaches. The first entails the combination of a fixed set of input variables including demand and generation information as well as transmission control and reliability constraints. Therefore, they analyze the system based on one case only, and miss the opportunity to give probabilities, weights, or importance to certain cases. Uncertainties due to unpredictable output of solar, wind and hydro energy, demand and outages or network contingencies (i.e. random uncertainties) are then not adequately addressed [L'Abbate et al. 2011]. They generate attention for a probabilistic approach as the interaction of stochastic parameters create an extensive amount of possible scenarios.

Probabilistic approaches require known probability density functions (PDFs) of the desired random input variables. Hence, a sample of historical data is necessary to determine stochastic parameters and include them in the analysis. A common method for probabilistic models is the Monte Carlo (MC) method [Li et al. 2007; L'Abbate et al. 2011], which runs simulation of the same model multiple times by drawing different numbers from the PDFs of stochastic samples of input variables (see section 2.1.2). Deterministic approaches offer superior calculation times but miss the effect of the probabilistic nature of generation and demand, and component failures or outages. However, often deterministic reliability criteria such as a N-1 or N-2 contingency criteria and load balance constraints are used in most probabilistic models because of computation time problems [Li et al. 2007].

In order to cope with non-random uncertainties scenarios describing possible future developments can be generated. This requires the creation of several extreme deterministic cases (sets of input variables) to cover a range of possible outcomes. In unbundled markets generation parameters such as generation operational costs, locational prices and investment plans are not perfectly transparent to the transmission operator, hence the creation of scenarios is essential from a TEP perspective. This is especially true for the generation expansion closure, i.e. the knowledge about future installed energy generation capacities [Oloomi Buygi et al. 2006].

Next, sensitivity analysis can be applied to parameters that are uncertain but not easily addressed in probabilistic models or via scenarios. This would entail rerunning the model while varying only several parameters. Examples of parameters that could be addressed in sensitivity analysis are fuel and carbon prices. Addressing the volatility of these prices is difficult, and both deterministic and probabilistic assumptions are likely to fall short on forecasting long term values.

Modeling Complexities

Not all three TEP pillars can be addressed in high detail and models are simplified to make them viable. It depends on the objective of a study which pillar should be addressed in highest detail and which can be simplified to some extent. E-Highway recognizes the following complexities that relate to the three pillars described above [Panciatici et al. 2013].

- Temporal complexity
- Spatial complexity
- Stochastic complexity

Firstly, temporal complexity relates to static or dynamic pillars in that it deals with the amount of detail in the time series. When adopting a dynamic approach spatial complexity may have to be reduced in order to perform the simulation in a reasonable time frame. When considering the performance of specific power components under the occurrence of a fault, studies might consider time scales of seconds or even milliseconds. In TEP, when dealing with long time horizons and large networks and generation facilities, static approaches with hourly evaluation is the norm [Migliavacca et al. 2014].

Second, spatial complexity relates to the bundled/unbundled pillars, as well as to the increased capacity of renewable energy that is generated far from loads. An increasing amount of independent generation plants call for a larger number of nodes. Clustering similar nodes can reduce spatial complexity and decrease simulation time but will inevitably lead to reduced model accuracy as well [Latorre et al. 2003].

Lastly, stochastic complexity relates to the deterministic or probabilistic pillar. Probabilistic simulation methods require more computational time than deterministic models. Therefore, here the trade-off will be between the number of simulation runs (and amount of stochastic input variables) and the speed of simulations [Panciatici et al. 2013].

Complexity Implications

Some trade-off between these complexity pillars will need to be made since current modeling tools are not fit to meet the most computationally heavy options. That is, using a long-term dynamic unbundled probabilistic model will have very large computational times. The choice on which complexities to include depends on the uncertainties that ought to be addressed.

Our research aims at identifying options for multi-terminal expansion and initially deals with a two-terminal system in a specific location. It will be considered sufficient to use a simplified nodal grid to reduce spatial complexity, where nodes around the interconnector will be more detailed than nodes located far from it. For more specific explanation on the nodal grid please refer to section 2.2.1.

Moreover, our approach will be static, where some points in time will be considered for evaluation, but commissioning dates are decided ex-ante. Depending on the installed technology and the time of connection, different time instants for commissioning could be considered but the timing is not optimized as in dynamic approaches. Between time instants we have periods which last a couple of years. For the exact temporal set up see section 2.2.2.

Lastly, the main complexity of the model will be of stochastic nature. Multi-terminal expansion is uncertain and risky as there are still no major projects of its kind [E3G et al. 2013]. Random uncertainties are large as interconnectors in the North Sea grid will deal with increasingly large renewable energy flows (e.g. Norwegian hydro and German solar energy), especially considering the long life time assumed for interconnectors. We address the time series to cope with these uncertainties in section 2.2.3.

2.1.2 Modeling Methods

In this section we elaborate on the modeling methods applied. We first analyze the underlying theory of DC power flows. Then we elaborate on optimization methods and the method of choice for our case study. Next we discuss the simulation methods and MC analysis as the preferred simulation method. Lastly, we introduce the modeling software.

DC Power Flow

An essential tool for the analysis of costs and benefits in a transmission system, is the calculation of power flows. Power flows refer to the transfer of electricity between nodes. The main function is moving the power from producer or power generators, to the consumer or end user. Several other parameters such as efficiency of the lines, and nodal prices will then determine the economic impacts of the power flows.

In general, power system analyses use either AC or DC power flow methods (also called AC or DC load flow) to model power flows. DC power flow is a simplification of AC power flow that gives estimations of flows in AC systems. It is commonly used when fast and repetitive calculations are required, but also leads to less accurate results. The simplification is based on a linearization of the nonlinear AC system according to a set of assumptions:

- Resistances are negligible (compared to reactances), $R \ll X$ [Ω]
- Voltage angle differences $\theta = \theta_n - \theta_m$ [degrees] between buses n and m are negligible so that $sin(\theta) = \theta$ and $cos(\theta) = 1$.
- Bus voltage magnitudes $|V|$ (in V) are 1 pu.

Equations 2.1 and 2.2 present the AC power flow equations for active and reactive power between buses n and m in W and var respectively, where G is the conductance $[S]$ and B the susceptance $[S]$. The implication of the first assumption is that the conductance G in the reactive Q and active P power flow equations 2.1 and 2.2 respectively, can be neglected.

$$P_n = \sum_{m=1}^{N} |V_n||V_m| \left(G_{nm}cos(\theta_n - \theta_m) + B_{nm}sin(\theta_n - \theta_m)\right) \tag{2.1}$$

$$Q_n = \sum_{m=1}^{N} |V_n||V_m| \left(G_{nm}sin(\theta_n - \theta_m) - B_{nm}cos(\theta_n - \theta_m)\right) \tag{2.2}$$

The second assumption makes the sine term equal to θ and the cosine terms equal to 1, simplifying the equations further. The third assumption will remove the voltage magnitude terms. Rewriting leads to the notion that reactive power flow is small relative to the active power and hence further simplification allows us to neglects Q altogether. This lead to the DC power flow equation:

$$P_n = \sum_{m=1\ m\neq n}^{N} B_{nm}(\theta_n - \theta_m) \tag{2.3}$$

Currently, DC power flow approximations are used in the majority of techno-economic analysis of networks and TEP grid optimization models [Quintero et al. 2014]. They provide good approximations of active power flows in the network considering the main requirements of an X/R ratio of no less than 4, and the voltage profile that should be sufficiently flat [Purchala et al. 2005]. In general, for long term TEP the average error of DC power flow can be limited to around 5% compared to the non-linear AC power flow model [Purchala et al. 2005].

Other disadvantages of DC modeling are that reactive power cannot be calculated and DC power losses are also difficult to consider [Hemmati et al. 2013]. In this research we are interested in the economical outcomes over long time horizons and not so much in the technical aspects of balancing and reinforcements due to operational issues under extreme cases, justifying the usage of DC power flow approximations. Moreover, AC power flow models require non-linear optimization methods and are generally larger, complex programming problems.

Optimization Methods

In the literature many optimization methods have been proposed and examined, most of which are still in the research level and not adopted in real-life cases yet. In general a classification can be made between three types of optimization methods [Li et al. 2007; L'Abbate et al. 2011]:

- Mathematical optimization methods
- Heuristic methods
- Meta-heuristic methods

Mathematical optimization methods find an optimum based on a mathematical problem formulation, often called the objective function. This usually entails optimization of one or few problems and involves the need of simplifying a great deal other aspects that hence should be verified after the optimization result is obtained [L'Abbate et al. 2011]. Typically, for regulated markets the optimization problem is one of cost reduction in order to transfer benefits to consumers by operating the network economically. In unbundled environments the producer's interests of maximizing profits became an additional objective [Lee et al. 2006].

Common examples of mathematical optimization methods include linear programming (DC power flow), non-linear programming (AC power flow), mixed integer programming and bender's decomposition. Other examples are typically in the research stage and therefore not addressed here, they can be found in [Hemmati et al. 2013]. Advantages of these methods are accurate results and low computational times. However, adjusting constraints and power system equations can be tedious.

Heuristic methods are techniques that provide step-by-step evaluation and selection procedures on the basis of logical or empirical rules. The searches are local and carried out until no better solutions can be found anymore. Assessment criteria are usually cost minimization or reliability or contingency related criteria [L'Abbate et al. 2011].

The main problem of heuristic methods is the termination of the optimization algorithm at local optimums instead of global optimums. This problem typically grows when the complexity and size of the network increase. Advantages are the straight forward usage of these methods and the support for DTEP [Hemmati et al. 2013].

Meta-heuristic methods combine features of mathematical optimization and heuristic methods giving rise to higher quality solutions for large problems and DTEP approaches. Examples are genetic algorithms, simulated annealing and tabu search [Hemmati et al. 2013].

The objective of this research of assessing the socio-economic outcomes of multi-terminal expansion from a broad perspective using a simple network model with few nodes, so far has led us to consider long-term DC power flow, STEP approach. The most convenient optimization method therefore will be that of mathematical optimization in the form linear programming. This is also in line with the common educational power system analysis software tools as will become clear.

Linear Optimal Power Flow

In this section we assess the implications of our choice for linear DC power flow optimization method or Linear Optimal Power Flow (LOPF) . LOPF refers to using the DC power flow approximation and combining it with a mathematical optimization method. We address the network components and equations that are applied in our research and the choice for the objective function.

The fundamental components are the buses n, to which all other components can be attached. Other components are loads L [MW], generators s, and branches in the form of lines l and links l. Energy flow f [MW] in these buses is conserved, meaning that the power injected is the same as the power withdrawn for the bus at any time instant t.

$$\sum_{s} G_{n,s,t} - \sum_{s} f_{n,s,t} - \sum_{s} L_{n,s,t} = \sum_{l} K_{nl} f_{l,t} \tag{2.4}$$

Here, $G_{n,s,t}$ is the dispatched generation [MW] at bus n for generator s at time t, and K_{nl} is the incidence matrix that stores the starting and ending bus of each branch. For the line components, which are used in the AC onshore network of our model, the power flow $f_{l,t}$ in line l at time t is calculated by the difference in voltage angles $\theta_{n,t} - \theta_{m,t}$ [degrees] at bus n and m, divided by the line reactance x_l [Ω].

$$f_{l,t} = \frac{\theta_{n,t} - \theta_{m,t}}{x_l} \tag{2.5}$$

Where the power flow may not be higher than the capacity f_l of the line:

$$|f_{l,t}| \leq f_l \tag{2.6}$$

For controllable branches, which we call links instead of lines and are the DC offshore transmission links, the power flow is merely subject to the constraint as depicted in equation 2.6 for the lines. Moreover, if the flow is positive it withdraws $f_{l,t}$ from bus0 and injects $\eta_l f_{l,t}$ in bus1, where η_l is the efficiency of the branch. We apply the objective function to the variable operational costs of the generators, from here on called the marginal costs or variable operation and maintenance costs interchangeably.

$$\sum_t w_t \left[\sum_{n,s} VOM_{n,s,t} G_{n,s,t} \right] \tag{2.7}$$

In this formula w_t is the weighting of the snapshot at time t, $VOM_{n,s,t}$ [€/MWh] is the marginal cost of the generator s at bus n at time t, and $G_{n,s,t}$ [MWh] is the dispatch of the generator s at bus n and time t. We do not integrate minimizing capital costs of generation, storage and branches (both lines and links) in the objective function, since we are interested in the market behavior and we do not optimize the investments (in the further report called expansions), but rather choose to evaluate several pre-determined expansions. Furthermore, we consider storage facilities as flexible (conventional) generation as a conservative simplification due to the lack of reliable time series estimations for hydro inflow.

The model obeys constraints on generation dispatch $G_{n,s,t}$, which may not be higher than the nominal capacity $\bar{G}_{n,s}$ [MW] times the availability of the generator $\bar{G}_{n,s,t}$ [pu of nominal capacity] at that specific time t.

$$G_{n,s,t} \leq \bar{G}_{n,s} * \bar{G}_{n,s,t} \tag{2.8}$$

For our flexible generators the availability $\bar{G}_{n,s,t}$ is considered 1. Hence, depending on the objective function these generators may be fully dispatched at all times if it is economically viable (no restrictions were put on the ramping rates and start up time). For solar and wind power the availability is set according to the time series generated, see section 2.2.3.

Modeling Software

The objective and scope of the research require several modeling characteristics. In the choice for the modeling approach, these aspects are taken into account, as well as personal preference. The following arguments were considered when the choice on Python's modeling package Python for Power System Analysis (PyPSA) was made:

- A complete power system analysis tool with built-in technical simulations of components would be preferred, so that focus can be on the Monte Carlo and cost and benefits aspects of the model.
- The model must be capable of optimizing dispatch.
- DC linear load flow was the preferred choice due to its simple use. Simplifications are justified by the fact that we are interested in the long term economical consequences, not the short term operation under extreme events [Quintero et al. 2014].
- The modeling tool has a lot of build in options including the simple creation of nodal grids including all network components.
- The need for a solid user friendly interface that is suitable for beginning engineers.
- Preference for an open source software package.
- The reliability of calculation with Python.

PyPSA fulfills all these demands. Although we used Matlab for the creation of the time series as the result of the database format, we used PyPSA for the optimization, network model and computation of the economic indicators. PyPSA is similar in its set up compared to other power analysis tools. The LOPF is performed using:

- the (Python Optimization Modeling Objects) pyomo optimization modeling package;

- the Python-GLPK solver (used by Pyomo as a default).

Monte Carlo Simulation

Stochastic model input in the form of RES generation, load forecasts and outage probabilities will be inputted in a model as single variable values. Therefore some deterministic output will be generated. This could create a false sense of accuracy as input variables exhibit randomness. There are several tools to implement probabilistic effects in a power flow model, including Fourier transform, point estimate and fuzzy logic, to name a few. These are all complex tools that aim to reduce computational times of large probabilistic models. It is common practice to validate these approaches by using the more cumbersome MC approach [Morales et al. 2010; Harr 1989], justifying the use of MC for our analysis.

Contrary to the newer more complex models, for the MC simulation it is necessary that PDFs of all stochastic variables are fully known. It draws single random values form these distributions each time the model is run. It then uses this deterministic value as an input for the model and runs the simulation. By running the same simulation many times based on the different random values drawn, a range of possible outputs can be generated with additional information on the accuracy of results. Hence, with the correct (large amount of) input information, the MC is considered valid [Harr 1989] in order to predict a range of possible outcomes. The drawback is its heavy computational effort to run a ton of simulations sequentially.

However, MC simulation allows for a trade-off between convergence of results and computational time as for all results some convergence in the mean, variance and coefficient of variation can be perceived. This can be done by computing the coefficient of variation after each run and see when this value converges around a set value.

$$CV_{runs} = \frac{\sigma_{runs}}{\mu_{runs}} \tag{2.9}$$

Here μ_{runs}, σ_{runs} and CV_{runs} are the mean, standard deviation and coefficient of variation, respectively. By specifying an allowed relative error in the coefficient of variation, one can see after how much MC simulation runs the relative error is below the set threshold. The relative error indicates the confidence interval or range around the mean with a certain coverage probability. The relative error after each run up till *runs* can then be computed according to:

$$\varepsilon_r = \frac{N^{-1}(1-\delta/2)\sqrt{\sigma_{runs}/runs}}{\mu_{runs}} \tag{2.10}$$

where ε_r is the relative error, N^{-1} is the inverse of the standard normal distribution and δ is a measure of the desired coverage probability according to $1-\delta$. E.g. a 95% coverage probability indicates $\delta = 0.05$ [Rueda Torres et al. 2009]. An appropriate relative error may be based on a set value in advance (e.g. up to 5%) or by running the model and deciding an acceptable trade-off between relative error and computational time. We adopt the second approach.

2.1.3 Research Framework

Until now, we have addressed the underlying modeling methods for our TEP research. The next step is defining the methods to achieve our objective. The question is what type of results do we desire and how to receive the results. We conclude this section by attempting to answer the first sub question, introducing our research framework.

Quantitative vs Qualitative Research

The involvement of private investors inducing the switch from a regulated environment to a restructured or unbundled one, is increasingly embraced as it is viewed as beneficial for competition and in creating one European Super grid [Jong et al. 2006]. The division of ownership of generation and transmission facilities among different stakeholders with differing interests makes least cost methods under some reliability constraints not the only objective anymore. It will also be necessary to look into the division of costs and benefits among stakeholders.

Moreover, interconnecting different countries or pricing areas will involve dealing with multiple organizations in different regulatory regimes. As such, interests are more diverse and the regulatory environment more complex. It will therefore be hard to address the complexity of the multi-actor environment with large regulatory uncertainties using only a qualitative approach. An assessment methodology should be embraced where these issues are addressed qualitatively.

Cost Benefit Analysis vs Multi-Criteria Analysis

The methods mostly used to assess the socio-economic implications of expansions include the social cost benefit analysis (CBA) and multi-criteria analysis (MCA) . Both methods measure differences in all costs and benefits for society between the situation with and without the expansion [De Nooij 2011].

The CBA method is often adopted *ex-ante* for large infrastructure projects where clear strategies are present, costs and benefits are mostly monetizable and external costs play an important role. The MCA is often used *ex-post* for sustainability assessment and in general where criteria are less strict and hardly monetizable and a qualitative approach suffices. Therefore, the trade-off is between catching all the effects that are in play but having a more ambiguous trade-off between criteria, and a more limited but easily implementable quantitative result [Beria et al. 2012].

Criteria that are often assessed include technical criteria such as thermal stability, voltage, reactive power and short-circuit criteria, economic criteria including investment costs, project risks and change in network losses, and socio-economic criteria such as social welfare, security of supply, and sustainability [De Nooij 2011]. In general, ENTSO-E identifies four main objectives that TSOs should take into account when planning new investments [ENTSO-E 2015b]:

- Network reliability should be maintained or improved.
- Social (overall) welfare should be increased.
- Technological advances should be considered.
- Planning should occur beyond the 10-year time horizon.

The quantitative analysis of specific technical criteria are beyond the scope of this research as we are interested in the socio-economic consequences of multi-terminal expansions. Accurately assessing the technical criteria would imply the need for a higher nodal resolution and more complex modeling approach including AC power flow analysis and higher temporal resolution of the time series to model the extreme cases in which technical problems usually arise. For the long-term socio-economic assessment however, these simplifications are justified as we are interested in the aggregated social and economic impacts of the expansions at the chosen time horizon.

Economic and social criteria are of main interest to this research. Where possible we will quantify these criteria and use CBA. However, the multi-lateral decision making environment and regulatory uncertainties are difficult to quantify and hence require a more qualitative approach. We will therefore look in existing methods for TEP to identify the assessment criteria they use.

Existing Methodologies

There are several methodologies developed for assessment of large long-term TEP projects. We identify and comment on these in order to create our own CBA approach as is done in section 2.4.

ENTSO-E developed a combined MCA and CBA methodology to assess grid development projects stressing the fact that many indicators are hardly monetizable [ENTSO-E 2013]. Therefore, most indicators do not have monetary units and the effects of all indicators cannot simply be compared to get an overall project ranking. ENTSO-E states that the objective of their multi-criteria CBA methodology is to identify Projects of Common Interest (PCIs), expansion projects where multiple TSOs are involved, and that considerably improve benefits for European society. Furthermore, ENTSO-E states cross-border cost allocation to be an important aspects but a detailed analysis is stated to be beyond the scope of the ENTSO-E methodology. Figure 2.1 shows the indicators assessed in the ENTSO-E multi-criteria CBA methodology.

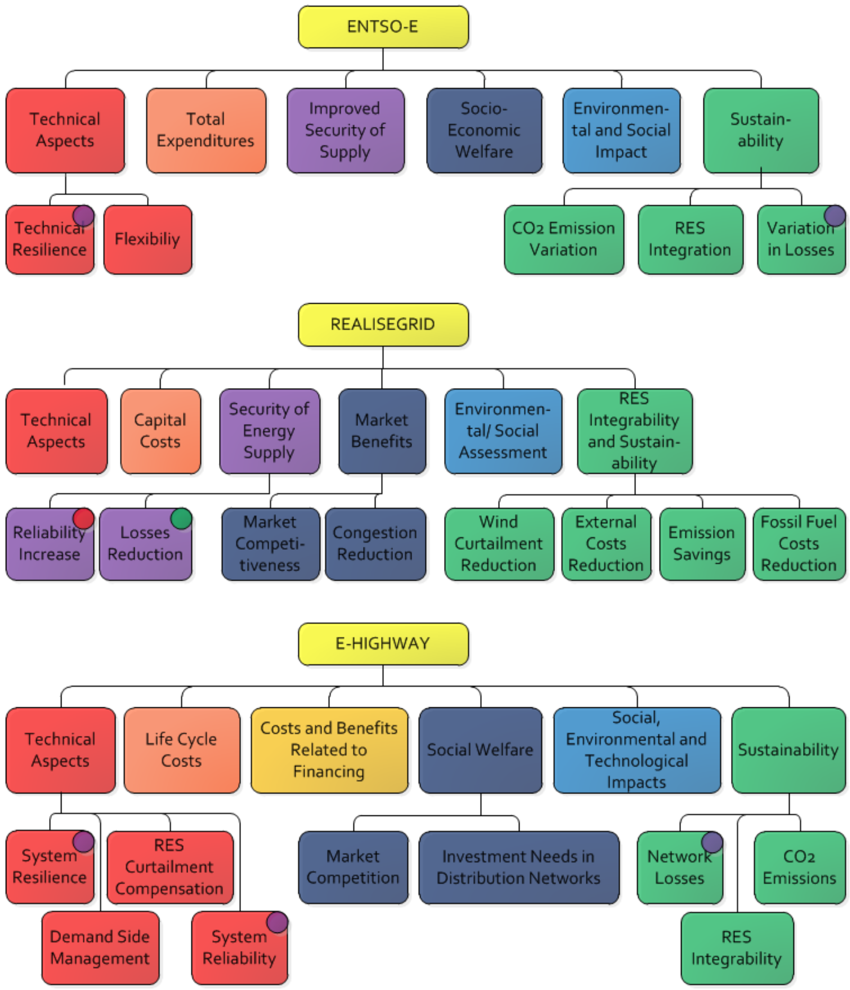
The RealiseGrid project uses the CBA/MCA approach [Migliavacca et al. 2011b]. The objective is to develop a cost benefit classification of the most important projects in the Trans European Network. This aim of comparing multiple projects leads to the preference of one single evaluation criterion. Therefore CBA is preferred over a MCA or mixed approach. RealiseGrid criteria are also displayed in figure 2.1 for comparison. Arrangement and sub division of benefit indicators are different to that of ENTSO-E. There is not a clear structure in cost benefit indicators, the RealiseGrid report [Migliavacca et al. 2011b] emphasizes this as they show multiple arrangements, e.g. using stakeholder (TSOs, generation companies etc.) groups as pillars for the different benefits.

The e-Highway2050 adopts a CBA approach on the basis of similar arguments [Migliavacca et al. 2014]. CBA avoids the possibility of weighting factors too high because they overlap and it makes comparison of results more easy as it applies common metrics (among other arguments). Characteristics of the e-Highway methodology are again listed in figure 2.1. In contrast to ENTSO-E an attempt to assess cost of allocation is made in this methodology. The aim of e-Highway2050 is to define methods and tools to support planning of the electrical highway system.

The arrangement of costs and benefits in figure 2.1 is subjective since some are ordered differently in another methodology, to make it more relevant and comparable a hierarchical structure is implemented for all methodologies where this is not necessarily the case for respective methodology reports. Colored dots in the frames indicate other suitable pillars where costs or benefits could have been part of. It must be stressed that similar criteria might be measured differently across methodologies.

Elements of all methodologies are used to develop a fitting methodology. Not much

Figure 2.1: Costs and benefits assessed in the ENTSO-E, RealiseGrid and E-Highway methodologies.



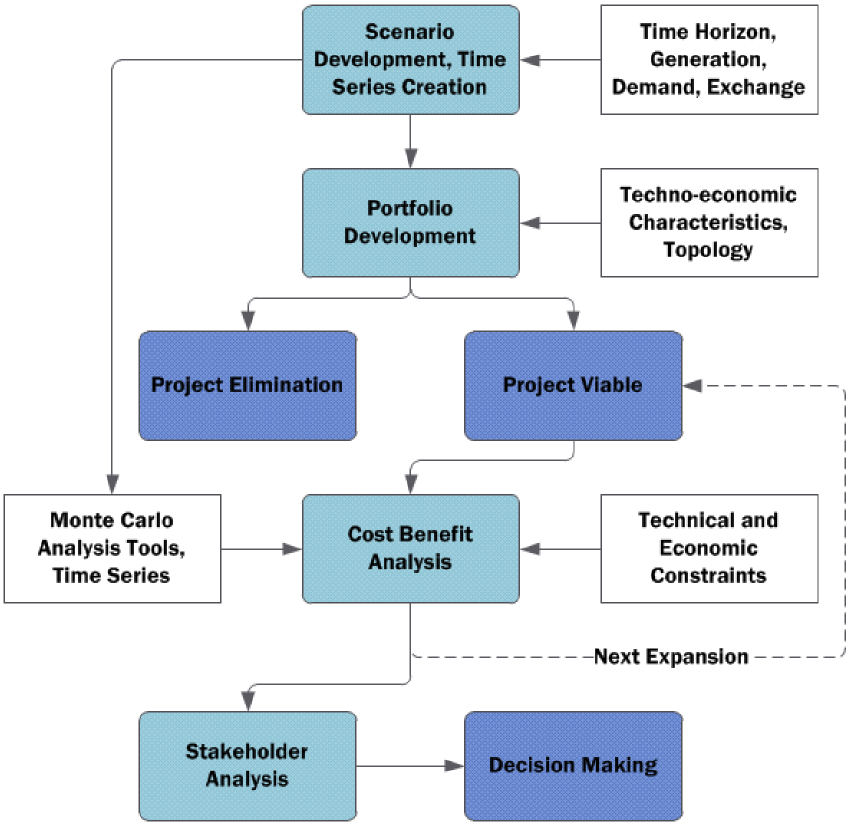
attention will be paid to the social and environmental factors associated with the expansions that are hard to monetize. Public attitudes (social acceptance), biodiversity, land use, health and well being are concepts that are hard to evaluate and out of our central interest of social CBA. Therefore, these types of impacts are summarized under the light blue pillar in figure 2.1. However, we stress the importance to develop a complementary (qualitative) stakeholder analysis to address the regulatory uncertainties that are not accounted for by the model.

Conclusion

On the basis of the identified TEP characteristics, uncertainties, modeling methods and the objective of our research, we develop an overarching research framework that serves as a guide to the research and addresses the set up of the thesis, see figure 2.2.

The first step is the retrieval and creation of input data in order to develop the scenarios. This entails development of scenarios and time series. We then focus on identifying expansion projects that are potential candidates and could provide interesting insights for the COBRAcable development.

Figure 2.2: Socio-economic research framework.



The uninterrupted arrow indicates the iteration in which assessment of the grid without any project is performed (base case). CBA is then applied to the selected portfolio expansions. This is the quantitative analysis that is performed in our model. For the CBA we require the identified modeling tools and input in the form of scenarios and time series.

The base case where no expansion is incorporated should be compared with the result where the COBRAcable is expanded. The single terminal expansion (dashed arrow) then relates to the iteration of all expansion projects.

When the expansions have been examined, a complementary qualitative analysis will be performed. To address the large amount of stakeholders and interests we perform this qualitative analysis on the basis of a stakeholder analysis, where we comment on the factors that have not been accounted for by the CBA and address regulatory uncertainties.

As a last step the model would result in a decision. The socio-economic framework is created in such a way that it could be applied by any stakeholder interested in the socio-economic effects of an expansion. In our case the decision making refers to conclusions of the COBRAcable case study.

2.2 Model Input

This section serves the purpose of acquainting the reader with the retrieval of the appropriate input data. We will start with the evaluation of the simplified grid model that ought to simulate the network surrounding the COBRAcable.

For the creation of scenarios we have looked into existing scenarios as developed by frameworks of ENTSO-E and E-Highway. ENTSO-E has supplied us with 2020 data and their four visions for 2030. E-Highway supplied us with data for their five scenarios for 2040 and 2050. Five year periods are considered by linearly interpolating between the time instants at ten year intervals. For specific data further explanation will be given as some simplifications of this data has been performed.

Apart from the scenarios, we will elaborate on the chosen approach for time series creation for generators and demand. For capacity exchange we did not create time series.

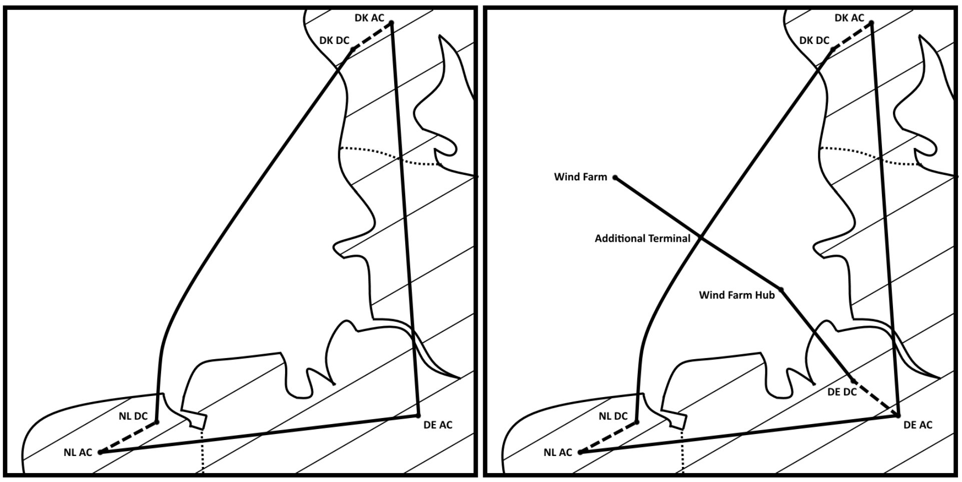
2.2.1 Grid Model

The grid configuration in this case study uses national resolution for the nodes surrounding the COBRAcable. The Netherlands, Denmark and Germany are all represented by single AC nodes of 380 kV. All generation and loads for the respective countries connect to theses nodes. Next to that, for each country there is one DC node (320 kV) to which the offshore HVDC grid can be connected. These DC nodes form the links between onshore buses (national AC nodes) and offshore DC buses that represent the offshore grid.

The offshore DC buses have higher resolution than its onshore AC counterparts. No nodes are aggregated in the offshore grid since the analysis focuses on the offshore cost and benefits occurring from expansion projects. Hence we model offshore DC buses, such as the expansion terminal of the COBRAcable or a wind farm hub, at nodal resolution.

Between onshore nodes, AC transmission lines are drawn from the Netherlands to Germany and from Germany to Denmark. Between AC and DC nodes converter links are modeled and between offshore DC nodes, DC links are used. In figure 2.3 the base case situation is depicted, and a fictional case with all the expansions considered in this research. Note that in fact these expansions will not occur all at the same time but they are all shown for illustration.

Figure 2.3: COBRAcable grid model for the base case and an example where all the expansions considered are shown in one picture.



For the COBRAcable capacity of 700 MW is assumed [Hoveijn 2013], and an offshore length equal to 290 km where the terminal point is assumed to be exactly midway. In reality there is also some onshore cable length before the sub sea interconnector is implemented, this

Table 2.1: DC link and converter variables.

	DC links
capacity	700 MW
voltage	320 kV
resistance	0.02 ohm/km
length	variable
efficiency	equation 2.56
capital cost	1900 €/km

	Converters
capacity	714 MW
efficiency	98%
capital cost	equation 2.25

is however in the order of 10-20 km and therefore neglected. Moreover, the terminal being in the exact mid point is also an assumption as in reality this would depend on the location of the generation connection facility. In order to make the analysis of all expansions comparable we choose the terminal to be at half the total length.

Next, the DC converters are assumed to have 714 MW capacity to be able to supply total COBRAcable capacity after efficiency (2%) losses. The converter possibly will have a capacity of just 700 MW. However, this would not alter flows very much (maximum 2% assuming links are congested), justifying the assumption.

Lastly, for the AC lines reactance x of 0.03 Ω is based on Beautois [Buatois et al. 2014], and resistance r of 0.02 Ω/km is assumed for DC links [Chondrogiannis et al. 2015].

2.2.2 Scenario Development

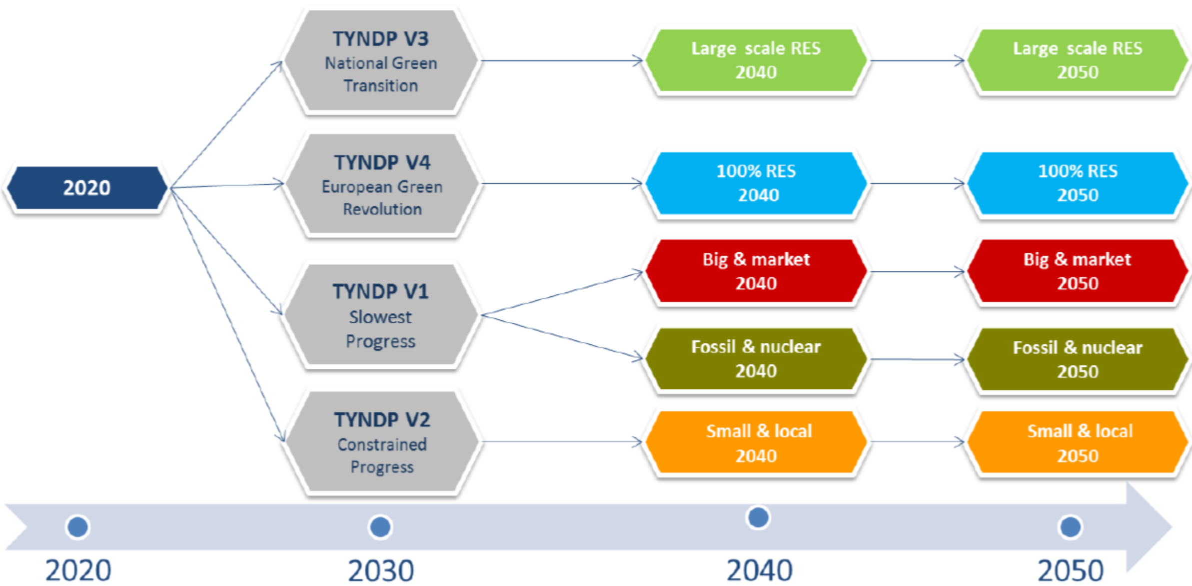
In this section we identify methods for scenario development and address our case study scenarios. Scenarios are descriptions of alternate hypothetical futures and are a tool to cover some non-random uncertainties [Oloomi Buygi et al. 2006], they also describe different pathways or trajectories towards such a future. Not all possible trajectories can be evaluated and as such some different scenarios are developed that cover the extremes of possible future developments to create some range of outcomes.

To get an adequate range of scenarios for long term energy planning the following points are of importance, as also described in the ENTSO-E methodology [ENTSO-E 2013]:

- Time horizon
- Demand development
- Generation dispatch
- Exchange patterns

Scenarios have been developed in many formats by varying organizations including the public scenarios developed in existing expansion planning methodologies. Some of the main sources are the Ten Year Network Development Plan (TYNDP) for 2020 and 2030 updated every two years [ENTSO-E 2015b] and those of e-Highway, supplying scenarios for 2040 and 2050 [Gronau et al. 2015; Bruninx et al. 2013], based on the TYNDP scenarios of ENTSO-E. See figure [2.4] for reference.

Figure 2.4: Scenarios as developed by ENTSO-E for 2020 and 2030 and e-Highway for 2050 and interpolated for 2040 [Gronau et al. 2015].



E-Highway has built its scenarios for 2050 independently from the ENTSO-E visions and distinguished between a 'big & market' and 'fossil & nuclear' scenario which would cover the slowest progress vision of ENTSO-E. Data for 2040 was retrieved by linearly interpolating between 2030 ENTSO-E and 2050 E-Highway scenarios, where 'big & market' and 'fossil & nuclear' were aggregated into vision 1 [Gronau et al. 2015]. This interpolation method may be used in order to assess other time instants as well. In this model, we call the time between instants where model assumptions are updated, the periods. During a period run, assumptions of the time instant prior to that period are used throughout the whole period.

Focus of this thesis is on the allocation of social costs and benefits and not on scenario development. Therefore, assumptions on scenarios are derived from available data such as the ENTSO-E and E-Highway data.

Time Horizon

It is stated that HVDC interconnectors have expected lifetimes of 30-40 years [L'Abbate et al. 2010]. Most power generation technologies typically have similar or slightly less operational time [ECF 2010]. However, a common critic in literature, e.g. about levelized cost of electricity for different generation technologies, is the great variation of assumed lifetimes having consequences for the subsequent market analysis validity. Moreover, for wind turbines an expected 20-25 years lifetime is common and widely recognized as reasonable, though large offshore wind farms have yet to reach such age. For solar panels on the other hand, large variations occur in the literature [Branker et al. 2011], ranging from 20-40 years.

Thus, we argue that depending on the amount of time the interconnector is already in operation at the moment of expansion connection, and the lifetime of this connected technology, a time horizon may be chosen. However, it would be better to assume the lifetime of the interconnector as the main indicator for the time horizon since after decommissioning of the terminal connection the interconnector continues to generate costs and benefits.

Currently, most investments in the energy sector are made on a conservative assumption of project lifetime (e.g. for TSO's 5-10 years in Nordic countries and 7 years in the Netherlands) [Fulli et al. 2009]. Only few are long term and 20+ year assessments like that of e-Highway are rare because of the increasingly greater uncertainties, especially from around ten years onwards (see figure 2.5 for reference), and the lack of appropriate tools to do that. Short term assessments decrease uncertainty in the outcome as many assumptions on future topology, technologies, market and dispatch parameters will need to be made.

For reasons of comparison all scenarios should use the same time instants and thus same period lengths. Expansions could then occur at various time instants (between consecutive periods). Guidelines on energy system-wide cost benefit analysis by the European Parliament that should be followed by projects if they want to apply for the status of PCI, propose a 5 year length for period duration [Parliament et al. 2013].

Figure 2.5: Common scenario time horizon definition in TEP projects.

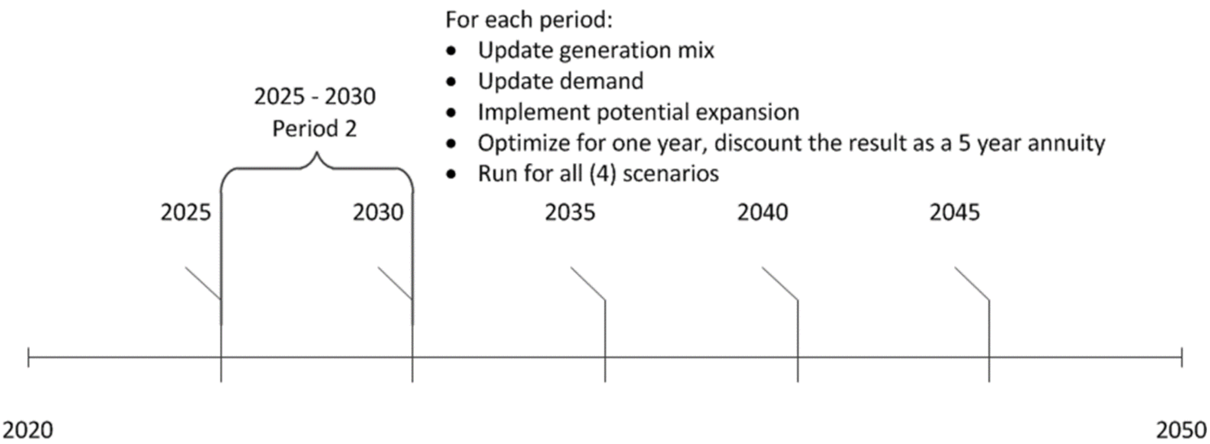


Figure 2.6: Temporal set up of the scenarios.

Figure 2.6 shows the set up of model. The time line is divided in 5 year periods. After each period, demand and generation profiles are updated according to the ENTSO-E and E-Highway scenarios. Therefore, there is only the necessity of the calculation of one year in each period. Annuitizing the result to cover the full period, and discounting to a NPV will then cover the costs and benefits over one period. This will then not only be performed for one year in each period, but also for each scenario. Therefore, each period will deliver 4 different yearly outcomes.

Demand Development

In order to assess possible future scenarios it will be necessary to estimate development of the demand side. This entails the change of loads attached to the grid over time at intermediary time instants until the time horizon is reached. A common means is the estimation of annual demand based on the following steps [Bruninx et al. 2013]:

- Step 1: Make a snapshot of current population, GDP, electrification and energy efficiency parameters per country of interest.
- Step 2: Use information about population and GDP growth to assess the total amount of assets available to buy electricity and use regression analysis to find the correlation between these two variables.
- Step 3: Make assumptions about the change in usage of energy sources, the switch to electricity supply for transport and heating facilities in favor of sustainability will enforce electrification.
- Step 4: Technological advance may lead to increased energy efficiency, depending on the state of innovation and development.

Each of these steps should be evaluated to retrieve the most likely development of variables. However, to account for the uncertainties involved in such estimations, different assumptions should be made in multiple scenarios and cover some likely future development pathways. For our long term research we again refer to the ENTSO-E and E-Highway scenarios to avoid having to create them. Information on the total yearly energy demand for all countries is available for all ENTSO-E and E-Highway scenarios and the data required for the COBRAcable case study is depicted in figure B1 of Appendix B.

Generation Mix

On the supply side many different generation technologies are considered. Future RES development trajectories, the in- or exclusion of nuclear power and/or carbon capture and storage, and the occurrence of innovative competitive technologies, among other, lead to a wide range of possible future scenarios. These are also considered in the ENTSO-E and e-Highway scenarios. Deriving assumed installed generation capacity per technology is done by following these steps [ENTSO-E 2013]:

- Step 1: Make a snapshot of the current generation mix in the countries of interest.
- Step 2: Assign these mixes to the nodes or clusters in these countries, with possible minor adoptions to distinguish between different generation mixes of regions within a country.
- Step 3: Identify possible major future trends to define trajectories of specific technologies, together they will form the generation part of the scenario.

Most of the information will be derived again from ENTSO-E and E-Highway scenarios. Total installed capacities for each technology in European countries are used to scale maximum per unit capacity as defined in the generator time series. Section 2.2.3 elaborates on the creation if the time series, figures B3-B6 of Appendix B show the generation capacity scenarios as used in the COBRAcable case study.

Distinction is made here between *flexible* and *variable* technologies. Flexible technologies refer to those energy sources that can be addressed 'instantly'. In practice, start up time and ramp rates define how quick a generator can respond to changing loads. In the model, they are assumed to react immediately to changing demand. Flexible technologies therefore do not require time series input, as they can generate any capacity between zero and their maximum installed capacity. Dispatch of these technologies is therefore only dependent on their marginal cost and the total demand.

Variable technologies are the ones that are intermittent. The maximum power output is not only based on the installed capacity but also on the energy source availability. For these technologies time series need to be created, e.g. by analysis of historical wind and solar data. These time series can be normalized to a per unit value and scaled based on the updated generation capacities for each period. This is explained in section 2.2.3.

Exchange Patterns

For power exchange between nodes of our internal grid, the net transfer capacities (NTCs) between the nodes set the limit to power flows between them. The optimization will then decide on the actual capacity exchange.

Exchange patterns with external nodes will have increasing importance as the reliance on RES technologies increases, especially in the countries surrounding the North Sea. Therefore, it is required to model power exchange with i.e. France which has high nuclear power capacity or central Europe, where significant hydro power capacity is installed.

An option is that external nodes could be modeled by assessing the generation mixes and optimizing dispatch for these nodes. The nodes could then be in national resolution or even regional resolution (adding national generation mixes). This would require significantly more work on scenarios and more computational time.

Another option would be to set generation in external nodes equal to the NTC between the external node and the internal grid and setting marginal cost of generation and total demand for these external nodes to zero. That way, when there is not enough generation available in the internal grid there is always backup from surrounding countries, giving a more realistic scenario compared to when these exchanges are zero.

We again refer to the ENTSO-E and E-Hihgway scenarios, which were the source of the net transfer capacities (NTCs) between European Member States. Power transfer between the simplified grid and external nodes is modeled by creating three external nodes, consisting of Nordic Europe (NEU), Central Europe (CEU) and Western Europe (WEU), see figure 2.7. Numerical values of NTCs can be found in figure B7 of Appendix B.

2.2.3 Time Series

In this section we will discuss methods for creating time series input. We identify these methods and apply these to our case study. It will first be necessary to evaluate the optimization method of the model.

Optimization of the TEP model occurs at a predefined time instant within a year, called a snapshot. Usually, hourly time series are created so that optimizations are performed for hourly snapshots [Bruninx et al. 2013; ENTSO-E 2013], generating 8760 yearly snapshots with equal weightings of 1. This would require the creation of hourly time series.

To save time, the optimizations could occur less often by reducing the amount of snapshots and increasing the weightings. This simplification leads to time series cases that

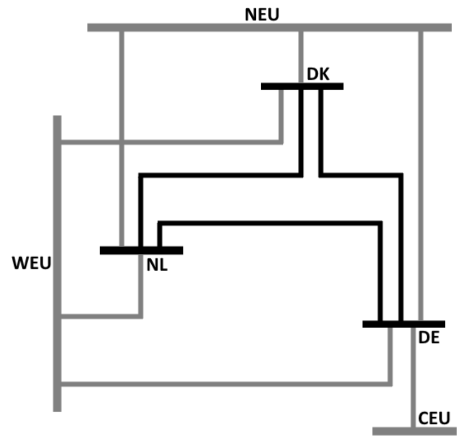


Figure 2.7: External nodes and their connection to nodes of the internal grid.

provide more averaged results, as multiple hourly time series values are considered to compute the snapshot value.

Time Series Creation Methods

Creation of time series based on complex modeling approaches is an extensive research topic and these methods are therefore considered beyond the scope of this research. Examples are non-linear models such as artificial neural network, support vector machine and fuzzy logic models, or combinations of these [Shi et al. 2012]. Approaches to creating time series that were considered in this research are:

- Develop autoregressive moving average models (ARMA). These linear models offer a stochastic approach where also autocorrelation (correlation between consecutive time series values) can be considered.
- Consider the stochastic variables deterministic, this simplification may be justified when seasonal, weekly and daily patterns are clearly visible and do not change much throughout a year.
- Create separate time series cases for specific yearly segments consisting of multiple hours. The time series cases are combined from wind, solar, hydro and load cases. This can be considered a compromise between prior two approaches, drawing values from distributions for each time series case, but not considering any temporal autocorrelation as that will be accounted for by each time series case occurring in different parts of the day, week or season.

ARMA models rely on the combination of previous point values and error estimations. Hence, they forecast future values based on previous values and some observed errors, accounting for temporal correlation between consecutive time steps [Shi et al. 2012]. We disregarded the use of ARMA models early on in the time series creation process since we chose to implement a reduced number of yearly snapshots to reduce the computational time. The ARMA model could still have been applied to create hourly time series on which the creation of time series cases is based, but this means averaging forecasted values and losing autocorrelation properties. Hence, the usefulness of ARMA over the other methods was not apparent anymore.

The choice between second and third option may be justified by assessing the coefficient of variation and by looking at variation of the mean and the variance for specific time series cases. If the creation of time series cases significantly reduces these parameters, this option can be considered more relevant than the deterministic option. If on the other hand, these parameters are only slightly reduced, we conclude that the accuracy of creating cases is only marginal while computational time may be increased considerably. Then a deterministic approach is justified.

Consider the time series case a set of values taken at specific times from the total sample, then:

$$\mu_{tscase} = \frac{1}{n} * \sum_{i=tscase(1)}^{n} x_i \tag{2.11}$$

$$\sigma_{tscase} = \sqrt{\frac{1}{n} * \sum_{i=tscase(1)}^{n} (x_i - \mu_{tscase})^2} \tag{2.12}$$

$$CV = \frac{\sigma_{tscase}}{\mu_{tscase}} \tag{2.13}$$

where μ_{tscase}, σ_{tscase} and CV are the time series case mean, standard deviation and coefficient of variation, respectively. Wind, solar or load cases could be distinguished for example on the basis of weekday/weekend, base/shoulder/peak, winter/summer. Manual iteration of creating different cases and assessing the parameters is performed to decide on the desired cases. Combination of wind, solar and load cases results in the total time series cases. For example, creating wind cases for summer and winter, and solar cases for night and day, leads to four combined cases: winterday, winternight, summerday and summernight.

After time series cases are decided upon, cumulative distribution functions (CDFs) can be designed for each case. In the MC analysis, for each period and scenario new numbers will be drawn from the CDFs of the respective time series cases. Time series case weightings can be assigned to indicate for what part of the year case distributions apply. If a large amount of time series cases is needed to considerably improve these statistic further, then for computational reasons fewer cases could be favorable.

The time series or time series cases will be normalized to per unit values and are updated according to a scaling factor determined by the new annual demand for each specific scenario and period (see figure B1 of Appendix B for the annual demands of our case study).

Spatial Correlation

The time series need to be created for the locations of interest where the individual time series need to be spatially correlated, i.e. there must be some dependency between values at the same time for different locations. This dependency is derived from historical time series data. We first need to assess the correlation (matrix) C_X of the historical data X consisting of m variables.

$$X = (X_1 \cdots X_m)^T \tag{2.14}$$

$$C_X = \begin{bmatrix} \sigma_{X_1}^2 & \sigma_{X_1}\sigma_{X_2} & \cdots & \sigma_{X_1}\sigma_{X_m} \\ \sigma_{X_2}\sigma_{X_1} & \sigma_{X_2}^2 & \cdots & \sigma_{X_2}\sigma_{X_m} \\ \vdots & \vdots & \ddots & \vdots \\ \sigma_{X_m}\sigma_{X_1} & \sigma_{X_m}\sigma_{X_2} & \cdots & \sigma_{X_m}^2 \end{bmatrix} \tag{2.15}$$

Here C_X is our correlation matrix of X and σ is the standard deviation. Then we apply the Cholesky decomposition, which decomposes the correlation matrix into its lower triangular matrix L and its conjugate transpose L^*. This allows us to impose the correlation of the historical data on a set of (uncorrelated) random generated variables drawn from a normal distribution $Z \sim N(0, 1)$.

$$C_X = LL^* \tag{2.16}$$

$$Z_L = ZL \tag{2.17}$$

Lastly, we transform Z_L to a uniform distribution U by applying the normal cumulative distribution function Φ, and apply the inverse cumulative distribution funtion G of parametric distribution for each case and country as found after fitting [Morales et al. 2010].

$$U = \Phi(Z_L) \tag{2.18}$$

$$Y = G(U) \tag{2.19}$$

Wind Time Series Data

For both wind and solar time series we refer to the the ECMWF online databases [*ERA Interim, Daily*]. Their ERA Reanalyses databases provide historical data for wind and solar (among many other climate and weather related variables) on a 3-hourly basis. We have used 20 years of data from the start of 1990 until the end of 2009. Reanalyses data provides data on a large geographical scale which is based on interpolation of measurements at certain geographical locations. The data was collected with 0.5 degree (longitude and latitude) resolution where we have picked appropriate locations for onshore Netherlands, Germany and Denmark and offshore Netherlands, Germany, Denmark and North Sea wind hubs respectively. Note that is a rough approximation as in practice wind farms are not confined to one specific location. Moreover, we have interpolated 3-hourly values to get hourly values, which could lead to a perceived reduction of the variance.

Data on wind was taken at a height of 100m above ground and in m/s. It consists of two different data components, the U and V components. These different components are interesting when concerned about wind direction. We took the value of the overall net wind vector to get the total wind velocity since we assume wind turbines capable of adjusting their orientation to maximize wind power utilization.

To calculate per unit values power output, as required by PyPSA, we took an average wind power curve based on common Siemens and Vestas turbines as defined in comparative research paper [Staffell 2012] and divided wind turbine power output by its power rating. The applied wind power curve can be found in figure C2 of appendix C.

Solar Time Series Data

Solar variables are called surface solar radiation downwards (SSRD) and indicate the radiation flux in $Wm^{-2}s$. So e.g. the daily mean would be calculated by assessing the accumulated flux at two time instants 24 hours apart and dividing the difference in flux by the amount of seconds in a day. This way, we calculated 3-hourly radiation mean in Wm^{-2} and interpolated to get hourly values.

To account for radiation coming in at other angles than directly from above at 90°degrees and the unknown surface area occupied by solar panels, we first normalized the radiation:

$$Y_{n,t} = \frac{y_{n,t}}{\frac{1}{yr}\sum_{t=1}^{8760*yr} y_{n,t}} \frac{\sum_{t=1}^{8760} G_{n,t}}{\bar{G}_n} \tag{2.20}$$

where Y_i, t is the pu value of nominal installed solar capacity at bus n and hour t, $y_{i,t}$ is the time series hourly SSRD in Wm^{-2} and the last term is a summation of y_i, t over the total historical sample and averaging per year yr in $Wm^{-2}yr^{-1}$. Then we benchmark the total yearly radiation against the capacity factor, which is the second term in the equation where the numerator is the total yearly solar production at bus n in Wh and the denominator is the total installed solar capacity $\bar{G}_n$ at bus n in W.

In the model we multiply the pu value with the nominal capacity $[MW]$ that is installed at that time instant (which is updated in each scenario and period) to get the hourly production in MWh.

Demand Time Series Data

For demand time series we refer to the ENTSO-E 2020 expected progress scenario which can be found on their website. This data consists of hourly values of demand $[MWh]$ for all European Member States, as forecasted for the year 2020. Hence, instead of multiple years of historical data we here refer to one year of hypothetical data. This is due to the fact that demand continuously evolves over time whereas solar and wind variables are assumed to stay relatively steady (neglecting the effects of climate change). However, the evolution of demand can be accounted for by ENTSO-E and E-Highway national demand scenarios, which indicate the total yearly consumption, allowing to scale the demand time series. The variability of demand is much lower compared with generation, leading to clear daily patterns.

Combined Cases

In order to make a choice on the correct approach to creating the time series, we evaluate wind, solar and load cases throughout the year. We filtered out data for every hour and every month to see if there was significant variation in the mean, variance and coefficient of variation between different hours and months respectively. A trade-off was then made between creating more wind, solar and load cases to reduce these variations further, and computation time as increasing number of cases could drastically increase the computational time. Figure C1 in Appendix C illustrates the coefficient of variation for wind, solar and demand time series. Table C1 further comments on the choices made for the wind, solar and load cases. The cases are as depicted in table 2.2.

Summer and winter are defined as the periods April-September and October-March respectively. Day and night are defined as 7AM-6PM and 7PM-6AM respectively. Times for peak, shoulder, low and zero cases differ per season and daily interval to account for the variability of solar radiation throughout the seasons and the year. Note that e.g. for the wind case *winternight*, there is no peak or shoulder solar case (weighting was found to be zero) which makes sense since we do not expect solar generation in winter nights. Summer nights on the other hand are longer, giving rise to case 4 in which solar generation reaches shoulder values. The decision on what segments apply for solar cases was made based on an iterative procedure of reducing coefficient of variation while varying the timing segments.

Table 2.2: Time series cases as a result of combining load, wind and solar cases.

case	**weighting**	**wind case**	**solar case**
1	1464	summerday	summerdaypeak
2	366		summerdayshoulder
3	365		summerdaybase
4	363	summernight	summernightshoulder
5	317		summernightbase
6	1516		summernightzero
7	728	winterday	winterdaypeak
8	544		winterdayshoulder
9	217		winterdaybase
10	695		winterdayzero
11	217	winternight	winternightbase
12	1967		winternightzero

By combining all wind and solar cases we ended up with the time series cases where the weightings are the total amount of hours per year that a certain time series case occurs. The demand for each case was established by looking at the value of the demand at all time instants t that belonged to a certain case (a set of values $\bar{x}$ from all values x of the year [MWh]) and averaging these for each country node n.

$$\mu_{loadcase,n} = \frac{1}{N}\sum_{t=1}^{N} \bar{x}_{case,n,t} \tag{2.21}$$

Here $\mu_{loadcase,n}$ is the average demand occurring in a specific combination of wind and solar cases $case$, N is the weighing of the case which is equal to the number of values in the $\bar{x}$, and $\bar{x}_{case,n,t}$ is each value in the case for country node n and time instant (hour) t. Then, to get the pu load case per country $loadcase_n$ we divide by the total demand L_n for country n in that year [MWh].

$$case_n = \frac{\mu_{case,n}}{L_n} \tag{2.22}$$

Since in this case the demand time series is for 2020 we divide by the total demand in 2020. For each successive period we multiply by the new total demand to get the actual demand in MWh.

For wind cases Weibull distributions were fitted and parameters extracted for each case. For solar cases a function that fitted all parametric distributions was used as for some cases other distribution functions were appropriate compared to others. The time series were then generated by drawing normally distributed random numbers for all locations, all cases and the total amount of MC runs. The next step was applying spatial correlation as found in the historical data.

Lastly, for each case the correlated time series were inverted to the appropriate parametric distribution. In the model, for every run a new value is drawn for all locations and wind and solar cases.

2.3 Portfolio Development

The purpose of this chapter is presenting the methods of a preliminary evaluation of potential installations to be connected to future terminals. The scenarios discussed in the section **??** define possible future grid characteristics, simplifying a great deal the advanced resolution of the actual grid. The node illustrating the additional terminal however, will be modeled in a nodal resolution. Of course, the outcome of the cost benefit analysis will then rely in a large part on the choice of the technology connected to this node. The research question relating to portfolio development is defined as follows:

What projects are viable candidates for connection to an additional COBRAcable terminal, considering energy technology trends, and project timing, sizing and topology?

The objective here is to select an investment portfolio and identify viable technologies based on prognoses in existing literature. The outcome will be inputed in the Monte Carlo cost benefit analysis to find an optimal solution and compare between different stakeholder groups.

In the first section (2.3.1) we identify projects that are viable or even likely option for the short term. These are the projects that could be implemented in the first 15 years from the starting point. Though in TEP approaches the first 10-15 years are called mid to long term projects already, for the sake of simplicity we refer to all projects adopted in this time frame short term candidates. These projects will be based on available plans for future North Sea grid development like the ENTSO-E Ten Year Network Development Plan (TYNDP).

Next, we identify interesting projects that could take place in the longer term (section 2.3.2). It will be less straightforward to establish such projects as uncertainty for energy trajectories is apparent. Assumptions will need to be based on literature on the subject of upcoming technologies, conceptual planning ideas, future performance and learning curves.

In the third and last section we look into the topologies that are possible for the connection of remaining technologies to the additional terminal(s). Hence, here we look into the costs associated with the network or transmission that derives from connection of the energy technology to the terminal. The portfolio that is left indicates a selection of viable investment options that could be analyzed further.

2.3.1 Short Term Candidates

We consider renewable energy technologies as well as conventional fossil fuel options, energy storage options and further interconnection that can be installed to a terminal of a sub sea HVDC power cable. Some may be disregarded in an early stage of the research, others will be candidates for the portfolio selection.

Though in practice not an exhaustive list, these (groups of) technologies could be considered (see table 2.3):

Table 2.3: Energy and technologies types considered. The right column indicates which projects are selected in Chapter 3.1.

Energy type	**Technology**	**Expansions**
Wind energy	Onshore	None
	Offshore	1,2,3,4,5,8
Marine energy	Tidal	None
	Wave	None
	Ocean thermal	None
	Marine current	None
	Osmotic	None
Fossil energy	Oil	None
	Gas	None

Energy type	**Technology**	**Expansions**
Energy storage	Hydro (pumped)	None
	Thermal	None
	Compressed air	None
	Battery	None
	Fuel cell	None
Intercon-nection	Direct	6,7
	Indirect	4,5
	Other	None

Narrowing down the suitable options will be based on a literature research. For short term projects it is considered sufficient to follow these steps:

- Assess the current trends.
- Review the projects currently under consideration.
- Identify which of these could potentially be attached to the interconnector.
- Per technology type that is considered to have potential, assess the most suitable project or projects and include them in the portfolio.

The step first constitutes trends, for example in policies, public attitude and fuel prices, on different energy technologies and the impact on the investment forecast. It will help in narrowing down the type of projects that are likely to be implemented so that further research in the specific project types can be done. For this, again reference to developed scenarios for the same time frame of the likes of EIA, ENTSO-E and NSOCGI is made.

For the area of interest, then review projects that are currently considered, be it in the conceptual planning or consenting stage. This requires looking into online databases of projects, which are also likely to be found in research papers like that of E3G or in open source databases for specific technologies (e.g. `4coffshore.com` for wind farms, sub stations and cabling).

Based on the technical specifications of the interconnector of interest, the surrounding network and the projects, a selection of projects can be made per technology type. Appropriate variables would be total capacity, timing, and location. Then lastly, per technology type deemed suitable for connection, one or several particular projects in the project pipeline could be chosen to implement in the model for cost benefit analysis.

Currently the most obvious choice for multi-terminal expansion is an offshore wind farm. The first projects that combine sub sea interconnectors with offshore wind farms are already planned, e.g. the Energy Bridge between Ireland and the UK and Kriegers Flak between Germany and Denmark which are meant to be commissioned even before 2020 [E3G et al. 2013].

2.3.2 Long Term Candidates

Long term projects are more difficult to assess due to high uncertainty on future grid configuration and energy technologies. Still, to some extent projects could be selected based on them being in the conceptual design stage. Ideas on what the future North Sea grid should look like and what kind of technologies that may have been disregarded in the short term, could be implemented in the longer term.

Also, these longer term candidates could be combined with projects that have already been identified and assessed in the short term analysis. This iterative procedure hence requires evaluation of the short term candidates at an earlier stage than long term candidates.

Some characteristics of energy technologies make them unsuitable for connection. We addressed these in an early stage to prevent further analysis of candidates that were deemed inviable. However, now we have to think of the possibility that these characteristics are improved in the future. Think of:

- Minimum and maximum capacity of the energy technology.
- Maturity of (offshore) application of the energy technology.
- Performance and cost effectiveness.
- Considerable negative externalities of the energy technology.

The first point specifically relates to generation and storage technologies where it might not be feasible to implement them at all scales. Some might be only useful for decentralized implementation. For this research, centralized generation and storage will be of main interest. We do not consider demand side management or decentralized technologies, this is a simplification validated by the fact that we are interested in the offshore costs and benefits.

E-Highway has put significant effort in assessing technology development between 2030 and 2050. Their deliverable D3.1 provides extensive quantification of cost projection and technical variables, all in relation to their scenarios [Vafeas et al. 2014]. Their criteria in assessing viable long term technologies are similar to ours.

An example of long term projects is the installation of multiple wind farms to a hub connected to the interconnector. An analysis by EWEA shows for example, that if all wind farms planned up to 2030 would be connected via shared hubs, savings of €14 billion could be achieved.

2.3.3 Topologies

When studying expansion options, the exact configuration of the grid has a large impact on the eventual allocation of costs and benefits. Currently, most HVDC links are point-to-point, in the North Sea the share of this type of interconnectors is currently 100%. If expansions are considered, configurations could get more complex. We can distinguish between three types of design choices related to this configuration: the topology, or layout of the system, the converter types and locations, and the arrangement of sub stations [Liang et al. 2016].

In this research we focus on the topology, which is the geographical configuration of the grid in terms of the locations of the generation and storage technologies, loads and cables connecting them. Converter stations are assumed at all onshore nodes, which makes the power flows in the offshore grid fully controllable. Sub station are those places where different grid assets connect on a busbar, they require components such as transformers and switchgear. Implementing these would be necessary for a detailed technical analysis, but is not required for our long term techno-economic model.

The base case would consist of only the point-to-point interconnecter, where the nodes are AC buses. Expansions introduce new link(s) and technologies where a DC offshore buses or terminal will appear. The eventual topology, or DC grid, would only be a first step toward

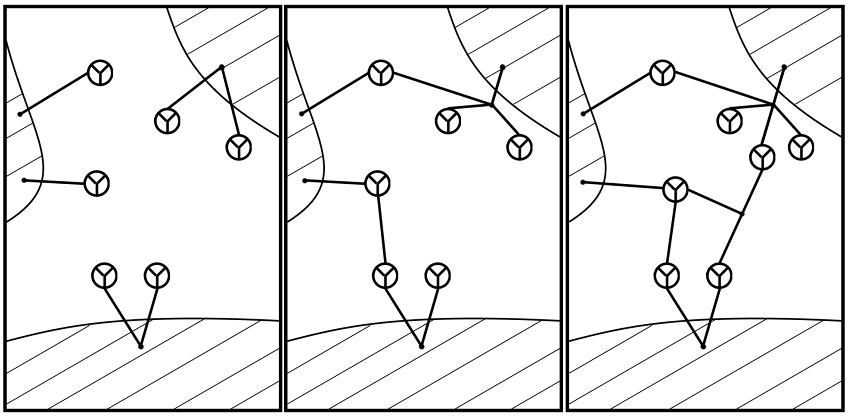


Figure 2.8: Radial topology (left) has direct connection between offshore facility and onshore network, grid topology center increases these connections between countries, meshed topology right gives typical further connection as seen onshore, allowing for loop power flows.

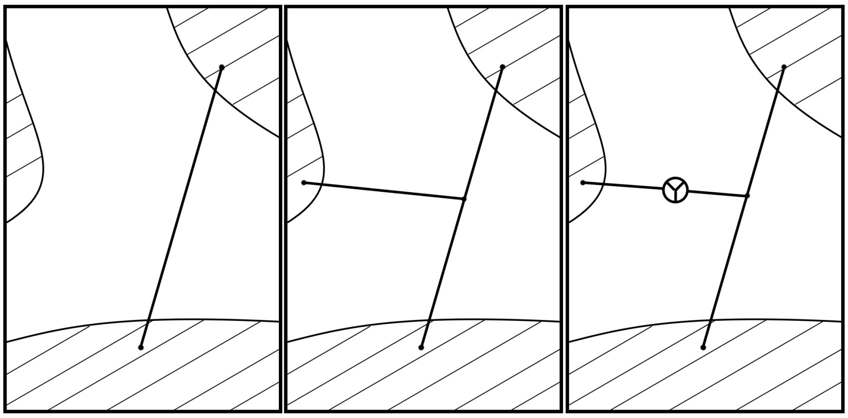


Figure 2.9: Point-to-point (left), direct (center), and indirect interconnectors (right). The first refers to the COBRAcable base case, the second has a direct interconnection with a third country, and the last uses a wind hub obtaining indirect interconnection.

a true meshed DC system with multiple DC buses. Figure 2.8 shows these types of configurations.

The first steps toward an offshore meshed grid are illustrated in figure 2.9. The left picture shows the base case point-to-point interconnector, the middle picture shows a direct (tee-in) interconnection and the right picture shows an indirect connector (or wind hub connection). The direct interconnection could also stop at a wind farm instead of onshore. This would create a teed-in wind farm.

Table 2.4: CBA indicators and their units.

Indicator Group	CBA Indicator	Symbol	Unit
Total Costs	Capital Costs	CAPEX	M€
	Operation & Maintenance Costs	OPEX	M€
Socio-economic Welfare	Socio-economic Welfare	SW	M€
	Consumer Surplus	CS	M€
	Producer Surplus	PS	M€
	Congestion Rent	CR	M€
Sustainability	RES Integration	RESint	MW
	Curtailment Reduction	CurRed	MWh
	Avoided Fuel Cost	AFC	M€
	CO2 Emissions	Em	kton
	CO2 Costs	EmCost	M€
Reliability	Energy Not Served	ENS	MWh
	Security of Supply	SoS	M€
Network Losses	Network Losses	Los	MWh
	Network Losses Costs	LosCost	M€

2.4 Cost Benefit Analysis

The CBA indicators will be the main results of our model. They will allow evaluation of the distribution of different costs and benefits among the countries and stakeholders involved. The sub question posed is:

What will be the social and economic benefits of the COBRAcable expansions, how are they distributed among countries and stakeholders?

First, we have identified the costs and benefits that need to be assessed. All indicators assessed in this researched are presented in table 2.4, including the symbols and units used throughout the report. The indicators are grouped. We distinguish between total costs, total (socio-economic) welfare, sustainability, reliability and network losses indicators.

Every separate cost or benefit is named a CBA indicator. Where possible, we have monetized these indicators. Monetized values are subject to the principle of cost of capital which leads to decreased present value of future cost and benefits due to discounting. The first section elaborates on the discounting as applied in this research. Subsequent sections elaborate on the CBA indicators, starting with the total costs of the system.

Discounting

Discounting involves accounting for the changing monetary value in time by calculating the present value of future cash flows. It is often a source of uncertainty in the CBA calculations and debated by TSOs and regulators [De Nooij 2011].

In the field of energy investments it is argued that higher discount rates lead to less investment in new, more expensive and higher efficiency technologies since the upfront capital cost will have high impact on the total costs and the reduced future cost due to higher efficiency has lower impact [Hermelink et al. 2015]. The same source states that when establishing total energy system cost and benefits, social discount rates should be implemented. A usual value for the social discount rate would be 4%. The monetized cost and benefits that result from the model will be annuities that need to be discounted according to the timing (the period i in which it occurs) and the period length (L) to be able to achieve the net present value (NPV) :

$$NPV = annuity * \left(\frac{1-(1+r)^{-n}}{r}\right) - annuity * \left(\frac{1-(1+r)^{-(n-L)}}{r}\right) \tag{2.23}$$

In this equation the first term relates to the NPV of the annuity up till the end of period i where $n = i * L$ is the total amount of years that has passed. The second term subtracts the value of the annuity up to the start of the period so that the NPV is only based on the annuity in the specified period i and not for all periods that preceded the period of interest. For costs that are incurred only once at a specific instance normal discounting is performed, according to:

$$NPV = expenditure * (1-r)^n \tag{2.24}$$

2.4.1 Total Costs

We will distinguish between authorization, installation and asset capital costs (CAPEX) and operation and maintenance costs (OPEX) . All costs are calculated for a single year per period. CAPEX occur at the start of a period, i.e. they only occur once and are not annuitized. OPEX will be incurred throughout period and therefore single year values are annuitized and discounted to the first year of the period. In the end results for all periods will be discounted to the 2020 NPV values.

Capital Costs

Installation costs and the costs of assets are lumped under CAPital EXpenditures (CAPEX) or capital costs. Voltage Source Converter (VSC) capital costs are calculated according to:

$$CAPEX_{converter} = 0.083 * 10^6 P + 28 * 10^6 \tag{2.25}$$

This equation computes the cost in M€, P is the converter capacity [MW] and is based on a cost review of REALISEGRID [Migliavacca et al. 2011a]. Hence, the costs are an assumption based on past projects. Here, these capital costs include all costs, including engineering, project planning and taxes, except the costs related to transmission. We did not include analysis of Current Source Converters as these converters are not capable of controlling active and reactive power separately and hence are less favourable for connecting large wind farms, nor did we distinguish between different types of VSC converters.

For DC links the same source established a price of 1900 k€/km on capital costs for a ± 300 kV, 700 MW submarine HVDC XLPE cable which is the same technology as applied in the COBRAcable. It must be stressed that these values are indicative, as e.g. installation costs vary per country based on the cost of labour.

Next to that, costs might increase or decrease with time. However, in its cost review, E-Highway indicates a range of ±20% in 2050. This assumption is based on a trade-off between learning curves and future material costs. Hence, the average cost until 2050 remains the same for HVDC XLPE sub marine cables [Vafeas et al. 2014].

For offshore wind farms, cost reductions are one of the drivers of offshore wind farm development. Therefore, we will assume some cost reduction for wind farms for consecutive periods. Although this assumption needs be treated with care since larger turbines further offshore and different support structures might cause the opposite trend. In its extensive cost comparison that accounts for these aspects, DIW states capital costs for offshore wind farms to be 3000 €/kW in 2010 based on a rough average of the reviewed literature [Schröder et al. 2013]. Then, based on cost projections it foresees capital cost reduction of 4.4% every five years.

For the capital costs of the tee-in joint, or additional terminal of the interconnector, exact values are hard to find. There are studies that evaluate tee-in projects [De Decker et al. 2011], but cost figures on which proportion is made up of terminal costs is unclear. The costs are uncertain as it is a new procedure. Costs of converters can be estimated according to our formula, but the installation cost and actual jointing costs are not. The case study of the Dogger Bank wind farm connection either radially to British shore, or directly teed-in to the BritNor interconnector, gave rise to a difference in wind farm connection costs of 290 M€. However, it remains unclear what other costs (next to the tee-in joint) are considered in the connection costs. We therefore choose to leave it out of the model and look into the effect of different terminal costs ex-post, where an assumption of of M€seems reasonable as a first estimate.

The model computes costs according to the values described above. However, these are general assumptions. Apart from the cost uncertainties due to for example delays and weather conditions, actual costs may vary due to government funding (socializing costs) or connection charges, potentially impacting division of costs among generators, consumers and TSOs. In the stakeholder analysis we will assess these impacts.

Operation and Maintenance Costs

Operation and maintenance costs (O&M) or OPerational EXpenditures (OPEX) relate to the costs that occur constantly throughout the lifetime of a technology. They can be divided in variable O&M (VOM) and fixed O&M (FOM) costs. Variable costs concern the costs that are dependent on the usage or quantity that is used, where as the fixed costs are independent of this. The first will be discussed later (section 2.4.3) as they are the drivers for generation dispatch, the latter are discussed in this section.

Fixed O&M costs include personnel, maintenance and insurance costs and are often assumed a certain percentage of CAPEX. E-Highway adopts fixed O&M costs for HVDC XLPE cables and VSC converters of 0.2% and 2% respectively [Vafeas et al. 2014]. REALISEGRID uses OPEX of 1.5-5% for transmission assets, which include expenditures for relocation and losses as well [Migliavacca et al. 2011a]. Since we will deal with network losses separately in section 2.4.5, we will consider 0.2%.

For offshore wind farms the fixed O&M costs are more uncertain as they depend in large part on the distance to shore, turbine characteristics, and weather conditions such as winds, salt water and tides. DIW's cost comparison identified variation in estimates varying from 75 to more than 300 €/kW per year in 2020 [Schröder et al. 2013]. Based on our own analysis of DIW's literature research and ECF's analysis we assume a price of 90 €/kW per year [ECF 2010].

Decommissioning

Decommissioning of offshore wind farms is a new undertaking. Costs of decommissioning can be extensive, but the exact figures have yet to be recognized. A report on offshore installation decommissioning states a prices of 45.000 c [CCC 2010], TKI indicates decommissioning costs of 105 M€for the Borssele wind farm, leading to a price of 75.000 €/MW [TKI et al. 2015]. The costs are uncertain due to complexity of the procedure, but also because there is no single procedure yet. Per wind farm environmental analyses must be performed. In our research we will not address decommissioning costs in the model. Calculation of decommissioning costs is straightforward however (since they are assumed only dependent on generation capacity), therefore they can be addressed ex-post.

2.4.2 Socio-economic Welfare

The implementation of a transmission or generation project will change the power flows between bidding areas as compared to the situation without the project. It allows the bidding area with lower electricity prices to export power to an area with higher prices, hence it opens up the possibility to increase socio-economic welfare. Consumers, producers and transmission owners may benefit from such a project.

In regulated environments a least cost method is applied by the responsible TSO to fulfill needs of security of supply. Main incentive is to increase transmission capacity so that all loads can be supplied at the same costs. Therefore it is a consumer based approach where costs tend to be socialized [Migliavacca et al. 2014]. With unbundling of generation, transmission and distribution sectors, interests started to change and sometimes even oppose each other as not every stakeholders' interests are aligned.

Therefore, the mechanism of socio-economic welfare (SW) or total surplus and its decomposition into consumer surplus (CS), producer surplus (PS) and merchant surplus or congestion rent (CR) is embraced. We will refer from here on to congestion rent, as the term merchant may be confusing, since it could imply interconnector operation by a merchant instead of the regulated TSO. This method accounts for the possibility of increased total socio-economic welfare while one of these surpluses may be negative when a project is implemented. This could lead to one of these stakeholder groups to oppose a certain project.

$$SW = CS + PS + CR \tag{2.26}$$

For the calculation of the socio-economic welfare indicators we build upon the work performed the existing methodologies but borrowed the formula notations largely from by the Californian ISO [Awad et al. 2004].

Consumer Surplus

The consumer surplus captures the costs or benefits allocated to the consumer and measures the difference between what a consumer is willing to pay versus what it actually has to pay, price P when a certain quantity is produced according to load L. Willingness to pay is often measured in the Value of Lost Load ($VOLL$) in €/MWh [Schröder et al. 2015].

$$CS = (VOLL - P) * L \tag{2.27}$$

In this equation the term $P * L$ is equal to the consumer payments CP. This equals the producer revenue when there is no congestion. Otherwise, locational prices differ and the average price $\overline{P}$ should be used. More precisely:

$$CP_{i,t} = \overline{P}_{i,t} * L_{i,t} \tag{2.28}$$

Variables tend to vary with nodes or regions within an area as well as in time. To account for these differences between all n regions every ith region for every specific time t [h] must be summed.

$$CS_t = \sum_{i=1}^{n}(VOLL_{i,t} - P_{i,t}) * L_{i,t} \tag{2.29}$$

Assessing values for $VOLL$ is ambiguous, assumptions for $VOLL$ tend to differ a lot in literature and across different consumer categories (e.g. industrial or residential) [Schröder et al. 2015]. However in the end we are interested in the change of consumer surplus compared to the base case without any project which means the $VOLL$ cancels.

$$\Delta CS = CS_{expansion} - CS_{base} \tag{2.30}$$

Therefore, we can also look into the difference in consumer payments. The consumer payments are equal to the CP, hence it can be calculated for each node by multiplying the locational (nodal) price by the total nodal demand at all times.

$$\Delta CS = CP_{base} - CP_{expansion} \tag{2.31}$$

Producer Surplus

Generators are the producers in the power grid. The producer surplus measures their benefits by differencing the producer revenue (PR) and variable production cost (PC).

$$PS = PR - PC \tag{2.32}$$

When there is no congestion in the system (and assuming inelastic demand) producers receive revenue equal to the term $P_{i,t}*L_{i,t}$ in the CS equation. When there is congestion however, prices tend to vary according to the location. With K generators, the kth generator's price $P_{i,k,t}$ is equal to the Locational Marginal Price (LMP).

$$PS_{i,t} = \sum_{k=1}^{K} G_{i,k,t} * (LMP_{i,k,t} - VOM_{i,k,t}) - FOM_{i,k,t} \tag{2.33}$$

$G_{i,k,t}$ is the generator dispatch for generator k, $VOM_{i,k,t}$ is a function for the marginal costs consisting of fuel costs, carbon prices and some other variable operation and maintenance costs, $FOM_{i,k,t}$ indicates the fixed costs for operation and maintenance of the generator. VOM and FOM are separated since the first depends on dispatch G.

$$PS_t = \sum_{i=1}^{n} PS_{i,t} \tag{2.34}$$

And again taking the difference between expansion project and base case:

$$\Delta PS = PS_{expansion} - PS_{base} \tag{2.35}$$

Congestion Rent

If there is congestion, transmission owners come into play as well. There is a revenue to be made since there is a difference in the prices consumers pay (CP) and the nodal prices generators pay at generation buses.

$$CR_t = CP_t - PR_t \tag{2.36}$$

In case of two regions connected in radial fashion the price difference between them is the shadow price and the CR is directly proportional to it and the transferred power (T):

$$CR = (CP_1 + CP_2) - (PR_1 + PR_2) = (P_1 - P_2) * T \tag{2.37}$$

Congestion rent of for an expansion as compared to the base case is calculated as:

$$\Delta CR = CR_{expansion} - CR_{base} \tag{2.38}$$

Welfare Allocation

The indicators for socio-economic welfare only address total social benefits in the whole system. To allow for an analysis per stakeholder, we can compute zonal or nodal CS, PS and SW. Assuming national resolution where each country i is represented by one node we can calculate the benefits for these nodes via:

$$\Delta CS_i = CP_{base,i} - CP_{expansion,i} \tag{2.39}$$

$$\Delta PS_i = PS_{expansion,i} - PS_{base,i} \tag{2.40}$$

$$\Delta SW_i = SW_{expansion,i} - SW_{base,i} \tag{2.41}$$

Zonal surpluses sum to get the total surplus for the whole system. E.g. for the total producer surplus we the following formula applies [Migliavacca et al. 2014]:

$$PS = \sum_{i=1} PS_i \tag{2.42}$$

The other indicators are calculated in a similar way. Following the same method, we may specifically look into the nodal benefits at the offshore nodes, for example to assess producer surplus due to an offshore expansion.

Now to distribute offshore benefits of shared assets, some distribution matrix may be applied to allocate these benefits to the relevant onshore buses. This holds for the congestion rent. As interconnectors connect different price zones, with often different TSOs, congestion rent need to be shared between TSOs. Hence, for all interconnecting lines rents may be shared among the buses to which they are connected. For one interconnector between node i and j, assuming equal sharing:

$$CR_i = \frac{1}{2}(P_i - P_j) * T_{i,j} \tag{2.43}$$

$$\Delta CR_i = CR_{expansion,i} - CR_{base,i} \tag{2.44}$$

In a similar way offshore producer surplus may be allocated to all countries that benefit from it. Assuming equal sharing of offshore producer surplus at node h between countries i, j and k for example results in:

$$\Delta PS_{i,j,k} = PS_{h,i,j,k} \begin{bmatrix} 0 & \frac{1}{3} & \frac{1}{3} & \frac{1}{3} \\ 0 & 1 & 0 & 0 \\ 0 & 0 & 1 & 0 \\ 0 & 0 & 0 & 1 \end{bmatrix} \tag{2.45}$$

The correct allocation methods may not be as straightforward as implied by this section. In reality, not all countries may benefit equally and therefore either some different allocations must be implemented, or some form of compensation or *re*-allocation is required. This is specifically true where regulations and unbundled markets create different benefit allocations and risks for stakeholders in one country compared to the other.

Next to that, many other regulatory aspects may give rise to alternate distribution of costs and benefits. Subsidy schemes, operational regulations and financing issues are examples. We refer to the stakeholder analysis where we address these issues.

2.4.3 Sustainability

An additional benefit that comes with the implementation of large transmission projects, is the increased opportunities for renewable energy generation. Firstly, the introduction to new areas opens up opportunities for RES integration in the system that was previously unreachable. The *RES integration* indicator is a measure for the total increase in RES.

Secondly, it facilitates an integrated network spreading a larger geographical area, leading to possibilities to import from excess RES areas and acquiring further RES penetration in the energy market. ENTSO-E [ENTSO-E 2013] and REALISEGRID [Migliavacca et al. 2011b] use a method which compares the total RES connected [MW] and avoided RES spillage [MWh] for different scenarios. We will look at the *Curtailment Reduction*.

Other benefits of RES integration are the reduced costs related to conventional generation facilities. In the *Avoided Fuel Cost* subsection we discuss the benefits of the reduced amount of fossil fuel on the operational costs of the whole system. Lastly, the avoided CO_2 emissions are discussed.

Sustainability indicators will be a means to assess the feasibility of an expansion. Projects that score well on these indicators will have reduced risk of long or costly consenting procedures and public opposition, and will be more likely to apply for funding. We will address this further in the stakeholder analysis.

RES Integration

We take into account the RES potential by looking at currently and future installed RES, including the generation mix per area. An objective could be assessing how much RES we can add while preserving reliability and monetizing the outcome, also called capacity credit [Migliavacca et al. 2011b]. In this research such an objective will not be implemented since optimization of the capacity to be installed is not performed. Rather, projects with set capacities are selected when designing the portfolio. Therefore, this benefit *RESint* will just be a result of the increased energy generation from the RES facility installed [MW].

Curtailment Reduction

In the NSOG, future development is estimated to be mainly in the form of increasing wind power generation capacity. Distinction should be made between countries that have curtailable wind generation at all times (related to optimal dispatch) and countries in which curtailment may only occur at some maximum wind velocity [L'Abbate et al. 2011]. Then, expansion potential may be calculated for both these type of countries, whereas curtailment reduction may only be calculated for the first type. We will address this in the stakeholder analysis.

In this CBA we will assume zero marginal costs for wind, and implement simplifications for conventional sources such as excluding start up, cool down and ramping times. Therefore fully dispatchable wind for all nodes is assumed. The consequence of this is that curtailment reduction can be calculated purely by the displacement of energy supply from conventional sources by energy from wind. Thus, we calculate the curtailment reduction ($CurRed$) by:

$$CurRed = RESGen_{expansion} - RESGen_{base} \tag{2.46}$$

In this formula, $RESGen_{base}$ is the total RES production in the base case, $RESGen_{expansion}$ is the total RES production for the expansion project, and $CurRed$ is the curtailment reduction. All are measured in [MWh/yr]. Curtailment reduction is monetized by multiplying the displaced energy generation by the marginal costs of the displaced generation. Increased RES penetration by additional transmission capacity will be a driver of decreasing these costs as conventional generation with higher marginal costs can be displaced by RES generation.

Avoided Fuel Cost

Future fossil fuel prices are volatile and provide uncertainty to generation facility operators. RES integration decreases the total uncertainty on the network's operating costs deriving from fossil fuels as they get replaced by RES. However, it still makes the calculation of the total benefits arising from the replacement of fossil fuels somewhat ambiguous.

We are able to make assumptions about the total benefits from avoided fuel costs since we know the total change in conventional generation per generator. The next step is coming up with future fuel price scenarios that cover a range of possible pathways to be able to correctly monetize the CBA indicator.

In this research we sum all variable O&M costs, including fuel costs, carbon prices and potentially remaining variable costs, in the generation marginal cost. We do this as marginal costs of conventional energy sources tend to consist for the largest part of the fuel costs and carbon pricing [ECF 2010]. Thus we need to consider fuel costs separately and calculate it by multiplying the respective generation (which will be dispatched according total marginal cost).

$$\Delta AFC = AFC_{expansion} - AFC_{base} \tag{2.47}$$

ENTSO-E scenarios have some notion on fuel prices but as such only information on 2020 and 2030 periods exists [ENTSO-E 2015b]. We assume this data also for other periods and address the impact of changes in these scenarios in a sensitivity analysis.

CO2 Emissions

As with most other indicators, the benefit of decreased emissions will be internalised in SW. CO_2, SO_2 and NO_x are considered to be the main pollutants. Knowing emissions of these compounds and the production per power plant, total emission can be measured in tons [ENTSO-E 2013; Migliavacca et al. 2014] and consequently be monetized [Migliavacca et al. 2011b]. Currently, mainly information on carbon emissions is available, so we will only address these.

Production of plants can be derived from the generation mix scenarios. Using specific emission numbers or fuel emissions factors per technology, the total amount of emissions that result from the total annual production can be retrieved.

$$Em_i = \sum_{k=1}^{K} FEmF_k * G_{i,k} \tag{2.48}$$

Generation mixes within a zone or region i are considered equal, therefore the annual emissions Em_i [ton/yr] per region can be calculated by multiplying the fuel emission factors $FEmF_k$ [ton/MWh] for each technology k with the generation dispatch $G_{i,k}$ [MWh/yr] and summing all technologies.

$$\Delta Em = Em_{expansion} - Em_{base} \tag{2.49}$$

CO2 costs

Multiplying the CO2 emissions by zonal prices gives the monetized estimation of a certain scenario in a specific region. It must be noted that currently only CO_2 is priced according to the Emission Trading Scheme and prices differ in different countries [Ellerman et al. 2007].

$$EmCost = \sum_{i=1}^{n} (Em_i * EmP_i) \tag{2.50}$$

$EmCost$ is the total emission costs of the scenario [€] and EmP_i is the emission price in a specific region [€/ton]. As before, comparing base case with the scenario where the project is implemented gives our result for the benefits:

$$\Delta EmCost = EmCost_{expansion} - EmCost_{base} \tag{2.51}$$

Here, $\Delta EmCost$ is the total decrease in emission cost [€] which is the difference between the project emission cost $EmCost_{project}$ and the scenario specific emission cost $EmCost_{base}$. To derive the difference over the total life time of the expansion, the same methodology can be applied. In this research we did not regard the effects of carbon capture and storage so fuel emission factors can be considered approximately unchanged during this time, but changing generation dispatch and emission prices should be taken into account.

As with avoided fossil fuel costs, we will apply ENTSO-E carbon prices for the scenarios in all periods. Even though these are only given for 2020 and 2030. In the sensitivity analysis we will address deviations from the ENTSO-E carbon prices. See Appendix A for emissions, fuel prices, carbon prices and marginal cost of different energy sources. Note that marginal costs are slightly higher than the sum of fuel prices and carbon prices. This stems from additional variable maintenance costs [ECF 2010].

2.4.4 Reliability

An important societal benefit is the security of supply, often called system reliability as it deals with maintaining or improving performance of the grid. It depends on the amount and duration of outages or interruptions. It is a non trivial indicator as assessment implies the need to give some value to a certain rate of performance, e.g. customer reliability R 99% of the time. A common line of thought is illustrated in figure 2.10. Customer marginal cost function will decrease with security whereas the costs for the utility will increase for increased reliability. Hence there is an optimum R_{opt} [Billington et al. 2013].

In the subsections below we elaborate on the methodology regarding reliability assessment from the TSO's perspective and perceived cost for customers. The first deals with the Energy Not Served (ENS) the second relates to assessment of the Value of Lost Load ($VOLL$).

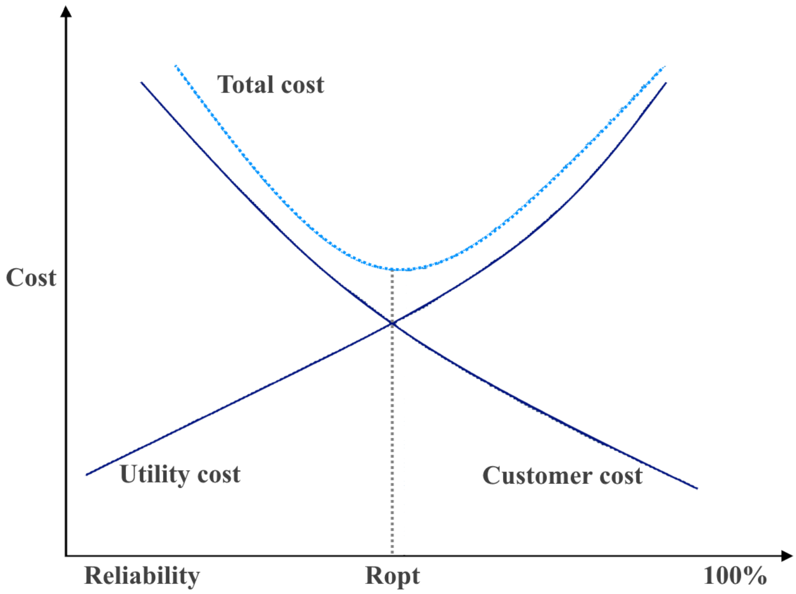


Figure 2.10: Reliability and cost evaluation [Billington et al. 2013].

Reliability indicators serve to assess the potential of an expansion project to increase security of supply. This is one of the three pillars of European policy. A negative effect on security of supply may significantly harm the feasibility of an expansion. For example, projects may only apply for funding if they prove to be of benefit to grid reliability. This will be assessed in the stakeholder analysis.

Energy Not Served

The difficulty of assessing the costs for TSOs is the probabilistic nature of breakdowns. In this regard, MC analysis could be a useful tool as it can implement the probabilities and expected durations of failures in the system. However, it is not uncommon for a socio-economic analysis to consider these technicalities deterministic [Li et al. 2007].

There are many approaches to calculating ENS, often called Loss of Load Expectation ($LOLE$) as well. It depends on the generation and demand scenarios as well as on the probability analysis related to the total amount of time outages are in effect.

In this research we chose to address only the ENS of the offshore transmission grid as we are interested in the cost and benefits that stem from offshore expansions. This can be done for example by turning of components in several MC runs according to the outage probability percentage. Another approach might be running the whole model with the outage occurring and later taking weighted averages of the results.

In our research we will establish calculation of ENS by implementing generators with infinite capacity. When optimizing dispatch these 'ENS generators' will automatically fulfill demand if it is not fulfilled by the other generators as their marginal costs will be set higher than all other energy technologies.

$$ENS_{i,t} = L_{i,t} - \sum_{k=1\ k \neq ENS} G_{i,t,k} = G_{i,t,k=ENS} \tag{2.52}$$

Here $L_{i,t}$ is the load in zone i ant time t [MW] and $G_{i,t,k \neq ENS}$ is the generator dispatch of all generators except the ENS generators [MW]. We compare ENS between the expansion and base case to analyze the effect of the expansion on the total unserved energy.

$$\Delta ENS = ENS_{project_{outage}} - ENS_{base_{outage}} \tag{2.53}$$

Security of Supply

Extensive research has been performed in assessing perceived value of energy that is not supplied to the customer. The value tends to vary considerably. In general it is believed that this value is based on a set of attributes [Migliavacca et al. 2011b], relating to different aspects:

- Outage attributes: outage duration, season, day, time of day etc.
- Customer characteristics: type of business or household, back-up equipment etc.
- Geographical attributes: Temperature, humidity etc.

Therefore, methods distinguish between a lot of attributes in the computation of $VOLL$, and there is no straightforward or standardized way to do it [Billington et al. 2013].

As the calculation of $VOLL$ requires extensive research without significant accurate results, we resort to values already calculated in existing literature. In Europe researches with regard to this parameter has mainly been carried out in Germany. They tend to vary significantly across countries and between different sectors. This has been found by comparative studies [Schröder et al. 2015], which compiles residential and industrial and commercial results of studies conducted between 2004 and 2014.

However, this data is typically calculated for short term $VOLL$ which is generally perceived higher than the value of an outage that occurs far in the future. We therefore use a price of 1500 €/MWh which is based on a long-term TEP model [IIT 2012].

In order to assess the total Security of Supply SoS [€] based on $VOLL$ we set the marginal cost of the ENS generators equal to $VOLL$. We then need to multiply by ENS [MWh].

$$SoS_t = \sum_{t=1} VOLL * ENS_t \tag{2.54}$$

$$\Delta SoS = SoS_{base} - SoS_{expansion} \tag{2.55}$$

ENS and SoS will be indicative of the expansion's project potential to increase reliability. The reliability indicators will not give insight in specific stakeholders, as they indicate social benefits that apply to all stakeholder involved. They are however important in assessing the feasibility of our expansion projects.

2.4.5 Network Losses

Part of the costs and benefits calculated in the socio-economic welfare are related to the efficiency of the system, i.e. the losses that occur. It is common to distinguish between two main components of network losses [L'Abbate et al. 2011]:

- Variable losses, also called Copper (Cu) losses, are based upon the electrical resistance of conductors and hence directly related to the current flowing through it.
- Fixed losses, also called Iron (Fe) or no load losses, are a result of magnetizing forces when transforming power. These are not a function of the current.

In our DC load flow model, we have to make assumptions on the losses that occur in the system, and we will therefore not be able to specifically address the variable losses. We will set efficiencies of offshore components since we are only interested in the benefits that arise from offshore investments and changes. Therefore we assign efficiencies only to converters and interconnectors. The network losses are then calculated by taking the difference between power input and power output.

For converters and DC links efficiencies are noted. Converter stations are assumed to have 98% efficiency [Bresesti et al. 2007]. Some dependency on the cable capacity and cable length is assumed for the efficiency of DC links via the following formula:

$$\eta_{DClink} = 1 - 2r * \left(\frac{P}{V}\right)^2 * L/P \tag{2.56}$$

Here η_{DClink} is the DC link efficiency, r is the cable resistance (Ω/km), P is the cable nominal capacity (W), V is the cable nominal voltage (V), and L is cable length (km) [Teixeira Pinto 2014]. The network losses for an expansion can then be calculated according to:

$$\mathit{\Delta}Los = Los_{base} - Los_{expansion} \tag{2.57}$$

Network Losses Costs

Monetization of the network losses can be done by simply assuming the nodal price where the converter is located, and taking the average of nodal prices of the terminals of a line and multiply these values with the network losses. Then the indicator is calculated via the following formula.

$$\mathit{\Delta}LosCost = LosCost_{base} - LosCost_{expansion} \tag{2.58}$$

Network losses are an important aspect for the feasibility assessment of expansions. They will form part of the operational expenses of an interconnector, hence an unfair or unequal allocation of network losses costs among participating stakeholder could form a barrier for the project.

2.5 Stakeholder Analysis Framework

The research question aims at identifying options for multi-terminal expansion. Possible drivers and bottlenecks will not only be the result of technical, social and economic variables, i.e the results of our CBA model. It will also be necessary to see which expansions are feasible from the specific stakeholder's perspective considering regulatory uncertainties that have not been accounted for in the CBA model. Therefore we need to develop tools that identify interests in and consequences of the implementation of a multi-terminal expansion project for the main stakeholders. This will give us further insight in the costs and benefits that arise from expansions, complementing the quantitative CBA with a qualitative stakeholder analysis. The following question is generated:

What are the drivers and bottlenecks for the main stakeholders involved in the COBRAcable expansions?

We first need to identify the main stakeholders. Section 2.5.1 gives an overview of the main stakeholders or stakeholder groups that are involved. Here we also elaborate on the main stakeholders of the COBRAcable case study.

Next, we analyze the drivers and bottlenecks based on the stakeholder criteria. These are the criteria a stakeholder needs to address when assessing the feasibility of an expansion project. As the topic of an integrated offshore grid is only recently being researched, standardized approaches have yet to be developed. An interesting book (*HVDC Grids*) that attempts to do this, devotes a major part to planning and operation of HVDC grids, where specifically the governance model is a useful tool to analyze regulatory uncertainties that are involved in offshore expansion projects [Liang et al. 2016].

These uncertainties mainly stem from the separate management of sub systems by different actors and add to the uncertainties due to RES intermittency and future scenarios. Hence, the stakeholder analysis complements the CBA in that it deals qualitatively with the regulatory uncertainties involved in the project for different stakeholders (e.g. consenting processes, subsidy schemes), whereas the CBA aims to quantify socio-economic uncertainties in future grid developments (e.g. energy prices, generation mixes). The governance model consists of the following five criteria, which could be regarded as stages in the project process:

- Planning: The identification of required investment projects. Relating to the coordination between governments, grid operators, generator companies, environmental groups, consumers and regulators in order to get approval of project initiation.
- Ownership: The ability to decide upon property rights. Relating to who is responsible for the asset and its operation, regulation schemes are closely related to asset ownership.
- Financing: The possibility to acquire the necessary funds. Relating to investors and financial risks like cost of capital and investment cost.
- Pricing: The possibility for stakeholders to recoup their investment. Relating to transmission pricing which in turn is based on the cost allocation between stakeholders and ownership.
- Operation: The rules defined to ensure reliable and efficient operation. Relating to grid codes specifying reliability standards, grid access rules, grid support etc.

These criteria may relate to several stakeholders and CBA indicators, as well as to the stakeholder attributes as can be seen in table E1 in Appendix D. We analyze the criteria based on a selection of sub criteria which are introduced in the following sections.

We also developed a methodology to assess attributes of the stakeholders identified. Attributes give an abstract representation of the interests and behavior of the stakeholders. This methodology is derived from the common stakeholder analysis theory. The standard approach to finding the attributes in a stakeholder analysis is by counseling the stakeholders. Such an analysis is beyond the scope of this thesis, we therefore focus on stakeholder criteria and refer to Appendix D for the stakeholder attributes and dimensions for a a more extensive analysis.

2.5.1 Stakeholders

We deal with the existence of many organizations on both the national and European level, sometimes with contradicting interests. In this subsection we identify stakeholders per group.

The process of identification involves brainstorming who has stake in the project and systematic grouping of stakeholders and their status. The brainstorming should lead to a broad list of stakeholders and some general groups of stakeholders as seen in figure 2.11, which is the graphical representation of the stakeholder identification as developed and adapted by Freeman [Freeman 1984]. Depending on the analyst's interests and approach, and nature of the sector, some individual stakeholders or groups may be left out. This categorization is straightforward and easy to use. It makes the search for stakeholders with influence on the central stakeholder more structured.

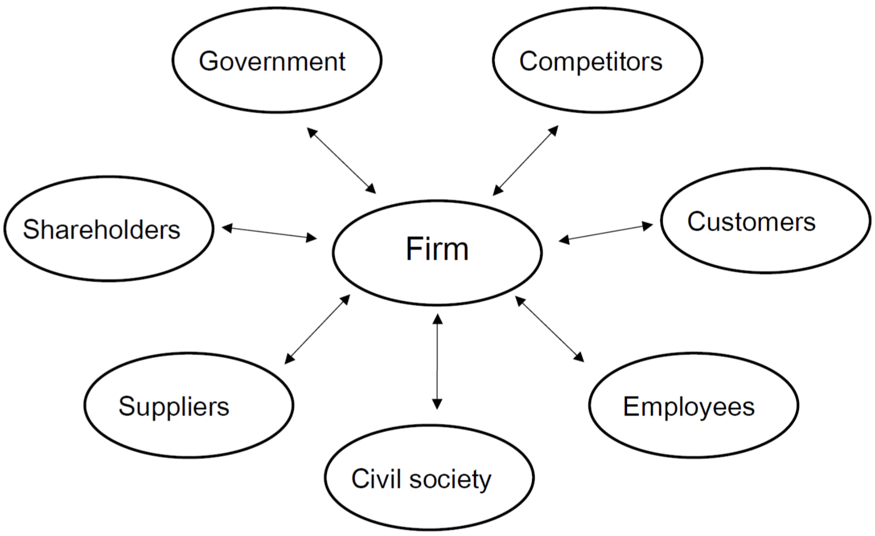


Figure 2.11: Original graphical representation of the stakeholder map [Freeman 1984].

Figure 2.11 clarifies the importance of choosing the central stakeholder. A firm conducting the stakeholder analysis would appoint their own firm or management as the central stakeholder as they would mainly be interested in the impact of stakeholders on their own organization. We will look from multiple stakeholder perspectives and therefore multiple central stakeholder could be chosen.

Figure 2.12 gives an indication of the stakeholder groups involved in multi-terminal expansion, where for clarity the arrows are left out. Also, overlapping of the groups indicate the mixed nature of stakeholder attributes.

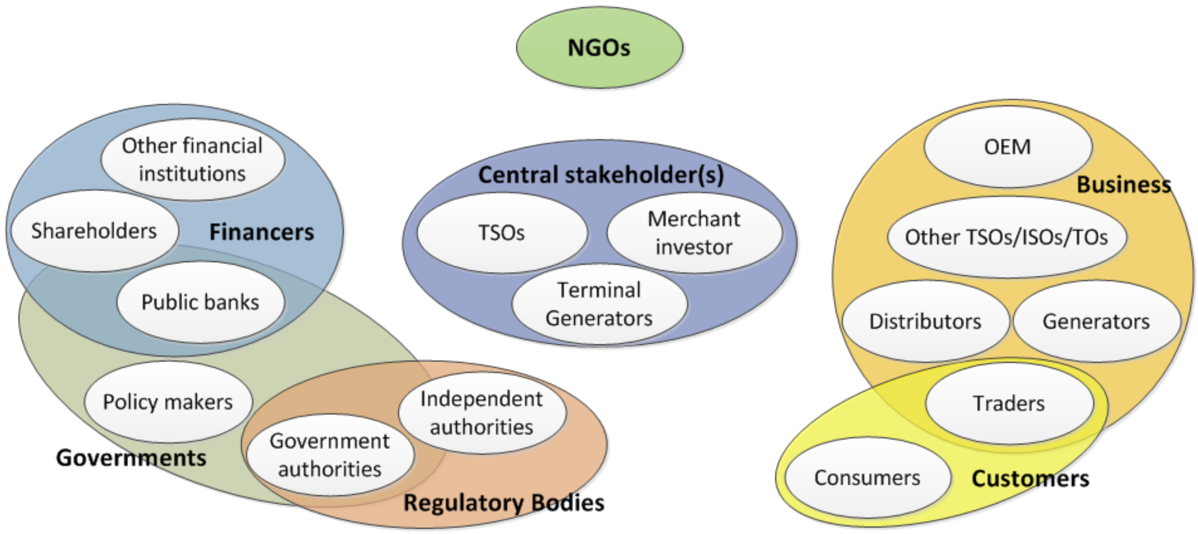


Figure 2.12: Stakeholder map indicating European stakeholder groups.

In our case, we are dealing with a project where potentially multiple investing stakeholders participate. Most interconnectors currently installed were financed by the national Transmission Network Operators (TSOs) involved. However, some planned interconnector projects are financed by merchant developers or on a hybrid basis [E3G et al. 2013]. We define the TSOs involved to be central stakeholders.

Moreover, integrated projects including the installation of both an interconnector and an expansion project will also include the expansion project owner as a central stakeholder. The focus of this research will be on these central stakeholders.

Lastly, the unbundled environment gives rise to a close connection between the investing stakeholders and those that develop and enforce policies and regulations. Therefore, we also focus on the stakeholder groups of governments and regulatory authorities during our analysis of the main stakeholders.

Policy Makers

Policy makers are mainly concerned with meeting their policies and targets, and not so much with the means to achieve them. On the European level this is the European Commission (EC). An important goal of their policy is an increasingly integrated grid with high RES shares to ensure energy independence and a sustainable future. 20-20-20 targets - cutting emissions from 1990 by 20%, reaching 20% market share for RES, and a 20% improvement of energy efficiency by 2020 - are an example of these policies [Moldan et al. 2012]. Therefore, interests of policy makers are in reducing emissions, RES integration and security of supply.

Unfortunately, policy makers on the national level (the respective governments and ministries) interpret policies and guidelines differently, potentially restraining cooperative attitudes among potential investors for multi-terminal expansion. Furthermore, European energy directives set different targets for different Member States and require the Member States to provide National Renewable Energy Action Plans (NREAPs) that give details on the proposed trajectory towards the targets. These national trajectories also differ. As an example, currently the Netherlands has its 2020 RES share target set at 14% and Germany at 18%, whereas Denmark has already surpassed that percentage and aims at a share of 30% in 2020 [Beurskens et al. 2011].

Regulatory Bodies

Regulatory bodies or authorities monitor the activities of TSOs, this includes the assessment of planned expansions in terms of socio-economic costs and benefits, sustainability and efficiency. Their main objective is facilitating the European network integration by ensuring market competition and fair cost allocation [*Mission & Objectives*].

European regulatory bodies include the Agency for the Cooperation of Energy Regulators (ACER) and the Council of European Energy Regulators (CEER) . Both organizations complement each other. ACER is a EU agency as defined by directives and regulations of the Third Energy Package. Its main task is monitoring national energy regulators and working towards a single EU energy market for both electricity and gas. It does so by creating tailored regulations based on the policies and directives as put out by the EC [*Mission & Objectives*]. CEER is a non-profit organization that complements ACER's work on legislation. Furthermore, it provides a platform for European regulators to cooperate, engage and assist one another. CEER's objective is similar to that of ACER [*Activities*].

The national regulatory authorities are agencies under the respective ministries. Autoriteit Consument en Markt or Authority Consumer and Market (ACM) in the Netherlands, the Danish Energy Regulatory Authority (DERA) in Denmark and the Bundesnetzagentur (BNetzA) in Germany. These agencies interpret European legislation according to national values and make sure the regulation as set out in the policies and directives of the EC and national governments are enforced. Next to that they play an important role in creating network rules and codes [Flament et al. 2015].

An important consequence of expansion assessment by national regulatory authorities is that an expansion may be rejected on the basis of national welfare, whereas total regional welfare may be increased. This implies the need for an appropriate TEP approach from the regulator's perspective, including transparent data and assumptions, close involvement with other stakeholders, and the accounting correctly for other TEP characteristics as identified in earlier sections.

Transmission System Operators

European Network of Transmission System Operators for Electricity (ENTSO-E) is the overarching body of all TSOs from Member States. Its mission is to fulfill various legal mandates for the benefit of customers and the society at large. ENTSO-E is a guiding entity for policy makers, regulators and stakeholders, that provides network development plans and proposes standardized methods to assess transmission projects. The share the objective of policy makers: security, market integration and sustainability [*Reliable. Sustainable. Connected.*].

The COBRAcable investment is equally shared between the two TSOs of the Netherlands and Denmark. In the Netherlands, TenneT TSO B.V. is the TSO. TenneT is one of the larger European TSOs as it is also active in a considerable part of Germany (from here on called TenneT TSO GmbH), contributing for a large part to the *Energiewende* thanks to its involvement in offshore activities in the German North Sea. Hence this is also the TSO involved in the COBRAcable expansion. The Danish TSO Energinet.dk and TenneT are state-owned enterprises.

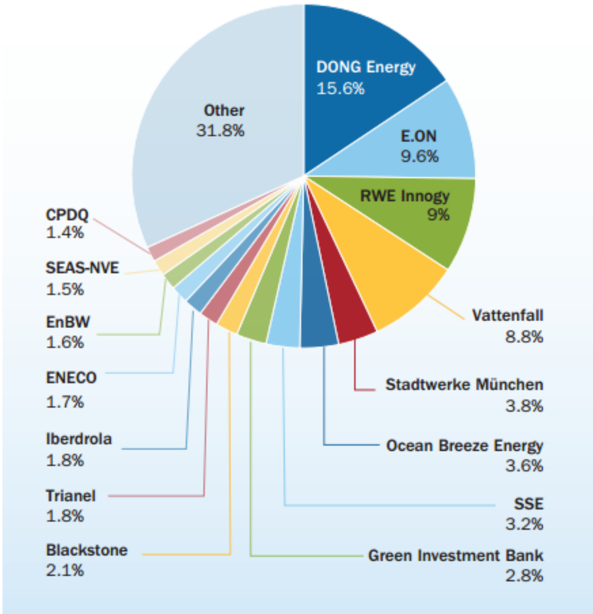
The planning tasks of TSOs consist of the feasibility study of the expansion and entail close involvement with policy makers and regulators. Apart from the similar objectives compared to policy makers and regulators, they have interest in the technical criteria. Moreover, they have a key part in facilitating coordination between the stakeholder involved. For example, they will form a vital link between policies, regulations and the generators.

Generators

Generation facilities are the stakeholders that produce and inject power into the system. They exhibit variation in power capacity, technology type, marginal cost function, availability etc. The introduction of RES brought about increasing capacity and availability uncertainties. These stakeholders, together with TSOs, can be considered planning stakeholders. For our case study, the main generator facilities will be wind farms.

There are many players that develop and own offshore wind farms. As of 2015, the market shares of offshore wind in Europe are as shown in figure 2.13. It can be seen that there is considerable competition although the top 6 owners together control 50% of the total installed capacity. All of these are also active in the German North Sea.

Figure 2.13: Market share in terms of installed capacity as of 2015 [Ho et al. 2015].



Due to the unbundled environment, wind farms will have differing interests compared to TSOs. Their main objective will be maximizing profits and increasing market shares.

Consumers

We consider consumers as one group. If the whole consumer group of one country benefits it is assumed that this holds for residential, industrial and commercial end users. Interests are first and foremost high reliability and low costs. Apart from that the market for 'green' energy continues to grow, as does the trend for distributed (decentralized) generation by consumers themselves. Benefits are mainly measured in the consumer surplus. Social criteria such as security of supply and environmental benefits can be considered valuable for consumers as well [ENTSO-E 2015b].

In the case study we distinguish between consumers of Denmark, Germany and the Netherlands. Their national surpluses are assessed, as well as the social benefits that arise from the expansions.

2.5.2 Planning

Preliminary assessment of the attributes is important in minimizing unexpected obstacles in the planning stage of the project. Which actors will take part in the project and what are their stakes? What risks and bottlenecks of project implementation could be present? In this part we will discuss some important criteria relating to the planning process and indicate the relevance to specific attributes.

Planning Practices

Planning practices include the mechanisms to improve cross-border projects and ensure investments are in projects that provide most benefits. What are the options to reduce risks of joint planning and permitting and mandating developers to invest in most beneficial projects? Specific mechanisms will mostly be addressed in the separate stakeholder criteria sections, but a qualitative analysis of main planning practices for expansions is performed here. This will be informative as more complex expansions will require specific multilateral planning mechanisms.

National planning practices include different rules and guidelines compared to the regional level. National regulatory agencies will need to approve of a transmission expansion plan based on a predefined set of criteria for reliability, economic, social and environmental impacts [Liang et al. 2016], e.g:

- Environmental Impact Analysis: procedures differ among countries, close regard must be paid to potential environmental interest groups that might cause delays in the permitting procedures.
- Cable routing: a holistic approach must be agreed upon between national authorities, current cable routing processes are deemed inefficient due to unclear guidelines on nature areas.
- Compensation and support: TSOs expect a more harmonised and standardised EC regulation on compensation and support schemes [de España 2013].

For integrated projects where both interconnector and generation facilities are installed, additional difficulties arise to define what type of license or license regime should apply [E3G et al. 2013; de España 2013].

For interconnections, the onshore part of the investment has most potential to objections, this is expected in the future as well. Planning should focus on this onshore part, creating social awareness by promoting project in terms of security of supply, market integration, strategy, project implications [de España 2013].

For offshore connection with generation facilities areas of environmental concern are subjected to the Directorate-General for Environment which is the environmental department of the EC [de España 2013].

Coordination of asset development

Coordination of asset development is important to prevent the network from being underused. This relates to the correct sizing of the investment project capacity and clear coordination between network connection facilities and generator connection facilities. Especially in hub designs, if the wind farm is already built but the interconnection or hub is not completed (or vice versa), stranded investments are the result [E3G et al. 2013]. The problem also relates to priority grid connections. When in one country priority grid connection (or priority access) of the RES generator is required and in the other it is not, there is a risk that the wind farm will only be able to feed the grid with priority access as the other country/TSO has no incentive to build the connection. Hence, there is a risk for stranded assets and the question is whether compensation is needed in that case [Flament et al. 2015]. These timing and sizing issues are directly addressed by the project portfolio which constitutes several expansions with different capacities and commissioning dates.

2.5.3 Ownership

There are certain implications, risks and obligations for the owners of network assets that specifically relate to which parts are invested in, owned and operated by whom. We elaborate on the effect of ownership structure (the unbundled environment) on regulations. This criterion is again closely interlinked with other criteria.

Ownership structure

The ownership structure has consequences for the asset owners. In Europe most network facilities are owned by regulated TSOs. Apart from regulated ownership there are a few instances where merchant investors are involved [Liang et al. 2016]. Generation facilities on the other hand are often owned by independent developers. Contradictions in interests may be apparent when TSOs and wind farms have different liabilities across borders. We look into the effect of the regulated ownership by addressing the most important regulatory incentives for investment. In the case study we identify the possible barriers that arise for the expansions of our case study due to these regulations. The main economic properties of the regulations, as identified by Glachant [Glachant et al. 2013] are:

- allowed remuneration of the TSOs;
- risks born by the TSOs;
- incentives for cost reduction;
- distribution of efficiency gains to users.

We address the allowed remuneration of the TSOs separately in the transmission remuneration sub criterion (section 2.5.5). The other three are tightly interlinked with each other. Risks for regulated ownership are due to cost or performance based incentives that may lead to under or over investment, consequent financeability issues, and more or less risky behavior from the investor. How this translates to consumer prices is decided to a large extent by the regulator via transmission tariffs, also discussed in section 2.5.5. There are several mechanisms in place that address the points as discussed above. The main mechanisms are:

- Cost-plus: the regulator authorizes a specific return on investment, this does not incentivize the TSO to improve performance but decreases its risk.
- Price/revenue cap: a fixed price is set by the regulator, inducing the TSO to reduce costs so that the difference can be retained as revenue.
- Yardstick competition: the costs and efficiency of the TSO are benchmarked to other similar TSOs. Performing better than best practice or average will induce larger profits [Liang et al. 2016; Glachant et al. 2013].

In practice complex combinations of different mechanisms are in play. For example, different mechanisms may be applied to different costs (e.g. cost-plus for CAPEX and price caps for OPEX), not all assets may be included in the Regulated Asset Base (RAB) , and regulations may be updated after each regulatory period with different lengths in different regimes [CEER 2016]. In general, we see that trade-offs are made between remuneration and cost reduction, and between transfer of efficiency gains and cost reduction.

In the scope of the case study, it is informative to assess the ownership structure as it has implications for the interplay between TSOs and other investors. An environment where joint investment and operation are allowed would align interests easier then in the unbundled market. We address the implications of this on the expansions.

2.5.4 Financing

Large infrastructural projects such as those in the energy sector require investors to incur great sunk costs compared to operational expenditures. This brings large dependence on financiers and increased uncertainties related to financial risk. Next to that, varying regulatory regimes give different incentives to stakeholders for remuneration and cost reduction, impacting the financeability of a project. We address several criteria that relate to financing of the investments.

Investment Cost Allocation

Investment cost allocation is an issue for expansions where assets are shared. Stakeholder may benefit differently from the shared assets like transmission assets that are used to transfer wind power to multiple countries. Therefore investment costs should be allocated in such a way that stakeholders are incentivized to continue the investment. In the North Sea area, connection costs are usually incurred by TSOs. Hence, the question here would be whether different TSOs contribute equally to investments or whether an alternate allocation structure should be implemented to ensure a fair distribution of benefits [NSCOGI 2012].

Moreover, the TSOs may incur losses on their congestion rent due to RES connection, and the wind farm developer experiences infrastructural cost savings due to less cabling required. Therefore, cost allocation between wind farm developer and TSOs could be necessary. We address here *investment* allocation schemes, excluding operational costs or benefits that are incurred over the lifetime of the project.

We do not take into account reinforcement costs for the TSOs. This assumption could mean reduced benefits for TSOs, since combined projects may reduce reinforcements costs for the TSOs [NSCOGI 2014]. Reinforcement costs could be allocated among stakeholders as well.

Typical investment cost allocation schemes are [NSCOGI 2014; Hadush et al. 2015]:

- Equal share, or 50-50 distribution between TSOs (in case of two TSOs).
- Regional shares, based on the cable length in the territorial waters.
- Proportional to stand-alone, allocates the investment costs to TSOs and generator based on the costs a TSO or generator would incur for a standalone project
- Louderback, the division of infrastructure costs to countries depending on their direct costs and a share of the common costs.
- Shapley value, an allocation method build upon game theory.
- Proportional to benefits, net benefits are calculated per country and losers are compensated by winners.

There are different variations of these cost allocation methods, and extensive methodologies are described [Flament et al. 2015; NSCOGI 2014]. This research provides simplified figures on investment costs. Therefore, not all cost allocation methods could be properly addressed. Louderback allocation for example builds on the notion of attributable costs and common costs. These definitions in itself vary in literature and relate to specific cost aspects that are not discussed here [NSCOGI 2014]. Shapley value and proportional to benefits are not considered due to complexity, and our consideration of investment costs (excluding benefits) only, respectively. We will address equal shares, regional shares, and proportional to stand-alone costs.

Considering two players, proportional to stand-alone cost allocation can be computed as follows:

$$C_A = \frac{Csa_A}{Csa_A + Csa_B} * C_{common} \tag{2.59}$$

Here C_A would be the cost allocated to A, based on the stand alone investment costs Csa of player A and B, and C_{common} is the total investment costs of the combined project. This type of computation would still allow further allocation according to equal or regional share principles.

Investment cost allocation is interlinked with recurrent cost allocation, i.e. the costs and benefits that occur throughout the lifetime of the project. We will assess the latter in the transmission remuneration criteria.

PCI Funding

PCI funding can be a source of debt for integrated projects. The large sunk investments in the offshore industry require extensive financing. The money needed to achieve 40 GW of offshore wind energy in the North Sea area amounts to tens of billions of euros [Arapogianni et al. 2013]. An important means to attract investors would be applying for the status of Project of Common Interest. ENTSO-E produces regional investment plans and lists of PCIs on a bi-annual basis that address these issues. For priority corridors such as the North Sea area, projects are assessed based on similar economic indicators as used in this research. On these grounds projects may be found eligible for status of PCI. Then, the EC may decide on a grant to support the project investors.

Additional benefits of PCI status may be quicker permit granting processes, lower administrative costs and increased transparency [Parliament et al. 2013]. Several barriers such as priority access of RES and curtailment compensation may be addressed via PCI statuses in the future as well [Flament et al. 2015]. To apply for PCI status, regional groups are established that propose and evaluate these projects on a regional basis. The Northern Seas offshore grid would be the regional group addressing the priority corridor in the North and Baltic Sea. They consist of representatives from Member State, European Commission, TSOs, national regulatory authorities, ACER and project promoters [Parliament et al. 2013]. We address the impact PCI funding could have on the feasibility of our expansions.

2.5.5 Pricing

In order to recover the investment costs, it will be necessary to decide on the cost allocation. Who will pay for what and how much should be paid. We cover here the operational costs and benefits, distinguishing Pricing criteria from Financing criteria. We start by looking into the means TSOs and generators have to remunerate their investments, next we look into support schemes.

Transmission remuneration

Transmission remuneration is based on regulated transmission tariffs that can be set after the TSO's investment proposal is approved by the regulatory authority, and the congestion rents a TSO receives over transmission congestion between different price zones. The (regulated) transmission tariffs or charges are used to allow for the TSO's cost recovery of transmission facilities by allocating it to network users [Liang et al. 2016; NSCOGI 2012]. These consist of costs for the TSOs such as losses, system services and the infrastructure, and non-TSO costs such as RES and non-RES support mechanisms, financing activities of regulatory authorities or other institutions and stranded costs [Fernández et al. 2016]. Partially, remuneration may also be fulfilled by the congestion rent over the interconnector, but these usually do not cover all expenses of the TSO [Liang et al. 2016]. Regulation defines that these revenues should be used for the purpose of either:

- guaranteeing availability of the allocated capacity on the interconnector;
- further investments for maintaining or increasing interconnector capacities;
- income, after the regulatory authority has decided upon whether transmission tariffs need to be adjusted accordingly [De Jong et al. 2007].

Transmission tariffs are complex mechanisms that could vary in time, per voltage level, based on the support tariffs, per region and per project [Fernández et al. 2016]. The most common categorization is among flow-based and non-flow-based methods. The former dictates prices based on the actual utilization of each user, the latter allocates costs based on total nodal injection and withdrawal and the distance between these two. Therefore, we will assess the effect of transmission tariffs on our expansions qualitatively by looking into the national regulations and tariff proposals for our case study.

Connection remuneration

Connection remuneration is the remuneration of the generation connection facilities that connect to the interconnector or other transmission facitity. Here the generation facility refers to the transmission asset that connects the offshore generator with the network facility that transfers power to the end users [Liang et al. 2016].

Remuneration depends on connection charging as defined by regulations in the country where the generation technology is connected to the transmission asset. Three classifications are adopted. Deep connection charging obliges the generators to account for internal grid connection, interconnection to main grid and reinforcements to the main grid caused by their connection. Shallow connection charging implies no need to account for costs of reinforcements to the main grid and super-shallow connection charging only holds the generator responsible for internal grid [Liang et al. 2016; NSCOGI 2012].

From the view of economies of scale, it is argued that TSOs should account for these connection costs [Flament et al. 2015], hence super shallow connection regime would apply.

This criterion directly impacts the interests and risks of generation developers. However, current national regimes differ. This will have an effect on the distribution of socio-economic welfare. Therefore, we address the consequence of connection regimes for our expansions by looking at the trade-off between investment costs for the TSO and the generation developer.

Furthermore, generating and consuming network users may be charged differently among countries. Therefore, wind farms will choose to feed into countries where none or low transmission charges are applied to generating network users, as it increases their profits. European legislation on this matter only states that charges should reflect cost benefit calculations [Flament et al. 2015] and thus does not provide specific guidelines to correct transmission remuneration approaches.

Support schemes

Support schemes are the mechanisms that incentivize developers to construct generation facilities. Regulations are such that the minimum subsidy level is incorporated under which for instance wind farms are profitable. Which subsidy applies to a generator located in one zone but selling part of the power to another is still an unsolved problem. A zone that does not profit should not provide subsidies or should be compensated. On the other hand, subsidies from two different zones cannot be claimed on the same power flow [Glachant et al. 2013; NSCOGI 2012]. The main support mechanisms for RES are in the form of feed-in-tariffs or feed-in-premiums. The former are fixed prices per MWh, the latter constitutes the wholesale market price plus a fixed additional price per MWh [NSCOGI 2012].

The Renewable Energy Directive (RED) allows national mechanisms for support to accomplish individual targets. It includes flexibility mechanisms, which allow countries to subsidize generation outside their national borders through joint projects and allows for harmonized support schemes. These flexibility mechanisms are supported but not mandated by the RED. Therefore subsidy regimes typically differ among countries, and wind farm developers can only apply for subsidies of the countries they are located in. Currently, generators will choose the country that supplies the most favorable total package in terms of support and connection charges. Harmonised support schemes would separate the two mechanisms [NSCOGI 2012]. It is clear that a wind farm interconnected to two countries but located in a third country, would require the use of flexibility mechanisms as the project can not provide net benefits to them.

2.5.6 Operation

In order to reach acceptable network reliability and efficiency standards, regulatory frameworks have been set up to ensure secure grid operation. Again, the international nature brings up several important aspects the central stakeholders should take into account. Codes and guidelines are increasingly put forward by European legislation which is decided upon by the trilateral relationship between the European Commission, ACER and ENTSO-E, although in practice continuous feed back with TSOs and other stakeholders is carried out [Liang et al. 2016].

It must be stated that the CBA model is focused on investment and overall welfare arising from the expansions. There is a simple operational approach where transmission flows are based on marginal bus prices. Detailed analysis of the criteria below would therefore require a more specific modeling approach.

Congestion Management and Capacity Allocation

Congestion management and capacity allocation relates to prioritizing flows. The Third Energy Package is European legislation on the matter. Its regulation 2009/714 mandates the non-discriminatory operation of interconnectors. In other words, there should be no preference on the allocation of interconnector capacity and the direction of the flows. In case of a combined project there should thus be no preference between trade (congestion rent) and offshore generation capacity [NSCOGI 2012], and non discriminatory feed-in of the wind farm.

Moreover, ACER's guidelines on Capacity Allocation and Congestion Management state that all flows should be allocated through implicit auctions, which means that capacity is allocated on the day-ahead market, as opposed to explicit auctions with long term capacity allocation based on transmission rights. This poses risks to an offshore wind farm connected to an interconnector as capacity is scarce [Gaventa et al. 2012]. We will address the implication of our expansions on the principle of non-discriminatory operation.

Priority Dispatch

Priority dispatch deals with prioritizing generation facilities. The Electricity Market Directive of the Third Energy Package states that the TSO is responsible for dispatching the power generation systems, and that up to a maximum of 15% of the time Member States may dispatch indigenous generation. However, the offshore generation facility would need the commitment that it can feed its production into the grid at all times, as is also defined in the priority access principle of the RED. In the case of RES connection to an interconnector, these regulations contradict one another [Fouquet et al. n.d. E3G et al. 2013]. Moreover, there could be conflict with the capacity allocation and congestion management mechanism. Therefore, this criterion is directly linked to the capacity allocation criterion, and addresses the risks for TSOs and wind farm developers in combined project solutions.

When RES generation does need to be curtailed - in case the cable is congested and conflicts arise between trade and generation, or in order to keep balance in the system - the question of compensation for this curtailment arises. Wind farms would prefer feed-in to countries where these compensation mechanisms are in place. However, this would increase congestion further [Flament et al. 2015].

Moreover, TSOs may need to pay the wind farm owners to get them to curtail their production, i.e. negative electricity prices would occur [NSCOGI 2012]. This is because output based compensation incentivizes wind farms to produce electricity even when it is not needed (due to subsidy schemes). TSOs would then need to pay an amount equal to the subsidy in order to stop the wind farm production and keep system balance. Other arrangements are that the wind farm pays for access to the interconnector, or a full priority dispatch with reservation of the variable capacity needed (as wind power varies per day) and no additional charge is demanded [NSCOGI 2013]. We will analyze the consequences of priority dispatch for TSOs and wind farms of our expansions.

CHAPTER 3

Results

In this chapter we will present the results of the COBRAcable case study, aiming to answer the main research question. We follow the structure of the sub questions. Firstly, we present the portfolio as created for the COBRAcable case study (section 3.1). The argumentation and justification for choosing certain expansion candidates will be provided, as well as how they are inputed into the model.

Next, the CBA results of all selected expansions are presented in section 3.2. Emphasis is placed on the distribution of cost and benefits among countries and different (groups of) stakeholders in compliance with sub question 3 and the overall objective.

Lastly, in section 3.3 we will discuss the results of the stakeholder analysis. Results are based on literature review as consultation of stakeholders is beyond the scope of the research. Nevertheless, it will provide interesting insights in the issues of future offshore grid development as perceived by the stakeholders involved.

3.1 Portfolio

In this section we introduce the COBRAcable expansions, starting with an analysis of the energy technology trends. These trends will give insight in the future development of specific technologies and hence in the possibility they will be implemented in the future. We then continue with the analysis of probable projects for the short and long term. We end up with an expansion project portfolio.

3.1.1 Energy Trends

In their international energy outlook, the Energy Information Administration (EIA) projects that global RES capacity will increase by an average of 2.9% per year to 2040. Excluding hydropower changes this figure to 5.7% per year [EIA 2016]. Wind and solar capacity experience the quickest growth, followed by geothermal energy, biomass and waste, and marine energy sources.

Nuclear power expected average yearly increases are around 2.3%. However, OECD countries do not participate in this increase, where Europe even experiences a slight decrease. Especially around the North Sea area where Germany plans a nuclear phase-out by 2022.

Gas production increases world wide due to high fuel efficiency and low emissions compared to other fossil sources. In Europe an increase of from 8.7 % share in 2020 to 11.1%

share in 2035 is expected. More than half of this is meant for electricity production leading to a gas consumption increase for power to 3.6% per year.

Although world wide crude oil production will continue to increase, this trend is interrupted for OPEC countries. Specifically, the generation share of oil will decrease steadily from 2.8% to about 1.5% in 2035 in the North Sea area. This happens under reference, low oil price and high oil price scenarios. The current decline in oil investments and increase in delays and cancellations is expected to continue. Some oil fields in the North Sea are even closed down earlier than expected.

The ENTSO-E scenarios for 2030 are in compliance with the outline of the EIA energy outlook. Its regional investment plan [ENTSO-E 2015a] following the TYNDP 2016 states that the North Sea grid is a favorable region for interconnection due to:

- Nuclear phase-out in e.g. Belgium and Germany in the short term and the coal-gas shift.
- Large hydro capacity with variable inflow potentially leading to long periods where extensive or limited amount of stored energy may be available.
- Large capacity of thermal based generation systems.

Their slow progress scenarios (vision 1 and 2) envision the continued use of coal facilities and minor necessary investments in the short term for the North Sea grid, except for some reinforcement in the internal grid in Denmark. This is due to significantly lower share of RES. The progressive visions (3&4) however, require extensive reinforcements in the short term already as new bulk power flow patterns are established.

3.1.2 Short Term Candidate: Offshore Wind

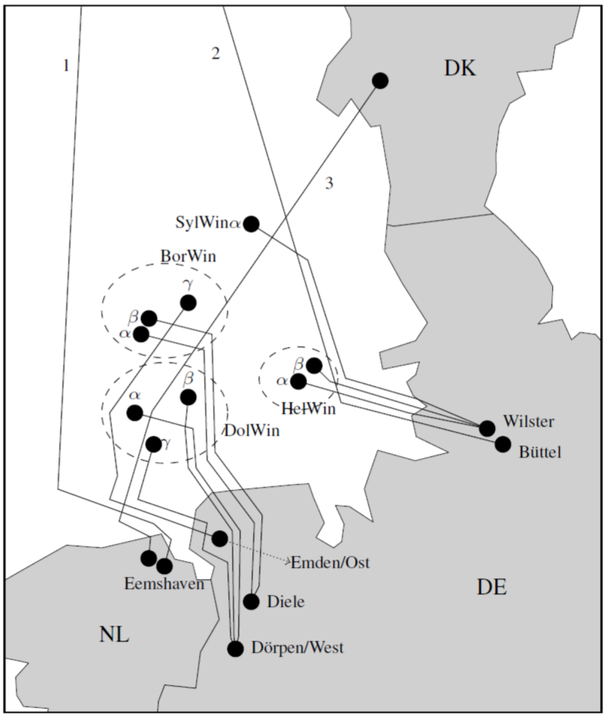
The interest in offshore wind technology has increased rapidly due to the generally higher and steadier wind speeds at these locations, and the lower amount of resistance from social interest groups and local inhabitants [Chondrogiannis et al. 2015]. Furthermore, the costs of such installations are expected to continue to decline. The Northern European region is the front runner and has a significant amount of offshore wind power capacity planned in the near future, most of which will be located in English and German territory. Offshore wind capacity in the North Sea is expected to increase from 40 GW in 2020 to 114 GW in 2030, accounting in a large part for the total increase in Europe [de España 2013]. Offshore wind farms are currently the only renewable energy sources that are planned to be interconnected to transnational HVDC cables in the North Sea grid, making them the prime candidate for this portfolio.

For the COBRAcable, the installation of a wind farm will be the main, if not only contender up to 2030. The European Commission already allocated funds under the European Economic Recovery Programme (EEPR) to allow TenneT and Energinet.dk to connect a future wind farm along the COBRAcable route [Hoveijn 2013; De Decker et al. 2011]. The topology of such an expansion would be tee-in, which can be considered as a first step to a meshed grid solution, although the offshore generation system might not act as a hub to the shore.

German wind farms would be most interesting for connection to the COBRAcable since these are located furthest offshore, allowing for the greatest infrastructure cost savings. However, Germany has already built an extensive sub station/cabling infrastructure in the North Seas including their DolWin, BorWin, HelWin and SylWin sub stations (see figure 3.1). Many wind farms in the pipeline are intended to be connected to these sub stations.

Therefore, it will be interesting to distinguish between wind farms that have passed the conceptual planning stage and of which the converter sub stations are chosen, and wind

Figure 3.1: Expected offshore grid connections and sub stations in the German North Sea at the end of 2020. 1. NorNed, 2. COBRA cable 3. NordLink [Irnawan et al. 2016].



farms that are still in design phase or dormant. The first group could be considered to form a hub between German mainland and the COBRAcable. The second could be interconnected to the COBRAcable alone. First, we identified four different regions where batches of wind farms are located based on the 4COffshore database [*Global Offshore Wind Farms*], that were recognized to be available for connection to the COBRAcable, see figure 3.2.

The first region is in the north and consists of the Nördlicher Grund, Sandbank and Sandbank Plus wind farms, the second region is in the central part and consists of Amrumbank West, Kaskasi II, Nordsee Ost and Meerwind Süd Ost wind farms. Third, we have a large batch of wind farms in the western region consisting of Skua, Gannet, Area C I/II/III, Heron, Seagull, Petrel (all 400MW), and another batch in the north western part, including Horizont I/II/III/IV, the GAIA I/II/III/IV/V and Witte Bank wind farms. See table 3.1.

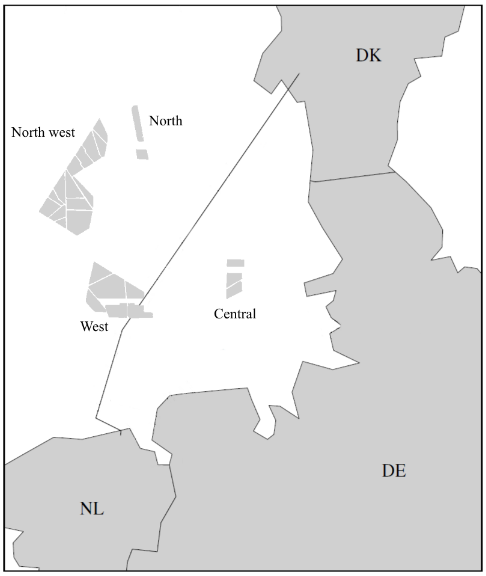
For all groups that are located closest to the COBRAcable their are some remarks to be placed:

- The wind farms in the central regions are or likely will be (Kaskasi II) connected to German onshore. These will therefore be considered candidates for wind farm hub expansions.
- The dormant wind farm projects in the north west form a viable option. No connection points have been decided upon and they located far from shore, giving increased opportunities for infrastructural cost savings by interconnection to the COBRAcable.
- The wind farms in the west have significant converter infrastructure in the vicinity (to the south), although extensions and new capacity needs to be built/is in development.
- In the northern region there are three wind farms that already have radial connections nearby. These wind farms are considered less serious candidates.

Table 3.1: Wind farms in German North Sea in northern, central, west and north western regions.

North	**MW**	**Status**	**Connection**
Nördlichter Grund	384	authorised	Sylwin2
Sandbank	288	construction	Sylwin1
Sandbank Plus	240	authorised	-
Central			
Amrumbank West	302	commissioned	Helwin2
Kaskasi II	272	consenting	-
Nordsee Ost	296	commissioned	Helwin1
Meerwind Süd Ost	288	commissioned	Helwin1
West			
Skua	400	dormant	-
Gannet	400	dormant	-
Petrel	400	dormant	-
Seagull	400	dormant	-
Heron	400	dormant	-
Area C I/II/III/IV	400	dormant	-
North west			
Horizont I/II/III/IV	222-450	dormant	-
Gaia I/II/III/IV/V	280-560	dormant	-
Witte Bank	708	dormant	-
Aiolos	1280	dormant	-

Figure 3.2: Wind farm candidates.



The timing of COBRAcable expansion with a wind farm is uncertain. In its business case report TenneT states that expansion is not foreseen in the short term considering all cable capacity used for power trade more beneficial than a combined option. Although it is not stated what this short term would be [Hoveijn 2013]. Because of this uncertainty we will look at installation of a 400 MW wind farm after period 1 in 2025 and after period 2 in 2030. Delays are usually in the range of two years, so the chosen time instants will not exactly count for potential delays [ENTSO-E 2015b].

Regarding storage facilities or further interconnections, there are some conceptual ideas present, but these should be considered only for the longer term, if at all. The short term expansions identified are elaborated below.

Expansion 0 - Base Case

This will be the case where no expansion has occurred yet, and only the COBRAcable itself will be in operation. See figure 3.3.

Expansion 1, 2, 3 - Single Wind Farm

The first expansion candidate considers the addition, via a tee-in connection, of a 400 MW ofsshore wind farm to the interconnector in 2030 (**Expansion 1**). This is based on the wind farms that are located north west from the COBRAcable. This includes the GAIA and Horizont wind farms that are in dormant states and for which currently no sub station connection is defined. Additionally, two alternate versions of expansion 1 may be considered for comparison, see figure 3.4:

- **Expansion 2** Larger capacity (900 MW) of the wind farm, which could lead to increased curtailment and reduced trade benefits as capacity will be used to transfer wind power.
- **Expansion 3** Introducing the expansion at an earlier moment, in 2025 to analyze the effect of timing.

Figure 3.3: COBRAcable expansion 0 or base case.

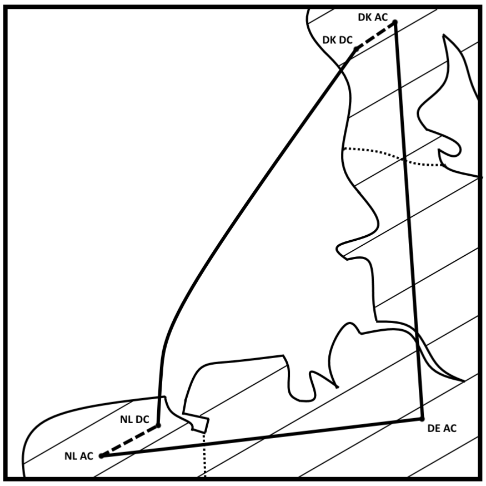
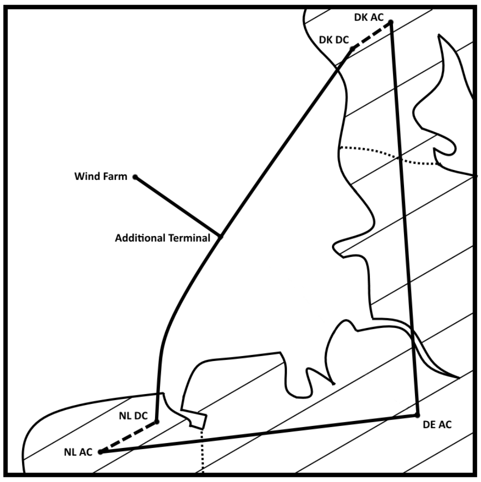


Figure 3.4: Topology expansion 1, 2 and 3.



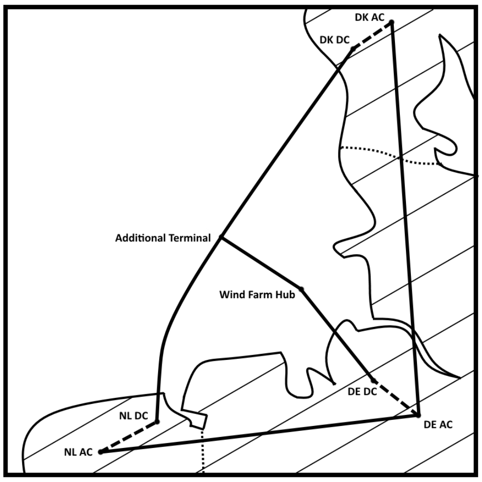
In its case study of the COBRAcable, the EWEA introduced the same case of a 400 MW wind farm expansion [De Decker et al. 2011]. We chose to consider the same case to validate results, and gain additional insights in cost and benefit allocation among stakeholders. However, in expansion 3 we will also look into different timing of the same project which we assume will give useful insights in the appropriate planning schedule.

In the same study EWEA also studied the effect of increasing capacity of the wind farm while keeping the interconnector capacity the same. It concluded that when wind farms with around double capacity of the transmission cable are connected, it would increase net benefits since capacity could flow to both countries at full interconnector capacity. Capacities lower than this, but higher than cable capacity could also be interesting options. We chose to go with 900 MW, which could for example be accomplished by connecting Horizont II, III and IV (planned 894 MW), or GAIA I and IV (910 MW) in the north west. This capacity will also allow comparison with expansion 5.

Expansion 4, 5 - Indirect Interconnection

The next case defines the expansion of the COBRAcable with an indirect interconnector. That is, instead of a DC link connecting directly to Germany, a connection is made with an existing wind farm or wind farms (a hub) that are radially connected to an onshore AC bus, see figure 3.5. The central region is of main interest, it consists of a group of four wind farms, of which three are fully commissioned and all are around 300 MW in capacity and connecting to the HelWin2 Converter sub station. The dormant wind farms as identified in the beginning of this section could also apply for hub connections (section 3.1.2).

Figure 3.5: Topology expansion 4 and 5.



For better comparison with the results of case Expansion 2 and 3, we chose to examine the effects of an indirect interconnector to Germany integrating 400 MW (**Expansion 4**) and 900 MW (**Expansion 5**) respectively. For 900 MW additional justification can be made by connecting three existing wind farms in the central region which are Amrumbank West, Nordsee Ost and Meerwind Süd Ost (together 885 MW), or by looking at the Sandbank, Sandbank Plus and Nördlicher Grund wind farms in the far north (together 912 MW). These expansions will be commissioned in 2030 as well.

3.1.3 Long Term Candidates: Integrated Network

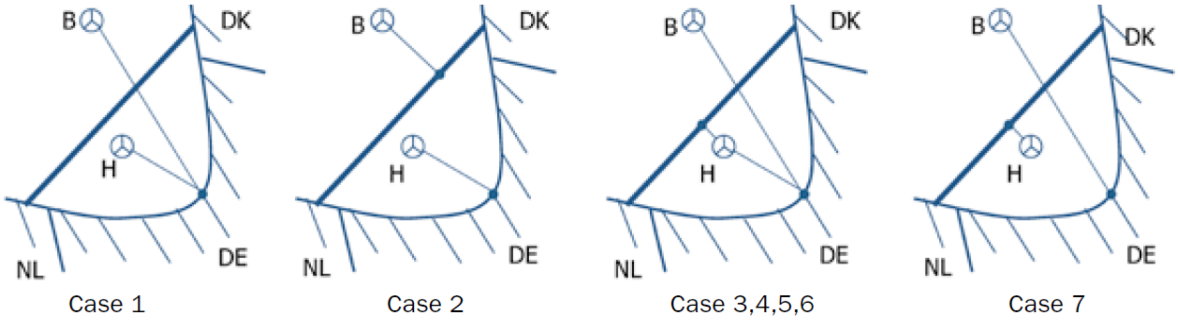
For long term projects we look into some possible generation and storage opportunities but focus on different grid arrangements. We continue where we left in subsection 3.1.1, starting with an assessment on renewable technologies.

The expansion of wind capacity will remain an important and likely possibility for the long term. This could entail both adding capacity to existing hubs, or the creation of new hubs to be connected to the grid. As mentioned before, EWEA already addressed these particular projects and the relation between costs and benefits, and distance of the hubs to the interconnector [De Decker et al. 2011]. Their studied cases are shown in figure 3.6.

Expansion 6 - Direct Interconnection

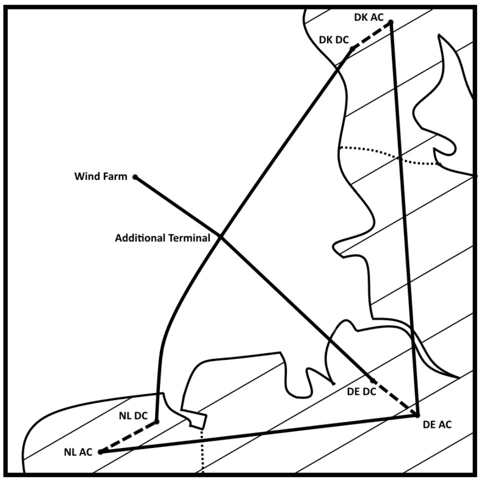
In **Expansion 6** we evaluate a direct interconnection of the COBRAcable with Germany, in 2040. This direct interconnection means there is no intermediary wind farm hub between the

Figure 3.6: COBRAcable expansion cases as identified by EWEA, where case 3,4,5,6 have different allocation of capacities among wind farms and interconnectors [De Decker et al. 2011].



COBRAcable terminal and the Germany onshore bus, see figure 3.7. It is not clear whether such an expansion would ever be considered, given the current interests in wind farm development in Germany and hence the possibility to include a wind farm. However, this expansion could provide interesting insights in the trade-off between (direct) interconnection developed only for congestion rent and (indirect) interconnection where part of the capacity of the interconnector will need to be reserved for wind power transfer purposes. We will assume equal cable capacity compared to COBRAcable, which is 700 MW. Another assumption is the successful implementation of Expansion 1; a tee-in wind farm.

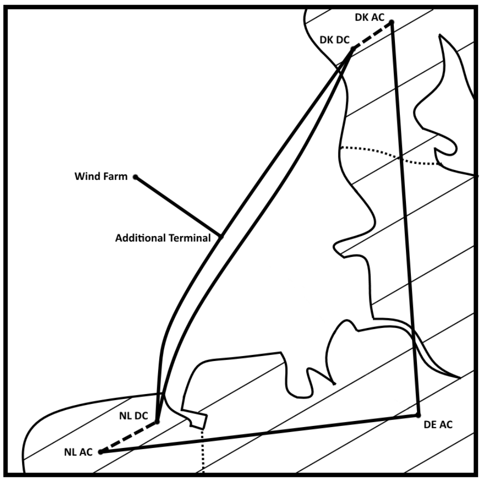
Figure 3.7: Topology expansion 6.



Expansion 7 - COBRAcable 2

There are conceptual plans for a second interconnection between Denmark and the Netherlands (unofficially called COBRAcable 2 from here on), effectively doubling the transfer capacity between these countries [ENTSO-E 2015a]. In **Expansion 7** we will analyze the effects of such an additional transmission expansion occurring in 2040, assuming Expansion 1 has been implemented in 2030. The expansion occuring in 2040 is an assumption that allows for better comparison with expansions 6 and 8.

Figure 3.8: Topology expansion 7.

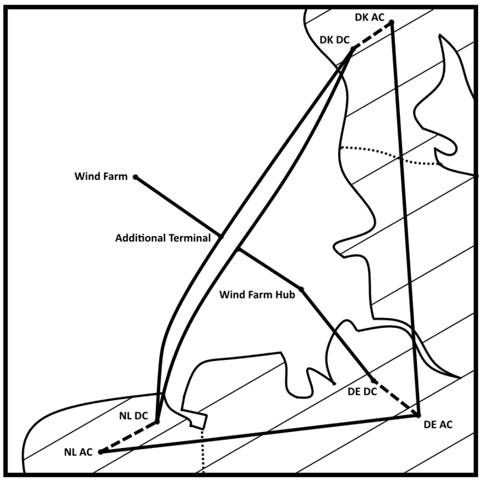


Expansion 8 - Increase Wind Capacity

What EWEA did not study is the economical consequences of increasing wind farm capacity at a later point in time. This could especially have high consequence if the infrastructure capacity is already made adequate for this expansion at an earlier point in time.

In this case, **Expansion 8**, we will assume a 400 MW wind farm is installed directly to the COBRAcable in 2030 and extra capacity of 500 MW is added to COBRAcable2 in 2040. 500 MW is only justified by the fact that total capacity will be 900 MW again, allowing for better comparative results. An overview of all expansions is given in Appendix E.

Figure 3.9: Topology expansion 8.



Disregarded Options: Future Research

In this section we will give the rationale for not considering some other interesting options. We present them here with the notion that they could be addressed in future research.

The offshore connection of onshore solar panels (due to high infrastructure costs) and expensive installation (and maintenance) of offshore solar panels are not deemed viable for interconnection to the COBRAcable. Although there are conceptual plans for floating solar islands (e.g. by DNV KEMA), these were put on hold as findings showed there would be conflict with the many large offshore installations present [Greenmatch 2015]. The COBRAcable does already allow trade of the increasing onshore solar capacity.

Marine energy technologies are currently not enough developed to serve dedicated large scale generation purposes. Osmotic or salinity gradient technology will likely remain inapplicable on a large scale in the future. Ocean thermal energy in turn will only be suitable in locations where the temperature difference is large enough, the North Sea is not one of those [Magagna et al. 2015]. E-Highway assumes even wave and tidal energy competitiveness will not be achieved by 2050, where technical potential for tidal is too low and efficiency for wave technology will also remain an issue [Vafeas et al. 2014].

The decline in oil generation and increasing forced decommissioning of countless platforms in the North Sea give rise to new options. The concrete structures of the platforms are typically able to last long after the lifetime of the energy technology itself [Lockett 2015]. They can thus be used as bases for other energy sources such as geothermal or gas generation and storage facilities. However, in the vicinity of the COBRAcable no offshore oil or gas platforms are present. E-Highway considers future oil production obsolete due to cost and performance issues [Vafeas et al. 2014], as is also confirmed by their long term scenarios. Gas production might increase due to the coal-gas shift, but its still considered very unlikely an offshore platform is going to be build in Germany in the future.

We are concerned with the large scale centralized technologies in this model, as low capacity technologies do not seem viable for connection to an offshore interconnector due to relatively low expected benefits compared to capital expenditures. Therefore, we considered pumped hydro, compressed air, battery, pumped heat (thermal) and fuel cell storage.

Offshore pumped hydro power by building a large energy island has been a conceptual idea for quite a while, for example around 2007 in the Netherlands [Verheij et al. 2007]. There are also other examples, but they were dismissed for various reasons. Currently however, there is another proposal for an energy island 'iLand' for the coast of Belgium [E3G et al. 2013]. Although in the short term such an island would not be expected, it could be interesting in the longer term.

Compressed air energy storage is a promising technology for the future. Although use must be made of underground caverns or other large storage spaces. Batteries are another technology expected to be competitive in the long term as an energy storage means. These would take considerably less space but are costly. Fuel cells experience the same issue, investment costs consist mostly of conversion technology costs and not of storage costs [Körner et al. 2015].

However, since storage in this research is being modeled as if it were conventional (flexible) generation, considering the case of storage expansion is not perceived as generating meaningful results.

Lastly, we did not assess the option of asymmetrical cable dimensions: increasing the capacity of one part of the interconnector as seen from the expansion connection terminal. This could lead to better results if the capacity is increased at the side of the cable at which bus prices are highest. This would allow power flow for both trade (congestion rent) and wind power generation purposes. The BritNor and NordLink have demonstrated that this can be beneficial and offset higher infrastructure costs [De Decker et al. 2011].

3.2 Costs and Benefits

In this section we will elaborate on the MC simulation results for different expansions. The MC simulation has performed 300 runs for each expansion. The argument for this is that the relative error - with 95% coverage probability - is below 5% for our socio-economic welfare indicators for all periods and scenarios. For the other indicators, maximum values of the relative error are around 5%, with network losses costs as an exception. However, for 300 runs the relative error for the latter still typically remained below 10%. These ranges are considered appropriate, as the analysis is meant for indicative results on the allocation of costs and benefits. Moreover, since many assumptions are made for input variables, reducing the relative error could falsely create high perceived accuracy. Hence, the accuracy as given by the relative error is based on our fixed assumptions and accounting for variations in these assumptions would reduce the accuracy. For more information on the relative error refer to Appendix F.

All monetary results are calculated as the NPV for 2020 and depicted in [M€]. The units of other indicators will be specified in the text. We will present our expansion results in a comparative matter, starting with an overview of the economic indicators for all scenarios and each expansion in section 3.2.1. In subsequent sections we zoom in to groups of similar expansions to address the allocation of cost and benefits. This grouping will be done for short term candidates - single wind farm expansions (1, 2 and 3) and wind farm hub expansion (4 and 5) - and long term expansion candidates (6, 7 and 8).

3.2.1 Overall Results

In this section we present the overall results. We compare the total benefits of all indicators for all expansions. Hence, we do not look into the distribution of benefits among countries. Starting with socio-economic welfare and continuing with sustainability, security of supply and network losses indicators.

Socio-economic Welfare

Figure 3.10 presents the results for welfare indicators. Firstly, we note that high RES scenarios generate the most welfare for most expansions. Expansion 7 and 8 present the most remarkable results. Contradictory to the results of the other expansions, total welfare is not improved under scenario 4 for these expansions. These are the only expansions that increase interconnector capacity. It seems that under high RES this has a deteriorating effect on the marginal bus prices and hence reduces CR and PS while raising CS significantly. In section 3.2.4 we will elaborate more on how this is caused.

Second, from these figures wind farm hub expansions (4 and 5) seem the best option. Total socio-economic welfare is highest for these expansions, although for scenario 1 and 3 they are surpassed by expansion 7 and 8. The larger wind farm capacity of expansion 5 increases benefits further. Comparing with expansion 2 and 8 (also 900 MW offshore wind capacity) shows these improvements are higher for expansion 5. Moreover, expansion 5 is the only project experiencing positive impacts on congestion rent compared to base case for all scenarios. The reason is that capacity flows from the wind farm do not necessarily take up transmission capacity for trade, since wind power can be directed to the e.g. Germany while the COBRAcable itself can still be used for trade purposes.

We notice the trade-off between consumer surplus and producer surplus in all cases. This result is supported in other researches [De Decker et al. 2011] and is explained by the fact that we did not account for transfer of costs and benefits between producers and consumer, e.g. via socialized transmission tariffs, taxes or feed-in tariffs. This is discussed in the stakeholder analysis. Moreover, this research identified similar orders of magnitude for the socio-economic welfare.

(a) (b) (c) (d)

Figure 3.10: Total SW (a), CS (b), CR (c) and PS (d) for all expansions at the end of 2050.

Sustainability

In terms of sustainability indicators (figure 3.11) all expansions provide benefits, with exceptions for CO_2 costs in conventional scenarios for expansion 4.

Avoided fuel costs scale proportional with the amount of wind capacity installed for expansion 1, 2 and 3. For other expansions this effect is still there but the relation is less strong. Moreover, this indicator is improved by increased interconnection capacity as is illustrated by expansions other than 1, 2 and 3. This is because wind power flows to the country with highest prices, which generally is the country with conventional generation dispatch. Lastly, high conventional capacity creates stronger positive impacts due to replacement by wind. Overall, avoided fuel costs are achieved best by high wind capacity and high interconnection capacity, under low RES scenarios.

CO_2 costs are carbon emissions [tonnes] weighted by carbon prices [€/tonne]. These carbon prices are a magnitude 4 larger in scenario 3 and 4 compared to 1 and 2. Therefore, because of large carbon price uncertainty, costs and benefits for high RES scenarios may be overstated. Nevertheless, CO_2 costs for expansion 4 increase compared to base case for scenario 1. This can be explained by the fact that the most expensive generation technologies are not necessarily the most polluting. Generation marginal costs are based on both fuel prices and CO_2 costs, and as we can see avoided fuel costs are relatively high for expansion 4 in scenario 1 and 2, indicating that wind power did replace the most expensive conventional sources. Indeed, for scenario 1 and 2 coal is cheaper than gas (figure B2) while its emissions are higher.

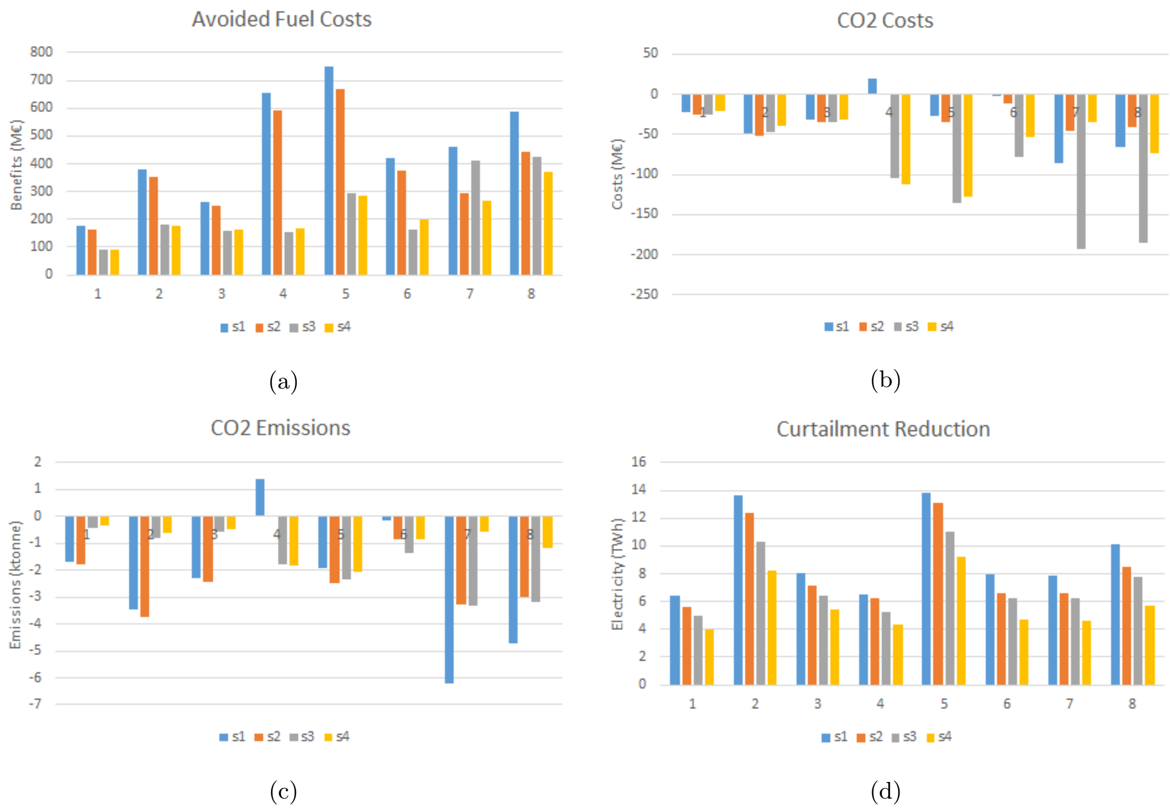
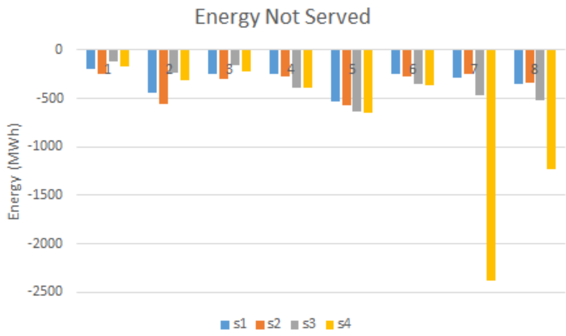


Figure 3.11: Avoided fuel costs (a), CO_2 costs (b), CO_2 emissions (c) and curtailment reduction (d) indicators for all expansions at the end of 2050.

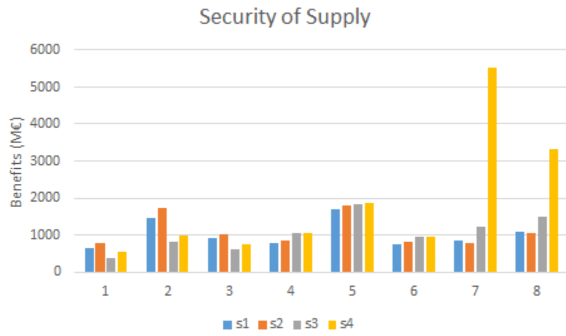
Conventional generation replacement is measured in curtailment reduction. We see that amount of installed wind power has direct effect on the benefits. This is a consequence of our method of computing curtailment reduction: multiplying total additional RES generation by the costs of displaced generation sources. This explains also the differences between scenarios, slow progress scenarios will have more displaced expensive technologies than high RES scenarios.

Security of Supply

Security of supply gives a monetized value for ENS and is directly proportional to it as there is no distinction made in $VOLL$ for different scenarios or periods. Although this is not a hard number, the differences between expansions are still indicative. Interestingly, further interconnection increases security of supply for high RES scenarios, whereas single wind farm integration has most effect of SoS in slow progress scenarios. Also, we see that security of supply is increased significantly in the high RES scenario for expansion 7 and 8. The impact of additional interconnector capacity provides benefits for security of supply if large RES capacities are installed.



(a)

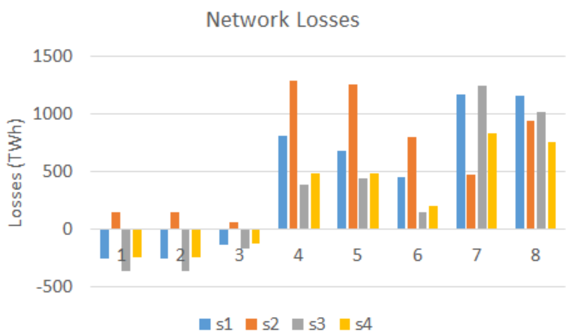


(b)

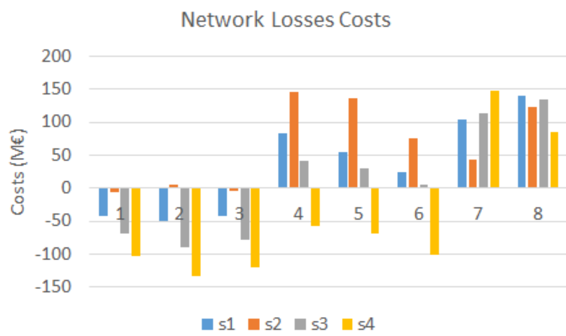
Figure 3.12: Energy Not Served (a) and its monetized value (b) for all expansions at the end of 2050.

Network losses

Network losses increase for expansions with additional interconnections, see figure 3.13. The extra cabling gives rise to more losses. However, when monetizing these losses the impact is soothed since the electricity price of these losses is generally lower, especially when RES generation brings the price down. Then, in some cases the costs of the losses even decline while the losses increase.



(a)



(b)

Figure 3.13: Network losses (a) and its monetized value (b) for all expansions at the end of 2050.

3.2.2 Single Wind Farms

A summary of the characteristics of single wind farm expansions (1, 2 and 3) is given in table 3.2. Total benefits resulting from expansion 3 are biased since the wind farm will be in operation 5 years more compared to expansions 1 and 2. Therefore we will also address the effect of decommissioning of expansion 3 in 2045.

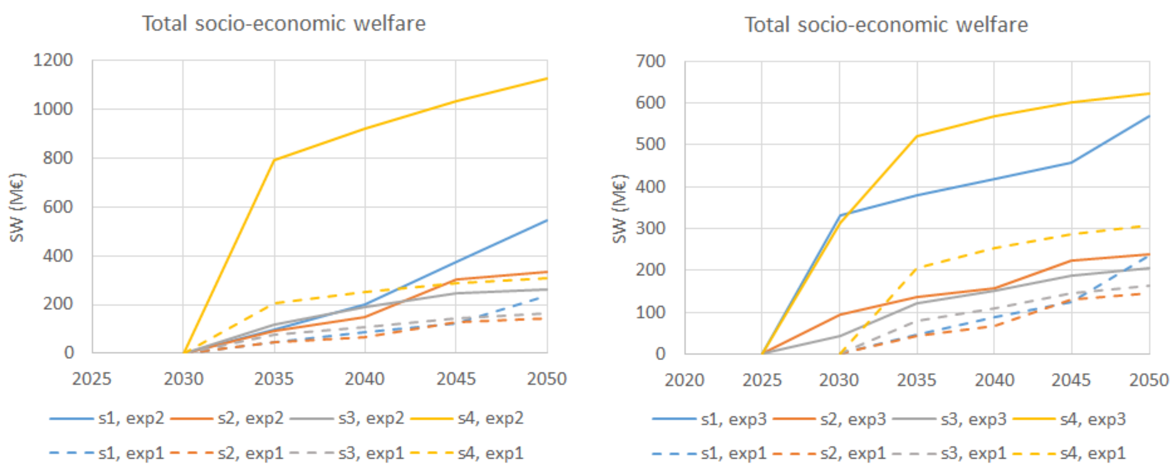
Table 3.2: Single wind farm expansions.

	Expansion 1	Expansion 2	Expansion 3
Investment type	Wind farm	Wind farm	Wind farm
Capacity	400	900	400
Timing	2030	2030	2025

Welfare Allocation

Table 3.3 shows the total SW, for all three expansions. It is evident that total socio-economic welfare is increased under all scenarios and for all expansions. We see that the larger sizing of expansion 2 has large impact on the SW, specifically in scenario 4. In the same way expansion 3 has a large impact on the SW, even when the same operational life time of 20 years is considered (Exp 3 2045). Furthermore it is interesting to see that welfare is decreased by 20% comparing expansion 3 (2050) and expansion 3 (2045) for scenario 1, but that this figure is diminished to below 10% for other scenarios. An explanation is that our scenarios predict that increases in RES generation capacity occur later for scenario 1. Looking at figure 3.14 shows these results stem mainly from timing of the scenarios. Early periods contribute significantly to the total SW.

Accounting for decommissioning costs does not change this figure much, will change the figure but will not affect the ranking much. This is since the discounted decommissioning costs will be in the order of some tens of M€.



(a) Accumulated SW expansions 1 and 2.

(b) Accumulated SW expansions 1 and 3.

Figure 3.14: The effect of sizing (a) and timing (b) on the total socio-economic welfare.

Table 3.3: Total socio-economic welfare (SW) in 2050 as compared to base case, for expansion 1, 2 and 3 [M€].

	Exp 1	Exp 2	Exp 3	Exp 3 (2045)
s1	237	544	570	458
s2	146	333	239	223
s3	163	261	207	189
s4	310	1128	625	603

To gain some insight in the division of SW among the countries, refer to figure 3.15. From figure 3.15a it is clear that the main winner under all expansions in each scenario would be the Netherlands, their benefits are similar throughout the scenarios. Germany also experiences SW growth, especially under high RES capacity scenario 4. Scenario 3, with similar wind capacity but less solar capacity, leads to less favorable SW outcomes. Denmark is considered a loser for that scenario. Furthermore, expansion 2 is highly uncertain for Denmark. Under high RES including high solar and biofuels generation (scenario 4), it experiences large benefits. But when only relying on high wind capacity the opposite occurs.

(a) (b) (c) (d)

Figure 3.15: National SW (a), CS (b), PS (c) and CR (d) indicators for expansion 1, 2, and 3 at the end of 2050.

The larger wind capacity connected to the COBRAcable leaves less room for power trade with the Netherlands. The changes in consumer and producer surplus are caused by lower bus prices due to low marginal costs of RES. Marginal bus prices decline as less capacity from expensive generation is dispatched. Therefore, producers are less able to make profit and consumers benefit from the lower prices. Congestion rent in turn decreases if interconnector capacity is reserved for wind power, and thus not for trading. This is exemplified by lower congestion rent for expansion 2 and for high RES scenarios.

Consumer surpluses are high for all countries, and congestion rent and producers surpluses mostly fall below zero. The Netherlands is an exception, where for scenarios other than scenario 4, PS and CR are around zero and sometimes positive. At the same time its benefits are relatively steady between scenarios.

We see that from the TSOs perspective, single wind farm expansions would not be economically beneficial if they are not compensated in any way (in reality transmission tariffs may be increased to offset the steep increase in CS and decrease in CR respectively, as will be discussed in the stakeholder analysis). Moreover, some TSOs incur larger losses compared to base case than others. Re-allocation mechanisms may be required to incentivize TSOs to invest in the expansions. Especially expansion 2 gives rise to discrepancies among the three countries. We address this in the stakeholder analysis.

Wind Farm Benefits

Wind farm benefits are the benefits that arise due to offshore wind generation of the expansion. They consist of capital costs, fixed O&M costs and their surplus. Hence, we do not assume any subsidy schemes or funding. Moreover, we assume super shallow connection regimes. We will address these assumptions in the complementary stakeholder analysis. Total benefits for wind farm developers will be around zero in all cases when no additional funding or subsidy schemes are applied. This can be seen in figure 3.16.

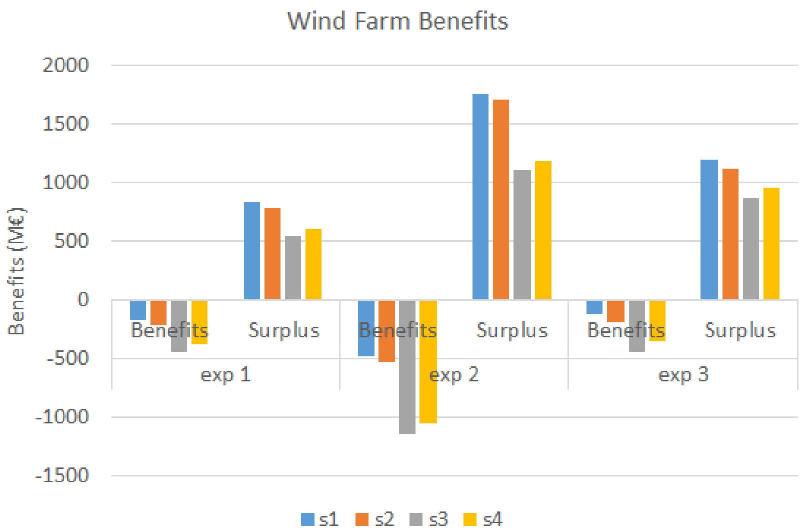


Figure 3.16: Total wind farm costs at the end of 2050.

Effects are largest in scenario 3 and 4. This is the consequence of an impaired wind farm producer surplus when prices fall under high RES integration.

3.2.3 Wind Farm Hubs

In this section we will look more closely in expansion 4 and 5. In section 3.2.1 we have seen that the total socio-economic welfare is increased most for these expansions as compared to the base case. They are especially interesting as they are short term candidates. However, it will be interesting to see if different countries and stakeholders benefit equally. Table 3.4 gives an overview on the characteristics of expansion 4 and 5.

Table 3.4: Wind farm hub expansions.

	Expansion 4	Expansion 5
Investment type	Wind farm hub	Wind farm hub
Capacity	400	900
Timing	2030	2030
Connection point	COBRA Germany	COBRA Germany

Welfare Allocation

We refer to figure 3.17. For expansion 1, 2 and 3 socio-economic welfare is mostly distributed to the Netherlands. However, we see that the hub connection to Germany significantly decreases Dutch benefits, while improving German welfare. Denmark's benefits are still uncertain although expansion 5 now clearly indicates total benefits under all scenarios. To see where these results stem from we look into distribution among stakeholders.

Figure 3.17b depicts the consumer surpluses in the countries around the COBRAcable. German and Dutch consumers benefit the most, where in general surplus increases with more sustainable scenarios. An exception is scenario 3, in which Germany's solar capacity growth has stagnated, and reliance is on power generation from gas while carbon prices are high. The result is an increase in consumer surplus (and decrease in producer surplus) due to the opportunity to import cheaper wind energy from the wind farm hub.

Trends in the producer surpluses can also be explained by the scenarios. In scenario 1 for expansion 4 we see that German producer surplus is positive. Despite the increased wind capacity due to the expansion, more conventional generation with nonzero marginal costs are dispatched. The interconnection of the COBRAcable with Germany gives the latter the opportunity to transfer more conventional power to Denmark and the Netherlands. In scenario 1, their RES cannot fulfill the demand and their marginal prices are above German marginal prices.

The most significant difference between single wind farm expansions and expansion 4 and 5, is the congestion rent. In the former, congestion rents are mostly negative compared to base case. For the latter however, congestion rents are typically increased. The alternate (three terminal interconnector) configuration allows the COBRAcable to be used for trade purposes while Germany benefits from wind power generation. Hence, the hub expansion makes Denmark and the Netherlands reap more benefits from congestion rent, while Germany can share in wind power generation benefits and congestion rent. However, when wind power capacity surpasses that of the interconnector (expansion 5), these benefits shift.

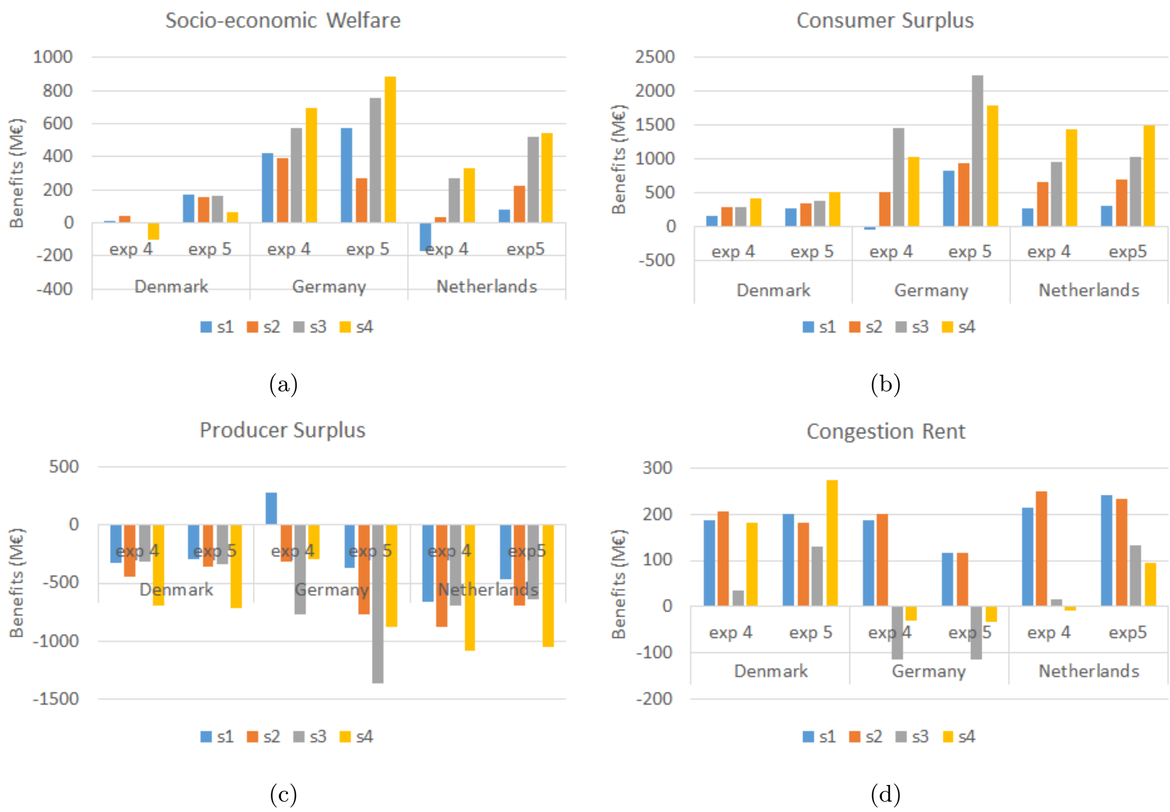


Figure 3.17: National SW (a), CS (b), PS (c) and CR (d) indicators for expansion 4 and 5 at the end of 2050.

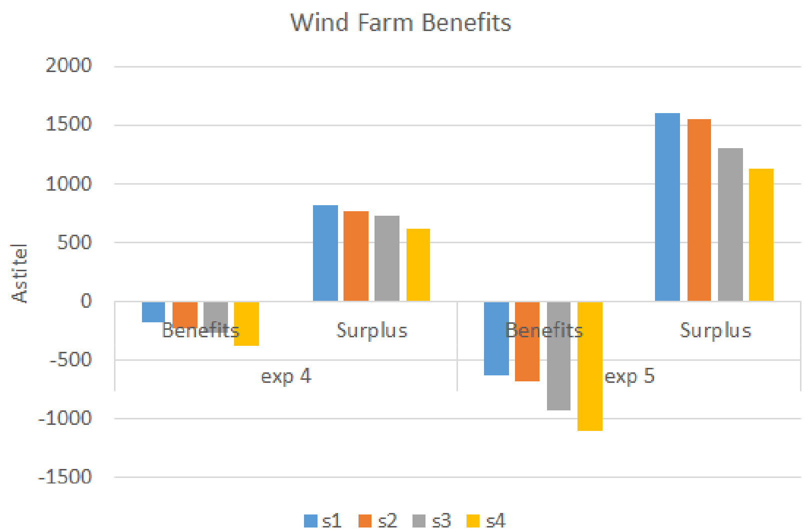


Figure 3.18: Total wind farm costs at the end of 2050.

Wind Farm Benefits

We see the same effects when looking into benefits and surplus of expansion 4 and 5 compared to the single wind farm expansions. Without any support, the benefits for wind farm developers do not weigh up to costs (see figure 3.18). The order of benefits and surplus is also the same as in the single wind farm expansions. These effects would be increased under shallow connection regimes. Potentially more so than for single wind farm expansions since connection of the wind farm is now both to the COBRAcable and to onshore Germany. This is addressed in the stakeholder analysis.

3.2.4 Long Term Expansions

Lastly, we compare the long term candidates. Expansion 6 differs substantially from expansion 7 and 8, but to be concise we analyze these in a comparative matter. Table 3.5 gives a summary on the characteristics of these expansions. The long term candidates are more complex and more uncertain than the expansions covered so far. We stress this throughout the analysis of the results.

Table 3.5: Long term expansion candidates.

	Expansion 4	Expansion 5	Expansion 6
Investment type	Wind farm + Interconnection	Wind farm + Interconnection	Wind farm + Wind farm hub + Interconnection
Capacity	400 MW	400 MW	900 MW
Timing	2030 + 2040	2030 + 2040	2030 + 2040 + 2040
Connection point	COBRA + COBRA/Germany	COBRA + Denmark/Netherlands (COBRA 2)	COBRA + COBRA 2/Germany + Denmark/Netherlands (COBRA 2)

Welfare Allocation

Figure 3.19 presents the national allocation of socio-economic welfare for the long term expansions. For clarity reasons the outliers of expansion 7 and 8 (Netherlands scenario 4 in CS and PS) have been left out. Consumer surplus in these cases reaches 16000 M€, producer surplus benefits are around -12800 M€. These are likely caused by the shift in merit order in the Netherlands. The increased interconnector capacity and high RES generation leads the most expensive generators in the Netherlands to be redundant, the consequence is a drop in producer surplus and a rise in consumer surplus. National prices converge as the Netherlands has the most conventional (expensive) generation capacity, and price differences over the interconnectors fall leading to less congestion rent.

The results indicate that this effect occurs for both expansion 7 and 8. However, the wind farm hub in expansion 8 improves socio-economic welfare, especially for Germany, where wind generation considerably reduces the producer surplus in Germany.

For expansion 6, although total SW was found to improve compared to base case, Denmark suffers from minor losses. The direct interconnection between the COBRAcable and Germany can be seen as an increase in capacity between Germany and the Netherlands and

Germany and Denmark, but it also creates competition among COBRAcable capacity for transfer between the Netherlands and Denmark. The prices in Denmark and Germany being similar, only a slight change in congestion rent occurs. For scenario 3, where Germany's solar capacity has fallen behind, the price differences decrease further.

Figure 3.19: National SW (a), CS (b), PS (c) and CR (d) indicators for expansion 6, 7 and 8 at the end of 2050.

Wind Farm Benefits

Figure 3.20 presents the benefits and surplus for the offshore wind farm. It is important to note that for expansion 8 the benefits and surplus of the two separate wind farms are summed, where for the second wind farm (commissioned in 2040) only revenues until 2050 were taken into account. The results show that benefits are higher under conventional scenarios which is to be expected.

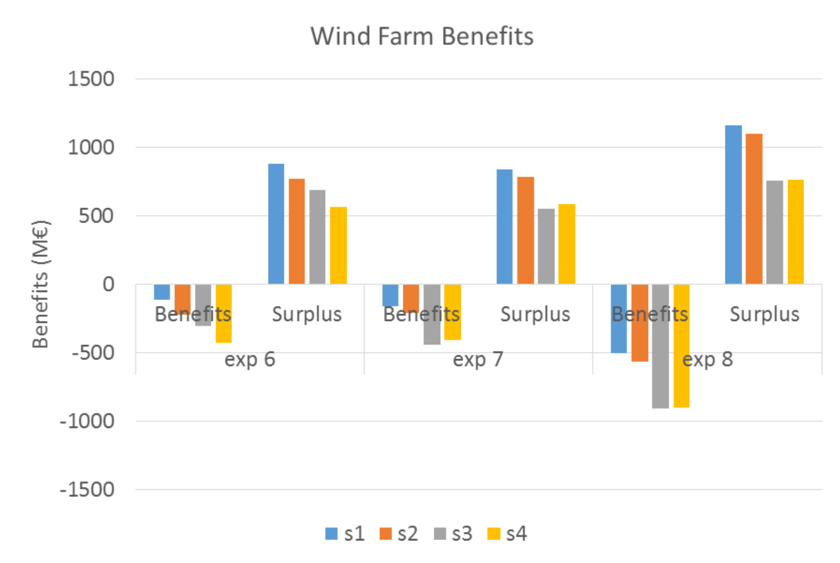


Figure 3.20: Offshore benefits for long term expansions.

3.2.5 Sensitivity Analysis

Marginal costs provide the main uncertainty that is not properly accounted for in the time series or scenarios. Since marginal costs is an important parameter in the CBA model, as it directly impacts the objective function of optimal dispatch, we analyze the effects of changes in the fuel prices and carbon prices respectively. In reality fuel and carbon prices are very volatile, which we did not account for currently in the CBA model. Hence, this sensitivity analysis is performed to look at the effects of a changing merit order on the outcomes of the CBA.

Sensitivity Cases

We analyzed the following cases of fuel and carbon prices as compared to the fuel and carbon prices that have been used in the model and are presented in table B2 of Appendix B:

- Fuelup: Increase the fuel prices by 30%.
- Fueldown: Decrease the fuel prices by 30%.
- Carbondown: Set carbon prices to values of the lowest scenario.
- Carbonup: Set carbon prices to values of the highest scenario.

The consequence is the set of parameters as shown in table 3.6. When altering fuel prices, the carbon prices stay at the normal level, and vice versa. In all sensitivity cases the total marginal prices are adjusted accordingly. The merit order in some cases will change due to the different cases. For example, in the *Carbonup* case, the impact will have a profound effect on the ranking of biofuels as these are assumed to have zero carbon footprint but have a high fuel price.

Table 3.6: Sensitivity analysis parameters of fuel and carbon prices [€/MWh].

	normal fuel				increase 30%				decrease 30%			
	s1	s2	s3	s4	s1	s2	s3	s4	s1	s2	s3	s4
biofuels	34	34	34	34	44.2	44.2	44.2	44.2	26.2	26.2	26.2	26.2
gas	34	34	26	26	44.2	44.2	33.8	33.8	26.2	26.2	20	20
coal	11	11	10	8	14.3	14.3	13	10.4	8.5	8.5	7.7	6.2
lignite	4	4	4	4	5.2	5.2	5.2	5.2	3.1	3.1	3.1	3.1
nuclear	2	2	2	2	2.6	2.6	2.6	2.6	1.5	1.5	1.5	1.5
oil	50	56	56	42	65	72.8	72.8	54.6	38.5	43.1	43.1	32.3
other non RES	20	20	20	20	26	26	26	26	15.4	15.4	15.4	15.4
	normal carbon				lowest level				highest level			
	s1	s2	s3	s4	s1	s2	s3	s4	s1	s2	s3	s4
biofuels	0	0	0	0	0	0	0	0	0	0	0	0
gas	7	7	38	30	7	7	7	7	30	30	30	30
coal	15	15	68	68	15	15	15	15	68	68	68	68
lignite	18	18	73	79	18	18	18	18	79	79	79	79
nuclear	0	0	0	0	0	0	0	0	0	0	0	0
oil	11	11	46	49	11	11	11	11	49	49	49	49
other non RES	15	15	64	68	15	15	15	15	68	68	68	68

Effects on the Results

We present the results as the percentage change in the CBA indicators compared to the normal values cases. For our carbon sensitivity cases this has the implication that the outcomes of the unchanged scenarios will not change.

From figure 3.21 it becomes clear that changing the carbon and fuel prices can have large effects on the total socio-economic welfare. The fuelup and fueldown cases do not change the merit order compared to normal case, yet it increases the benefits considerably. This makes sense since the effect of replacing higher cost conventional fuels with zero marginal costs be will larger and vice versa. Expansion 4 seems especially sensitive to our sensitivity cases. This unexpected result shows that sensitivity is valuable to the analysis and the outcomes of the model should be treated with caution. Overall, SW is still increased for all expansions, but the analysis indicates that the results of our CBA depend to a large extend on the parameters that are inputed.

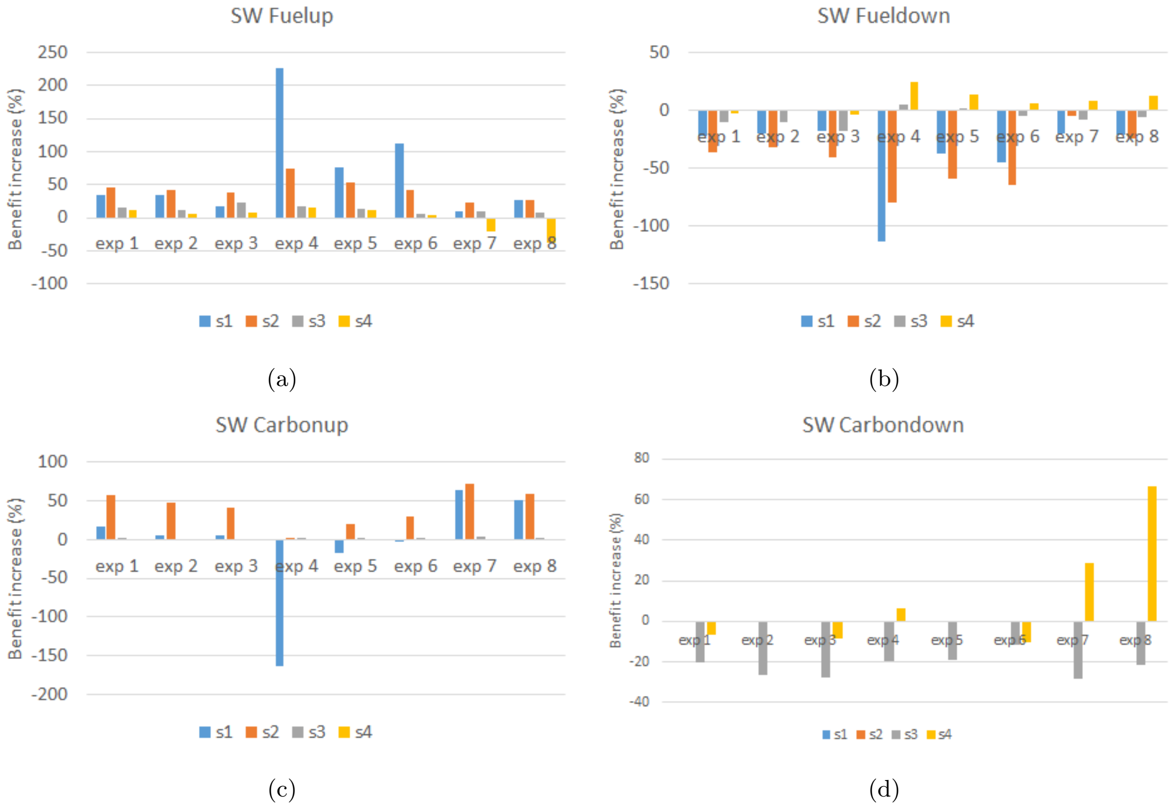


Figure 3.21: Fuelup (a), fueldown (b), carbonup (c) and carbondown (d) sensitivity cases results as a percentage change compared to normal case results.

For carbonup and carbondown cases the merit order does change. Following the same reasoning the increased marginal prices in general increase the benefits of an expansion as the replacement of conventional fuels will have a larger effect. Again, the results show large sensitivity to marginal cost changes. There is even a large spike in expansion 4 that dips a -100%, meaning that socio-economic welfare in this case is in fact less than the base case.

Analyzing further the effect of our sensitivity cases on other indicators is beyond the scope of this research. The main result here is that we see how important the generator marginal cost uncertainty is to the outcome of our model.

3.3 Stakeholder Analysis

In this section the results of the stakeholder analysis are presented. It must be stated that these results are obtained via literature review and not by direct information of stakeholders. However, the analysis still presents some interesting insights.

Furthermore, during the process of analyzing different stakeholders and interests, we quickly recognized the relations between the TSOs and other stakeholders, since the unbundled market forms give rise to a large interdependency on regulation, both in national and European context. Therefore, to refrain us from repetitive conclusions in separate analyses for each stakeholder, we address them all by looking from the main stakeholder's perspectives.

3.3.1 Planning

Planning Practices

For the single wind farm expansions, the COBRAcable itself will have been constructed on a bilateral basis before the expansions occur. Therefore, the changed purpose of the interconnector gives rise in the shift in surpluses, including a negative impact on the congestion rents. This is why TenneT has stated that wind farm connection would not be commissioned at the same time as the interconnector [Hoveijn 2013]. Furthermore, the effect is amplified by the required interconnector down time if the wind farm is installed and tested. Considering a necessary down time of a couple of months, the congestion losses for expansion 1, 2 and 3 (compared to base case when the interconnector stays operational) would already amount to 10-100 M€.

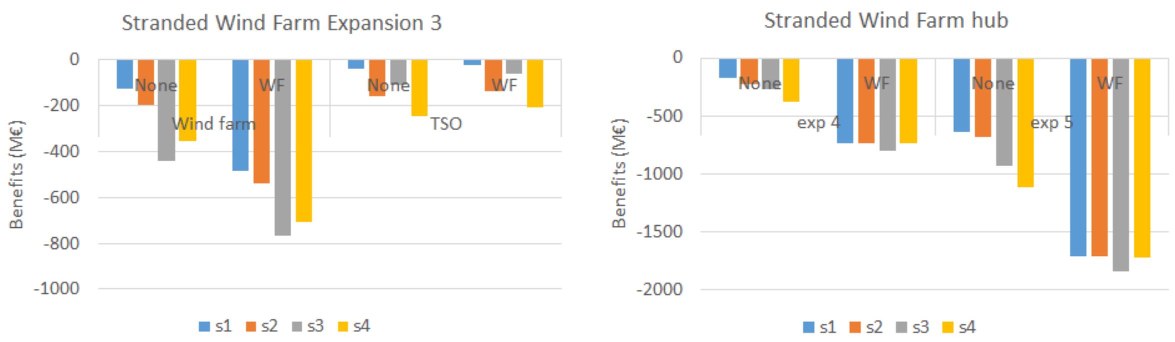
For expansions where combined projects occur at the same time, these risks can be addressed ex-ante. Stakeholders can decide on cost and benefit allocations in the planning stage and no changes in legal status or operations are required. However, since different energy technologies are implemented simultaneously the risk of delay or canceling of one of the stakeholders poses a risk. We refer to this problem in section 3.3.1.

Moreover, for wind farm hub and long term expansions we enter the realm of multilateral planning. The involvement of Germany in the planning process may complicate matters further. Currently, in all three countries close engagement with the governments is required for maritime spatial planning to make sure assessments need only be done once as surveys and routing proposals might well be influenced by e.g. changing seabeds or the commissioning of conflicting projects. For the COBRAcable trajectory, environmental impact assessment procedures in Denmark are considered quicker than for the Netherlands and Germany, where for the latter the time needed is around 2 years without delay [Hoveijn 2013]. Therefore standardization of application procedures is required.

Coordination of Asset Development

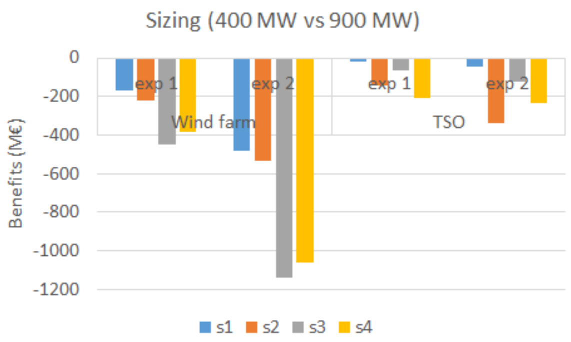
Relating the risk of stranded assets to our expansions could provide insights in the consequences for the wind farm operators and the TSOs. We start by looking at expansion 3. We compare the consequence of delay of either the wind farm or the interconnection in expansion 3 by a single period. Hence, in the normal case both wind farm and interconnection are commissioned in 2025, and in the (hypothetical) stranded wind farm case the cable is commissioned in 2030.

We see (3.22a) that the consequence of a stranded wind farm could be large for the wind farm developer, whereas the consequence for the TSOs is actually positive, since it can use its capacity for trade purposes. This is not including the investment of implementing the



(a) Benefits for wind farm and TSO in case of stranded wind farm.

(b) Benefits for wind farm in case of stranded wind farm, versus normal commissioning.



(c) The effect of sizing on the wind farm and TSO benefits.

Figure 3.22: The effect of stranded assets relating to project timing and sizing on the benefits for wind farms and TSOs.

terminal to which the wind farm is connected, but assuming a 200 M€investment the effect of installing the terminal five years early would amount to NPV of 37 M€. This would pose a risk to the TSO.

The risk of stranded assets is especially large for wind farm hubs (figure 3.22b), as the wind farm relies on connections to multiple nodes. In Germany there is priority grid connection, in e.g. the Netherlands this is not the case [Flament et al. 2015]. Therefore, the hub interconnection might become a radial connection to Germany if the interconnection between hub and COBRAcable is delayed. Then the full capacity of the wind farm may not be commissioned. Hence, this risk of parallel planning (reserved capacity on the hub) is prevalent for the wind farm developer in expansion 4, 5 and 8.

Sizing of wind farms will also have impact on the costs and benefits for the stakeholders involved (figure 3.22c). If the wind farm size is greater, it will be able to make more profits on the output. However, when it surpasses the cable capacity it will not be able to feed its power output at all times. Since we do not account for economies of scale for larger wind farms (i.e. CAPEX and OPEX scale proportionally with capacity), we expect this to be of negative impact to the wind farm. Also, the TSOs will lose congestion rent due to the low marginal cost wind farm feed-in.

Adding to this is the fact that total wind farm capacity should be covered by the connection capacity according to German legislation [Flament et al. 2015]. However, for wind farm hubs (where the wind farm is also connected to other countries) this amount of capacity might not be needed since not all power will need to be fed into Germany.

Lastly, for TSOs the risk in wind farm hubs are also larger. This is because congestion will increase if the wind farm is only connected to one node. Modeling this would require a whole new expansion configuration, therefore we suggest addressing this in further research.

3.3.2 Ownership

Ownership Structure

Just as most European member states, the Dutch, Danish and German asset ownership is regulated via the TSO model. This implies full transmission system asset ownership and fully unbundled transmission system operation. TenneT BV, TenneT GmbH and Energinet.dk are all 100% state owned limited-liability companies (TenneT DE is owned by the Dutch TenneT TSO). The regulation schemes differ however.

The Netherlands and Germany have similar schemes, including revenue cap regimes on the total expenditures (CAPEX and OPEX) and applying international benchmarking to determine revenue allowances and efficiency targets.

In the Netherlands, the allowed return on investment and financeability are relatively low compared to other member states (around 5%). The incentives for cost reduction and efficiency transfer to consumers are high due to ambitious efficiency targets that apply to old sunk investments. This has negative implications for TSO remuneration and hence risks are higher. Regulatory periods in the Netherlands are 3 years, which is low and gives rise to extra risks for TenneT BV as efficiency transfers occur more often allowing for less remuneration, and regulative parameters may be adjusted more often [Glachant et al. 2013].

The regime in Germany is more moderate and the risks for the TSOs are lower, since the allowed return on investment is higher (around 7%). This is flexible as there is a mechanism in place that allows to rapidly adjust the revenue streams when investment levels do not match historical or projected levels. However, efficiency targets are set on most investments reducing the financeability. Moreover, there are high incentives for cost reduction in Germany due to incentives specifically addressed to the CAPEX [Glachant et al. 2013]. Regulatory periods in Germany are 5 years leading to less risk for Germany compared to the Netherlands.

Regulation in Denmark is more according to cost-plus principle, allowing tariffs to only cover incurred costs and an interest rate. Ex-post evaluations on necessity and efficiency of investments are conducted by DERA, leading to tailored regulations for different investments. In the future a more integrated scheme for offshore network is expected [NordREG 2012].

The implications of these structures in relation to the expansions are that TenneT BV may be less inclined to perform large investments (expansions 6, 7 and 8) than TenneT GmbH, as financeability is lower. Moreover, the incentive based revenue cap system of the Netherlands and Germany might prefer mature technologies over new ones as there is a risk that OPEX is high, reducing benefits. Therefore, specifically the development of wind farm hubs (expansions 4, 5 and 8) is at risk. The cost-based scheme in Denmark controls these risks relating to large and new investments, as the revenue is set.

3.3.3 Financing

Investment Cost Allocation

For the COBRAcable itself, investment cost allocation is straightforward as the TSOs could share equally the costs. When there is a further direct interconnection with Germany as in expansion 6, TenneT BV, TenneT GmbH and Energinet.dk could share these costs equally. Or, if regional shares are considered, TenneT GmbH might finance the connection fully. Therefore, these investments might require negotiation between TSOs but will not be subject to difficult allocation schemes. Difficulties will arise however, when wind farms are integrated in the interconnections. Part of the capacity of the interconnector will now be used for wind power flows and the wind farm saves infrastructural costs. An attempt is made to look at the stand-alone costs of the wind farms and interconnectors. This is largely based on assumptions but will suit the purpose of explaining its effect.

Since there is few information available on similar investments, we again assume the cost of the additional terminal of around 200 M€. Table 3.7 shows the effect of stand-alone cost allocations. The stand-alone costs are computed differently for the different expansions. For single wind farm expansions, we assume TSO stand-alone cost to be the same as combined project costs. For hub expansions and expansion 6, the stand-alone cost of the TSOs would be that of a direct interconnector to Germany. Expansion 7 TSO stand-alone costs would be including the COBRAcable2, and for expansion 8 COBRAcable2 and interconnection to Germany. Lastly, for wind farm stand-alone costs, radial connection is assumed.

We see that the TSOs will be better of when using the stand-alone cost allocation scheme. This makes sense since the wind farms have the largest cost savings compared to their stand alone configuration. Also, the highest impact is achieved for expansion 6. Here the direct interconnection to Germany is a significant portion of the common costs of the combined project that mimics a radial connection to onshore Germany. The large cost allocated to the wind farm could be made up for by its opportunity to distribute power to adjacent countries. However, our results showed that the offshore producer surplus is increased only slightly compared to expansion 4 for which the investment costs of the wind farm are much less. Hence we can conclude that the stand-alone allocation method would be preferable for the wind farm in a hub configuration.

Table 3.7: Expansion investment cost allocation.

	Normal allocation		**Stand-alone allocation**	
	Wind farm	TSOs	Wind farm	TSOs
exp 1	666	108	688	87
exp 2	1499	244	1523	220
exp 3	855	133	879	108
exp 4	666	349	585	323
exp 5	1499	485	1384	466
exp 6	666	341	792	215
exp 7	666	454	798	322
exp 8	1172	776	1324	624

In the table we have summed the investment costs for the respective TSOs. Applying regional shares would generate figures for the respective TSOs. For single wind farm expansions and expansion 7 (only COBRAcable2) the costs of the TSOs can be assumed split between Energinet.dk and TenneT BV. The other expansions are more interesting. Applying strict regional rules for these expansions would mean that TenneT GmbH would incur large investment costs while the other TSOs will benefit as well. Sharing equally for the hub or direct interconnector could also be unfair considering the German TSO would benefit from the large investment of the COBRAcable. More thorough research would be required, also considering the benefits the investment will give to the respective TSOs.

However, difficulties may arise when for example a wind farm is located in one country and connected to the other country. The first would not want to provide access for the wind farm as it does not benefit from the wind farm. The latter would be not be willing to finance it since part of the connection is not in its own country. There is currently no European legislation on this but a proposed harmonised regulation constitutes periodical contributions of TSOs to be used for compensation [Flament et al. 2015]. For combined projects, similar problems hold. Therefore, we will address the outcomes of the CBA by looking into different allocation of investments in the expansion projects.

PCI Funding

The Northern seas are listed in the NSOG priority corridor. Currently, a set of five different interconnectors have been listed in the Denmark, Germany and the Netherlands as PCI to increase transmission capacity. €5.85 billion is allocated under the Connecting Europe Facility (CEF) to be distributed among PCIs between 2014-2020. The COBRAcable is included in this list, and has received an European Energy Program for Recovery grant based on its status as a PCI. This grant is a 86.5 M€ EC fund to be used by the Danish and Dutch TSOs. The motivation for awarding the grant is based on the possibility of wind farm integration to the COBRAcable.

The effect of a similar fund would be an incentive for TSOs to invest in expansions with further interconnection possibilities. This could relate to expansion 7 and 8 where the COBRAcable2 is installed. It was found that a similar grant of 86.5 M€ could amount to a significant share of the total investment costs for these expansions projects. In the super shallow regime such an amount could relieve TSOs investments costs by 20% 14% for expansion 7 and 8 respectively.

3.3.4 Pricing

Transmission Remuneration

Transmission remuneration differs between Denmark, Germany and the Netherlands. ENSTO-E calculates the so-called unit transmission tariff that aims at grasping the different tariffs within a country in a normalized tariff [Fernández et al. 2016].

In Denmark the unit transmission tariff is almost 42 €/MWh and the highest amongst member states. This is due to the large non-TSO costs (31.50 €/MWh) that are implemented in the tariffs, and hence these costs are not allocated to Energinet.dk. Furthermore, Denmark uses a fully flow-based approach in the calculation of its transmission tariffs. However, in current literature and in practice, flow-based models are not available yet for HVDC systems. Flows are controlled by the HVDC converters and controllable links and hence the tariffs may be influenced accordingly [Liang et al. 2016]. Therefore, currently alternative methods must be applied to the COBRAcable and its expansions. Denmark allocates 3% of its transmission tariffs to producers that inject power and 97% to consumers.

In Germany unit transmission tariffs are 11 and 7 €/MWh for TSO and non-TSO costs respectively, whereas in the Netherlands only 3.5 €/MWh is implemented. Furthermore, these countries have much more non-flow-based methods of cost allocation, and allocate 100% of the tariffs to consumers.

For interconnectors a fixed tariff must be set in advance for all countries to implement. The different tariffs and approaches between the three countries might hamper the decision on the tariffs set and therefore pose risks to the TSOs. This risk would be higher for expansions that include further interconnection with Germany.

The risks may be higher for the wind farms of our expansions however, due to the DERA's charging of producers by 3%. This is addressed in the next section.

Connection Remuneration

In case of interconnectors, both the Netherlands and Germany apply shallow connection charges whereas in Denmark all investments will be socialised via access tariffs (super shallow). It is expected that for future RES connection to interconnectors, connection charges will be the same as current radial connection charges. If not, they will be expected to be more beneficial to generation company in order to incentivize the offshore grid expansion [Glachant et al. 2013].

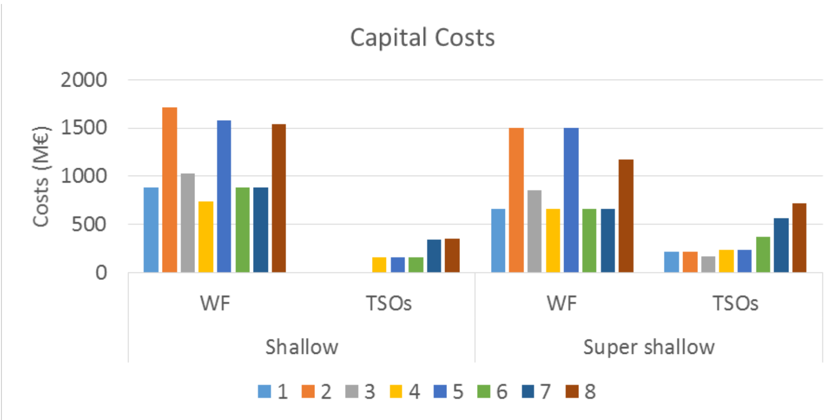


Figure 3.23: Costs under shallow and super shallow regimes.

Figure 3.23 shows the effect of different connection charges on the capital costs of the wind farms and TSOs. Since we do not take into account balancing and reinforcements costs, a deep regime would generate the same figure as the shallow regime. Furthermore, in this calculation we assume that the indirect interconnection of the wind farm hub expansions will be accounted for fully by the TSOs (even in shallow regime). The added costs for the wind farm will thus only be due to the converter station. The additional costs for the wind farms in the shallow regime will reduce their revenues, the additional costs of the TSOs in the super shallow regime will usually be socialized.

In the Netherlands and Germany, full transmission tariffs are calculated to the consuming grid user. In Denmark, 3% of the transmission tariffs are allocated to the producers and the remaining part to the consuming grid users [Fernández et al. 2016]. However, in Denmark transmission prices are paid by the offshore wind farm, only to be refunded later by price supplements. A possible barrier could arise when the wind farm feeds the Danish grid and applies for Danish support schemes, but is not eligible for the price supplement. This might push the wind farm to feed into other grids more, leading to congestion [Flament et al. 2015].

In the results of our CBA, power flows are mostly to the Netherlands for all expansions, suggesting that this risk is not high. However, the increased costs of a shallow expansion regime might pose significant risk to the wind farm as exemplified by figure 3.23. Assuming the costs for a wind farm hub will be socialized since connection to two far-off points will be expensive for a wind farm, the wind farm hubs are a preferred choice. If not, a risk-averse competitive wind farm will not consider the expansion.

The total effect on remuneration of the wind farm is not only decided by connection regime and the generation part of the transmission tariff, but also dependent on the support scheme and the regulation regarding wind curtailment in case of interconnector congestion. We will address this next, and in section 3.3.5 respectively.

Support Schemes

In Denmark wind farm prices are set by location-specific tenders. When the wind farm is outside of the Danish North Sea area, difficulties arise in defining the remuneration for these wind farms. In the Netherlands also tender principles apply, but these are not location-specific, meaning offshore wind farms outside Dutch North Sea area could possibly apply for Dutch subsidies. German support schemes mostly do not rely on tenders yet and are administratively set, and could therefore apply to wind farms outside of their area [Flament et al. 2015]. If a wind farm is able to apply for support from a different country, it could choose feed-in into a country where support is most generous, while it is located in another country. Unfair advantage to the wind farm would be the result. NorthSeaGrid therefore suggest that a wind farm should alway get support from the country it is located in [Flament et al. 2015]. In our expansions the German support scheme then applies to our expansions.

In Germany support schemes are based on the difference between a guaranteed tariff and monthly average electricity price. The total premium is than allocated to the wind farms at the end of each month. The subsidy scheme distinguishes between different years of operation. For the first 12 years of operation, the guaranteed tariff is 154 €/MWh for wind farms operating within 12 nautical miles and in a depth of less than 20m. A further distance from shore and deeper sea will increase the period of 12 years by 0.5 months/mile and 1.7 months/m respectively. For the remainder of the years in a 20 year subsidy period, a subsidy of 39 €/MWh applies [TKI et al. 2015]. For our calculation we assume 15 years of the full guaranteed tariff and 5 years of 39 €/MWh.

Figure 3.24a shows the effect of current German subsidies on the profits for the wind farm developers. For this calculation capital expenditures, fixed O&M costs and producer surplus where taken into account for the case without subsidies. 154 €/MWh for the first 15 years and 39 €/MWh for the next 5 years were added for the cases with subsidies. That is, we assume the total guaranteed tariff is being calculated to the wind farm developers.

We see again that the effects of timing and sizing are large. Earlier development gives rise to less discounted subsidy cash flows (expansion 1 compared to 3). The effect of sizing is exemplified by expansion 2 and 5 and less so by expansion 8, due to the additional 500 MW for expansion 8 being installed at a later time and subsidies and producer surplus for beyond 2050 of this capacity not being taken into account. We see that the height of the subsidies is linked to the sizing. Without subsidies the larger expansions are more costly, but when we apply the

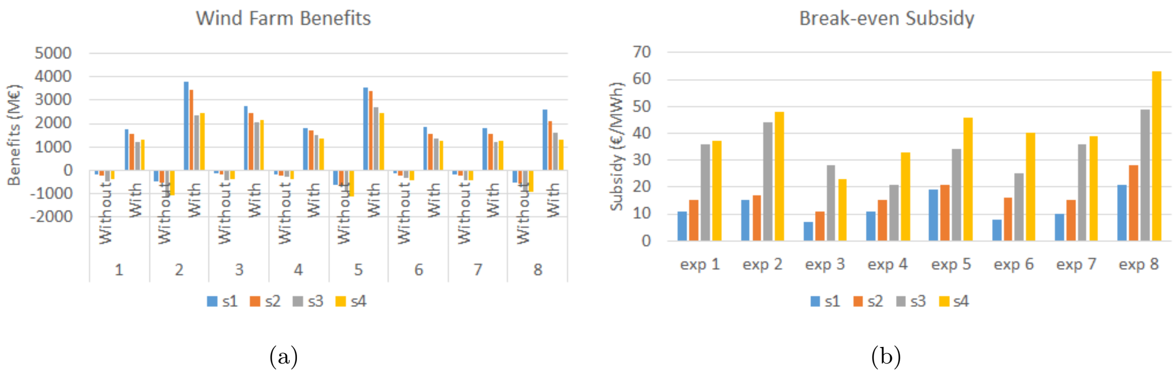


Figure 3.24: Wind farm benefits with and without German subsidies (a) and the subsidies required for a wind farm to break-even (b).

full German guaranteed tariff, benefits well surpass their smaller equivalents.

Figure 3.24b shows the necessary subsidies for wind farms to break-even. We see that under high RES scenarios an increase of up to 400% compared to low RES scenarios is required for wind farms to be profitable. This is a consequence of the lower wind farm surplus due to lower prices when RES capacity with zero marginal costs is prevalent. We therefore see that current German regulation incentivizes wind farms to commission plants as soon as possible, but that this exactly induces the high RES scenario trajectories. Furthermore, NorthSeaGrid assumes a normalized difference between commodity price and guaranteed tariff of 60 €/MWh [Flament et al. 2015], this would allow all expansions to break-even considering that the second wind farm (500 MW) of expansion 8 would receive 10 more years of subsidies after 2050.

The main objective of Germany on this support set up would be that the subsidies are socialized only to German consumers. Flexibility mechanisms in the RED allow states to engage in joint projects, creating the possibility to support projects outside their zone by transferring benefits between participating countries.

Tax rates will partly offset the impact of subsidies on the distribution of welfare among producers and consumers. The effects of tax rates are similar among Denmark, Germany and the Netherlands, applying corporate income tax rates of around 25 % and similar depreciation terms [TKI et al. 2015]. However, the effect for Denmark and the Netherlands will be an increase in consumer surplus since only taxes and no subsidies apply, whereas in Germany consumer surplus will decrease as a consequence of the subsidies.

3.3.5 Operation

Congestion Management and Capacity Allocation

In the case of our expansions, issues arise due to the offshore wind farm being located in a different price zone (Germany) than where the bids are placed (Netherlands and Denmark, and Germany for expansions 4, 5, 6 and 8). Hence, it is unclear which national rules should apply.

Considering our COBRAcable case, the location of the wind farm in a floating bidding zone that is not the same as the bidding zones of the terminals of the COBRAcable, leads the wind farm to always be able to feed-in electricity to the highest price bidder, i.e. Denmark or the Netherlands (as occurs in the CBA model). Hence, we arrive at a conflict with the non-discriminatory principle as the wind farm has advantage over radially connected wind farms that can only feed into one price zone.

An option might be the designation of a separate bidding zone to the wind farm. There can be no congestion between this separate bidding zone and the low price bidding zone (since power will be allocated to the higher price zone), thus the wind farm price will always receive the lower price [NSCOGI 2013]. Hence, this presents risks to the wind farm and it would prefer radial connection.

A solution could be including the offshore wind farm in one of the bidding zones of the COBRAcable terminals. Then the wind farm will always receive the price of the bidding zone it is connected to. This way, the wind farm will be treated like any other radially connected wind farm [NSCOGI 2014].

The solution would be implementable in case of expansion that interconnect the German onshore grid. However, for single wind farm expansions and expansion 7 (no further direct or indirect interconnection with Germany) such a structure may not be straightforward as the wind farm is located in German territory, leading to legal issues of the interconnector asset. A more harmonized approach may be required.

Here, we assume the usage of implicit auctions which is in line with our CBA model. However, where Denmark adopts these implicit auctions, Germany normally uses explicit auctions for capacity allocation of wind farms [NSCOGI 2013]. The Netherlands adopt separate approaches for different neighboring countries. Currently, between Germany and Denmark there are exceptions in place that facilitate coordinated capacity allocation. Hence, experience indicates this risk can be overcome between these countries.

Priority Dispatch

As mandated by European legislation, in all three countries priority dispatch of RES is implemented. When there is congestion on the COBRAcable including a wind farm, the issue of curtailment arises as Germany and Denmark will compensate RES generation curtailment, whereas the Netherlands does not. This could lead to an unfair distribution of welfare [Flament et al. 2015]. Specifically, constraining the RES generation means that generation costs will go up (as wind farms have around zero marginal costs and congestion implies that there is some higher market price), the higher market prices become raise, and the value of interconnector power is decreased.

Moreover, there exist some discrepancies between Denmark and Germany. In Denmark the wind farm need not pay any form of access rights whereas this is the case in Germany through the use of explicit auctions to purchase long-term transmission rights. Therefore, there are market risks in Germany for interconnected wind farms that do not exist for radially connected wind farms [NSCOGI 2013].

The most obvious implications of these schemes for the expansions are the uncertainties for the wind farms. Especially for wind farm hub configurations where the wind farm may directly feed two countries (Germany and Denmark or the Netherlands) at the same time. If curtailment is better compensated for power flows in a certain direction, the wind farm would prefer connection to either the COBRAcable or radially to Germany and not in a hub configuration. This implies the need for harmonized procedures.

CHAPTER 4

Conclusions & Recommendations

4.1 Conclusions

The ambitious targets set out by the European Commission regarding market integration and renewable energy generation imply a move towards an increasingly integrated grid. This increased scope requires a novel approach to address the diverging interests of different actors. Currently, there is a lack of regional coordination to adequately address the drivers and bottlenecks for international investments in the offshore grid. Moreover, the unbundled power market leads to conflicting interests between investors in transmission facilities and renewable generation. In this thesis, we set out to develop a framework that could cope with the uncertainties regarding this multi-disciplinary and multi-actor problem, answering our main research question:

What is the socio-economic feasibility of expansion options of the COBRAcable from the perspective of the main stakeholders, and how to assess this?

Our research showed that assessing the feasibility of expansions of the COBRAcable is subject to many uncertainties and assumptions. The results can not be grasped in a single answer. Rather, we present overall conclusions of the case study, based on a critical notes to be taken into account when evaluating the opportunities for multi-terminal expansions. We link these critical notes to the general socio-economic framework, elaborating on the strengths and weaknesses of TEP and our own framework. We present our conclusions by addressing the sub questions separately.

Overall, we have provided a novel approach to addressing the problem of multi-terminal expansion. We have shown the added value of a quantitative analysis looking into the distribution of costs and benefits among countries, and of a complementary qualitative analysis to address further regulatory uncertainties and elaborate on the distribution of costs and benefits. Furthermore, our analysis of TEP approaches and the case study has provided insights and recommendations to address the shortcomings of current approaches and our own framework, and the regulatory issues that arise due to the multi-lateral expansion problem.

4.1.1 Sub Question 1

What modeling methods are currently applied in the field of expansion planning and what methods are suitable for the COBRAcable case study?

In TEP, choices need to be made on the modeling approach with the research scope and objective in mind. A large research scope implies the need for concessions in several aspects of the model. These aspects include a static or dynamic approach depending on the interest of the researcher on optimizing the expansion timing, bundled or unbundled markets which give rise to diverging interests and additional planning complexities, and deterministic or probabilistic modeling to account for different types of uncertainties. A trade-off needs to be made between modeling complexities and uncertainties, and development of an acceptable computational performance of the model.

A mathematical optimization method in the form of linear optimal power flow has been identified as a common approach for long-term socio-economic researches, as they generally provide accurate outcomes for aggregated results over long time horizons, without placing a high computational burden on the model. Similarly, Monte Carlo analysis is the mostly adopted method to account for random uncertainties as it is easy to implement and straightforward to use.

The scope of the COBRAcable case study is regional and unbundled. We addressed this by implementing national nodal resolution to be able to evaluate costs and benefits on a national level and for different stakeholders. Furthermore, since we are interested in the market behavior of our model we optimize dispatch. We do not include expansion optimization, leading us to the choice of a static modeling approach. A further implication of this is that we use linear optimal power flow and Monte Carlo analysis as the main tools to account for random uncertainties stemming from renewable energy generation. They suit the purpose of our research of identifying long-term socio-economic costs and benefits.

Although these simplifications are justified based on the scope and objective of our research, validation of the framework remains a large issue in TEP due the range of uncertainties. Even when considering a case study, the model will still be only assessed based on a constrained set of assumptions and scenarios. Validation procedures should include the evaluation of other modeling methods. Even though mathematical optimization and Monte Carlo are well developed and often considered as validation tools for other modeling methods, the lack of comparison with other tools is a main shortcoming of the current research, especially considering the outcomes of the CBA are complex and extensive.

4.1.2 Sub Question 2

What projects are viable candidates for connection to an additional COBRAcable terminal, considering energy technology trends, and project timing, sizing and topology?

Based on developed criteria and a literature review we conclude that the focus for offshore HVDC grids is on the increase of interconnection capacity. Together with onshore interconnectors these are considered the main investments needed to facilitate a more integrated competitive European market, a reliable grid and the integration renewable energy generation. Furthermore, regarding offshore generation technologies, offshore wind energy development is prevalent. Especially in the German North Sea territory where near shore wind farm locations have become scarce rapidly, the interest for offshore interconnection to for example the COBRAcable is raised.

Due to the trend in Germany of many offshore wind farms being radially connected to the shore via large offshore sub stations, we distinguish between wind farms for which the manner of onshore grid connection has yet to be defined, and those where radial connection is planned or commissioned. Then, several wind farms of the first type are considered as single wind farm tee-in expansions for the COBRAcable. The second group is identified as candidates for hub connection. Lastly, we identified some candidate expansion where further interconnection and wind farms are combined. These further interconnections consist of a direct interconnection to Germany and a second cable between Denmark and the Netherlands (COBRAcable2).

Our portfolio development is preliminary and straightforward. The approach to selecting the expansions is qualitative in order to provide a range of interesting expansions as an input to our analysis. For planners to identify an optimal expansion, the portfolio development should be based on a more quantitative analysis. Then, further aspects that could be assessed include asymmetric connection cable capacities, multiple combinations of interconnection and generation capacities, alternative topologies and a deeper analysis into the effect of timing.

4.1.3 Sub Question 3

What will be the social and economic benefits of multi-terminal expansion, how are they distributed among countries?

We have identified several CBA indicators based on which we analyzed the portfolio expansions. These include total costs, socio-economic welfare, sustainability, reliability and network losses indicators. Detailed technical indicators were not considered, but will be of main interest to project developers. Therefore, we stress the importance of such analyses when identifying feasibility of expansion projects. This exemplifies a shortcoming of our developed framework and objective. Some main findings are given below.

- Under the set of assumptions regarding scenarios, time series, component parameters and fuel and carbon prices, all expansions typically improve total socio-economic welfare, and sustainability and reliability indicators. Sensitivity analysis on fuel and carbon prices showed similar results, but also indicated that sudden unexpected outliers could appear and caution must be taken in making assumptions about these values.
- Our scenarios provided useful insights in different outcomes that exist in possible alternative futures. In terms of total socio-economic welfare, our high RES scenario 4 provided the largest improvements compared to base case. However, we again see that there exist outliers which need further analysis to be explained in detail.
- Due to its relatively low share in RES and high share in gas, the Netherlands has on average the highest nodal price setting. The result is that this country is the main winner under all expansions, most notably the single wind farm hub expansions. Germany also benefits from all expansion, although there is larger variation, and thus uncertainty, between scenarios. For Denmark the benefits are much more uncertain, exposing large variations between scenarios (shifting between positive and negative results). This indicates the need for mechanisms that ensure the cooperation of Denmark. Again, consideration on the choices of marginal costs values is necessary. Not only the values chosen but also the assumption of the same marginal costs for the same energy technologies in different countries.
- Total consumer surplus is increased and total producer surplus is decreased for all expansions and each scenario, due to the price reducing effect of low marginal cost wind farm integration. This is a consequence of our CBA model not taking into account regulatory and financial mechanisms. There are costs that will be socialized and hence moderate the results as benefits will be transferred from consumers to TSOs and wind farm developers. This outcome is supported by similar methodologies which therefore state that total socio-

economic welfare is a more meaningful indicator. However, we adopted the stakeholder analysis to look a bit further in these effects.

- Congestion rent is highest for wind farm hub expansions. For single wind farm (tee-in) expansions congestion rent is reduced in all scenarios as it means that less capacity is available for trade purposes. For all expansions compensation mechanism may be required.
- Sustainability benefits, including reduction of CO_2 emissions, avoided fuel costs and curtailment reduction, and security of supply benefits, are all significantly increased for each expansion. From a regional (European) perspective, we therefore consider these effects as a minor determinant for COBRAcable expansion selection.
- Network losses increase, but the costs of these losses decrease, moderating the negative effects. For large transmission infrastructure expansions they should be taken into account and balanced by the benefits however.

Additional remarks on uncertainties are made with respect to TEP in general and our overall socio-economic framework.

Firstly, we emphasize that the uncertainties from scenarios and fuel and carbon prices should not be underestimated. Significant changes in surpluses occur between different scenarios for the same expansion, and for different sensitivity cases. Our sensitivity analysis is a first step towards validation of outcomes based on marginal costs but more time is required to properly validate the results. Moreover, our time series cases and sensitivity cases still relied on fixed variables throughout a modeling period. Therefore, we did not take into account the high volatility that exists for these variables. We assumed that the average economic outcomes at a long-term time horizon will remain similar under this assumption, but the analysis of congestion or further technical analysis, will rely in large part on the extreme circumstances that occur when variables are volatile.

Secondly, there are uncertainties is costs which stem from cost uncertainty of energy technologies and discount rates. We did not include sensitivity analysis nor validation on the CAPEX and OPEX. We only included several assumptions to be able to address consequences of cost allocation and support schemes in the stakeholder analysis. Moreover, we adopted a single value for the social discount rate. Since even for a low discount rate the main costs and benefits are incurred in earlier periods, the choice of this value may alter the results and hence the advantage of investing sooner. From a single planning stakeholder's perspective the analysis should be performed at higher discount rates as well.

Thirdly, further uncertainties in the outcome derive from regulatory uncertainties which are not accounted for in the CBA model. The distribution of welfare among consumer and producer surplus depends to a large extent on the remuneration schemes. High transmission tariffs and feed-in tariffs will be detrimental for consumer surplus while the latter will increase the producer surplus. We analyze this uncertainty further in the stakeholders analysis.

Fourth, the model's code and assumptions pertaining to the MC analysis, CBA and optimization, has been verified by an expert review [Dedecca, João Gorenstein, 2016]. Further validation of the MC analysis by using other modeling approaches such as point estimate or fuzzy modeling has not been performed. Furthermore, we did not perform verification with other power system analysis tools such as Matlab, since Python has been found a more reliable tool, nor did we verify the current model by AC load flow analysis, which can be justified for long-term TEP but is a shortcoming.

4.1.4 Sub Question 4

What are the drivers and bottlenecks for the main stakeholders involved in the project of multi-terminal expansion?

We have identified five stakeholder criteria with multiple sub-criteria and used the COBRAcable as a case study to analyze the options for multi-terminal expansion. The main findings are summarized below.

- There is a risk for the TSO in the changed legal status of the transmission asset when a wind farm is interconnected. TSOs must be properly incentivized to be willing to give up congestion rent and embark on the new, risky investment of multi-terminal expansion. A multi-lateral approach is required to ensure participation of all stakeholders.
- Currently, the planning permits and procedures differ among countries. Cross-border investments need repetitive permitting costing time and money. Moreover, planning regimes enforce permitting procedures vary in content and timing (Denmark facilitates less costly and lengthy procedures compared to the Netherlands and Germany). There is a need for standardization.
- Especially expansions that consist of a wind farm hub will face an increased risk of stranded assets, since there is parallel planning of assets. Delays and different connection priorities could harm the wind farms. Hubs are often commissioned at large capacity to connect multiple wind farms, giving rise to risk of stranded converter terminals.
- Economic regulations have impact on the preferred investment. Cost-based regulation (e.g. Denmark) favors new technologies due to reduced risk of uncertain costs, and larger investments since there is a fixed return on investment independent of costs. TenneT may have other impacts, as the incentive-based regulation incentivizes cost reduction and risk averseness.
- Cost allocation of investments becomes an issue when wind farms are connected to an interconnector, since the wind farm has reduced infrastructural costs, whereas the TSOs have increased infrastructural and operational costs. When TenneT is involved in further interconnection, there is also a problem of cost allocation of this interconnection.
- Funding remains an issue in the large sunk costs transmission infrastructure sector. Applying for PCI status could help relieve this by applying for grants. This could for example be done for COBRAcable2.
- The wind farm will base its investment decision on the possibilities for remuneration. Super shallow connection regimes, as in Denmark, are preferred to reduce investment costs, but transmission tariffs allocated to producers in the same country, may hamper the remuneration. In Germany and the Netherlands shallow charging and no producer transmission tariffs apply.
- Feed-in tariffs contribute to the remuneration of wind farms as well, and forms a major barrier to our expansions as benefits are allocated to multiple countries whereas the subsidies are paid for by Germany. Current legislation makes support from outside the country difficult (NL) or impossible (DK, DE). There is a need for a harmonized support structure.
- Efforts should be maintained to prevent discrimination between teed-in and radially connected wind farms. This implies treating them the same way in terms of capacity allocation and congestion management, priority dispatch, connection regime and bidding regime. In the case study this is difficult especially for teed-in connection as the wind farm lies in a

different bidding zone than interconnector terminals without connecting to the German onshore grid.

- Curtailment reduction is organized differently among countries. Negative wind farm prices should be prevented as they could lead to TSOs and consumers paying more, while reducing producer surplus. A suggested approach is harmonizing the interconnector capacity allocation in implicit auctions, as is currently done in Denmark.

The stakeholder analysis has addressed multiple aspects that are of relevance to multi-terminal expansion. The list of criteria is not exhaustive, but the intention was to create more insight in the results of the CBA. Overall, the study indicated that the complexity of the multi-terminal expansion problem reaches much further than the uncertainty relating to input variables. It shows that expansion planning processes should adopt a wider approach addressing the relevant stakeholders and regulatory uncertainties.

Note that the stakeholder analysis serves the purpose of complementing the outcomes of the CBA. It provides further nuance to the CBA results without generating specific quantitative results and without validating outcomes. The analysis in its current form should therefore be used as such an additional tool to analyze main drivers and barriers, and caution should be taken when basing quantitative results on the analysis.

We suggest that the stakeholder analysis should be developed further to incorporate stakeholder consultation and address their attributes in conjunction with the developed stakeholder criteria.

4.2 Recommendations

In this research we presented some broad conclusions about multi-terminal expansion planning and the COBRAcable. Keeping these in mind, we present a set of recommendations which provide indications for further analysis, addressing the limitations of our research and TEP modeling in general. We start with a set of general recommendations.

4.2.1 General Recommendations

The case study as presented in this thesis must be considered as an illustrative example to address the importance of a large scope in the process of identifying options for multi-terminal expansions. This scope and the complexity of the problem require a cautious approach where focus should be on the first steps towards achieving a fully meshed offshore grid. This is supported by the uncertainties that are inherent to long-term planning. Therefore, neither stakeholder should adopt numerical conclusions directly, but should beware of accuracy limitations and hence interpret them as exploratory conclusions.

There is a need for a more structured approach to overcome the complexity of the long-term expansion planning problem. Current literature largely focuses on specific aspects of the problem without putting it in a broader picture. Some methodologies have already embarked on the journey to a more structured approach with a European scope such as ENTSO-E, REALISEGRID and E-highway, but there is a further need for an overarching structure that links important aspects, technical, socio-economic and regulatory. This implies better transparency from the side of stakeholders and more aligned methodology in literature, and perhaps most importantly more clear regulatory regulations and guidelines that apply to all Member States.

We considered an unbundled environment and not the possibility for merchant transmission investors to confine the scope of the research and since it did not apply to our case study. Such a scope would create a different perspective of the stakeholder analysis as presented in this research. Therefore, including it in the stakeholder analysis could provide insights in the costs and benefits when such a solution is applied.

The model assumptions and simplifications should be taken into account when this model is used. Current limitations, their implication and the possibility to address them in our model are depicted in table 4.1. Further validation and verification regarding these assumptions would be required.

4.2.2 Recommendations to TSOs and Wind Farms

Our present analysis incorporates simple assumptions on investments costs and cost allocation. Further research is required to develop suitable new mechanisms that could provide for the correct incentives for TSOs and wind farm developers to engage in an expansion project.

TSOs should increase transparency on behalf of research. ENTSO-E does provide on-line information on future scenarios and methodologies but remains implicit about the underlying technical assumptions. National TSOs could play a role in increasing the available information.

The current research predefines a set of expansion options. Closer collaboration between TSOs and wind farm developers could enhance the portfolio development. This could for example be in the form of separate analysis by the wind farm, or adopting a joint DTEP approach. Moreover, close engagement of TSOs with national regulators should be maintained to address the regulatory issues as defined in section 4.2.3

The current research does not provide analysis of typical technical constraints. However, also regarding these costs, uncertainties arise as to which stakeholder should provide for which balancing and reinforcement costs and whether cost allocation should be provided. Hence, further analysis in the COBRAcable case is desirable.

4.2.3 Recommendations to Policy Makers and Regulators

There is a need for new planning approaches to reduce the risk of planning stakeholders, both on the national and regional level. Standardized procedures for permitting and maritime spatial planning are required to pave the way for more streamlined investments to reduce the time and costs of the procedures. Harmonization and joint planning could address the risks concerning parallel planning and stranded assets.

In the same way, more harmonized national regulations are required regarding the economic regulation, the electricity market and network operation. European legislation currently has limitations in that it mostly provides loose guidelines but does not mandate Member States, leaving adjustment of national regulations accordingly, open for own interpretation.

For economic regulation, currently different incentives are given to national TSOs. The implications of these differences for investments could be studied further. In general, harmonizing economic regulations could align interests of stakeholders.

Furthermore, market coupling via implicit auctions and super shallow connection charging regimes should be striven for to decrease the market risk for wind farm developers. This implies a change in national regulations for e.g. Germany.

Support schemes require additional attention, as the case study showed that even bi-lateral projects can be hampered by the current regulations. Flexibility mechanisms that allow for international support could be developed further, or the appropriate tools for cost and benefit allocation should be developed to allow support regimes of the location of the wind farm to be used.

Lastly, we stress the importance of appropriate tools to compensate those stakeholders that do not benefit from projects. Optimal methods for investment cost allocation and ex-post compensation or cost re-allocation currently do not exist for multi-lateral projects. We propose to treat teed-in wind farms similarly to radially connected wind farms, and build compensation mechanisms from there to shift costs from TSOs to wind farms.

Aspect:	**Assumption:**	**Implication:**	**Model incorporation:**
marginal costs (carbon prices and fuel prices)	only updated between scenarios, moreover highly uncertain	highly volatile, could affect the temporal distribution of costs and benefits	updating every period easily implemented, volatility within a year hard to implement
demand and generation scenarios	updated once per period	low fluctuation of cost and benefits within a period	period duration can be reduced
storage	modeled as flexible generation	probably underestimated net social benefits and an altered distribution of benefits	PyPSA allows for storage modeling and time series
security and reliability	component outages not included	uncertain, compared to base case further interconnection may improve security of supply	included possibility to model offshore component outages
demand response	no demand response included in scenarios	future benefits may be underestimated	has to be developed
perfect competition	no market power	beneficial for consumers, not for producers	has to be developed
modeling approach	linear (DC) power flow approximation	simplification of real power flow, some error in model outcomes	PyPSA does not support optimization of non-linear (AC) load flow yet
balancing and reinforcements	not included in cost calculations	reduced benefits for generation connection facility	has to be developed
grid resolution	national resolution for countries, nodal resolution for offshore terminals	large effect of low or high RES values	easily extendable
discount rate	same social discount rate for all costs and benefits	potential overstatement of future costs and benefits	could be addressed in sensitivity analysis

Table 4.1: Model assumptions, their implications and possibility to include in the model.

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Appendix A - Grid Components

Table A1: Nodal grid branches and branches parameters.

name (bus0-bus1)	type	x	r	expansions
DK-DE	Line	0.03	0	all
DE-NL	Line	0.03	0	all
DK-NEU	Line	0.03	0	all
DK-WEU	Line	0.03	0	all
DE-NEU	Line	0.03	0	all
DE-CEU	Line	0.03	0	all
DE-WEU	Line	0.03	0	all
NL-NEU	Line	0.03	0	all
NL-WEU	Line	0.03	0	all
Off1-DK	Link	0	0.02	all
Off1-NL	Link	0	0.02	all
Off1-Hub	Link	0	0.02	4,5,8
Off1-DE	Link	0	0.02	6
Off2-DK	Link	0	0.02	7,8
Off2-NL	Link	0	0.02	7,8
Off2-Hub	Link	0	0.02	8
Hub-DE	Link	0	0.02	4,5,8
DK-DK DC	Converter	0	0	all
DE-DE DC	Converter	0	0	4,5,6,8
NL-NL DC	Converter	0	0	all

Table A2: Nodal grid buses and buses parameters.

name	v_nom	carrier	v_mag_pu_min	v_mag_pu_max	expansion
Denmark	380	AC	0.9	1.1	all
Denmark DC	320	DC	0.9	1.1	all
Germany	380	AC	0.9	1.1	all
Germany DC	320	DC	0.9	1.1	4,5,6,8
Netherlands	380	AC	0.9	1.1	all
Netherlands DC	320	DC	0.9	1.1	all
Offshore1 DC	320	DC	0.9	1.1	all
Offshore2 DC	320	DC	0.9	1.1	7,8
Hub	320	DC	0.9	1.1	4,5,8
Nordic Europe	380	AC	0.9	1.1	all
Central Europe	380	AC	0.9	1.1	all
Western Europe	380	AC	0.9	1.1	all

Appendix B - Scenarios Data

Table B1: Demand scenarios for Denmark, Germany and the Netherlands [TWh].

	2020-2025	2025-2030	2030-2035	2035-2040	2040-2045	2045-2050
	scenario 1					
DK	37.7	38.9	39.4	40	40.6	41.2
DE	540.7	546.8	584.1	621.4	658.8	696.1
NL	118.9	122	136.4	150.8	165.1	179.5
	scenario 2					
DK	36.7	36.8	34.7	32.7	30.7	28.7
DE	526.7	518.8	505.6	492.5	479.3	466.2
NL	115.2	114.6	115.4	116.3	117.1	118
	scenario 3					
DK	38.2	39.8	42.9	46	49.1	52.2
DE	521.6	508.7	585.3	661.9	738.5	815.2
NL	116.1	116.4	136.5	156.6	176.7	196.8
	scenario 4					
DK	38.9	41.2	41.6	41.9	42.3	42.7
DE	540.9	547.2	576.8	606.4	636.1	665.7
NL	119.2	122.6	132.1	141.7	151.2	160.7

Table B2: Emissions [ton/MWh] IEA 2015 and variable costs [€/MWh] as proposed by us, based on IEA, ENTSO-E and ECF scenarios [ENTSO-E 2015b; ECF 2010].

	emissions	fuel prices				carbon prices				marginal cost			
	all	s1	s2	s3	s4	s1	s2	s3	s4	s1	s2	s3	s4
biofuels	0.04	34	34	34	34	0	0	0	0	43	43	43	43
gas	0.36	34	34	26	26	7	7	38	30	42	42	55	57
coal	0.77	11	11	10	8	15	15	68	68	27	27	74	77
lignite	0.95	4	4	4	4	18	18	73	79	23	23	78	84
nuclear	0	2	2	2	2	0	0	0	0	2	2	2	2
oil	0.74	50	56	56	42	11	11	46	49	62	68	103	92
other non RES	0.0	20	20	20	20	15	15	64	68	36	36	85	89

Table B3: Generation mix scenario 1 as compiled from ENTSO-E and E-Highway [MW] [ENTSO-E 2015b; Bruninx et al. 2013].

	scenario 1						
		2020-2025	2025-2030	2030-2035	2035-2040	2040-2045	2045-2050
DK	Offshore wind	3265	3290	5130	6970	8450	9930
DK	Onshore wind	2850	2900	4870	6839	9170	11500
DK	Solar	840	840	1035	1229	1424	1619
DK	Biofuels	1781	1720	1985	2250	2625	3000
DK	Gas	2206	2640	2195	1750	1375	1000
DK	Coal	795	410	605	800	600	400
DK	Hydro	9	9	8	7	6	4
DK	Lignite	0	0	0	0	0	0
DK	Nuclear	0	0	0	0	0	0
DK	Oil	740	735	368	0	0	0
DK	Other non-RES	0	0	0	0	0	0
DE	Offshore wind	55885	62200	61032	59864	59081	58297
DE	Onshore wind	9175	11850	13017	14184	14967	15750
DE	Solar	52050	57240	55869	54497	53125	51753
DE	Biofuels	7420	6960	7418	7875	8251	8625
DE	Gas	24652	21138	25444	29750	40375	51000
DE	Coal	25140	23365	20683	18000	15000	12000
DE	Hydro	11203	13257	12394	11531	11896	12261
DE	Lignite	17228	12610	11505	10400	9400	8400
DE	Nuclear	4054	0	0	0	0	0
DE	Oil	2353	1026	513	0	0	0
DE	Other non-RES	7520	8650	4325	0	0	0
NL	Offshore wind	4700	4900	6366	7832	9760	11688
NL	Onshore wind	1750	2100	3081	4062	5081	6100
NL	Solar	4550	4000	3865	3730	3596	3461
NL	Biofuels	2665	300	650	1000	1438	1875
NL	Gas	10265	8757	11629	14500	20313	26125
NL	Coal	2305	4610	4705	4800	4600	4400
NL	Hydro	38	38	33	28	23	18
NL	Lignite	0	0	0	0	0	0
NL	Nuclear	486	486	243	0	0	0
NL	Oil	0	0	0	0	0	0
NL	Other non-RES	5155	5080	2540	0	0	0

Table B4: Generation mix scenario 2 as compiled from ENTSO-E and E-Highway [MW] [ENTSO-E 2015b; Bruninx et al. 2013].

	scenario 2						
		2020-2025	2025-2030	2030-2035	2035-2040	2040-2045	2045-2050
DK	Offshore wind	4475	5710	5599	5488	5208	4928
DK	Onshore wind	2750	2700	2361	2021	1881	1740
DK	Solar	840	840	648	455	262	69
DK	Biofuels	1781	1720	1735	1750	2125	2500
DK	Gas	2188	2604	2052	1500	1250	1000
DK	Coal	795	410	605	800	400	0
DK	Hydro	9	9	8	7	6	4
DK	Lignite	0	0	0	0	0	0
DK	Nuclear	0	0	0	0	0	0
DK	Oil	740	735	368	0	0	0
DK	Other non-RES	0	0	0	0	0	0
DE	Offshore wind	52173	54775	62260	69745	77582	85419
DE	Onshore wind	6463	6425	6737	7049	7325	7600
DE	Solar	46860	46860	62464	78068	93672	109275
DE	Biofuels	7420	6960	8980	11000	13000	15000
DE	Gas	21815	15463	14232	13000	14500	16000
DE	Coal	25140	23365	18083	12800	7200	1600
DE	Hydro	11203	13257	12394	11531	11896	12261
DE	Lignite	17228	12610	9505	6400	3200	0
DE	Nuclear	4054	0	0	0	0	0
DE	Oil	2353	1026	513	0	0	0
DE	Other non-RES	7520	8650	4325	0	0	0
NL	Offshore wind	4900	5300	7836	10372	12452	14531
NL	Onshore wind	1130	860	809	758	479	200
NL	Solar	5100	5100	11716	18332	24949	31565
NL	Biofuels	2665	300	1275	2250	3375	4500
NL	Gas	9774	7776	6888	6000	6500	7000
NL	Coal	2305	4610	3505	2400	1200	0
NL	Hydro	38	38	33	28	23	18
NL	Lignite	0	0	0	0	0	0
NL	Nuclear	486	486	1043	1600	1600	1600
NL	Oil	0	0	0	0	0	0
NL	Other non-RES	5155	5080	2540	0	0	0

Table B5: Generation mix scenario 3 as compiled from ENTSO-E and E-Highway [MW] [ENTSO-E 2015b; Bruninx et al. 2013].

	scenario 3						
		2020-2025	2025-2030	2030-2035	2035-2040	2040-2045	2045-2050
DK	Offshore wind	4095	4950	8637	12324	15408	18492
DK	Onshore wind	4300	5800	11856	17912	24572	31231
DK	Solar	1405	1970	2129	2288	2447	2606
DK	Biofuels	1781	1720	1985	2250	2625	3000
DK	Gas	2759	3746	2873	2000	2125	2250
DK	Coal	795	410	605	800	400	0
DK	Hydro	9	9	10	11	12	13
DK	Lignite	0	0	0	0	0	0
DK	Nuclear	0	0	0	0	0	0
DK	Oil	740	735	368	0	0	0
DK	Other non-RES	0	0	0	0	0	0
DE	Offshore wind	67860	86150	89048	91945	95273	98600
DE	Onshore wind	10550	14600	16185	17769	18923	20077
DE	Solar	53800	60740	59162	57584	56006	54428
DE	Biofuels	8610	9340	9170	9000	9000	9000
DE	Gas	31298	34429	30715	27000	34000	41000
DE	Coal	20927	14940	12670	10400	7200	4000
DE	Hydro	13393	17637	16059	14481	14690	14899
DE	Lignite	16028	10209	7505	4800	2400	0
DE	Nuclear	4054	0	0	0	0	0
DE	Oil	2276	871	436	0	0	0
DE	Other non-RES	8510	10630	5315	0	0	0
NL	Offshore wind	6500	8500	9906	11312	13153	14993
NL	Onshore wind	2800	4200	5598	6996	7960	8923
NL	Solar	10250	15400	13094	10787	8480	6173
NL	Biofuels	5055	5080	4540	4000	3500	3000
NL	Gas	10565	9358	10179	11000	16750	22500
NL	Coal	0	0	400	800	800	800
NL	Hydro	38	38	55	71	88	104
NL	Lignite	0	0	0	0	0	0
NL	Nuclear	486	486	1043	1600	1600	1600
NL	Oil	0	0	0	0	0	0
NL	Other non-RES	5155	5080	2540	0	0	0

Table B6: Generation mix scenario 4 as compiled from ENTSO-E and E-Highway [MW] [ENTSO-E 2015b; Bruninx et al. 2013].

	scenario 4						
		2020-2025	2025-2030	2030-2035	2035-2040	2040-2045	2045-2050
DK	Offshore wind	4758	6275	9338	12400	15554	18708
DK	Onshore wind	4675	6550	10832	15113	20357	25600
DK	Solar	1123	1405	1564	1722	1880	2038
DK	Biofuels	1781	1720	2235	2750	3250	3750
DK	Gas	2759	3746	2873	2000	1500	1000
DK	Coal	795	410	605	800	400	0
DK	Hydro	9	9	10	11	12	13
DK	Lignite	0	0	0	0	0	0
DK	Nuclear	0	0	0	0	0	0
DK	Oil	740	735	368	0	0	0
DK	Other non-RES	0	0	0	0	0	0
DE	Offshore wind	64544	79517	83378	87239	92783	98326
DE	Onshore wind	11975	17450	20280	23109	25155	27200
DE	Solar	52925	58990	68893	78795	88697	98599
DE	Biofuels	8610	9340	13920	18500	23125	27750
DE	Gas	31298	34429	26465	18500	15750	13000
DE	Coal	20927	14940	11470	8000	4000	0
DE	Hydro	11827	14505	14279	14052	15542	17032
DE	Lignite	15436	9026	6913	4800	2400	0
DE	Nuclear	4054	0	0	0	0	0
DE	Oil	2276	871	436	0	0	0
DE	Other non-RES	8510	10630	5315	0	0	0
NL	Offshore wind	4998	5495	8194	10892	12945	14997
NL	Onshore wind	2950	4500	8101	11701	13801	15900
NL	Solar	7400	9700	12837	15974	19111	22247
NL	Biofuels	5055	5080	4790	4500	4250	4000
NL	Gas	10565	9358	7679	6000	4500	3000
NL	Coal	0	0	0	0	0	0
NL	Hydro	38	38	55	71	88	104
NL	Lignite	0	0	0	0	0	0
NL	Nuclear	486	486	243	0	0	0
NL	Oil	0	0	0	0	0	0
NL	Other non-RES	5155	5080	2540	0	0	0

Table B7: Scenarios for NTC as compiled from ENTSO-E and E-Highway [MW] [ENTSO-E 2015b; Bruninx et al. 2013].

	2020-2025	2025-2030	2030-2035	2035-2040
	all	all	all	all
DK-NEU	4080	4080	4080	4080
DK-WEU	1400	1400	1400	1400
DE-NEU	2365	2715	7215	11715
DE-CEU	13286	14786	15786	16786
DE-WEU	7200	8100	8100	8100
NL-NEU	700	700	2200	3700
NL-WEU	3400	3400	3400	3400
	2040-2045	2040-2045	2040-2045	2040-2045
	s1	s2	s3	s4
DK-NEU	4330	6080	7080	4080
DK-WEU	1400	1400	1400	1400
DE-NEU	14965	14715	32715	28215
DE-CEU	18286	17286	19286	25786
DE-WEU	8600	8600	8600	13100
NL-NEU	5450	3700	7200	10700
NL-WEU	4150	3400	5400	8400
	2045-2050	2045-2050	2045-2050	2045-2050
	s1	s2	s3	s4
DK-NEU	4580	8080	10080	4080
DK-WEU	1400	1400	1400	1400
DE-NEU	18215	17715	53715	44715
DE-CEU	19786	17786	21786	34786
DE-WEU	9100	9100	9100	18100
NL-NEU	7200	3700	10700	17700
NL-WEU	4900	3400	7400	13400

Appendix C - Time Series

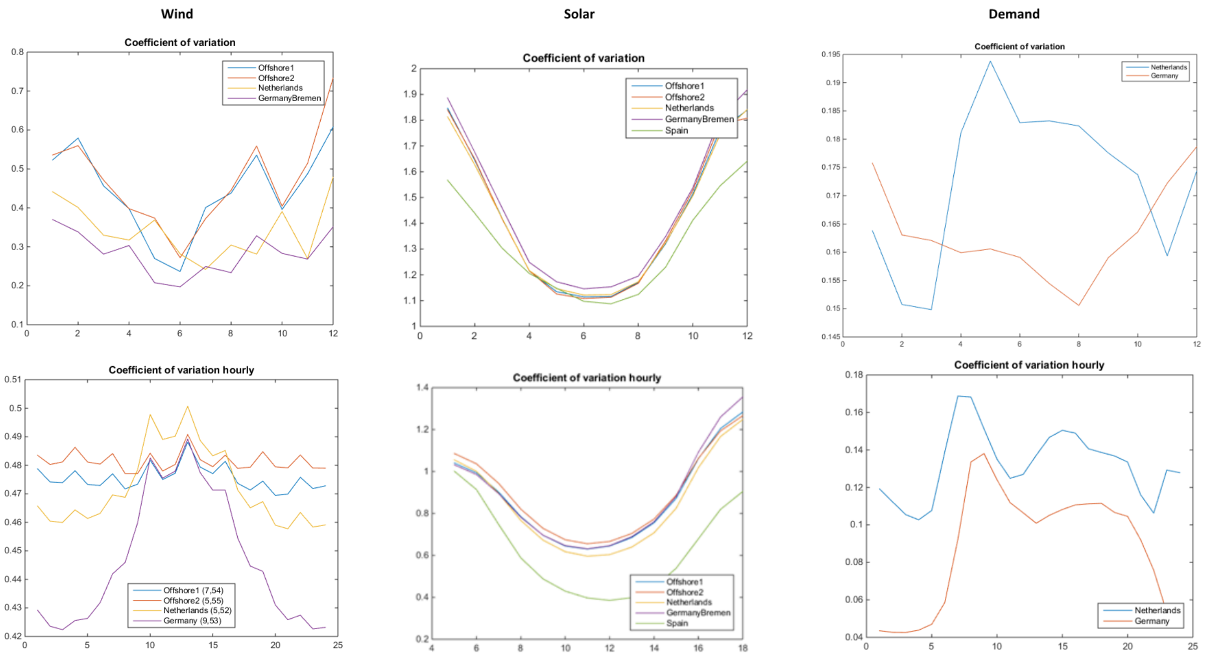

Figure C1: The coefficient of variation for hourly and monthly set of data based on 20 year data for wind and solar, and 1 year data for demand.

What is clear from the demand picture of figure C1 is that coefficients of variation are relatively low (max 0.2) compared to the wind and solar data. Moreover, its shape has clear patterns with peak base and shoulders occurring at the same points in time. Wind coefficient of variation is a lot larger than for demand. However, it does remain relatively constant over different hours, i.e. there is little patterns in wind speeds throughout the day. For solar variations are much higher due to the day night patterns and cloudiness.

For demand it was concluded that deterministic time series could be used. After evaluating coefficients of variation we found that they could be decreased to around 0.1, but only after creating considerable amount of load cases. For example, the coefficient of variation for the whole year in Germany was evaluated to be 0.17 and for the Netherlands 0.18. Table C1 indicates that creation of a significant amount of load cases did not reduce the values that much. Peak, shoulder and base are defined as specific segments of the day, e.g. peak from 12AM to 2PM. Manual iteration on selecting these time segments got them down to the values as pictured in table.

Table C1: Coefficients of variaton for 12 different load cases.

			Germany	Netherlands
summer	**weekday**	**peak**	0.13	0.12
		shoulder	0.15	0.11
		base	0.13	0.10
	weekend	**peak**	0.12	0.11
		shoulder	0.14	0.15
		base	0.12	0.12
winter	**weekday**	**peak**	0.14	0.14
		shoulder	0.11	0.15
		base	0.14	0.16
	weekend	**peak**	0.12	0.12
		shoulder	0.11	0.12
		base	0.11	0.10

Following the same method, for wind time series it was expected that the addition of seasonal cases would have larger beneficial effect then creating daily cases. However, it was found that yearly coefficients of variation (varying between 0.45 and 0.50 for all locations) were not influenced very differently by distinguishing between all months (varying between 0.39 and 0.48) compared to by hours (varying between 0.44 and 0.53). Therefore, we chose to consider four wind cases:

- summerday: 0.45-0.47
- summernight: 0.41-0.47
- winterday: 0.43-0.48
- winternight: 0.42-0.46

For solar cases creating different cases per day was important because of the high variability throughout the day. We ended up with eight cases by combining summer and winter seasons with night, peak, mid and low cases. The segments however did not perfectly correspond with the day and night cases as developed for wind, since for example solar radiation in summer may be occurring well beyond 6PM. Creating more daily cases was found to be detrimental as during a season a certain hour experiences high variation. More seasonal cases reduces the coefficient for some seasons but increased them for others.

In picture C2 we have drawn from several wind power curves and generated an average power curve to apply to the time series and get the pu value.

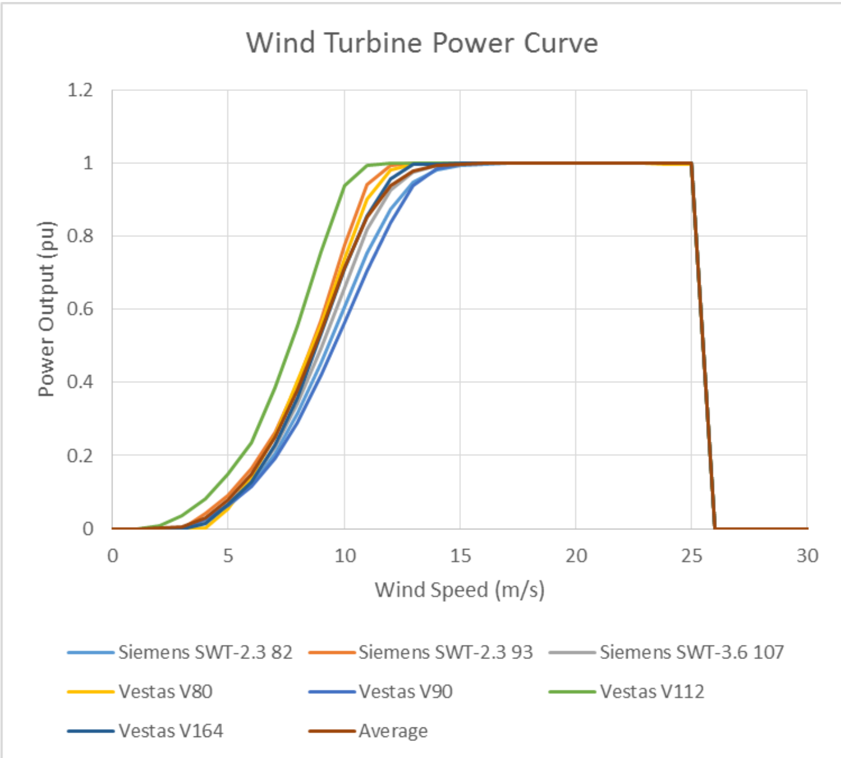

Figure C2: Wind power curves, average power curve is used for all installed wind capacities (pu of installed capacity) [Staffell 2012].

Appendix D - Stakeholder Attributes

To get a clear view on the roles and interests of stakeholders several categorizations have been proposed. A paper by Hermans distinguishes between four dimensions in stakeholder analysis where the purpose is to provide public policy actors with information on the multi-actor process of policy making [Hermans et al. 2009]. A preliminary stakeholder analysis should address all four dimensions, and based on the relevance of dimension(s) to the topic.

- Perceptions: The view stakeholders have of their environment. That is for example other stakeholders, the network and policies.
- Values: The motivation and desired direction of the stakeholders. Interests, goals, preferences are examples.
- Resources: The means stakeholders have to accomplish their objective or strategies. Relates closely to power and influence.
- Networks: This dimension places stakeholders in the context of relations with each other. The social patterns and relations are defined by the other dimensions.

The scope of policy making suits this research well. The simultaneous policy goals of the EU like increasing energy security, climate change mitigation and energy market integration make for a dynamic and uncertain environment for stakeholders to thrive. Priority on these energy policies is assumed to be equal but over time it has been inconsistent. Moreover, the interaction between different policies is not always clear [Strambo et al. 2015].

Perceptions

According to Thomas a perception is an image through which the complex, ambiguous world which surrounds an actor can be made sense of and acted upon [Thomas et al. 1966]. In the definition of the DANA methodology [Bots et al. 2000] such an image can be thought of as the underlying assumptions a stakeholder has regarding specific factors or criteria of the problem, which are based upon motivation, competence, experience and judgment. They define perceptions to comprise of all terms in which an actor thinks about a situation, including all assumptions an actor has about a situation. These assumptions can be about the present situation and about the future (they change over time). Therefore we identify two attributes that are related to the perceptions dimensions:

- Current view: The factual assumptions a stakeholder holds about the current state of its environment.

- Expectations: Assumptions regarding the change trajectory of the environment and the eventual state of it.

Here, the state of the environment is defined to be a set of factors about which the assumptions hold. Assumptions then relate to the value stakeholders give to these factors. The current view attribute helps in identifying whether there is an immediate relevance (e.g. a need or opportunity), whereas the expectations attribute helps in assessing future relevance. Some factors may be deemed irrelevant to the project, which is part of the perception of a stakeholder.

Values

Where perceptions relate to the subjective view, values relate more to the internal motivations and desires of a stakeholder. A common term encountered in the value dimension is that of interest, which directly relates to the definition of a stakeholder: an actor who has a stake, i.e. interest. And according to the definition of Freeman [Freeman 1984] stakeholders affect or are affected by the central stakeholder. This relates directly to the objectives of stakeholders. Conflicting or reinforcing objectives result in affecting or being affected by another. An objective is a tangible, desired outcome and therefore a more specific measure of interest [Hermans et al. 2009]. However, there will be uncertainties as to whether the set objectives will be achieved. Not only the average anticipated outcome will therefore be important in defining a stakeholder's interest, but also the amount of risk involved. We identify the two attributes:

- Objectives: The stakeholder's desirable outcome or state of environment in the future.
- Risk: The uncertainty involved in achieving the objectives.

Objectives differ from expectations in that the first only assesses a limited amount of factors, namely only the ones for which objectives are specified, while the latter aims at looking at assumptions of all factors involved and then specifying the most relevant factors. For risk, the importance is in identifying the factors that could be considered a point of uncertainty for the stakeholder. The risk attribute, like the objectives attribute, directly influences the interest of a stakeholder. Low risk will generally lead to higher interest for the stakeholder.

Resources

Just as the values dimension entails the interests of a stakeholder, the resources dimension could be regarded as that of power. Resources are the main tool a stakeholder has to express power or to influence others. A broader term, not only relating to the resources but also to other tools a stakeholder has to express power and in accordance with Bryson's terminology [Bryson 2004], we identify the bases of power attribute. Since power or resources may be derived from legislation or the role a stakeholder is assigned to fulfill, we use the participation attribute, also indicated by Bryson, among others. Thus the two attributes:

- Bases of power: The means, tools or resources a stakeholder has to follow its interests and influence others.
- Participation: The role a stakeholder fulfills, based on the decision making process.

Bases of power can be regarded as any support or sanction tools available to the stakeholder to influence others by for instance threatening or incentives [Bryson 2004]. Participation refers to the responsibility of a stakeholder or the role it fulfills in the decision making process. It may be merely an informing role, or a consulting, involved, collaborative or empowered role.

Networks

The networks dimension seeks to give an indication of the relations between all stakeholders. The method looks at the influence a stakeholder has on another. Influences may be unidirectional or bidirectional. Some form of quantification should be striven for, the primary influence direction of a bidirectional relation is a step in doing this. Based on this analysis a further simplification may be pursued, dropping the least influential stakeholders from further analysis.

Influence could be considered a product of the bases of power and the participation attributes as is done by Bryson [Bryson 2004]. To assign an attribute name and technique to evaluate this product we refer to interdependency between stakeholders:

- Interdependency: The mutual dependence of two stakeholders on each other.

A summary of dimensions and attributes can be found in table [D1]. Ordering the stakeholder criteria by dimensions and attributes creates a table with easy reference that will aid in the stakeholder analysis.

Table D1: Stakeholder attributes vs criteria.

	Perceptions		**Values**		**Resources**		**Networks**
	Current view	*Expectation*	*Objective*	*Risk*	*Bases of power*	*Parti-cipation*	*Inter-dependency*
Planning							
Ownership							
Financing							
Pricing							
Operation							

Appendix E - Portfolio Expansions

Figure E1: The expansion candidate portfolio.

Table E1: Expansion technologies: generation (wind farms) or transmission (interconnectors) and their timing.

Expansion	**Wind Farms**		**Interconnections**	
1	400MW	2030	-	-
2	900MW	2030	-	-
3	400MW	2025	-	-
4	400MW	2030	COBRA-DE hub	2030
5	900MW	2030	COBRA-DE hub	2030
6	400MW	2030	COBRA-DE	2040
7	400MW	2030	COBRA2	
8	400MW	2030	COBRA2	2040
	500MW	2040	COBRA2-DE hub	2040

Appendix F - Relative Error

Figure F1: Convergence of producer surplus and network losses costs for expansion 1 after 50, 100, 150, 200, 250 and 300 MC runs. Each dot represents a combination of scenario and period.

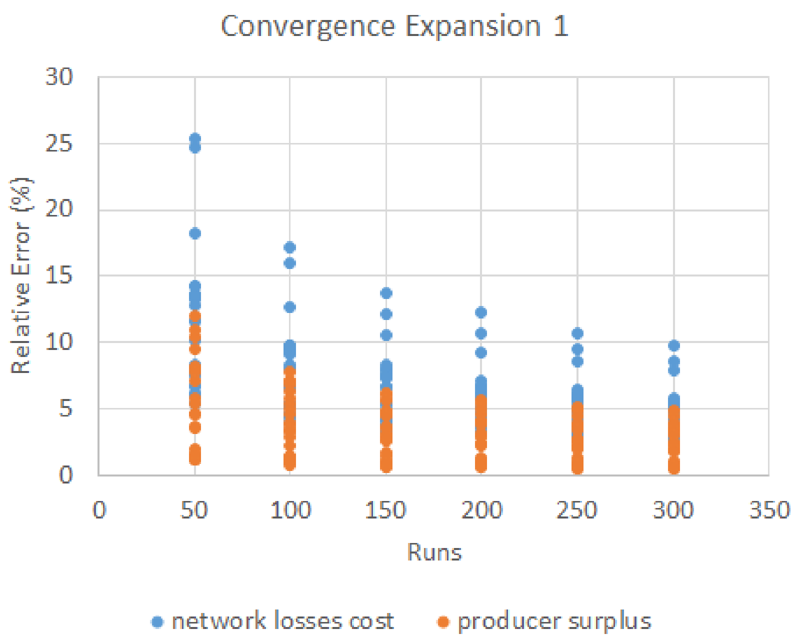

Table F1: Maximum relative error of all runs and scenarios (%) for each expansion per indicator after 300 MC simulation runs. Same time series are used for each expansion.

	Socio-economic Welfare			Sustainability				Reliability		Network Losses	
	CS	PS	CR	CurRed	AFC	Em	EmCost	ENS	SoS	Los	LosCost
exp 1	3.6	4.8	4.7	5.8	4.6	3.4	5.2	5.9	5.9	5.5	9.8
exp 2	3.6	4.8	4.7	5.6	4.6	3.4	5.1	5.9	5.9	5.5	9.7
exp 3	3.6	4.8	4.7	5.8	4.6	3.4	5.2	5.9	5.9	5.1	9.8
exp 4	3.6	4.9	4.8	5.3	4.6	3.4	5.1	5.9	5.9	5.5	7.2
exp 5	3.6	4.9	4.8	5.2	4.6	3.4	5.1	5.9	5.9	5.5	7.3
exp 6	3.6	4.9	4.8	5.6	4.6	3.4	5.1	5.9	5.9	5.5	7.3
exp 7	3.6	4.9	4.7	5.8	4.6	3.5	5.4	5.9	5.9	6.2	9.4
exp 8	3.6	5.0	4.7	5.6	4.7	3.5	5.4	5.9	5.9	5.5	8.2