# The Impact of Energy Storage on Long Term Transmission Planning in the North Sea Region

Master thesis in Sustainable Energy Technology

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## Acknowledgment

I would like to thank the Electrical Power System group of TUDelft, in particular my committee chair Professor Mart van der Meijden for his engagement in the project and his insightful comments and remarks. Furthermore I would like to express my deepest gratitude to my supervisor Dr. Madeleine Gibescu for her encouragement and continuous support throughout the project. I would like to thank my PhD supervisor Shahab Shariat Torbaghan for introducing me to the topic and for his invaluable help, support and guidance during the project. Last but not least, I would like to thank my beloved family for their understanding and endless love and my friends for their support throughout the entire process.

## Abstract

The variable nature of Renewable Energy Sources (RES) introduces substantial challenges to power system planning and operation. Different solutions are proposed to cope with the increasing RES penetration, such as taking advantage of smoothing due to expanding geographical distribution and large-scale integration of energy storage into power systems.

At the international level, there is a trend towards network expansion by increasing interconnection capacity between neighboring countries. However, a highly integrated transmission grid requires high level of coordination between national system operators. It also requires a consistent regulatory regime that addresses the needs of all stakeholders. Large-scale integration of energy storage (ES), on the other hand, facilitates operation of the system by balancing generation and consumption and smoothing out the RES-induced variability in both power in-feed and prices. However, since the addition of ES will alter the power flows in the system, there is a need for investigating the impact of energy storage on grid development.

This study presents a market-based optimization framework that solves the long-term transmission expansion problem under different levels of storage integrated with a meshed VSC-HVDC grid for a postulated scenario of offshore wind development. This is in general a nonlinear non-convex large-scale optimization problem. The model seeks to maximize the social welfare of all interconnected regions minus the investment capital of transmission infrastructure subject to technical constraints, under two different levels of ES capacities: unlimited capacity (idealized case) and limited capacity (realistic case). The results are compared with the base-case where transmission capacities are optimized without any ES present. In this formulation, storage is modeled as a not-for-profit unit, with marginal bid of zero for both charging and discharging power. Furthermore, it is assumed that each storage system is coupled with an offshore wind power producer.

A market structure, appropriate for operating a HVDC grid, can be derived based on accurate expressions of power flows over a meshed grid linking an arbitrary number of offshore and onshore regions. This results in a formulation that relates regional prices to congestion charges, not only by power-dependent terms but also by voltage-dependent terms. Making an approximation for the HVDC grid flows simplifies the pricing mechanism, resulting in a rule by which the amount of power to be exchanged is a function of only the electricity prices in different regions. It is also analytically proven that the optimization model sets the transmission capacities in a way that congestion shadow prices to be collected by the end of the economic life time of the project pay off the initial investment capital.

The optimization framework is applied to a multi-region, multi-time period case study closely resembling a future offshore wind and onshore market development scenario for the North Sea countries. The network consists of  $\pm 500$  kV, 2000 MW VSC-based bipolar HVDC cable connections. All simulations are implemented in MATLAB using the optimization toolbox.

The results of the work can support transmission system planners as well as private investors in offshore infrastructure, as it determines the most economically efficient design they should invest in. The proposed market mechanism also provides economic insight into the operation of a multi-terminal HVDC offshore grid for regulators, transmission system operators and offshore wind and electricity storage project developers.

## **1. Introduction**

EU has the plan to reach the 2020 targets of 20% increase in the share of RES in the gross final energy consumption (grow it to 75% by 2050) and reducing carbon emission by 20% by 2020. This ambitious goal have resulted in large increase in share of Renewable Energy Sources (RES-E) in the European power system. Meanwhile, a large share of conventional electricity producers should be replaced by RES producers. Among others, offshore wind electricity will have an important contribution in the future European energy mix [1], [2], [3].

However, large scale penetration of RES-E into the old power systems creates new challenges for system planners and operators. First, renewable energy sources are often located in remote locations far from the load centers. Hence, new transmission infrastructure is required to transfer power far distances to the onshore load centers. Second, power output of renewable sources depends on meteorological condition to a large extent and is, therefore, extremely volatile. The ultimate goal of system operator is to maintain security of supply by balancing the power supply and demand. Large scale integration of non-dispatchable source to existing markets challenges the security of supply to a large extent.

In order to overcome the variability of RES-E and potential risk they introduce to security of supply, several solutions are proposed [4]. One possible solution to alleviate the impact of power output fluctuations is to extend the geographical distribution of power system so that power deficiency in one region would be compensated by power surplus in another. This can be achieved by expanding the electricity grid by building new connections between neighboring countries. Long term transmission planning (LTTP) is a complex multidimensional multi-time period problem. In general, transmission planning decisions can be made centrally or decentrally. Before the introduction of electricity market, this problem was addressed by centralized models that seek to minimize the cost of production in all networks [5].

Emergences of electricity markets have altered the situation as new market driven issues are becoming more important such as: congestion revenues, market structure, etc. Under the new scheme, the purpose is to find the most economically efficient design which is not essentially the least expensive grid design. Transmission plays an important role in providing a non-discriminatory competitive environment for all parties. The main purpose of transmission planning is to maintain security of supply in the most economical way. In the new market based environment, there are new independent stakeholders that are involved in the decisions making with different desires. For instance, market operators and regulators seek to encourage competition among market participants and provide a non-discriminatory access for all consumers. The main concern of system planners is to maintain and improve security of supply [6] in the system by alleviating transmission congestions, improving network reliability and flexibility. Private investors are interested in less risky projects with higher rate of return [7]. Power suppliers are looking for new ways to reduce their cost of operation, maintenance and network charges. One can easily notice that different parties seek different desires.

In order to better account for the desires of all parties involved, here we decided to form the transmission planning problem in such a way that it maximizes the social welfare of all regions. In this context social welfare is defined as benefit of consumption minus cost of generation. It is a suitable economic measure as it reflects aggregated benefits of all the society (including

producers and consumers) same as [8], [5], [9]. In a perfectly competitive environment, both these approaches deliver similar results.

The second solution is to increase flexibility of the power system locally by large scale integration of energy storages into the system. Energy storage mitigates the power variations by storing energy when there is power surplus and dispatching it back when there is power deficit. In [10] the economic scheduling and operation of energy storage is studied. It is shown that energy storage smooth the variation in the wind power output as well as increasing the value of wind power in the electricity market.

Authors in [11] studied the optimal operation and management of energy storages as a price taker in a deregulated market. They assume operation of energy storage does not influence the market prices. However, this assumption does not hold for large scale energy storage in a wholesale electricity market. In [12] authors propose an optimization framework for sizing energy storage based on its optimal management in a competitive market. It shows that under dynamic pricing mechanism energy storage provides significant value on the electricity cost.

Energy storage is proposed as an alternative to transmission investment. In [13] the problem of long distance power delivery from the wind farms to the load centers is investigated, taking a purely economic approach. It proves locating energy storage together with the wind farm increases transmission utilization and decreases investment cost of transmission. However, it does not address the impact of energy storage on the market prices under large scale penetration of wind energy.

Optimal allocation of energy storage is studied in [14]. It proposes co-locating energy storage and energy storage distribution for efficient utilization of transmission capacities and more wind power integration into the grid. However, their work is limited to optimal allocation and scheduling of energy storage when the grid is fixed.

<u>Problem definition</u>: By far, expanding the transmission system is considered as one solution for system planners and operators to face the challenges arises from large scale penetration of wind production. However, the role of energy storage in grid expansion has not been studied yet. Based on the stated problem, the objective of this research and the research question are introduced as follows:

<u>Research objective:</u> Study the impact of different levels of energy storage integration on development of a VSC-HVDC based grid with multi-terminal connection

#### Research question:

What is the impact of energy storage on the problem of Long Term Transmission Planning (LTTP)? That is, the impact of energy storage on:

- 1. Grid design, including grid topology and transmission capacities
- 2. Pricing mechanism
- 3. Social welfare distribution and remuneration of every entity
- 4. Changes in nodal price variations of all units, direction of power flows, etc.

<u>Research approach</u>: The main objective of this study is to examine the impact of incorporating different levels of energy storage on the optimal grid design of a VSC-HVDC based grid. We take a market based approach. We introduce an optimization framework that maximizes the aggregated incremental social welfare minus total investment cost of transmission infrastructure, considering physical constraints. It is a non-linear, non-convex, multi-time period optimization problem. The analytical solution to the optimization problem gives the pricing mechanism, which is a formulation that express the relation between nodal prices of different price zones, power flows over interconnectors and associated transmission and congestion revenues.

Energy storage is mainly expected to contribute in improving social welfare of onshore regions by increasing the penetration of wind energy into the system. We model energy storage as a notfor-profit entity. Hence, the investment cost and operating revenue of these units are not considered in the problem formulation. Finally, every energy storage is co-located with the respective offshore wind farm next to it with an infinite transmission capacity.

To better analyse the impact of different level of energy storage integration into the grid, we introduce two energy storage capacity scenarios: Unlimited capacity Energy Storage (UES) – idealized case – to account for the maximum impact energy storage can have on the final results, and Limited capacity Energy Storage (LES): realistic case. The results of these two scenarios are compared with the base case of No Energy Storage (NES) scenario.

We do the simulations for a limited time period of 48hours. To investigate the sensitivity of final results on the selection of input data, we compare the optimization results determined for two different study periods of 48hours, one based on wind speeds and the other based market price differences.

<u>Contribution:</u> This work provides two major contributions:

1. Scientific contribution: Introduction of a novel approach in modelling and integrating energy storage in classic LTTP problem. The analytical solution to the optimization

problem also gives the pricing mechanism, which is a relation between the nodal prices and the power flows over interconnectors and associated congestion shadow prices.

2. Practical implications: The results of this work provide economic insight for transmission system operator and system planners into the operation of a multi-terminal HVDC based offshore grid in the North Sea.

#### **Outline of the report:**

This introduction stated the problem by reviewing the literature. It also formulated the research objectives and approach, and highlighted the scientific contribution and practical implications of this study. The rest of this work is structured as follows:

Chapter 2 provides the background on the topics covered in this thesis, which are optimization problems, offshore infrastructure, electricity market, and energy storage. Chapter 3 describes the methodology for solving the problem of LTTP without energy storage. It is followed by explaining our approach to incorporate energy storages into the problem formulation. The analytical solution to the problem of LTTP for a grid with energy storage is then presented. Chapter 4 explains the simulation results under different energy storage scenarios and for two different input sets. Chapter 5 explains the main conclusions and gives recommendations for future works.

## 2. Background

This chapter presents a brief review of most of different types of most common mathematical optimization (programming) problems. Here we have an overview on classify different types of optimization problems.

#### 2.1 Optimization problem

A mathematical optimization looks for the search space for one or several optima (minimum or maximum points) of a function. In other words, optimization problem is the process of finding the best available value for a function by choosing the variables within the allowed domain.

An optimization problem has three main elements:

- 1. Objective function: the quantity or the function to be optimized (minimized or maximized)
- 2. Decision variables (Controlling variables): the set of variables which values can be changed (varied) to find the optimal value of the objective function
- 3. Constraints: mathematical statements that put a higher or lower cap on values of variables and derivative functions

If there is no constraint on the variables, the optimization problem is named as *unconstrained optimization*. In *Constraint optimization* in contrary, the search space is restricted by constraints. Here the solver looks for the optimal value of the objective function by choosing the decision variables with respect to imposed constraints. In constrained optimization problem, a part of the domain of the variables is excluded from access.

General formulation of a constrained optimization problem is as follows:

Subject to  
$$\begin{array}{l} \min_{x} f(x) \\ h_{i}(x) = c_{i} \\ g_{i}(x) \geq d_{j} \end{array}$$

In which x is the vector of decision variables, f is the objective function,  $h_i$  is the vector of equality constraint and  $g_i$  is the vector of inequality constraint. All the functions (f : R $\rightarrow$ R, g: R $\rightarrow$ R and h: R $\rightarrow$ R) are by definition continuously differentiable functions. The feasible solution from the set of decision variables which optimizes the objective function is called optimal solution (optimal point) [15].

#### Classification of optimization problems:

Optimization problems are classified with respect to the specific form of their objective function, variables and constraints. A class of optimization problems is referred to as *Linear Programming* (*LP*). It includes optimization problems with linear objective function, real values of decision variables and linear equality and inequality constraints. On contrary to linear programming, *Non-Linear programming* (*NLP*) contains optimization problems which have real numbers for decision variables but its objective function and/or some of the constraints are non-linear functions [16].

An optimization problem is called *convex* if it has a convex objective function. There are different definitions for a convex function. One of the definitions is as follows: "function f is convex on an interval, if for all a and b in the interval, the line segment joining (a,f(a)) and (b,f(b)) lies above the graph of f" A convex optimization has a unique optimal point: its local optimum is also its global optimum. However, for a *non-convex* optimization, which has a non-convex objective function or constraints, a global optimum is not feasible to be found. It is due to the fact that, either a global optimum does not exist for such a problem, or the algorithm needs exponential computational time to find the optimum point (number of computational steps grow exponentially with the number of variables.) Non-convex optimization problem has several optimal points, or a set of optimal points called local optima.

Optimization problem is referred to as *non-smooth* if it has a non-smooth objective function or constraint function. A function is smooth only if that has derivatives of all orders. If not, different orders of smoothness can be defined. For example, a first order function is differentiable, and the derivative is continuous. Optimization problem is categorized as *smooth*, if it has first order smoothness. Traditional gradient-based algorithms (which use Hessian matrix) are only applicable to for first and higher order smooth problems.

An optimization problem is continues if all the variables of the optimization problem are continuous real numbers. On the other hand, if the optimization variables have discontinuity the problem falls in the category of *discrete optimization*. In the specific case, if the variables are restricted to be integers the optimization is called *Integer Programming (IP)*. The optimization is referred to as *Mixed Integer Programming (MIP)* if it comprises both integer and continues variables.

#### 2.2 Offshore infra-structure

#### Wind energy:

Wind energy is the available energy of wind that can be converted into mechanical or other forms of energy. The process of converting kinetic energy of the wind to electrical energy through a wind turbine is referred to as wind power generation. A wind turbine consists of system of blades rotating horizontally or vertically to generate electrical power. The power extracted by a wind turbine is given by:

$$P = \frac{1}{2}C_p \rho A v^3 \quad (2.2-1)$$

Where P is the power extracted from the wind farm [W],  $C_p$  is the power coefficient of the wind turbine [W.s<sup>3</sup>/kg],  $\rho$  is the air density [kg/m<sup>3</sup>], A is the area swept by the rotor blades [m<sup>2</sup>] and  $\nu$  is the wind speed [m/s]. [17]

As equation (2.2 - 1) shows, power output of a wind turbine is a cubic function of wind speed. Therefore, its variations influence the power output of a wind turbine significantly. To smooth out the effect of wind speed variations on the power output also maximizing the energy production while minimizing the capital cost, wind turbines are connected to each other (called clustered) before get connection to the grid. A wind farm is a combination of several wind turbines located at a specific region.

In this work, the power output of a wind farm is derived as total installed wind capacity times wind availability factor (WAF).

Windfarm power output = Windfarm Installed Capacity \* Wind Availability Factor (t)

WAF is the ratio of the power output of a wind farm divided by maximum wind power available during the hour under study.

Wind farms can be located onshore or offshore. Onshore wind energy faced an enormous growth in the last decade. However, there are encouraging reasons to move towards offshore wind production. Offshore wind has higher average wind speed with more flat profile comparing with onshore counterpart. Therefore, it provides higher power production and with fluctuations comparing with a wind farm of the same size onshore. In addition, there are environmental concerns that significantly challenge more integration of wind capacities, onshore and incentives shift to offshore locations. For instance, every wind farms impose visual and noise which, if located close to residential areas, creates public residence. Therefore it is becoming more difficult every day to obtain permission for building new onshore wind farms, especially in the vicinity of densely populated areas where load centres are. This negative impact can be overcome by constructing the wind farm in offshore locations far from residential areas where large number of wind farms can be constructed. These benefits come with higher cost to end user consumers and higher risk to the environment. Offshore wind farms are extremely expensive to build. It becomes even more severe if one incorporates the higher cost of transmission infrastructure that is essential to reinforce/build to transfer the produced energy [18].

Europe is the world leader in the offshore wind power. The first large commercial offshore wind farm was constructed in 1991 in Denmark, with total capacity of 4.95 MW. By the end of 2010, 2946MW offshore wind capacity was integrated into the European grid. This number grew to 6040MW of total offshore wind capacity distributed in 10 countries in Europe by the end of June 2013. [19] Europe is planning to install about 48GW offshore wind capacity by 2020 [20]. EU member states have to make huge investments to realize these ambitious targets. Therefore it is necessary to conduct an in-depth investigation on developments of offshore wind farms and transmission capacities to obtain an economically affordable efficient solution.

#### Offshore grid

Wind power variability and uncertainty are two major issues that come with large-scale integration of wind energy into power systems. Variability of wind power output is due to hourly, daily or seasonal fluctuations in the wind speed.

Wind power uncertainty arises from errors in forecasting of wind pattern [21]. One way to reduce the effect of these factors on the power system is to expand geographical distribution of the power system. The reason is, power deficiency in one region will be compensated by power excess in another, which itself alleviates the impact of variation of wind power output on power system operation. It also increases the economic use of the offshore resources and infrastructure. Increasing the interconnections between the countries, increases the security of supply, enhances international power trade and facilitates the competition in the electricity markets.

A rising issue regarding the offshore grid expansion is in long distance power transmission. Offshore wind farms are located far from each other and from onshore load centres. It is quite a challenge to find an optimal economic solution for transmitting offshore produced power over long distances, from offshore wind farms to onshore regions.

One can easily note that large quantities of offshore power will be transmitted through subsea cables. Due to technical reasons (charging current), AC technology tends to be less appropriate for sub-sea connection with distances over 60 km. HVDC cables are preferred over ac cables for underground and submarine applications. In general, HVDC technology is more suitable for transferring power over long distances. HVDC cables have negligible power loss and economic advantageous compared to ac transmission cables. HVDC cables do not have limitation on transmission distance and they can deliver large bulks of power over long distances with remarkably small losses [22].

Two types of convertors are used in HVDC transmission systems: Current Source Converter (CSC) and Voltage Source Converter (VSC). CSCs are referred to as line commutated convertors. Commutation is changing current direction (transferring the current from one phase to another). It requires a strong synchronous voltage source in CSCs. However, VSCs are self-commutated convertors. They have the capability of rapid power control by reversing the polarity of the DC cable.

Bulk power delivery, dynamic voltage control, self-commutated, higher controllability over power flow and economic advantages of VSC based HVDC transmission technology, make this technology appropriate for offshore grid applications. In addition, voltage source converters enable multi-terminal connections, which is a great advantage among other alternatives.

#### 2.3 Technical characteristics of power system operation

This section presents an overview of HVDC power flow, economic dispatch, and HVDC based optimal power flow and Long Term Transmission Planning (LTTP) problems.

#### 2.3.1 Power flow

In this section we briefly review HVDC power flow. In context of this work all problems are formulated using – so called – approximated HVDC power flow [9]. Here we start with the non-linear HVDC power flow, and derive the linear approximation and present the physical interpretation of the formulation.

Consider a system with two nodes "i" and "j", connected with interconnector "i-j" (Figure 1). In our simulation, every interconnector is assumed to be composed of number of  $N_{ij}$  identical parallel cables, each with capacity of  $K_{Max}$  and conductance of  $g_{ij}$ .



Figure 1 DC Power flow in a two-node system

From the Ohm's law, one determines the power flow of the interconnector when power flows from node i to node j (at the sending end (node (i))) as:

$$T_{ij}^{t} = N_{ij}.g_{ij}.\left(v_{i}^{t^{2}} - v_{i}^{t}.v_{j}^{t}\right) (2.2 - 1)$$

In which  $v_i^t$  is the voltage of node i at time t.

Equation (eq. 3.2 - 1) can be written as:

$$T_{ij}^{t} = \frac{N_{ij} g_{ij}}{2} \left( v_{i}^{t^{2}} - v_{j}^{t^{2}} \right) + \frac{N_{ij} g_{ij}}{2} \left( v_{i}^{t} - v_{j}^{t} \right)^{2} \quad (2.2 - 2)$$

The difference between the power injected into the interconnector at the sending end and the power withdrawn at the receiving end gives the power losses of the interconnector:

$$T_{ij,s}^{t} - T_{ij,r}^{t} = N_{ij} \cdot g_{ij} \cdot \left(v_{i}^{t^{2}} - v_{j}^{t^{2}}\right) \quad (2.2 - 3)$$

Assuming power losses is distributed equally over the interconnector, power transmission at the middle point of the line reads as:

$$T_{ij,mid\ point}^{t} = N_{ij}.\ g_{ij}.\ \left(v_{i}^{t} - v_{j}^{t}\right).\ \frac{\left(v_{i}^{t} + v_{j}^{t}\right)}{2} = \frac{N_{ij}.\ g_{ij}}{2}.\ \left(v_{i}^{t^{2}} - v_{j}^{t^{2}}\right)\ (2.2-4)$$

Substituting the left hand side of Equation 2.2 - 2 with Equation 2.2 - 4 and Equation 2.2 - 3 respectively, one can derive the power flow equation as:

$$T_{ij,s}^{t} = T_{ij,mid\ point}^{t} + \frac{T_{ij,losses}^{t}}{2} \quad (2.2-5)$$

Power losses normally account for 3% of total power injected into the interconnector. By neglecting power losses and replacing  $v_i^{t^2}$  with  $w_i^t$ , one determines the linearized approximation of the power flow: [9]

$$T_{ij,s}^{t} = T_{ij,r}^{t} = T_{ij}^{t} = \frac{N_{ij} \cdot g_{ij}}{2} \cdot \left(w_{i}^{t} - w_{j}^{t}\right) \quad (2.2 - 6)$$

Depending on the direction of the power flow Tij can be positive or negative  $T_{ij}^t = -T_{ji}^t$ . The net power injection from node i to the rest of the network is defined as follows:

$$P_{i}^{t} = \sum_{j}^{nb} T_{ij}^{t} \quad (2.2 - 7)$$

The impact of node i at time t on the rest of the system is captured with its net power injection  $(P_i^t)$ . It is positive if the node is injecting power intro the rest of the system and the opposite otherwise.

As outlined above, in our formulations power losses in transmission system is neglected. Hence, one can see that for each operating step, the aggregated injection of all nodes is zero, that is:  $P_1^t + P_2^t + \dots + P_{nb}^t = 0$ . Hence, using the approximated power flow, the power balance constraint is already accounted for and is not required to be included in explicit constraints.

The important variable in the DC power flow is the voltage magnitude. In fact the optimization solver seeks to find nb voltage values for each time step to determine power flows. The power flow over each interconnector is determined by the voltage difference between the two nodes at both ends of an interconnector (2.2 - 6). Hence the solution to the optimal power flow problem is a set of voltage values for every nodes from which one can obtain the optimal power flow. For the specific case of HVDC power flow, in contrary to linearized AC power flow, it is not possible to set a known (a reference bus) value to any of the nodes (the result of OPF (see section 2.3.3) is affected by selection of reference voltage). Therefore, any distribution of voltage value difference that results in an identical power flow is a set of answer for the OPF problem. There are infinite numbers of voltage combinations that yield same power flow as the OPF. This is the reason the optimization problem is *non-convex*. This characteristic of our OPF for HVDC system

lies in inherent properties of HVDC power flow which makes the optimal solution non-unique but identical.

#### 2.3.2 Economic measures

In our formulation contribution of each zone to the rest of the system is determined by its power injection into the rest of system  $(P_i^t)$ . The injection power nets out the effect of all the generation and consumption units in each node, and is calculated as:

$$P_i^t = P_G^t - P_D^t$$

In which  $P_G^t$  is the power generation and  $P_D^t$  is the power demand of the region. We define the incremental social welfare of region i at time t  $(SW_i^t)$  as benefit of consumption  $(B(P_D^t))$  minus cost of generation  $(C(P_G^t))$ . Social cost of every region, which equals the social welfare with opposite sign, can be expressed as a quadratic function of  $P_i^t$  as:

$$\Delta C_{i}^{t} = G(P_{G}^{t}) - B(P_{D}^{t}) = a_{i}^{t} \times P_{i}^{t^{2}} + b_{i}^{t} \times P_{i}^{t} \quad (2.3 - 1)$$

In which *a* and *b* are cost curve coefficients associated with node i at time t.(Figure 2).



Figure 2 Marginal cost curve as a function of power injection of node i

For a net exporter zone, Pi and the social cost (= - social welfare) of the region is positive. The derivative of the cost curve of a zone with respect to power injection of that zone gives the marginal price of the zone ( $\rho_i^t$ ) as follows:

$$\frac{\partial C_i^t(P_i^t)}{\partial P_i^t} = \rho_i^t = 2 \times a_i^t \times P_i^t + b_i^t \quad (2.3 - 2)$$

2.3.3 Economic Dispatch (ED) and Optimal Power Flow (OPF)

Economic Dispatch (ED) is the problem of finding the economic operation of a power system. It is the process of determining the optimum power output of the scheduled generation units to meet the load, satisfying the operational constraints (i.e., operational constraints of generators (ramp rate, min/max up and down time) and transmission lines are neglected). It can be formulated as a non-convex optimization problem with the objective function of optimizing an economic indicator (operating cost minimization, social welfare maximization) [23].

The Optimal Power Flow problem (OPF) is the problem of finding a power flow solution that minimizes or maximizes an objective function considering all technical constraints into account. The objective function of the optimization problem can be operation cost minimization or social welfare maximization. OPF is a non-convex optimization problem with the economic objective to optimize, satisfying the network physical constraints.

The optimal power flow problem for a DC based system has the following components:

- Objective function: maximizing the aggregated social welfare.
- Decision variables: squared voltage values at each node at each hour  $(w_i^t)$  and number of parallel lines  $(N_{ij})$ .
- Inequality constraints: constraints on decision variables and network operating limits (line flows, power and voltage constraints, etc.)

In a grid with specific load and generation capacity, solving the OPF gives the optimal voltage values and line capacities, while satisfying the technical constraints of the power system. Similar to ac power flow, the problem can be formulated in its general form using approximated HVDC load flow.

The analytical solution of the optimization problem, results in a pricing mechanism. Pricing mechanism is a formulation that express the relation between nodal prices of different price zones (here nodes) and congestion rents associated with interconnections connecting the zones through power flows. An ideal pricing mechanism is one where the power flows are only a function of nodal prices and congestion revenues.

OPF is used as a transmission expansion planning tool as described in literature [24]. The solution to the optimization problem gives the optimal grid topology and transmission capacities as well as the optimal power flow for each operating hour.

## 2.4 Electricity market

### 2.4.1 Electricity market: from monopolistic structure to perfect competition.

Electricity market shows the pattern of economies of scale in different levels, from generation to transmission and distribution. Traditionally, there was a local power plant responsible for power supply [8]. At transmission level, one single entity had the right to build and operate the transmission infrastructure. Therefore, the electricity industry was a vertically integrated utility, containing generation, transmission and distribution, with the characteristics of a natural monopoly at each level.

Recent developments in the electricity generation and raise of the small or medium scale generation capacities into the power system, such as renewable energies, made a move towards competition and deregulation in electric industry.

However, establishing a competitive market which allows generators and large scale consumers to trade electricity requires a coherent mechanism to control the coordination between the actors. The pricing mechanism of such a market should reflect the relation between power trades, power price and associated penalty charges, so that power always flows from less expensive region to more expensive one.

#### 2.4.2 Market arrangements:

There are two ways electricity can be trade between producers and consumers.

<u>Over the counter contract (OTC)</u>: OTC is a bilateral contract between the buyers and sellers. Traders negotiate on some terms and conditions as the basis of the contract. The contract has the information about the price and amount of electricity to be traded, and the time at which the trade should occur. The system operator collects the contacts from the traders at a set time before the delivery (gate closure) and manages the dispatch time of each generator to meet the demand at each time.

<u>Power exchange (electricity pool)</u>: Power exchange has a central organization that manages the organization of the pool and controls all the electricity transactions. The system operator coordinates generation and transmission Pool enhances competition in the market. In the pool concept, the focus is mainly on supply side than the demand side. Generators submit bids into the pool determining for every hour how much electricity they can provide at a given price.

Power exchange usually runs in a day-ahead-market. The market operator receives the bids and sets the prices with Locational Marginal Pricing (or nodal pricing), which optimizes the use of the generation unit and the transmission grid.

#### 2.4.3 Types of market: Day-ahead market / intra-day market

In a deregulated environment, electricity market is operated by an independent entity called the power exchange.

In <u>Day-ahead market (DA)</u> market parties are allowed to submit their electricity bids to the power exchange for the following day (next 24hr) before market closure time. The term "Bid" refers to an offer to buy or sell electricity in the market. Market participants have to meet criteria to become eligible to make bids and participate in the market. If a bid is cleared in the market, it brings legal obligations to the bid owner. The owner will be subject to penalties if it cannot deliver the service as stated in the bid. Every bid express contain information about volume of power the owner is willing to buy/sell and the desired price, and the starting time and duration the offer is valid. Market closure time is set by the regulators and differs for every power exchange. In Europe, it is mostly set at 12:00 hr (midday) a day prior to delivery day, for every weekday. After market closure, the operator informs participants that are cleared in the DA market, usually 3 hours after the closure time (the exact duration is stated in the regulation). After closure of DA market, market operator will not accept new bid from participants.

The <u>intraday market</u> creates possibility for trading after market closure of a DA market, up until 60-75 minutes prior to physical electricity delivery time. In <u>real-time market</u> prices are determined based on the actual operation of the grid and load conditions in 5 minutes intervals.

## 2.4.4 Pricing mechanism in perfectly competitive electricity market: uniform pricing/ pay as bid

<u>Uniform pricing mechanism</u>: In a day-ahead market, power exchange receives bids and offers from entities and clears the market in a way to meet the demand in the following day. After the bids are submitted, they are sorted in ascending (descending) order to form the aggregated supply (demand) curve for every hour. The intersection of supply and demand curve determines the market clearing price (MCP). Those suppliers (consumers) that have made bids with higher (lower) price than the MCP will be left out the market. The rest are cleared in the market and can trade according to the MCP and submitted bid. Hence suppliers provide power volume as stated in submitted bid, but they will be remunerated based on the MCP (which is always larger than or equal to their submitted bid). As the price is unique for all traders in the market, this pricing mechanism is referred to as "uniform pricing mechanism". The MCP equals the cost of producing one extra MWh power by the most expensive supplier in the market at that specific hour.

<u>Pay-as-bid pricing</u>: Pay-as-bid auction clears in the same way as to previous scheme. However, participants that are cleared in the market trade power based on their bid. So pay/receive money based on their initial bid. In contrast to the uniform pricing mechanism, in pay-as-bid auction market price is not set to the bid of the most expensive generation unit, but to the specific offer from each supplier. Therefore every supplier received the exact amount it asks for. Under this scheme, all participants will attempt to predict the MCP to be able to make their bids as close as possible its value. Therefore, markets that are operating under this scheme encounter price increase and higher risk.

### 2.5 Overview on energy storage technologies

#### 2.5.1 Classification

Energy storage systems can provide different applications for power systems. The large scale (utility scale) energy storage systems can be categorized by their application into two main groups: Power management, or Energy management. Power Management applications, such as power quality control or frequency regulation, deal with short duration discharge of the energy storage (ES), while Energy Management applications, such as load levelling or time shifting, deal with relatively long duration discharge.

These two applications can be further divided into two sub groups, based on how frequent the ES is used: Frequent Discharge applications, like daily load levelling, and Infrequent Discharge applications, such as capacity applications.

As mentioned above, energy management applications deal with "long-duration" storage, which means discharge duration of more than 4hours. For long-duration ES frequent discharge indicates daily use of ES during one year, and infrequent discharge indicates around 20 times discharge in one year (almost 2times per month).

Power management applications involve "short duration" discharge, from fraction of a second up to one hour. Generally frequent discharge in these types of applications implies hundreds to a thousand discharges during a year, and infrequent discharge implies 20 discharges in a year. It should be mentioned that given numbers are just an idea, and generally they depend on type of the application. In Table 1 a summary of the above mentioned classification and the possible technology for each application is presented.

Category	Hours of Storage	Use/Duty Cycle	Technology
Long duration- Frequent discharge	4 - 8	1cycle/day × 250 days/year	Lead-Acid/NaS/CAES Pumped hydro
Long duration- Infrequent discharge	4 - 8	20 times/year	Lead-Acid/NaS/ ZnBr/ Li- ion
Short duration- Frequent discharge	0.25 - 1	4×15 mins/cycle × 250 days/year	Flywheels/ Super Caps/ Pb-Acid/ Li-ion
Short duration- Infrequent discharge	0.25 - 1	20times/year	Flywheels/ Super Caps/ Pb-Acid/ Li-ion

Table 1 Energy storage classification - based on the application

Figure 3 shows different possible storage technologies used in different application, Power Management- short discharge time- and Energy Management- higher discharge time. It shows that pumped hydro energy storage and compressed air energy storage with the maximum discharge duration and maximum available capacity, are suitable for long duration energy management applications.



Typical storage capacity versus discharge times for energy storage technologies

Figure 3 Storage capacity vs. charge discharge of energy storage [25]

#### 2.5.2 Characterization

In order to decide on the type of ES technology, some chemical and physical characteristics are ought to be identified. This chapter elaborates the essential storage criteria.

#### Capacity

Capacity of the Chemical ES, expressed in Ampere-hour (Ah), indicates the electric charge that can be withdrawn from a fully charged ES. This parameter is set for specific conditions, such as a fixed room temperature and discharge rate. Therefore, to be more precise nominal capacity (CN) can be used, which is the total available Ah when battery is discharged at a certain current. For instance, the nominal capacity C5 implies a discharge in exactly 5 hours at a rate of C/5.

#### Lifetime

The lifetime (or time of replacement) of a storage device is the time after which the device either ceases to function or its performance is degraded to such an extent that it no longer fulfills its function (or its operating costs no longer justify its use). In more specific studies the difference between technological lifetime (LT) and lifetime in service (LS) should be mentioned.

Technological lifetime (LL) includes ageing (also called technological ageing or intrinsic ageing), regardless of the usage of the storage. Lifetime in service (LS) incorporates the

deterioration of the components in time due to the use of the device. Lifetime in service is depended on the number of cycles that the ES is able to operate with its maximum capacity.

#### Energy efficiency

In general "efficiency" of ES technology can be defined in several ways, depending on the application process or the elements from the system taken into account. Three types of efficiency can be introduced as:

- The instantaneous efficiencies (related to the chemical reactions in the battery, charge/discharge efficiency, etc.)
- The cyclic efficiencies (defined for a complete charge cycle, enforcement during charge and discharge, or averaged on a representative number of cycles)
- The yearly efficiencies (based on an extensive energy balance).

Among these types, the most common used in the literature is cyclic efficiency, the ratio of the energy delivered by a system during a discharge to the energy required to recharge the storage up to its initial state of charge (SOC).

#### The specific energy and energy density

The specific energy, also known as weight energy density, usually expressed in Wh/kg, or kWh/t, is the nominal energy per unit mass. Specific energy is a characteristic of energy storage, depending on the materials used in it. Energy density is defined as the nominal energy per volume (Wh/m3). These characteristics, usually considered as critical for on board applications, have a significantly lower importance in the case of stationary applications. Thus, they will only be presented by way of illustration.

#### Cost

Cost for the storage technologies used in power applications are preferably expressed in  $\ell/kW$ , while for technologies used for energy applications is expressed in  $\ell/kW$ . Technologies with lower capital cost per unit of energy are more appropriate to be used in Energy Management applications, and those with lower cost per power are better for Power Management applications [26].

#### 2.5.3 Energy storage technologies

In this chapter a summary of various types of mature ES technologies will be presented. It includes a description of each technology, specifications, grid applications and advantages and disadvantages among other ES technologies [25].

#### *Supercapacitors*

Supercapacitors are mostly used for Power Management applications. They can perform various functions in electric grids such as: transmission line stability, spinning reserve, phase correction, harmonics suppression, and area and frequency control. Their advantages over other forms of ES are their long cycle life, high charge/discharge rates, no overcharge, high cycle efficiency, low maintenance costs, reliability, and a rated voltage independent of the cell chemistry. Supercapacitors are in contrast quite sensitive to overcharging.

#### Flywheel

Flywheel energy storage systems can store energy in the form of kinetic energy of a rotating rotor. Flywheels are used in electric mobility applications and in smaller distributed power systems e.g. in UPS systems. Flywheels can support ancillary services like frequency response, provide short time support for spinning reserves and standby reserves. Flywheels also have possibilities in peak shaving in electrical power systems and in power smoothing in renewable energy systems.

#### Conventional batteries

Conventional battery categories today include the most technologically and commercially mature technologies, i.e. Lead Acid batteries (PbA) and nickel based batteries, including Nickel Cadmium (NiCd) and Nickel Metal Hydride (NiMH) batteries. All conventional batteries are commercially available on the market. High recyclability improves usability. Rechargeable type conventional batteries, which could be used in smart grids, are PbA, NiMH and NiCd type batteries. They are already used widely in end-user systems and in other grid applications.

#### *Li-ion batteries*

Lithium-ion batteries are expected to contribute to the energy storage in grids due to fast charging, light weight, and high energy density in comparison to their counterparts. The cost and development must be adjusted according to technological demand (energy and power). Lithiumion batteries are widely utilized in the portable electronics and are becoming the energy storage of choice for future electric mobility applications. Foreseen prospects for Lithium-ion technology in larger applications are significantly growing with respect to other electrochemical storage systems and, particularly, in combination with more innovative integration of electricity grids within the transport sector.

#### Non-conventional batteries

These types of batteries can be categorized into two groups:

- 1. High temperature batteries: NaS, Zebra batteries
- 2. Flow batteries

NaS batteries consist of sulphur at the positive electrode and sodium at the negative electrode as active materials, and a Beta alumina of sodium ion conductive ceramic, which separates both electrodes. NaS batteries work at temperatures around 300°C. Several MW systems can be easily constructed. The required area for NaS battery installation is approximately one third of that for a lead acid battery. Also, they have long-term durability: 15 years (approximately 10–20 years) and in operation they have no discharge of any pollutant gases, no vibration and operate at low noise levels. NaS battery systems provide solutions for energy management (peak shaving), reliability (outage) and power quality issues. These applications increase asset utilization, provide alternatives to meet peak demand and improve quality of service.

Flow batteries are a particular type of electrochemical energy storage system in which one or both the electro-active materials are dissolved in the electrolytes. At the moment two main types of flow batteries continue to be developed, i.e. Zinc/Bromine (ZnBr) and vanadium-redox flow batteries. ZnBr batteries have operational capabilities that make them useful as a multi-purpose energy storage option and can be used in various applications related to smart grid management. Redox flow batteries are particularly suitable for large-scale utility applications such as peak shaving, back-up systems and applications coupled with renewables, such as large-scale photovoltaic fields. Vanadium redox batteries also have a short response time and good power density that makes them suitable for Power Quality applications.

#### Compressed Air Energy Storage (CAES)

Compressed air energy storage (CAES) systems are a hybrid form of storage that is used for large-scale energy storage. The underlying principle of CAES is to rely on the elastic energy of air to store electricity for later expansion, which generates power via a natural gas turbine. The economic and technical performance of CAES plants is expected to continue to improve. The large size of CAES technologies (50-300 MW of energy) and their fast ramping rates (several minutes) make them suitable for system applications, such as load following, frequency regulation and voltage control. One feature of a new generation of proposed CAES plants is that they may be closely integrated with wind farms, representing a means of storing additional power generated off-peak.

#### Hydropower

Hydropower facilities with storage are the oldest and largest of all commercially available energy storage technologies, being used since the 1890s. The basic principle relies on gravity to store energy by use of a height difference between two reservoirs. Recent advances in PHS technology have been mainly related to two areas: a double stage regulated pump-turbine allows a very high head to be used for pumped storage, which provides higher energy and efficiency than previously and the use of a variable speed drive allows for additional grid support, e.g. through frequency regulation in pumping mode, and better efficiency, flexibility and reliability. The main applications for hydropower storage are wholesale arbitrage and peak power capacity, energy balancing, the provision of tertiary and secondary reserves, forecast hedging, transmission curtailment, time shifting, load following etc. They are more suitable for transmission than for distribution applications.

## 3. Methodology

In this section first, we introduce the optimization framework employed to solve the problem of long term transmission planning (LTTP), with no energy storage integration. It is a market-based approach that maximizes the aggregated incremental social welfare minus the total investment of the transmission infrastructure subject to physical constraints. On the basis of this framework, we solve the problem of LTTP under the influence of two levels of energy storage integration. Here we neglect the cost of energy storage. At the end, we derive the analytical solution to all three optimization problems and explain the pricing mechanism under each scenario.

#### 3.1 Transmission planning – without energy storage

In this section, we solve the transmission planning for a grid without energy storage. We explain the optimization framework and derive the analytical solution to the problem, from which one yields the pricing mechanism as explained further.

#### 3.1.1 Test system specifications

Figure 4 shows a schematic of the system under study. The system originally consists of 3 onshore price zones and 3 offshore wind farms. Each onshore zone is a country with both generation and consumption. From market perspective, each onshore zone is a perfectly competitive market and each offshore node comprises wind generators (and no load).



Figure 4 Schematic of a meshed grid without energy storage

The model is given the freedom to consider any possible interconnection between the regions. In general, for a grid with n nodes, there are n(n-1)/2 possible numbers of interconnectors. The system of 6 nodes has 15 interconnector possibilities, which are represented with the dashed lines in Figure 4.

#### **3.1.2 Optimization framework**

As mentioned before, the proposed framework solves the LTTP and optimal power flow problem at the same time. We form an optimization framework to maximize the aggregated social welfare minus total investment cost of transmission infrastructure, subject to physical constraints. Here the impact of each node at each time on the rest of the system is captured by its power injection into the rest of the system (Equation(2.2 - 7)). The contribution of each node on the aggregated social welfare is determined using the incremental social cost curve of that region which is represented by a quadratic function of the power injection of the region (Equation(2.3 - 1)). This formulation yields a non-linear, non-convex optimization problem. The results of the optimization problem include optimal grid topology, transmission capacities and optimal power flows over every line (through optimal voltage values).

Figure 5 presents the social cost curve of a wind farm. The maximum power a farm can produce is a function of wind farm's total installed capacity and wind speed. Here  $WAF_i^t$  express the power output of every wind farm for every hour as a percentage of total installed capacity.  $WAF_i^t$  is determined as explained in [9]. As outlined above, there is no power consumer in the offshore wind zones. Therefore, the incremental cost of generating power is zero for these units (the red line in Figure 5). Equation (2.3 – 2) gives the marginal price of offshore wind farms as zero.



Figure 5 Cost curve of offshore wind farm as a function of its power injection

#### Primary assumptions:

We form the optimization problem considering a number of technical and economic assumptions as follow:

1. Markets are perfectly competitive. That is:

- a. The information is known for all market participants.
- b. There is no "strategic behavior". The decisions of the market players do not depend on each other.
- c. No network externalities exist.
- 2. Transmission losses are negligible.
- 3. Fix per unit cost of building the grid

Different objective functions are proposed to solve the OPF problem (see section 2.3.3). However, our goal is to determine the grid design in such a way that the congestion rents to be collected throughout the economic lifetime of the project pay off the investment capital of building the grid. To do so, we define the objective function of the problem as: maximizing the aggregated incremental social welfare minus total transmission investment cost.

Subject to the following physical constraints:

- 1. Power limits of each node
- 2. Voltage constraints
- 3. Line flow constraint

The optimization decision variables are number of parallel lines connecting node i to node j, and voltage square of each node at each time.

As will be discussed later, the optimization framework is formulated using an approximated HVDC power flow, which neglects power losses and implicitly account for power balance equality constraint.

#### Problem Formulation

For a system with  $n_b$  zones, the LTTP reads as follows:

$$\max \Omega = -\sum_{t=1}^{T} \sum_{i=1}^{n_b} C_i^t(P_i^t) - \sum_{i=1}^{n_b} \sum_{j=1}^{n_b} \frac{k_{inv} \cdot 2 \cdot K_{base} \cdot L_{ij} \cdot N_{ij}}{2} \quad (3.1-1)$$
$$(w_i^t, N_{ij})$$

Subject to:

$$\begin{split} P_i^{min} &\leq P_i^t \leq P_i^{max} \quad \forall i, t \quad (3.1-2) \\ w_i^{min} &\leq w_i^t \leq w_i^{max} \quad \forall i, t \quad (3.1-3) \\ T_{ij}^t &= \frac{g_{ij}}{2} \cdot \left(w_i^t - w_j^t\right) \leq K_{base} \quad \forall i, j, t \quad (3.1-4) \\ N_{ij} \geq 0 \quad \forall i, j \quad (3.1-5) \end{split}$$

In which:

$$P_i^t = \sum_{j=1}^{n_b} 2.T_{ij}^t = \sum_{j=1}^{n_b} 2.N_{ij}.\frac{g_{ij}}{2}.(w_i^t - w_i^t) \qquad (3.1 - 6)$$

is the total power injection of node i at time t. We define  $w_i^t = v_i^{t^2}$  in which  $v_i^t$  is the voltage per each pole.

 $k_{inv}$  is investment cost of transmission line connecting node i to j

 $K_{base}^{(MW)}$  is maximum capacity of each parallel cable per each pole

 $L_{ij}^{(\text{Km})}$  is the distance between the connection points of region i & j.

 $N_{ij}$  is the number of parallel cables that form an interconnector i - j. Total capacity of the interconnector is  $N_{ij} \times K_{base}$ .

 $P_i^{min}$  is the minimum power injection of each unit (lower band of injected power of each region and should be calculated for each region).

 $P_i^{max}$  is the maximum power injection capacity of each unit (upper band of injected power of each region).

 $w_i^{min} \& w_i^{max}$ : lower and upper band of voltage square constraint

This constrained optimization problem is solved analytically by formulating the Lagrangian as follows:

$$\mathcal{L}(w_{i}^{t}, N_{ij}) = \Omega(w_{i}^{t}, N_{ij}) + \sum_{t=1}^{T} \sum_{i=1}^{n_{b}} \sum_{j=1}^{n_{b}} \mu_{ij}^{t} \left( K_{base} - \frac{g_{ij}}{2} \cdot (w_{i}^{t} - w_{j}^{t}) \right) + \sum_{t=1}^{T} \sum_{i=1}^{n_{b}} \alpha_{i}^{t} (P_{i}^{max} - P_{i}^{t})$$

$$+ \sum_{t=1}^{T} \sum_{i=1}^{n_{b}} \beta_{i}^{t} (P_{i}^{t} - P_{i}^{min}) + \sum_{t=1}^{T} \sum_{i=1}^{n_{b}} \gamma_{i}^{t} (w_{i}^{max} - w_{i}^{t}) + \sum_{t=1}^{T} \sum_{i=1}^{n_{b}} \varepsilon_{i}^{t} (w_{i}^{t} - w_{i}^{min})$$

$$+ \sum_{i=1}^{T} \sum_{j=1}^{n_{b}} \zeta_{ij} \cdot N_{ij} \qquad (3.1 - 7)$$

In which  $\mu_{ij}^t$ ,  $\alpha_i^t$ ,  $\beta_i^t$ ,  $\gamma_i^t$ ,  $\varepsilon_i^t$ ,  $\lambda^t$  and  $\zeta_{ij}$  are Lagrange multipliers associated with each constraint. The Karush–Kuhn–Tucker (KKT) optimality conditions states any set of variables that satisfy the following conditions is a local solution to the optimization problem:

$$\begin{split} \frac{\partial \mathcal{L}(w_{i}^{t},N_{ij})}{\partial w_{i}^{t}} &= 0 \quad \forall i,t \qquad (3.1-8) \\ \frac{\partial \mathcal{L}(w_{i}^{t},N_{ij})}{\partial N_{ij}} &= 0 \quad \forall i,j,t \qquad (3.1-9) \\ \mu_{ij}^{t} &\geq 0 \& \mu_{ij}^{t} \cdot \left(K_{base} - \frac{g_{ij}}{2} \cdot (w_{i}^{t} - w_{j}^{t})\right) &= 0 \quad \forall i,j,t \qquad (3.1-10) \\ \alpha_{i}^{t} &\geq 0 \& \alpha_{i}^{t}(P_{i}^{max} - P_{i}^{t}) &= 0 \quad \forall i,t \qquad (3.1-11) \\ \beta_{i}^{t} &\geq 0 \& \beta_{i}^{t}(P_{i}^{t} - P_{i}^{min}) &= 0 \quad \forall i,t \qquad (3.1-12) \\ \gamma_{i}^{t} &\geq 0 \& \gamma_{i}^{t}(w_{i}^{max} - w_{i}^{t}) &= 0 \quad \forall i,t \qquad (3.1-13) \\ \varepsilon_{i}^{t} &\geq 0 \& \varepsilon_{i}^{t}(w_{i}^{t} - w_{i}^{min}) &= 0 \quad \forall i,t \qquad (3.1-14) \\ \zeta_{ij} &\geq 0 \& \zeta_{ij}, N_{ij} &= 0 \quad \forall i,j \qquad (3.1-15) \end{split}$$

#### Pricing mechanism

From Equation (3.1-8) one determines the pricing mechanism as follows:

$$-\sum_{i=1}^{nb} P_i^t \cdot [\rho_i^t + \alpha_i^t - \beta_i^t]$$
  
=  $\sum_{i=1}^{nb} \sum_{j=1}^{n_b} \mu_{ij}^t \cdot K_{max}$   
=  $\frac{1}{2} \cdot \sum_{i=1}^{nb} \sum_{j=1}^{n_b} 2 \cdot T_{ij}^t \cdot [(\rho_j^t - \rho_i^t) + (\alpha_j^t - \alpha_i^t) - (\beta_j^t - \beta_i^t)]$  (3.1 - 16)

Equation (3.1 - 16) shows the pricing mechanism for a HVDC grid. The first term in the equation represents total nodal payment of every zone, the second term represents congestion revenue of line i-j and the last term shows the transmission revenue of all lines at time t. The equality shows that at each t transmission revenues is equal to the congestion revenues over all lines.

The nodal price of each zone at each time is equal to  $\rho_i^t + \alpha_i^t - \beta_i^t$ . Where  $\rho_i^t$  is the marginal cost of generation of that zone and  $\alpha_i^t$  and  $\beta_i^t$  are Lagrangian multipliers associated with Max/Min power injections, respectively.

Transmission investment recovery

From equation (3.1 - 9) one can show that:

$$2.\sum_{t=1}^{T} T_{ij}^{t} \left[ \left( \rho_{j}^{t} - \rho_{i}^{t} \right) + \left( \alpha_{j}^{t} - \alpha_{i}^{t} \right) - \left( \beta_{j}^{t} - \beta_{i}^{t} \right) \right] = K_{inv} \cdot 2. K_{base} \cdot L_{ij} \cdot N_{ij} \cdot T \quad \forall i, j \quad (3.1 - 17)$$

The first term of equation (3.1 - 17) shows the transmission revenue that would be collected by the end of the economic lifetime of the interconnector. The second term represents total transmission investment cost of building the interconnector i - j. Taking a summation over all i and j results the equality below which indicates the equality of total investment cost associated with building all the interconnectors with transmission revenue to be collected for all lines throughout the economic life time of the project:

$$\sum_{t=1}^{T} \sum_{i=1}^{nb} \sum_{j=1}^{nb} \frac{2 \cdot T_{ij}^{t} \cdot \left[ \left( \rho_{j}^{t} - \rho_{i}^{t} \right) + \left( \alpha_{j}^{t} - \alpha_{i}^{t} \right) - \left( \beta_{j}^{t} - \beta_{i}^{t} \right) \right]}{2}$$
$$= \sum_{i=1}^{nb} \sum_{j=1}^{nb} \frac{K_{inv} \cdot 2 \cdot K_{base} \cdot L_{ij} \cdot N_{ij} \cdot T}{2} \quad (3.1 - 18)$$

Taking summation over all t in equation (3.1 - 16), one can simply derive the following equality obtains:

$$\sum_{t=1}^{T} \sum_{i=1}^{nb} \sum_{j=1}^{n_b} \mu_{ij}^t \cdot K_{max} = \sum_{i=1}^{nb} \sum_{j=1}^{nb} \frac{K_{inv} \cdot 2 \cdot K_{base} \cdot L_{ij} \cdot N_{ij} \cdot T}{2} = \text{Total investment cost} \quad (3.1-19)$$

Equation (3.1 - 19) ensures the recovery of investment cost through congestion revenues to be collected by the end of economic life time of the project.

#### **3.2** Transmission planning – with energy storage

In this section, the problem of transmission planning when energy storage is included in the system is explained. We introduce an optimization framework that results in optimal transmission and energy storage capacities.

#### 3.2.1 Location of energy storage

The grid configuration mentioned above and illustrated in Figure 4 is referred to as the "base case" system. We integrated the energy storages into the base case system. An important consideration for a grid with energy storage is energy storage allocation.

Energy storage can be located onshore or offshore, depending on its utilization purpose. In this work energy storage is used as an alternative for transmission infrastructure. That is, we focus on energy storage for improving transmission lines utilization and increasing wind power penetration into the grid. Moreover, as mentioned in [14] locating energy storage at onshore zones may cause violating transmission line constraint. Therefore, we place energy storage offshore.

For efficiently utilizing the wind energy from all three offshore wind farms, we associate an energy storage unit to each offshore wind farm. Figure 6 illustrates the grid with energy storage integration. In the figure energy storage units are shown with red circles. Each energy storage unit is only connected to its associated offshore wind farm with a fixed interconnector, shown in the figure with the red lines.



Figure 6 schematic of grid with energy storage

When energy storage is added to problem formulation, its capacity is introduced as the third design variable. There are two approaches for determining the capacity of energy storage: either to include energy storage capacity as an independent variable in the optimization framework, or to calculate it as a dependent variable from the independent variables.

In this work, we do not introduce the capacity of energy storages as a new set of independent variable. It's mainly because the focus of this work is to study the impact of energy storage on LTTP. We model energy storage as a not-for-profit unit which contributes to the social welfare increase of onshore regions through increasing utilization of the offshore wind farms. Therefore, we are not interested in finding the optimal capacity of storage based on its investment cost and operating revenue. Therefore, instead of introducing new independent variable for storage capacity, we define it as a dependent variable.

We propose a general formulation for energy storage, regardless of specifications of each storage technology (i.e. ramp rate). We model storage as a "black box" with the potential to store the wind power during the high wind periods (or low consumption) and send it back to the system during low wind (or high demand) period.

There are two approaches to model the operation of the storage with the grid: considering energy storage and offshore wind farm together as a single node, or modeling energy storage as an independent node. In the first approach, the impact of energy storage and wind farm on the grid is determined by defining one power injection. While, in the second approach storage has an independent power injection into the system.



Figure 7 Placement of energy storage with the offshore wind farm

Throughout this research, we have explored both possible options for modeling the storage. We realized that formulating the problem considering energy storage and wind farm together as one node results in a simpler problem formulation. However, solving that problem is computationally intensive (if possible at all) as the problem becomes non-smooth. Therefore, we model energy storages as a separate zone which is connected with infinite capacity to the respective wind farm. The other formulation for the problem is stated in Appendix I.

A cost curve has to be defined for energy storages to integrate optimization framework as discussed in 3.2.2.

#### 3.2.2 Cost curve of energy storage

As a separate node, a power flow is assigned to energy storage. To derive the cost curve of energy storage, first we define a new variable (Storage Energy Content) as follows:

#### Storage Energy Content (SEC)

As mentioned before, energy storage can be used in power management or energy management application. In power management applications, the main purpose of energy storage is to send instant power to the system to control the abrupt changes. On the other hand, in energy management application, which is the focus of this work, energy storage saves power over time to dispatch it later. This power accumulation over time represents the amount of energy stored in the energy storage. Energy storage model deals with accumulated energy *during* every hour rather than handling *instant* power injection to/from energy storage node.

Energy flow of storage during time period t is defined as:

$$E_i^t = -P_i^t * \Delta t \quad (3.2-1)$$

In which  $P_i^t$  is storage injection power and  $\Delta t$  is the duration of the time period. If power injection is positive, storage is in discharging mode and its energy level declines. In the case that hourly time steps, storage energy change is equal to its injection power:  $(E_i^t = -P_i^t * 1hr)$ . That is, the terms "energy" and "power" can be used interchangeably if the time period over which the power is exchanged is one hour.

To model the power accumulation over time, we define Storage Energy Content as a variable of time  $(SEC_i^t)$ . It represents the amount of stored energy in the energy storage by the end of each operating step. Storage Energy Content of each storage unit at the end of each time period  $(SEC_i^t)$  is calculated by taking summation of all charge/discharge energy since the first operating state until the beginning the period under study (t). It equals the energy flow to the unit during the period  $(E_i^t)$  plus energy state of the storage in the end of the previous hour  $(SEC_i^{t-1})$ , with the following formulation:

$$SEC_i^{\ t} = SEC_i^{\ t-1} + E_i^t \quad (3.2-2)$$

In which  $SEC_i^{t}$  is the energy content of storage i at time t, and  $SEC_i^{t-1}$  is the energy content at the end of the previous hour. The formulation can also be written as:

$$SEC_i^{\ t} = \sum_{m=1}^t E_i^m = \sum_{m=1}^t -P_i^m$$
 (3.2 - 3)

As the above formulation shows, storage energy content is a function of the variations of power (energy flows) from the storage into system during operating hour under study and all previous ones.

Having SEC, we can explain the cost curve of the storage as follows, considering some assumptions:

We model energy storage as a not-for-profit entity. That is, it is not modeled in a way to sell the power to make revenue or to pay off its investment. Energy storage sells power with the same price it buys. As it is only connected to the wind farm, during the charging period it buys power from the wind farm with zero prices. It continues the power import until it reaches its maximum capacity. During the discharge period, storage exports power with zero prices, until it is fully discharged.

Figure 8 presents the social cost curve of an energy storage  $(\Delta C_i^t)$  as a function of power injection  $(P_i^t)$ . Positive injection power shows energy storage is discharging. The discharge limit is its energy content at the previous hour. Negative power injection means storage is charging. The charging limit is the storage capacity  $(k_s)$ . If storage capacity is unlimited, there is no limit for charging storage and  $k_s$  goes to minus infinity.



Figure 8 Cost curve of energy storage as a function of its power injection

It can be seen that storage and wind farm have similar marginal price. Storage buys and sells power at zero price. The only difference is that wind farm does not accept negative injections (power import), as there is no offshore load to consume the imported energy.

#### **3.2.3 Optimization framework**

The optimization frameworks for the two problems of LTTP with and without energy storage are generally the same. That is, the two problems have the same objective functions as follows:

$$\max(\Omega) = \sum_{t=1}^{T} \sum_{i=1}^{nb} Social Welfare - \sum_{i=1}^{nb} Transmission investment cost$$

The decision variables for the optimization framework are also the same as LTTP without storage: squared voltages and  $(w_i^t = (v_i^t)^2)$  and number of parallel cables every interconnector composed of  $(N_{ij})$ . However, the number of nodes (i) in this problem is 9 (3onshores, 3offshores and 3 energy storages).

The simplifying assumptions introduced for the LTTP problem without storage are hold for this problem. In addition, we have to make new assumptions to model energy storage in the grid as a separate node in a market based framework, as follows:

- 1. An infinitely large interconnection is considered between every wind farm and the storage next to it. Practically, there is no *physical* transmission line between energy storage and wind farm. The infinite line and storage power flow are required to be able to model operation of energy storage and incorporate it into the proposed - market based optimization framework.
- 2. The model is given freedom to charge/discharge storage at any power rating.
- 3. Storage is modeled as a not-for-profit entity. Therefore its investment cost and revenue is not considered in the model.
- 4. Specific operational characteristic of energy storage (i.e. charge/discharge efficiency or ramp rate) is not considered in the model.

The optimization constraints are the same as general LTTP problem mentioned in (3.1):

- 1. Voltage-square constraint  $\rightarrow 0.81^{pu} \le w_i^t \le 1.21^{pu}$
- 2. Number of parallel lines  $\rightarrow N_{ij} \ge 0$
- 3. Power injection constraint  $\rightarrow P_i^{min} \le P_i^t \le P_i^{max}$ 4. Maximum line flow constraint  $\rightarrow T_{ij}^t \le Kmax$

The upper and lower band of energy storage power injection is determined from its cost curve. The maximum positive power injection of every storage is the maximum energy charged in the device previously (i.e., SEC at the previous hour (SEC(t-1))). The negative power injection of the storage (charging model) can reaches up to the installed storage capacity. Therefore, for energy storage the third inequality constraint is:

$$-K_s \le P_{i,ES}^t \le SEC^{t-1}$$
 (3.2 - 4)

Using Equation (3.2 - 3) one can rewrite the right side of the inequality (3.2 - 4) as:

$$P_{i,ES}^{t} \le SEC^{t-1} \to 0 \le SEC^{t} \to 0 \le \sum_{m=1}^{t} -P_{i}^{m}$$
 (3.2-5)

If the capacity of storage is not limited (scenario UES – section 4.2), it is calculated as a function of SEC at the end of the optimization. In general, we define storage capacity  $(K_s)$  as the maximum value SEC reaches over all time, as:

$$K_s = Max (SEC^{t-1})$$
 (3.2 – 5)

Under the especial scenario of the limited storage capacity (scenario LES – section 4.2),  $K_s$  will be set at a fixed value and an extra constraint is required to be satisfied. Then, storage energy content cannot surpass the maximum installed capacity of that storage. Therefore, the extra fifth constraint for the problem of limited energy storage capacity is:

$$SEC^t \leq K_s \quad (3.2-6)$$

Equation (3.2 - 6) satisfies the capacity limit so that energy storage is not charged more than its available capacity.

#### Analytical solution

The analytical solution to the problem of LTTP storage can be derived with the same approach as section 3.1. Here we only present the resulted final pricing mechanism.

Under the scenario of UES, where the <u>storage capacity is not fixed</u>, optimization constraints and associated Lagrangian multipliers are similar to Equations (3.1-1) to (3.1-5). In addition, Lagrangian formulation and KKT optimality conditions remain similar to Equations (3.1-8) to (31-15)). The Lagrangian for the constrained optimization problem is:

$$\begin{aligned} \mathcal{L}(w_{i}^{t}, N_{ij}) &= \Omega(w_{i}^{t}, N_{ij}) + \sum_{t=1}^{T} \sum_{i=1}^{n_{b}} \sum_{j=1}^{n_{b}} \mu_{ij}^{t} \left( K_{base} - \frac{g_{ij}}{2} \cdot \left( w_{i}^{t} - w_{j}^{t} \right) \right) + \sum_{t=1}^{T} \sum_{i=1}^{n_{b}} \alpha_{i}^{t} (P_{i}^{max} - P_{i}^{t}) \\ &+ \sum_{t=1}^{T} \sum_{i=1}^{n_{b}} \beta_{i}^{t} (P_{i}^{t} - P_{i}^{min}) + \sum_{t=1}^{T} \sum_{i=1}^{n_{b}} \gamma_{i}^{t} (w_{i}^{max} - w_{i}^{t}) + \sum_{t=1}^{T} \sum_{i=1}^{n_{b}} \varepsilon_{i}^{t} (w_{i}^{t} - w_{i}^{min}) \\ &+ \sum_{i=1}^{T} \sum_{j=1}^{n_{b}} \zeta_{ij} \cdot N_{ij} \end{aligned}$$

Knowing that

$$\alpha_{i}^{t}(P_{i}^{max} - P_{i}^{t}) = \alpha_{i}^{t} \sum_{m=1}^{t} - P_{i}^{m} \qquad (3.2 - 7)$$

One can rewrite the term associated with maximum power injection for offshore nodes as follows:

$$\sum_{t=1}^{T} \sum_{i=1}^{n_b} \alpha_i^t (P_i^{max} - P_i^t) = \sum_{t=1}^{T} \sum_{i=1}^{n_b} \alpha_i^t \sum_{m=1}^{t} -P_i^m = \sum_{t=1}^{T} \sum_{i=1}^{n_b} -P_i^t \sum_{m=t}^{T} \alpha_i^m \qquad (3.2 - 8)$$

Applying the KKT optimality condition, one obtains the defiant ion of nodal price for every offshore zone as follows:

$$NP_i^t = \rho_i^t + \alpha_i^{\prime t} - \beta_i^t \qquad (3.2 - 9)$$

In which,  $NP_i^t$  is the nodal price of node i at time t and  $\alpha'_i^t$  is equal to  $\alpha_i^t$  for non-storage nodes and  $\sum_{m=t}^{T} \alpha_i^m$  for storage nodes.

From equation (3.2 - 9), one notice that the electricity price of hour "t", depends on the Lagrangian multipliers associated with maximum power injection at that hour, and the following hours. That is, power injection at each hour is affected by the nodal prices in the future. Therefore, nodal price of energy storage "i" at hour "t" depends on the future nodal price of storage which clearly shows non-causality of storage price in a competitive market.

When storage capacity is limited, one extra constraint is included in the formulation (Equation (3.2 - 6)). The KKT optimality condition, therefore, introduces a new Lagrangian multiplier associated with the new constraint.

$$\lambda_i^t \ge 0 \& \lambda_i^t (K_s - SEC^t) = 0 \ \forall t, i = ES$$
 (3.2 - 10)

Equation (3.2 - 9) is the KKT optimality condition for the abovementioned constraint and  $\lambda_i^t$  is the Lagrangian multiplier associated with the constraint. *SEC<sup>t</sup>* is a function of power injections of storage. Therefore, following the same method as in Equation (3.2 - 8), one can rewrite Equation (3.2 - 10) and derive the pricing mechanism. Under the KKT conditions the nodal price of energy storage for a limited storage capacity is derived as:

$$NP_i^t = \rho_i^t + \alpha_i^{\prime t} - \beta_i^t - \lambda_i^{\prime t} \quad \forall t, i = ES \quad (3.2 - 11)$$

In which  $\lambda_i^{t}$  is defined as  $\sum_{m=t}^{T} \lambda_i^m$ . Therefore, for the limited energy storage capacity nodal price depends on the penalty factor associated with reaching the maximum capacity and maximum injection capacity and the associated Lagrangian shadow prices in the future.

This formulation for energy storage, regardless of being limited capacity or unlimited, results in the same analytical solution as the problem of LTTP without storage (considering the new definition for.  $\alpha'_i^t$ ,  $\lambda'_i^t$ ). It shows that, total congestion revenue equals total transmission revenue collected at the end of the economic lifetime of the project, and it equals total cost of building the transmission infrastructure.

$$\sum_{t=1}^{T} \sum_{i=1}^{nb} \sum_{j=1}^{n_b} \mu_{ij}^t \cdot K_{max} = \sum_{i=1}^{nb} \sum_{j=1}^{nb} \frac{K_{inv} \cdot 2 \cdot K_{base} \cdot L_{ij} \cdot N_{ij} \cdot T}{2} = \text{Total investment cost} \quad (3.2 - 12)$$

#### 3.3 Data Acquisition

Proposed optimization framework, results in the optimal grid design for a mesh grid configuration, consist of three onshore regions and three offshore regions.

In order to have a realistic results, we apply the proposed framework to solve the LTTP for the HVDC offshore grid in the North Sea.

Amongst all countries involved in the North Sea -Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway, Sweden, and the United Kingdom - we select three countries that will have most significant impact on development of the offshore grid. Here we select Germany and UK due to extremely large wind power capacities they will install in the near future. Among other countries, Norway has a unique characteristics and being treated as a special case, due to large hydro reservoir capacities the country has. In general, Norway has rather liquid market with low average price (at least in low consumption zones: NO2, NO3, NO4). Due to special characteristics of the country, it is nominated as the third country into our scope.

#### *Modifying "a" coefficient of the cost curve*

To have more realistic results, we apply our model to simulated wind speed and empirical market data from April 2011 to March 2012. The problem is, today only a share of power trades are settled through power exchanges, In order for the offshore grid to better address the whole society's needs, one can assume load and generation as well as aggregated supply/demand curves are remain similar for the next 25 years. What changes is the share of power trades through exchange to total power trades. For simplicity, we assume that power will be settled through power exchange at the time we study. This is a reasonable assumption as there is strong trend towards realization of pan-European power market. Hence, the "a" cost curve coefficient in the quadratic cost curve has to be scaled down by *ceff* according to share of power exchange of each country in total power trades of that country:

$$a^{new} = a^{old} \times ceff$$

The share of Germany, Norway and UK power exchange from the total power trades are 42%, 73% and 10% respectively [27]. "*ceff*" value is accordingly similar values just to scale down a coefficient to make future markets more stable and liquid.

## 4. Results

In the previous chapters, we explained the problem of Long Term Transmission Planning under the presence of energy storage. We introduced an optimization framework to maximize the aggregated incremental social welfare of all interconnected regions at all times minus the investment cost of transmission infrastructure.

In this section, we present the results of applying the proposed frame work to the North Sea Grid. In order to investigate the impact of integrating storage capacity on the grid, we solve the optimization problem for two different levels of energy storage capacity: unlimited capacity (idealized case) and limited capacity (realistic case). The results are then compared with the base case where transmission capacities are optimized without any energy storage is present. These three optimization problems are referred to as "scenarios" for the rest of this work.

This chapter explains how the input data are selected and how the different scenarios are compared. It is followed by simulation numerical results and discussions.

## 4.1 Input selection

The available input data of the optimization model are hourly wind availability factor (WAF<sub>i</sub><sup>t</sup>) and cost curve coefficients ( $a_i^t \& b_i^t$ ) for one complete year (8760 time steps). As the number of time steps increases the number of optimization variables and the simulation time increases. For instance, a grid with three onshore and three offshore regions has 52'575 optimization variables if all 8760 time steps are considered (15 possible interconnections (Nij) and 6\*8760 voltage variables ( $w_i^t$ )), which takes indefinite time to be solved. To keep the computation time feasible, the number of input variables has to be reduced.

There are different feature selection techniques that are used to reduce the number of the original data and at the same time keep the correlation of the data. These techniques select subsets of the *relevant* and *effective* features to reflect the target of each representative subset, by extracting irrelevant and redundant data. The irrelevant data are those which do not provide useful information, and the redundant data are those which provide no more information.

However, energy storage is a causal system and the sequence of phenomena affects its operation. The common feature selection techniques do not reflect the causal relation of the original data and the clustered data. They select features identically and independently, ignoring the hierarchy and time dependency of the data. Therefore, these techniques are not effective when the sequence of the data should be maintained.

According to this argument, we are obliged to choose a limited period of consecutive hours to model energy storage. For the purpose of this study we select a time period of 48 hours. It should be mentioned that a set of 2 days data does not reflect all the variations and characteristic of 365 days effectively. Wind speed and market data vary significantly depending on the time of the year (summer/winter) and time of the day (morning/night). However, this analysis leads us to study the influence of the input variables ( $WAF_i^t$  and  $a_i^t \& b_i^t$  coefficients) on the optimization results.

We propose two sets of 48 consecutive hours. The (technical) results of the optimization are grid design and storage capacities. The factor forces the model towards increasing the transmission capacities is the price differences between the regions. Energy storage becomes more influential if there is large amount of wind power with high variations.

Following the above mentioned argument we introduce two methods for selecting the input variables: 1. Selection based on nodal price differences between the regions 2. Selection based on the level of wind speed (WAF). The remaining of this section explains the procedure of selecting two time frames.

#### 1. Selection based on price differences

Here we are looking for a set of two days with high price difference between onshore regions. That is, we determine the period which has the highest potential for building transnational interconnection. Nodal price difference gives the incentive to instructing interconnections. The regions with higher price are motivated to buy electricity from the regions with lower price. We need to identify the time period in which nodal prices have the largest difference.

Nodal price of onshore regions is determined as:

Nodal price = 
$$2 \times a_i^t \times P_i^t + b_i^t + \alpha_i^t - \beta_i^t$$

In which  $a_i^t$  and  $b_i^t$  are the cost curve coefficients, and  $\alpha_i^t$  and  $\beta_i^t$  are the Lagrange multipliers associated with the upper and lower power injection. Before building the grid, nodal price is equal to  $b_i^t$ . Therefore, to find the period with the largest nodal price difference, we investigate the distances between the  $b_i^t$  coefficients of every two regions at each time as:

$$\Delta b_{ij}^{t} = b_{i}^{t} - b_{j}^{t}$$

The period which has the largest  $\Delta b_{ii}^{t}$  value is the selection.



Figure 9 price differences of GE-NO, GE-UK and NO-UK for 8760 hrs

Figure 9 shows the nodal price differences of every two regions. The blue, red and black lines represent the price difference of Germany and Norway, Germany and the UK, and Norway and the UK, respectively. From this plot one can observe that nodal price of Germany and the UK is most often in the same range, while Norway's nodal price differs significantly in the periods shown under the red circle.

We first find a period with a large  $\Delta b_{ij}^t$  value, and then we extract a shorter period of consecutive 48 hours which has the largest  $\Delta b_{ij}^t$ . Largest price difference is recognized during the period between hours 3750 and 4700 has the largest nodal price differences. Here, nodal price of Norway is extremely lower than the other two regions. The 48 hours between hours 4012 and 4059 is selected with the most extreme nodal price differences.

#### 2. Selection based on WAF:

To illustrate the impact of WAF on energy storage operation and grid development, we select an extremely windy period. Wind speed at each location can be characterized based on its average value and standard deviation

To see the impact of all the regions in one value, we use the weighted average of WAF (WAF weighted) for the three regions, calculated by multiplying the WAF of each region at each time by the wind farm capacity.

$$WAF_{weighted}{}^{t} = \frac{WAF_{DE}{}^{t} * P_{G,DE} + WAF_{NO}{}^{t} * P_{G,NO} + WAF_{UK}{}^{t} * P_{G,UK}}{P_{G,DE} + P_{G,NO} + P_{G,UK}}$$

This value is the basis of further analysis in this section. The variation of WAF weighted over one year is shown in Figure 10.



Figure 10Wieghted WAF for Germany, Norway and the UK for 8760 hours

We introduce two indicators for each week: the average WAF over time and the standard deviation of WAF. Figure 11 shows 52 weeks of the year by these two indicators. The blue line shows the mean value of the WAF for each week, and the red line shows the WAF standard deviation in each week. High mean WAF implies a windy week and large standard deviation implies the week with highest variations in wind speed.



Figure 11 Mean value and standard deviation of the weighted WAF for 52 weeks

A representative week is expected to have high mean value and high standard deviation. Week 50 has the highest average WAF, and week number 42 has the highest standard deviation. However, we are looking for a week with the maximum value in both of these indicating factors, which is basically a week which has the least distance from the maximum of these two values. We define the Euclidean distance for every week as:

$$Distance = \sqrt{(WAF_{avg} - max(WAF_{avg}))^2 + (WAF_{std} - max(WAF_{std}))^2}$$

The week that has the shortest distance value is selected as the extreme representative week.

In which  $WAF_{avg}$  is the average wind availability factor of the week, and  $WAF_{std}$  is the standard deviation of the WAF of the week. The week which has the minimum distance value is the selected week.

Week 44 is defined as the windiest week of the year. In a similar way, day 5 and 6 of the week 44 are identified as the windiest days in the windiest week.

## 4.2 Scenarios

To see the impact of different level of integrating energy storage to the grid, we introduced three scenarios:

- 1. Grid design with no storage (NES)
- 2. Grid design with unlimited capacity of storage (UES)
- 3. Grid design with limited capacity of storage (LES)

The impact of energy storage on the more efficient utilization of the wind farms can be seen when infinite capacity of energy storage is available. By defining the idealistic UES scenario, we investigate the maximum impact energy storage can impose on the grid design. However, UES results in extremely large unrealistic storage capacities. We define a more realistic scenario (LES) and define a limited of 1GWh for the energy capacity of storage. Comparing the results of these two scenarios with the base case NES scenario, we determine the influence of different levels of energy storage capacities on LTTP.

The problem formulation of the first scenario is the reference case of transmission planning where no storage is considered. It is the original problem of LTTP, explained in (section 3.1). Under the second scenario (UES), we determine the optimal grid design when energy storage with unlimited capacity is integrated into the grid. The problem formulation for this problem is presented in section 3.2.

The pricing mechanism for these three scenarios is explained in chapter 3. Under NES, the pricing mechanism reflects the power injection at each time step. Under UES, power injection at each hour affects the nodal prices in future. Therefore, the price of power at each hour has the penalty factor of the proceeding hours. Under LES, nodal prices depend not only on the power injection of the future hours, but also on the capacity of the energy storage.

## 4.3 Simulation results

The optimization framework is applied to the test system explained in section 3, for input data elaborated in section 4.1 and scenarios of section 4.2. The network consists of  $\pm 500$  kV, 2000 MW VSC-based bipolar HVDC cable connections. All simulations are done in MATLAB R2011. The optimization solver is "fmincon", which is built-in toolbox for solving nonlinear, constrained optimization problems. We employ interior-point algorithm which is the choice for solving large-scale optimization problems.

Solver starts searching for a local optima from an initial point provided randomly by the user. The search procedure stops if the solver:

- 1. finds a local optima (where KKT optimality criteria is met),
- 2. gets stuck in a critical point which is not local optima (KKT does not hold but first order derivative is zero)
- 3. meets stopping criteria before it arrives at one of the aforementioned criteria

This is a non-convex optimization problem for which, rather than a "global optima", local optimal points can be found. By increasing the number of initial points we cover large part of the search space. In fact, we observed that the success rate of finding a local optima is quite low unless the solver settings (i.e. tolerance on the constraints) is very small. However, running the simulations with very small tolerances (with the order of magnitude of  $10^{-60}$ ) is an extremely time consuming procedure. Therefore, we apply the following iterative procedure.

- 1. generate initial points
- 2. solve the optimization problem for each and every initial point
- 3. sort the results in descending order of the aggregated incremental social welfare
- 4. select the initial point for which the highest social welfare is achieved
- 5. solve the optimization problem once again for the point with the highest social welfare tighter constraints
- 6. check the simulation result with the analytical solution (Investment cost = congestion revenue = transmission revenue)
- 7. if the equality does not hold, go back to step 4
- 8. if the optimal point is not reached after 10 trials move to the next largest social welfare (step 3) and moving to step 4 again

It should be mentioned that, if optimality criteria was not met after trying the procedure for 20 point (the first 20 points in step 3), we stop the procedure and accept the result with maximum 5% divergence from the analytical solution.

Here, we present the optimal grid designs for the two sets of representative days (section 4.1) and the three energy storage capacity scenarios (section 4.2). We compare the grid designs obtained for every two sets of representative days under each and every scenario.

#### 4.3.1 Input set 1: Large price differences

Figure 12 show the optimal grid designs for the first period (high price difference) under three scenarios of energy storage capacity: NES, UES and LES.



Figure 12 Optimal grid design under NES, UES and LES scenarios - Input set: High price difference

#### General observations:

In all three scenarios one can recognize a meshed grid design with three types of interconnections: radial connections from every onshore zones to its respective offshore wind farm, cross border interconnection between two offshore wind farms and a direct local connection (with infinite capacity) between each offshore wind farm and the respective offshore

energy storage. From comparing the three grid designs (under each energy storage scenario), the followings are observed: offshore wind farm of Germany and Norway are connected to each other and also to the other three onshore zones. Wind farm of the UK is only connected to UK onshore. Eventually, there is one shore to shore connection between Germany and Norway. The model managed to keep the level curtailments at zero for all grid designs under all operating states and storage scenarios.

#### No energy storage scenario (NES):

Due to the nodal price differences, Germany and the UK are net power importer and Norway is a net power exporter as the arrows show in Figure 12. Nodal price of Norway is extremely lower than of Germany and the UK (see Table 2). Therefore, there is a large incentive for Germany and UK to construct large transmission capacities and import relatively cheap power from Norway.

Figure 12 shows large <u>radial connection</u> capacities for the three countries. Germany and the UK, as net power importers, build large radial connection to deliver the available cheap wind energy to onshore consumers. On the other hand, Norway as a net power exporter, supplies its onshore cheap energy through the radial connection to offshore node and then to the rest of the system.

Aside from the radial connections, the grid has large <u>cross-border interconnections</u>. Nodal price differences between the onshore zones before the grid is built (Ex-Ante scenario) is the incentives towards building these interconnections. The first column of Table 2 compares high price of Germany and the UK against Norway. Germany imports power from Norway which has lower nodal price. UK imports power from the offshore wind farms of the other two countries. Therefore, the cross-border interconnections create opportunities for the net importer countries to benefit from the cheap power produced in Norway or offshore wind farms.

Table 2 Notal price of onishore and offshore regions [C/WI will of Germany, Norway and the UK - under Ex-Ante
(before building the grid), No Energy Storage (NES), Limited capacity Energy Storage (LES) and Unlimited capacity
<b>Energy Storage (LES) Input: High price difference</b>

Region	Scenario	Ex-Ante	NES	LES	UES
	Germany (€/MWh)	58.35	35.19	35.19	34.42
Nodal Price of Onshore zones	Norway (€/MWh)	3.50	31.55	31.56	30.88
	UK (€/MWh)	49.12	36.85	36.88	36.06
Nodal Price of	Germany (€/MWh)	0	34.40	34.4159	33.5131
Offshore wind farms	Norway (€/MWh)	0	32.76	32.8834	32.3881
III5	UK (€/MWh)	0	36.47	36.5010	35.7078

In Table 3 presents social welfare distribution of the three onshore regions. Under NES scenario, incremental social welfare of Germany and UK are positive, which shows that these regions benefit from building the grid. This observation is consistent with average nodal price decrease

in Germany and UK (comparing Ex-Ante and NES in the table). For Norway, on the other hand, incremental social welfare is negative. It implies Norway, as a net power exporter, provides benefit for the rest of the system which in turn results in a large increase in the nodal price of the country (compare price of Norway under Ex-Ante with NES in Table 2).

Table 3 Incremental Social Welfare Distribution of Each Onshore Region over 25 years in billion Euros (B €) – Under No Energy Storage (NES), Limited capacity Energy Storage (LES) and Unlimited capacity Energy Storage (LES) scenarios – Input: High price difference

Scenario Country	NES	LES	UES
Germany (B €)	128.23	128.51	133.93
Norway(B €)	-31.74	-31.84	-33.94
UK (B€)	199.04	199.76	205.47

#### Unlimited capacity Energy Storage (UES)

Under UES scenario grid topology and power flows directions remain the same as NES: Norway is net power exporter, Germany and UK are net power importers. However, transmission capacities are different under UES.

Comparing NES and UES in Figure 12 one observes an increase in the capacity of the radial connections and a decrease in the cross-border connections. This observation can be explained by comparing the financial results of NES and UES. We are using a market-based approach in which model tends to take advantage of the cheap energy by maximizing the aggregated social welfare of all regions minus total cost of transmission infrastructure (3.2 - 12). The zero curtailment level obtained for both NES and UES scenarios shows that it is economically most efficient to dispatch all the available wind into the system. That is, the grid is planned to be expanded in such a way there will be a corridor to transfer the offshore produced energy to onshore consumers of one the two countries (i.e., Germany or the UK. No is a pure exporter and has no contribution in consuming offshore produced wind) to avoid wind curtailment.

The model understands that the onshore region are in need for cheap offshore energy to that extent that economically it makes sense to build such large transmission capacities, regardless of the longer connection distances and the higher associated costs.

In our simulations, offshore energy storages are connected with unlimited transmission capacity to their wind farms under UES and LES. They are modeled as not-for-profit units and participate in electricity market with zero marginal price (Figure 8). Hence, they make bids to buy and sell the power with zero marginal price.

When there is a power surplus offshore, the electricity price of offshore wind farms is either zero or exactly equals the price of offshore wind farms it is connected to -when all interconnectors are congested. This price is equal to bid of storage for buying electricity. Hence, in the absence of any competitor, storage can easily buy and store the excessive power. When there is a power deficit, storage offers the stored energy again at zero price. The cheap storage price ensures that storage stays in the market when cleared and sells the power prior to more expensive conventional competitors. One may realize that utilizing the offshore wind farm with a storage

unit makes the operation of wind farms more flexible; on one hand they are in less need for sending power to far locations when there is a power excess, or when there is demand deficit in the local country. On other, they provide more power to offer when power is in deficit especially to the local onshore centers.

As the investment cost of energy storage is neglected, the model takes the opportunity to increase the flexibility of offshore zones by constructing as large storage capacities as required. At the same time it decides to increase the capacity of short distance connections (i.e., radial connections) and decreases the capacity of long distanced ones (i.e., cross-border connections) to reduce the investment cost of building the grid. One can see, the outlined amendments increase the share of offshore wind energy in power consumption of onshore regions during the peak load hours, which in turn increase social welfare even further comparing with the NES scenario.

Table 4 Incremental Social Welfare and Transmission Investment Cost over 25 years in billion Euros – under No Energy Storage (NES), Limited capacity Energy Storage (LES) and Unlimited capacity Energy Storage (LES) scenarios – Input: High price difference

	NES	LES	UES
Aggregated Social Welfare(B €)	295.53	296.42	305.47
Total transmission Investment Cost (B €)	17.49	17.47	17.28

From Table 4 one can observe that for the net importer regions (Germany and the UK), incremental social welfare increases from NES to UES scenario, and vice versa for the net exporter (Norway) .This observation is in line with the nodal price variations of these regions. Under UES, nodal price of Germany and UK decreases, while nodal price of Norway increases (Table 2)

 Table 5 Standard deviation of nodal price under Ex-Ante (before building the grid), No Energy Storage (NES), Limited capacity Energy Storage (LES) and Unlimited capacity Energy Storage (LES) scenarios – Input: High price difference

	NES	LES	UES	Ex-Ante
Germany	9.69	9.42	7.78	12.43
Norway	8.54	8.03	5.06	0.86
UK	6.97	6.79	4.30	8.40

Nodal price variation is another significant difference between NES and UES. As can be seen in Table 5 under UES nodal prices are less volatile and have lower fluctuations (so called smoothing effect). Figure 13 visualizes the influence of energy storage on price variations of nodal price in Germany.

Nodal price variations of Germany under the three storage scenarios are shown in Figure 13. The blue, red and green line represent NES, LES and UES scenario, respectively. One can observe that under UES, nodal price has smoother variations. This trend can be explained by looking into the operation of the storage.



Figure 13 Nodal price variations of Germant under No Energy Storage (NES), Limited capacity Energy Storage (LES) and Unlimited capacity Energy Storage (LES) scenarios – Input: High price difference

Energy storage is charged when the price is high and discharged when it is low. Figure 14 shows the charge/discharge profile of energy storage of Germany under UES scenario. The red arrows show whether the storage is getting charged or discharged. The positive values show that energy storage is at charging mode. This power flow is assumed to remain constant during each hour, and so is represented by red dashed lines in the figure. The blue curve shows the level of stored energy in the storage ( $SEC_i^t$ ) at the end of each hour. The energy level of storage increases constantly during charging hours. As an example, if storage constantly charges 1MW for one hour, at the end of the period the energy level would increase by 1MWh. Finally, the green line shows maximum energy level reached by the storage which we set as the storage capacity.



Figure 14 Energy storage charge/discharge profile under UES - Germany

By comparing Figure 13 and Figure 14 one may observe that when energy storage is charging, nodal price under UES scenario goes higher than NES scenario. In other words, energy storage influences the nodal prices by increasing the price at charging mode and the opposite during discharging. The same discussion holds for the UK as the other power exporter country. The relevant figures for the UK are present in Appendix II.

The Norwegian storage has a different charge/discharge profile. As Norway is a net power exporter, its energy storage does not provide power for the country. Therefore, charge/discharge profile of Norwegian storage does not follow the nodal price variations in the country. It rather tracks price variations in the two – importing- neighboring countries.

#### Limited Capacity Energy Storage (LES)

The optimization simulation for LES scenario results in similar observations as UES scenario. Transmission capacities, nodal prices and social welfare follow the same trend as moving from NES to UES scenario. However, as the capacity of energy storages are fixed at relatively small value, the influence of energy storage is not significant. Therefore, here we limit the explanations to the two extreme cases (i.e., NES, UES) which show the impact of energy storage more effectively.

#### Remuneration of offshore Wind farms and energy storages

Here we determine the remuneration of the offshore wind farms and energy storages. Remuneration is the compensation the region receives in exchange of the service it provides. It is the aggregated amount money it gains over a period by injecting power to the rest of the system and read as follows:

$$Remuneration_{i} = \left(\sum_{t=1}^{48} P_{i}^{t} * Price_{i}^{t}\right)$$

Where  $P_i^t$  is the power injection of zone "i" (either energy storage or offshore wind farm) and  $Price_i^t$  is the nodal price of that zone.

Table 6 presents the annualized remuneration for the offshore wind farms and energy storages, in million euros per year (M $\notin$ /yr). Under UES scenario, wind farms remuneration slightly decreases (1.1% for Germany, 0.8% for Norway and 2.4% for the UK). That is due to the decrease in the nodal prices from NES to UES scenario. This change is negligible from NES to LES scenario due to small influence storages have on nodal prices under this scenario.

Table 6 Annual Remuneration of Offshore Wind Farms and Energy Storages in million Euros -- under No Energy Storage (NES), Limited capacity Energy Storage (LES) and Unlimited capacity Energy Storage (LES) scenarios – Input: High price difference

Scenario	No Energ (N)	y Storage ES)	Limited Capaci	l Storage ty (LES)	Unlimited Storage Capacity (UES)	
Onshore zone	Wind Farm	Storage	Wind Farm	Storage	Wind Farm	Storage
Germany (M €)	2225.11	-	2225.67	12.75	2199.96	0
Norway (M €)	591.28	-	593.30	8.32	586.66	0
UK (M€)	4507.62	-	4509.40	9.22	4400.68	0

#### Remuneration of energy storages

In spite of the great impact they have, remuneration of energy storages is zero under UES scenario. This observation is in accordance with the way energy storage is modeled in our formulation: We incorporate energy storage as a non-for-profit entity that is only beneficial to the society. It can be seen in equation (chapter 3- pricing mechanism) that the total payment of the onshore regions pays for remuneration of the offshore entities and investment cost of the transmission infrastructures. Therefore, for a same grid design, lower remuneration of offshore entities imposes lower payments on onshore zones. It would be ideal for onshore regions to have social welfare increase for free. This is the case under UES where storage induces a large increase in social welfare. It is dispatched in such a way that the revenue from selling electricity at high price hours recovers the cost of buying the electricity at low price hours.

As the capacity of energy storages is limited under the LES, it is not possible for them to store as much energy as it is required for later use. This affects the onshore market in two ways:

- 1. Induce higher nodal price in onshore regions, as less power will be available during the peak hours
- 2. Higher investment cost of building more expensive large distanced cross boarder interconnectors

The higher price implies higher nodal payment especially during the peak hours. The limited capacity of storage implies that storage does not have enough power to fulfill a complete power cycle, in similar way to UES. Hence a part of storage cost has to be recovered through the society in the form the nodal payments. It is important to note that considering the investment cost of building energy storages based on prices of today ( $20 \notin kWh$ ) [25], energy storages are not cost effective.

One important issue regarding energy storage investment cost is that there is not a fixed value for energy storage investment cost. Current large scale energy storage technologies have not reached their maturity in the market, so any cost that we assume as the investment cost may change drastically in the coming years. Moreover, todays values for storage investment costs are so large that incorporating them into the objective function greatly affects the design and skew the results.

#### 4.3.2 Input set 2: High Wind

This section presents the optimal grid designs for the second set of two representative days (section 4.1) under the three energy storage capacity scenarios (section 4.2).

#### Grid design

Figure 15 shows the grid design for the first input set of the two windy days in January. The sub figures a, b and c are associated with the three energy storage scenarios: No Energy Storage (NES), Unlimited Energy Storage capacity (UES) and Limited Energy Storage capacity (LES).

The very first observation from the figures is, for all storage scenarios, the optimization model opts for radial connections from offshore wind farms towards the respective onshore regions. Besides, as the arrows show, all three onshore regions are net power importers under all energy storage scenarios.



Figure 15 Optimal grid design under NES, UES and LES - Input set: High wind

The radially connected grid topology implies that there is no incentive for the regions to build cross-national transmission capacities. The motivation towards cross-national power exchange comes from nodal price differences. As this set of input data is selected based on the wind abundance (so called wind availability factor (WAF)) and not the price differences, it is observed that for the selected period the price difference are small. The best optimal design the model derive is the radial plotted in the figure above.

#### No Energy Storage (NES)

One may note that under NES, every radial interconnector has a capacity equal to the maximum power generation of the associated wind farm Therefore the wind farms are subjected to no power curtailment.

#### Unlimited Capacity Energy Storage (UES)

Similar to the first input set (4.1.1), the capacity of interconnectors increases in under UES scenario. The largest increase in the capacities is for Norway, with 447%, followed by of the UK with 64% increase, and Germany with 10%. Moreover, the model assigns extremely large capacities to energy storages under UES scenario as follow: 56GWh for Germany, 57.44GWh for Norway and 134.5 GWh for the UK.

When energy storage with 57.44GWh capacity is connected to Norwegian offshore wind farm, the capacity of the associated connection is increased. It implies that onshore region of Norway imports more power compared to NES scenario. The same observation can be hold for the other two countries. It can be said that integrating energy storage into the grid encourages higher penetration of wind production in onshore zones. The large import under UES scenario induces an increase in incremental social welfare of all onshore zones (see Table 9) and a decrease in their average nodal price (Table 7) compared to NES.

#### Limited Capacity Energy Storage (LES)

Under LES scenario, capacity of radial interconnector in Norway increases by 37% comparing with the NES scenario. On the contrary, the capacity of radial interconnectors of Germany and the UK remain more or less intact. It shows that there is no incentive for Germany and the UK to import more power from the offshore wind farms. Limited capacity of energy storage (1GWh) is not as influential as offshore wind capacities are in determining the final design of the grid.

As Table 9 shows, incremental social welfare of Germany and the UK follow a similar trend as to those explained for high price difference period. That is, building the grid results in lower market price in onshore regions. Integrating offshore storages reduce the price slightly further.

On the other hand, transmission capacity of Norway increases by 1GW from NES to LES scenario. This increase is exactly equal to the maximum power the respective energy storage provides (the power that the energy storage with 1GWh is able to provide by discharging its total capacity in one hour). As Norway's offshore capacity is not very large (2GW), the country imports more offshore wind power with lower price to decrease its average price (see Table 7) and increase its social welfare (see Table 9).

Table 7 Nodal price of onfshore and offshore regions [€/MWh] of Germany, Norway and the UK - under Ex-Ante (before building the grid), No Energy Storage (NES), Limited capacity Energy Storage (LES) and Unlimited capacity Energy Storage (LES) Input set: High wind

Region	Scenario	Ex-Ante	NES	LES	UES
	Germany (€/MWh)	58.04	38.53	38.51	38.00
Nodal Price of Onshore zones	Norway (€/MWh)	50.08	42.50	42.87	43.62
	UK (€/MWh)	48.39	32.96	32.95	31.07
Nodel Price of	Germany (€/MWh)	0	37.41	37.21	36.88
Offshore wind	Norway (€/MWh)	0	41.18	45.04	42.30
1411115	UK (€/MWh)	0	32.58	32.61	30.69

By comparing the average Ex-Ante and NES price in Table 7, one observes decreasing trend in average nodal price of Germany and the UK against level of storage integration. When onshore region of Germany and the UK is connected to their respective offshore wind farm radially, large amount of wind power with low price is fed into the onshore region which causes a decrease in the nodal prices. However, the average nodal price of Norway does not change when the region is connected to the wind farm.

Table 8 shows the standard deviation of the nodal prices for the three energy storage scenarios (NES, LES, and UES), as well as for the scenario when the grid is not built (Ex-Ante). Comparing NES scenario with Ex-Ante, one observes that in this period of time, building the grid with no storage, or with limited capacity of storage does not have a noticeable influence on the price fluctuations. However, when energy storage with unlimited capacity is integrated into the grid, there is a significant drop in the standard deviation of the nodal prices

 Table 8 Standard deviation of nodal price under No Energy Storage (NES), Limited capacity Energy Storage (LES) and Unlimited capacity Energy Storage (LES) Input set: High wind

Scenario		<b>Ex-Ante</b>	NES	LES	UES
Nodal Price	Germany (€/MWh)	10.70	10.87	10.14	4.77
Standard Deviation	Norway (€/MWh)	22.44	22.44	22.14	10.91
2 C Flutton	UK (€/MWh)	14.12	13.11	12.79	2.45

#### Social welfare and transmission investment cost

Table 9 shows that integrating more higher level of energy storage increase the aggregated incremental social welfare of all regions. In contrary to the previous case, here higher level of energy storage integration increases the investment cost of building the grid as well. The reason is, here we only have radial connections. Increasing the capacity of offshore radial connections, increase investment cost of building he grid. However, in this case there is no cross boarder capacity to be excluded or weakened, therefore the investment costs increase up to 100%

Table 9 Incremental Social Welfare and Transmission Investment Cost over 25 years in billion Euros – Under No Energy Storage (NES), Limited capacity Energy Storage (LES) and Unlimited capacity Energy Storage (LES) Input set: High wind

Scenario Country	NES	LES	UES
Aggregated Social Welfare (B €)	257.5	263.1	290.9
Total transmission Investment Cost (B €)	0.289	0.274	0.456

Table 10 presents the incremental social welfare distribution among the three onshore countries for the three storage integration scenarios. As outlined above, all countries are net power importers and so benefit from building the offshore grid. Once again, increasing the storage capacities reinforces the radial connections and increase the utilization of the radial connection to a large extent.

Table 10 Incremental Social Welfare Distribution of Each Onshore Region over 25 years in billion Euros – Under No Energy Storage (NES), Limited capacity Energy Storage (LES) and Unlimited capacity Energy Storage (LES) Input set: High wind

Scenario Country	No Storage	Limited Storage Capacity	Unlimited Storage Capacity
Germany (B €)	137.2	123.8	129.1
Norway(B €)	0.00	18.4	28.6
UK (B€)	120.3	120.9	133.2

The importance of the time period selection can be well seen by comparing the results of the two representative input sets. One can recognize a large difference in the grid design: Under the high wind scenario the design is radial connection topology with large local transmission lines connecting each offshore wind farm to its associated onshore region. While, for the high price difference scenario the design is mesh grid topology, in which regions with higher price (Germany and UK) have more tendencies to import power from the region with lower nodal price (Norway).

Besides the overall grid configuration, capacities of the regional "onshore to wind farm" interconnector vary largely from one representative input data set to another. For the first set of input, two windy days in January, capacities of "onshore to wind farm" interconnectors are larger than for the second period, two days in September with lower average wind speed. The difference is more significant under the UES scenario.

## 5. Conclusion

Variable and non-dispatchable nature of wind energy imposes substantial challenge for power system planning and operation. Depending on the economic potential and considerations, transmission reinforcements or energy storage integration are considered as viable solutions. An optimal solution is expected to create new capacities for conducting cross-national power exchange and exploit offshore wind energy as efficiently as possible, at the same time, contribute positively to social welfare of onshore price zones.

In this work we take a market based approach to investigate the influence of large-scale integration of energy storage on long term transmission planning of VSC- HVDC based grid. We introduced a multi-time period static non-convex optimization framework considering physical constraints of the system. We model energy storage as a not-for-profit entity and neglect its investment and operational cost. To better illustrate the impact of storage on grid development, we compare three different scenarios for energy storage capacities: Unlimited capacity Energy Storage (UES) – idealized case – and Limited capacity Energy Storage (LES) – realistic case – and No Energy Storage scenario (NES) – base case.

The optimization solver determines the optimal grid topology and transmission and energy storage capacities. It also solves the problem of optimal power flow and determines power dispatch of every price zones for every hour. One remarkable feature of the proposed approach is that it accounts for all operating states in one go. Therefore, it captures the impacts of the past and the future operating states on energy storage operation.

The analytical solution to the optimization problem gives the pricing mechanism. It is a formulation that expresses the relation between nodal prices, power flows over interconnectors and associated congestion shadow prices. Formulating the problem as stated above, shows that for an optimal grid design transmission revenues will thoroughly recover investment cost of building the grid till the end of economic life time of the project. It also shows that under UES scenario, the nodal price of the storage at each hour is affected by the marginal prices of that unit in the future (proceeding hours). That is, charge/discharge cycle of the storage in the future hours influences its nodal price. Under LES, the nodal price of energy storage at every hour depends on the penalty charge associated with reaching the maximum storage capacity on Lagrangian multiplier associated with constraint regarding maximum capacity of energy storage as well as on the future nodal prices.

The grid topology is observed to be highly sensitive to the input selection. The model determines a radial topology for the high wind period and a meshed grid for the high price-difference period. Transmission capacities, on the other hand, are mainly affected by level of storage capacity. The abundant wind, available during high wind period, results in the radial topology and makes the onshore zones net importer of energy. Increasing the storage capacity makes a small increase in social welfare and decrease in average nodal prices. It also results in an increase in the capacity of radial connections by about 447% (Norway, under UES scenario).

For the meshed grid design determined from the high price difference period, however, we observe a trend towards constructing larger radial connections between each country and its respective offshore wind farm with the increase in the level of storage integration. The cross border connections, in an opposite way, are weakened. Therefore, integrating more storage

capacity results in less meshed and more radial grid design. It implies that countries would be less interdependent as more energy storage capacity would be integrated into their national power system.

During this period, Norway is a net exporter and therefore significantly loses benefit. Even the large Norwegian storage capacity under UES scenario does not alter the situation. It rather contributes to help the country providing relatively cheap energy for Germany and the UK. These two countries, on the other hand, are pure importer of energy.

Integrating energy storage in general results in higher social welfare and lower nodal prices in all regions, including offshore nodes. It also results in lower remuneration for the offshore wind farms. Moreover, it flattens the price profile of onshore regions, so make the nodal price more predictable.

The discussion on investment capita of energy storage shows that it should be less costly to be cost effective. With current market prices, energy storage is not economically efficient to decide on future development plans of a grid, with regard to the contribution of energy storage systems on market operation.

The proposed market mechanism provides an economic insight into the operation of a multiterminal HVDC offshore grid. The results support transmission system planners and private investors on their decisions regarding the size of transmission and storage infrastructures.

In the future we would like to study the impact of integrating energy storages on operation of intraday and balancing markets. We would also like to investigate the impact of storage on social welfare increase of onshore zones for a given grid design.

The proposed methodology is computationally costly. It is not applicable to real world problem unless the computation burden be kept low by reducing the size of the input set to the solver. It can be done through a clustering algorithm that determines the most representative operating states at the same time, maintain the temporal order of occurrence of events.

Finally, it seems reasonable to derive a more accurate mathematical model of energy storage that reflects the technical difference between different storage technologies. Also, the model for energy storage can be improved by employing a more robust optimization approach that accounts for inter-temporal constraints on generations (e.g., ramp rate).

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## **Appendix I**

Energy Storage and Wind Farm as a Single Node (Integrate ES into the offshore wind farm node)

We incorporate energy storage to save the excess not-dispatched wind power during high wind hours, and use it during low wind hours. Energy storage charge and discharge depends on wind farm power generation and dispatch. The amount of energy used for storage charge/discharge is referred to as wind power surplus ( $\Delta P(t)$ ) in our formulation. If wind power surplus is positive storage is charging, and if it is negative it is discharging. In each time step this wind power surplus is calculated depending on power generation and injection.

For each time step, wind power surplus is a variable of the available wind at that time step (Pi(t)), injection power from the wind farm at that time step (PG(t)), and the maximum allowed wind curtailment (MAC). For each time step, the model has the freedom to curtail maximum amount of (1-MAC) \* PG(t). During the high wind hours, after applying this curtail to the generated power, the extra wind power that is not dispatched during that time step will be sent to the storage.



which value is calculated as:

$$\Delta P(t) = PG(t) * (1 - MAC) - Pi(t)$$

If the injection power is within the window of allowed curtailment, (1-MAC)PG<Pi<PG, wind power surplus which should be sent to energy storage gets zero value. Therefore, energy storage will be charge or discharge during that time step.



During low wind hours the value of injection power is more than the value of wind generated power. In those time steps, wind power surplus will get negative value and energy storage will be discharged with  $\Delta P(t) * \Delta t$ . Value of  $\Delta P(t)$  is calculated as:



Energy storage accumulate this power surplus over time. By the end of each time step energy level of the energy storage, referred to as storage energy content (SEC(t)) in this work, is calculated as:

$$SEC(t) = SEC(t-1) + \Delta P(t)$$

In which SEC(t) reflects the current level of stored energy in the storage by the end of period t, and SEC(t-1) reflects level of stored energy in the energy storage at the beginning of period t.

## **Appendix II : Plots**

*Nodal price variations for Norway and the UK, under NES, UES and LES, for input set1 (high price difference)* 



## Storage Energy content (SEC) for Unlimited Energy Storage scenario (UES) for input set1 (high price difference)



## Storage Energy content (SEC) for Limited Energy Storage scenario (LES) for input set1 (high price difference)



