Vers une organisation mondiale des marchés de l'électricité.

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Towards a global electricity market

Master thesis realised with the aim of obtaining the degree of Master in electromechanical engineering

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Abstract

Recent years have shown an increase of CO_2 emissions, indicating that the strategies that have been set up in the last few decades to decarbonise our economies are failing. If solar and wind energies have to play a role in the energy transition, their deployment should be literally massified in the coming years before it becomes too late regarding climate change issues. As a possible solution to decarbonise the energy sector, one could imagine harvesting high quality renewable energy in remote locations where the potential is enormous such as in Greenland. This work stands within this context, and focuses on the evaluation of the potential benefits of harvesting energy from Greenland, assuming interconnections between North America, Greenland and Central Western Europe (CWE).

A sizing algorithm is proposed in order to optimise the installed capacity of wind farms as well as the HVDC links to repatriate energy to large load centres when Greenland is considered as a potential production hub. The Greenlandic region could be connected with Central Western Europe region and/or with North America. This interconnected model represents a hybrid model, because it contains subsystems whose market design is different. Indeed, the market design in the CWE region is zonal pricing and the market design in the region of the North America considered is nodal pricing. The main evaluation criterion is the total annual cost of the system.

A zonal pricing and a nodal pricing algorithms are run to determine the reference total cost of the CWE and North America regions when no interconnection is considered. From these reference scenarios, the possibility to install HVDC links, wind farms and/or storage units in Greenland are added to the system. The aim is to determine the total cost of the system when such installations are allowed. Simulations show that, under certain assumptions, an interconnection with the Greenland can lead to a decrease of the total annual cost up to 8%.

Another benefit of the Global Grid approach is highlighted via a CO_2 analysis. The objective of the optimisation problem is modified. The total CO_2 emissions replace the total cost of the system. The global CO_2 emissions are widely reduced thanks to the Global Grid approach for two main reasons : The CO_2 emissions of the wind farms in Greenland is negligible compared to the most polluting generators and the HVDC links allow to use less the most polluting units. The simulations show that when 50 GW of wind farms are installed in Greenland, the CO_2 emissions of the system are already reduced by 32%.

Finally, as there is also a wind potential in the European sea basins, the compromise between investing in Greenland and/or in European sea basins is studied. The optimisation problem is upgraded in order to allow the system to build offshore wind farms near the European continent. The installed capacities of the onshore wind farms near the European continent and the offshore wind farms in Greenland are optimised. The simulations show that there is interest to invest in European sea basins when the Levelized Cost of Energy of the project is below 61.54 €/MWh.

The sizing algorithm developed for this report allows the optimisation of a hybrid model. The total cost of the system could be minimised by installing storage units, HVDC links and wind farms in remote locations.

Acknowledgment

It has been a first experience for me to conduct such a long-term work that has also allowed me to be immersed in the world of research. Defining my own project, from the questions to the tools used to answer them, has been highly challenging at times and I definitely would not have been able to complete this thesis without support.

First, I would like to express my gratitude to my supervisor Professor Damien Ernst for giving me the opportunity to work on such an exciting topic.

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Moreover, I am deeply grateful to my family and Anouchka that have provided unwavering moral support all along the ups and downs. My thesis being also the conclusion of my five years of study, I feel particularly lucky that they have been so encouraging and stimulating during all this time, whichever way I went.

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List of Acronyms

- **ATC** Available Transfer Capability
- **CAPEX** Capital expenditure
- **CWE** Central Western Europe
- **ENTSOE** European Network of Transmission System Operators for Electricity
- **FBMC** Flow Based Market Coupling
- **HVDC** High Voltage Direct Current
- **JAO** Joint Allocation Office
- **LCOE** Levelized Cost Of Energy
- **LMP** Locational Marginal Prices
- **MAR** Regional Atmosphere Model
- **OPEX** Operational expenditure
- **PJM** Pennsylvania New Jersey Maryland Interconnection LLC
- **PTDF** Power Transfer Distribution Factor
- **RAM** Remaining Available Margin
- **TSO** Transmission System Operator

List of symbols

- N_n Number of nodes
- N_z Number of zones
- N_L Number of transmission lines
- N_G Number of generators
- $P_{ij,max}$ Line maximal capacity
- P_D Load
- P_G Generation schedule after market clearing
- P_G^{max} Maximum generation capacity
- P_G^{min} Minimum generation capacity
- x_{ij} Reactance of the line connecting the node i and the node j
- B_{bus} Bus Admittance Matrix
- δ Bus voltage angle
- C_G LCOE cost of generators
- P_A Aggregated power production per node/zone
- B_{line} Line Susceptance Matrix
- b_{ij} Suscpetance of the line connecting the node i and the node j
- Λ_L Set containing all transmission lines (hors HVDC)
- F_i^{max} Line maximal capacity
- T Number of hours considered
- Θ_z Set containing all zones
- Θ_n Set containing all nodes
- Λ_z Set containing all HVDC links between Greenland and the zonal model
- Λ_n Set containing all HVDC links between Greenland and the nodal model
- $P_{GR\rightarrow N}$ Power flow between Greenland and the nodal model
- $P_{N\rightarrow GR}$ Power flow between the nodal model and Greenland
- $P_{GR\rightarrow Z}$ Power flow between Greenland and the zonal model
- $P_{Z\rightarrow GR}$ Power flow between the zonal model and Greenland

- P_{inst} Installed capacity of wind farms
- P_{Tr} Installed capacity of HVDC links
- C_{capex} Capex cost of wind farm
- C_{opex} Opex cost of wind farm
- Δ_{Tr} Lifetime of HVDC links
- Δ_{W} Lifetime of wind farms
- Δ_{ST} Lifetime of the storage units
- C_{ST} Installation cost of the storage unit
- P_{ST} Installed capacity of the storage unit
- E_{ST}^{min} Minimum stored energy of the storage unit
- E_{ST} Stored energy in the storage unit
- P_{ST}^{d} Output power of the storage unit
- P_{ST}^{c} Input power of the storage unit
- $P_{ST}^{d,max}$ Maximum output power of the storage unit
- $P_{ST}^{c,max}$ Maximum input power of the storage unit
- β Binary variable equal to 1 if the storage unit is being charged and to 0 if the storage unit is being discharged
- η_c Charge efficiency of the storage unit
- η_d Discharge efficiency of the storage unit
- $CO_{2,Tr}$ CO_2 emissions attributed to HVDC links
- $CO_{2,G}$ CO_2 emissions associated to the energy production
- W_{wind} Wind speed
- $\mathcal{L}$ Set containing all offshore locations
- α Losses factor
- $P_{O\rightarrow Z}$ Power flow between offshore locations and the zonal model
- R_{100m} Resulting wind speed
- U_{100m} Eastward wind speed
- W_{100m} Northward wind speed

1 Introduction

At the genesis of this study was the following question: Is the interconnection between Europe, Greenland and North America, in the context of a Global Grid, profitable from an economic point of view? To answer this question, a representative model for Greenland, North America and Europe has to be created. The network part holds by PJM is used as reference for North America and Central Western Europe (CWE) is used as reference in Europe.

After the building of the models, a multi-period market clearing algorithm is proposed in order to perform the market coupling for this hybrid model and determine the potential interest of such interconnection. High Voltage Direct Current (HVDC) links are used to connect the different regions. The Greenland region is used as a potential production hub, where huge wind farms and storage units could be installed. Using cost assumptions, the multi-period market clearing algorithm computes the total cost and the prices inside each region.

The first step is to perform the market coupling for the PJM and the CWE models when they are isolated. The aim of these simulations is to determine a reference case for each model. This could be done by solving a nodal pricing model for the PJM model and by solving a zonal pricing model for the CWE model. The next step is to couple both markets separately with the Greenland. This provides more information about the potential of the interconnections.

By adding the installation cost of wind farms, storage units and HVDC links, the algorithm could be used to size these three parameters. Simulations could bring to light the interest of the multiple interconnections as allowing power transfers between the PJM and the CWE regions and permitting potentially the wind farm holder to sell the produced electricity at the peak price most of the time due to the jet lag.

In parallel to this, another benefit of the Global Grid is investigated. Under CO_2 emissions assumptions, the multi-period market clearing algorithm is refined with the goal to minimise the total CO_2 emissions of the hybrid system. The aim is to determine the potential reduction of CO_2 emissions.

Finally, a comparison between a massive investment in Greenland and in offshore wind farms in the European sea basins is analysed. The aim is to determine the Levelized Cost Of Energy (LCOE) of the offshore wind farms that need to reach a project to compete with onshore wind farms in Greenland.

The report is organised as follows: Section 2 provides an overview of the related works. Section 3 describes the three market designs cover in this project. Section 4 describes the optimisation problems that are created to perform the market clearing. Section 5 explains how the data required to create the three models were collected. In section 6, the results provided by the market clearing algorithm are analysed. Section 7 analyses the potential in the European sea basins.

2 Related works

The Global Grid approach to the energy transition has stimulated more and more research. The idea of realising intercontinental interconnections is not totally new. More than 20 years ago, [4],[5] were discussing the possibility of harvesting “cheap” energy from remote locations for powering the world, in particular by connecting Russia and North America or Europe and Africa and taking advantage of the time zones and seasonal diversity. In [6], the authors focus on the optimisation of such a solar- and wind-based energy system, both at a European level and a global level, in terms of generation, transmission, and storage capacities for different scenarios of highly renewable energy supply.

Two more recent papers were proposed by Chatzivasileiadis, Ernst and Anderson in 2013 [7],[8]. They further develop the global grid vision, taking into account more recent technological improvements (in particular HVDC links), and discuss the opportunities that may be offered by the global grid in terms of smoothing the intermittency of generation from renewables, reducing the need for large-scale storage capacities, as well as reducing the volatility of electricity prices.

Radu, Berger and Fonteneau recently proposed a new methodology for assessing the complementarity between renewable energy sources based on the notion of critical time windows [9]. This approach has already been used to evaluate the complementarity between Europe’s wind and Greenland’s winds [10].

The specific interconnection between the North America and Europe was studied by [11] and [12]. In [12], the authors describe the methodology to simulate an interconnected global power system with highly technical and temporal resolution. The case study they simulate interconnect the European model and the North-American model. In [11], a techno-economic analysis is performed for an interconnection size of 4 GW. The authors conclude that build a cable between Europe and North America could bring an annual socio-economic benefit of 177 M€.

3 Market Designs

The Electricity grid is a natural monopoly, because one company with a large interconnected transmission grid can transmit power more efficiently than several companies could [13]. Therefore, there is no possibility of competition in this market. This implies that the Transmission System Operator (TSO) is controlled by the public authorities to ensure fair access for all participants.

The transmission lines have a limited transmission capacity. In order to allocate this scarce resource efficiently, several congestion management methodologies have been developed. Most market designs fall into one of the three categories : nodal marginal pricing, zonal pricing or explicit capacity auctioning [2]. For this study, the nodal pricing and zonal pricing are considered.

3.1 Nodal pricing

In an electricity market with nodal market clearing, all relevant physical transmissions are taken into account in the market clearing algorithm. This implies that the commercial flows could be directly translated into physical flows. Thus, the capacity allocation happens simultaneously with the market clearing [1].

Practically, the market operator receives bids from sellers and buyers and clears the market, taking into account all network constraints. The price that receives the generators varies with respect to their location. Congestion in nodal market leads to difference in price at every node. This price signal is an incentive for the generators to increase their generation capacity at this node. The main drawback of nodal pricing is that generators located downstream of a congested line have market power.

3.2 Zonal pricing

A zonal market considers zones instead of all nodes. This means that a certain number of nodes are aggregated to create a zone. The network constraints inside a zone are not considered during the market clearing. This leads to uniform price within a zone. The difference in zonal pricing is that only transmission constraints between zones are considered.

For zonal pricing, there are mainly two kinds of capacity management methodology : Market Splitting and Flow Based Market Coupling (FBMC). Only the Flow Based Market Coupling is tackled in this study.

This methodology is used in the Central Western Europe's day-ahead market. Major features are the neglection of intra-zonal transmission constraints and the aggregation of parallel inter-zonal transmission lines [2]. Therefore, the complexity is decreased for the zonal market model because only a few lines are considered. These lines are called critical lines.

In FBMC, all critical lines are taken into account during the market clearing. For each line, two main parameters need to be taken into account : the Remaining Available Margin (RAM) and the zonal Power Transfer Distribution Factors (PTDF). These parameters are determined ex ante by the TSO. The determination of the PTDF matrix and the RAM is not tackled in this study, they are directly retrieved from [14]. More information about the determination of these parameters can be found in [15] and [1].

The two parameters RAM and PTDF define the flow domain for the FBMC methodology. The flow domain of the FBMC methodology is larger than the Available Transfer Capability (ATC) flow domain as seen in Figure 1. The FBMC methodology is chosen in the CWE because the Flow Based Market Coupling has a positive impact on the market compared to ATC market coupling [16].

3.3 Hybrid pricing

The concept of the hybrid market was already introduced by [17] and [18]. The hybrid pricing model is a concept for which the market is divided into different subsystems, where some apply zonal pricing and others apply nodal pricing. The difference in this study is that the congestion management scheme used is the FBMC for the zonal market. The Locational Marginal Pricing is

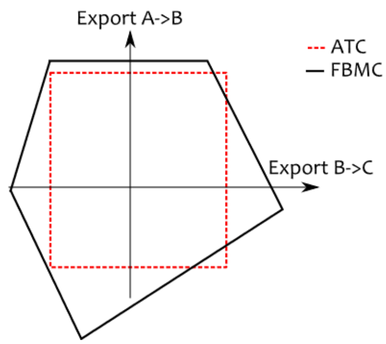

Figure 1 – Flow domain [1].

used for the nodal model. Furthermore, an additional region (Greenland) is used to connect both markets. In this last region, there is no load, but a huge production potential.

4 System modelling

In this section, the mathematical models of the market designs discussed in the section 3 are explained. The aim of the optimisation problem is to compute the market equilibrium. This process is called market clearing. The resulting market clearing price p_m is such that the quantity that the suppliers are willing to provide is equal to the quantity that the consumers wish to obtain [13]. The Figure 2 shows a graphical representation of the market clearing.

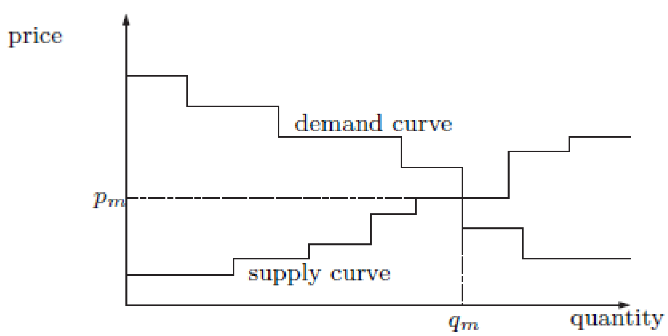

Figure 2 – Pricing in a Day-Ahead market with q_m the market clearing and p_m the market clearing price [2]

The market clearing can be performed by using the power flow equations. The original power flow equations for AC systems are non-linear equations of complex numbers. Indeed, there is a quadratic relationship between the voltage and power. Therefore, to avoid dealing with non-linear equations, linearised form of the power flow equations are used. This form is referenced in the literature as 'DC Power Flow Equations'.

The linearisation of the power flow equations can be obtained using the following assumptions [19] :

- Voltage constant and at nominal value (1 p.u.)
- Angle differences are small
- The resistance is significantly less than the reactance

4.1 DC Power Flow Equations

To explain the general DC Power Flow Equations, let us define the basic variables required. Consider a hypothetical network containing N_n nodes, N_L lines and N_G generators. The topology of this network is supposed to be known as well as the load at each node $P_D \in \mathbb{R}^{N_n}$, the line maximal capacity $P_{ij,max} \in \mathbb{R}^{N_L}$ and the production limits of the different generators $P_G^{min}, P_G^{max} \in \mathbb{R}^{N_G}$. x_{ij} is the reactance of the line connecting the node i and the node j. $B_{bus} \in \mathbb{R}^{N_n X N_n}$ is the bus admittance matrix which is calculated as described by Equation 4.1.

$$B_{bus,ij} = \begin{cases} \sum_{k=1}^{N_n, k\neq i} \frac{1}{x_{ik}} & if\ i = j \\ -\frac{1}{x_{ij}} & if\ i \neq j, x_{ij} \neq 0 \\ 0 & if\ i \neq j, x_{ij} = 0 \end{cases} \tag{4.1}$$

The production of the generators $P_G \in \mathbb{R}^{N_G}$ and the bus voltage angle of each bus $\delta \in \mathbb{R}^{N_n}$ are optimised in order to minimise the total cost of the system. The associated production cost $C_G \in \mathbb{R}^{N_G}$ is known. One node has to be chosen as reference. At this node, the bus voltage angle is imposed to be zero. This bus is called the slack bus. To simplify the notation, the aggregated production power per node is denoted by $P_A \in \mathbb{R}^{N_n}$.

The general form of the DC-OPF is the following. The aim of the optimisation problem is to minimise the generation cost of the power system (Equation 4.2). The production limits of the generators are enforced by Equation 4.3. The Equation 4.4 ensures the power equilibrium and the Equation 4.5 ensures the power flow in each line doesn't exceed the thermal limit of the line.

$$\underset{P_G,\delta}{\text{minimize}} \qquad C_G^T P_G \tag{4.2}$$

subject to :

$$P_G^{min} \leq P_G \leq P_G^{max} \tag{4.3}$$

$$B_{bus}\delta = P_A - P_D \tag{4.4}$$

$$-P_{ij,max} \leq \frac{1}{x_{ij}}(\delta_i - \delta_j) \leq P_{ij,max} \quad \forall\ lines\ ij \tag{4.5}$$

The DC-OPF has the power generation P_G and the voltage angle δ as optimisation variables. In our case, there is no interest to compute the bus voltage angle, because we focus on an economic analysis. To avoid the optimisation of the bus voltage angle, the DC-OPF can be rewritten using the Power Transfer Distribution Factor (PTDF). The necessary steps to obtain the PTDF version of the DC-OPF are the following [19].

Before computing the PTDF matrix, the Line Susceptance Matrix $B_{line} \in \mathbb{R}^{N_L X N_n}$ needs to be defined. The susceptance b_{ij} is the susceptance of the line connecting the node i and the node j. The Line Susceptance Matrix is described as :

$$B_{line,ij} = \begin{cases} \sum_{k=1}^{N,k \neq i} \frac{1}{b_{ik}} \quad if \ i = j \\ -\frac{1}{b_{ij}} \quad if \ i \neq j, b_{ij} \neq 0 \\ 0 \quad if \ i \neq j, b_{ij} = 0 \end{cases} \tag{4.6}$$

The PTDF matrix is defined as the product of the Line Susceptance Matrix and the modified Bus Reactance Matrix :

$$PTDF = B_{line} \tilde{B}_{bus}^{-1} \tag{4.7}$$

The Bus Reactance Matrix needs to be modified to be inverted. Per definition, this matrix is singular and thus not invertible. The following procedure is used to obtain $\tilde{B}_{bus}^{-1}$:

1. The row and the column that correspond to the slack bus are deleted to form the matrix $\tilde{B}_{bus}$. The dimension of this matrix is $N - 1 \times N - 1$.
2. Invert the matrix $\tilde{B}_{bus}$.
3. Add a row and a column of zeros that correspond to the slack bus. The matrix $\tilde{B}_{bus}^{-1}$ is obtained.

From Equation 4.4, the voltage angle can be isolated :

$$\delta = \tilde{B}_{bus}^{-1}(P_A - P_D) \tag{4.8}$$

The Equation 4.5 can be reformulated as :

$$B_{line}\delta \leq P_{max} \tag{4.9}$$

Using the definition of the PTDF (Equation 4.7), and by injecting Equation 4.8 into Equation 4.9 :

$$PTDF(P_A - P_D) \leq P_{max} \tag{4.10}$$

The DC-OPF formulation based on PTDF is the one used in this study. This DC-OPF formulation is described in the next subsection. Note that a power balance needs to be added, because the Equation 4.10 doesn't ensure the power balance anymore. The PTDF matrix can be directly obtained from a basic MATPOWER function, all the information about the network elements being known.

4.2 Nodal pricing model

The following optimisation formulation is the reference one for the nodal model. The variables related to the nodal model are identified by the superscript (n) if there is an ambiguity, i.e. the number of nodes is defined as $N_n^{(n)}$.

A system is assumed with a defined network topology containing $N_n^{(n)}$ nodes, $N_L^{(n)}$ lines and $N_G^{(n)}$ generators. The linear generator cost function $C_G^{(n)} \in \mathbb{R}^{N_G^{(n)}}$, the line capacity limitations $F^{max} \in \mathbb{R}^{N_L^{(n)}}$, the generator production limits $P_G^{min(n)}$,$P_G^{max(n)} \in \mathbb{R}^{N_G^{(n)}}$ and the load $P_D^{(n)} \in \mathbb{R}^{N_n^{(n)}}$ are defined in the model. As the topology of the network is assumed to be known, the PTDF matrix can be computed. The generation schedule $P_G^{(n)} \in \mathbb{R}^{N_G^{(n)}}$ is optimised in order to minimise the total cost of the system. $P_A^{(n)} \in \mathbb{R}^{N_n^{(n)}}$ is defined as the aggregated generation for each node.

Concretely, the objective is to minimise the total generation cost, as described by Equation 4.11. The scheduled production is subject to the production limits of the different generators (Equation 4.12). The power equilibrium is ensured by Equation 4.13. The power flows are computed thanks to the product of the PTDF matrix and the net position of each node. These power flows are constrained by the thermal limit of the lines (Equation 4.14). The following formulation is the general formulation for a specific time t.

$$\underset{P_G^{(n)}}{\text{minimize}} \qquad C_G^{(n)T} P_G^{(n)} \tag{4.11}$$

subject to :

$$P_G^{min(n)} \leq P_G^{(n)} \leq P_G^{max(n)} \tag{4.12}$$

$$\sum_{i=1}^{N_G^{(n)}} P_{G_i}^{(n)} = \sum_{i=1}^{N_n^{(n)}} P_{D_i}^{(n)} \tag{4.13}$$

$$F_i^{max} \leq \sum_{j=1}^{N_n^{(n)}} PTDF_{i,j} \cdot (P_{A_j}^{(n)} - P_{D_j}^{(n)}) \leq F_i^{max} \quad \forall i \in \{1, ..., N_L^{(n)}\} \tag{4.14}$$

4.3 Zonal pricing model

The following optimisation formulation is the reference one for the zonal model. The Flow Based Market Coupling is used as capacity allocation method. The Equation 4.18 can be checked during the market clearing thanks to the PTDF matrix and RAM gathered from JAO[14]. The variables related to the zonal model are identified by the superscript (z).

The zonal model contains $N_z^{(z)}$ zones, $N_L^{(z)}$ critical lines and $N_G^{(z)}$ generators. The generator cost function $C_G^{(z)} \in \mathbb{R}^{N_G^{(z)}}$, the load per zone $P_D^{(z)} \in \mathbb{R}^{N_z^{(z)}}$ and the generator production limits $P_G^{min(z)}$,$P_G^{max(z)} \in \mathbb{R}^{N_G^{(z)}}$ are known. The critical line capacity limitations $RAM \in \mathbb{R}^{N_L^{(z)}}$ are provided by JAO. The PTDF matrix estimating the power flow distribution in these critical lines in function of the net export is also provided by JAO. The optimal solution is found by changing the generation scheduled $P_G^{(z)} \in \mathbb{R}^{N_G^{(z)}}$ in order to minimise the total cost of the system. To simplify the notation, $P_A^{(z)} \in \mathbb{R}^{N_z^{(z)}}$ is defined as the aggregated generation for each zone. Note that the parameters related to the FBMC (PTDF, RAM and $N_L^{(z)}$) depend on the time.

The objective is to minimise the total generation cost as described by Equation 4.15. Generation is constrained by the minimum and the maximum generation level of each power unit (Equation 4.16). The Equation 4.17 ensures the power equilibrium of the system. The critical line constraints are taken into account by Equation 4.18. The resulting flow in each critical line is computed by multiplying the PTDF matrix by the next export of each zone. These resulting flows cannot exceed the RAM of the critical lines. The following formulation is the general formulation for a specific time t.

$$\underset{P_G^{(z)}}{\text{minimize}} \quad C_G^{(z)T} P_G^{(z)} \tag{4.15}$$

subject to :

$$P_G^{min(z)} \leq P_G^{(z)} \leq P_G^{max(z)} \tag{4.16}$$

$$\sum_{i=1}^{N_G^{(z)}} P_{G_i}^{(z)} = \sum_{i=1}^{N_z^{(z)}} P_{D_i}^{(z)} \tag{4.17}$$

$$-RAM_i \leq \sum_{j=1}^{N_z^{(z)}} PTDF_{i,j} \cdot (P_{A_j}^{(z)} - P_{D_j}^{(z)}) \leq RAM_i \quad \forall i \in \{1, ..., N_L^{(z)}\} \tag{4.18}$$

The nodal pricing model is very similar to the zonal pricing model. The power flows are computed thanks to the product of the PTDF matrix and the net export of each node/zone. The thermal limit of each line is used to constrain the power flow in the considered line. The main difference is that in the nodal model each line is considered. In the zonal model, only the critical lines are taken into account.

4.4 Hybrid pricing multi-period model

In the two previous subsections, the DC-OPF for the nodal and zonal models were described. In this subsection, the hybrid pricing multi-period model is tackled. This model is called hybrid, because it is composed of the zonal, the nodal and the Greenland models. The problem is called multi-period, because the state of some variables is time dependent. The multi-period formulation is based on [20]. The model is formulated over an optimisation horizon $\tau = \{1, ..., T\}$. For the simulations, T is equal to 8760 hours. Indeed, the reference year (2017) is not a leap year. The variables related to the Greenlandic region are identified by the superscript (Gr). The superscripts (Gr-n) and (Gr-z) relate the variables to the interconnection between the nodal and the Greenlandic regions and between the zonal and the Greenlandic regions. Note that only one node is considered for the Greenland model.

There are three distinct regions in this model, some sets are created to distinguish them. The set Θ_z contains all zones belonging to the zonal model. Θ_n is the set of all nodes belonging to the nodal region. The sets Ω_z and Ω_n are defined as the set of all generators respectively for the zonal and the nodal models. The set Λ_z represents all HVDC links between Greenland and the different zones. The set Λ_n represents all HVDC links between Greenland and the different nodes.

The main idea is the same as the previous DC-OPF. There is one power balance per region, transmission limits and production limits. Some additional variables are required to connect the different regions. The vectors $P_{GR\to N}(t)$, $P_{N\to GR}(t) \in \mathbb{R}^{N_n^{(n)}}$ and $P_{GR\to Z}(t)$, $P_{Z\to GR}(t) \in \mathbb{R}^{N_z^{(z)}}$ represent respectively the power flows from Greenland to each node of the nodal model, from each node to Greenland, from Greenland to each zone and from each zone to Greenland at a specific time t. It is not possible to only consider one variable between two distinct regions, because losses due to the HVDC links are modelled by decreasing the energy quantity at the receiving end.

The other additional variables are the size of the installed capacity in Greenland $P_{inst}^{(Gr)} \in \mathbb{R}$ and the size of the different transmission cables. There are the HVDC links between the Greenland and the CWE regions $P_{Tr}^{(Gr-z)} \in \mathbb{R}^{N_z^{(z)}}$ and between the Greenland and the PJM regions $P_{Tr}^{(Gr-n)} \in \mathbb{R}^{N_n^{(n)}}$. These variables can be fixed or be part of the optimisation problem. If the variables are part of the optimisation problem, they need to be taken into account in the objective function of the problem (sizing approach). The costs for the transmission $C_{Tr}^{(Gr-z)} \in \mathbb{R}^{N_z^{(z)}}$ and $C_{Tr}^{(Gr-n)} \in \mathbb{R}^{N_n^{(n)}}$ are the costs per MW associated to the interconnection. The lifetime of the cable $\mathit{\Delta}_{Tr}$ is fixed.

The basic hybrid pricing multi-period model computes the size of the HVDC links $P_{Tr}^{(Gr-z)}$ and $P_{Tr}^{(Gr-n)}$, the installed capacity in Greenland $P_{inst}^{(Gr)}$ and the dispatch of the generators ($P_G^{(Gr)}$,$P_G^{(n)}$ and $P_G^{(z)}$). The objective is to minimise the total cost of the system. This means that the sum of the total generation cost, the transmission costs and the installation costs of wind farms in Greenland need to be minimised. The Equation 4.19 formulates the objective function. As the cost to install transmission or generation in Greenland is only a coarse approximation, there is no discount rate. A sensitivity analysis for these costs is simulated instead. Note that the marginal cost for wind farms is neglected. Thus, the LCOE for the wind farms in Greenland is reduced to two terms, the CAPEX ($C_{capex}^{(Gr)}$) and the OPEX ($C_{opex}^{(Gr)}$).

$$\sum_{t\in\tau}\sum_{i\in\mathit{\Omega}_z} C_{G_i}^{(z)} P_{G_i}^{(z)}(t) + \sum_{t\in\tau}\sum_{i\in\mathit{\Omega}_n} C_{G_i}^{(n)} P_{G_i}^{(n)}(t) + \sum_{i\in\mathit{\Lambda}_n} \frac{P_{Tr_i}^{(Gr-n)} \cdot T \cdot C_{Tr_i}^{(Gr-n)}}{\mathit{\Delta}_{Tr}\cdot 8760} + \sum_{i\in\mathit{\Lambda}_z} \frac{P_{Tr_i}^{(Gr-z)} \cdot T \cdot C_{Tr_i}^{(Gr-z)}}{\mathit{\Delta}_{Tr}\cdot 8760} + \frac{P_{inst}^{(Gr)}\cdot T}{8760}\left(\frac{C_{capex}^{(Gr)}}{\mathit{\Delta}_{Tr}} + C_{opex}^{(Gr)}\right) \tag{4.19}$$

The technical and physical constraints of the multi-period problem are listed below:

1. Production limits The Equations 4.20 and 4.21 represent respectively the production limits for each generator of the nodal and the zonal regions. The production limits for these regions are assumed to be constant through the year. Therefore, there is no time dependence for these limits. The Equation 4.22 represents the production limits for the wind farms in Greenland. The upper production limit in Greenland varies with the wind conditions. $P_G^{(Gr)}(t)$ is the power produced by the wind farms in Greenland at the time t and $CF(W_{wind}^{(Gr)}(t))$ is the capacity factor of the wind farms in function of the wind speed at a specific time t.

$$P_G^{min(z)} \leq P_G^{(z)}(t) \leq P_G^{max(z)} \quad \forall t \in \tau \tag{4.20}$$

$$P_G^{min(n)} \leq P_G^{(n)}(t) \leq P_G^{max(n)} \quad \forall t \in \tau \tag{4.21}$$

$$P_G^{min(Gr)} \leq P_G^{(Gr)}(t) \leq P_{inst}^{(Gr)} \cdot CF(W_{wind}^{(Gr)}(t)) \quad \forall t \in \tau \tag{4.22}$$

2. Power Balances The Equations 4.23, 4.24 and 4.25 represent the power balance for each region. These power balances consider the local production and consumption in each region, but as well the power flows between the different regions. The losses of those flows are taken into account by introducing the loss factor $\alpha^{from \to to}$. The loss factor is equal to the unity minus the losses in the considered cable. Only the losses in the HVDC links between the different regions are taken into account in this study.

$$P_{A_i}^{(z)}(t) + \alpha_i^{GR \to Z} P_{GR \to Z,i}(t) = P_{D_i}^{(z)}(t) + P_{Z \to GR,i}(t) \quad \forall t \in \tau, \forall i \in \Theta_z \tag{4.23}$$

$$P_{A_i}^{(n)}(t) + \alpha_i^{GR \to N} P_{GR \to N,i}(t) = P_{D_i}^{(n)}(t) + P_{N \to GR,i}(t) \quad \forall t \in \tau, \forall i \in \Theta_n \tag{4.24}$$

$$\begin{aligned} P_G^{(Gr)}(t) + \sum_{i \in \Theta_z} \alpha_i^{Z \to GR} P_{Z \to GR,i}(t) + \sum_{j \in \Theta_n} \alpha_j^{N \to GR} P_{N \to GR,j}(t) \\ = \sum_{i \in \Theta_z} P_{GR \to Z,i}(t) + \sum_{j \in \Theta_n} P_{GR \to N,j}(t) \quad \forall t \in \tau \end{aligned} \tag{4.25}$$

3. Network constraints The thermal limits of the different lines are imposed by the Equations 4.26, 4.27, 4.28 and 4.29. ATC conditions are used for the HVDC links between Greenland and the two other regions. $PTDF^{(z)}$ stands for the PTDF provided by JAO. On the other hand, $PTDF^{(n)}$ is the PTDF matrix computed from the complete knowledge of the nodal network topology. The RAM, $PTDF^{(z)}$ and the number of critical lines $N_L^{(z)}$ depend on the time.

$$\begin{aligned} -RAM_i(t) \leq \sum_{j \in \Theta_z} PTDF_{i,j}^{(z)}(t) \cdot (P_{A_j}^{(z)}(t) - P_{D_j}^{(z)}(t) + \alpha_j^{GR \to Z} P_{GR \to Z,j}(t) + P_{Z \to GR,j}(t)) \leq RAM_i(t) \\ \forall t \in \tau, \forall i \in \{1, .., N_L^{(z)}(t)\} \end{aligned} \tag{4.26}$$

$$\begin{aligned} -F_i^{max} \leq \sum_{j \in \Theta_n} PTDF_{i,j}^{(n)} \left(P_{A_j}^{(n)}(t) - P_{D_j}^{(n)}(t) + \alpha_j^{GR \to N} P_{GR \to N,j}(t) - P_{N \to GR,j}(t) \right) \leq F_i^{max} \\ \forall t \in \tau, \forall i \in \{1, .., N_L^{(n)}\} \end{aligned} \tag{4.27}$$

$$-P_{Tr,i}^{(Gr-n)} \leq P_{GR \to N,i}(t) - P_{N \to GR,i}(t) \leq P_{Tr,i}^{(Gr-n)} \quad \forall t \in \tau, \forall i \in \Lambda_n \tag{4.28}$$

$$-P_{Tr,i}^{(Gr-z)} \leq P_{GR \to Z,i}(t) - P_{Z \to GR,i}(t) \leq P_{Tr,i}^{(Gr-z)} \quad \forall t \in \tau, \forall i \in \Lambda_z \tag{4.29}$$

The basic multi-period optimisation problem is described above. This optimisation problem can be upgraded by appending new possibilities or constraints to the model. One of the possibilities is to add storage in Greenland.

4. Integration of storage The aim of the integration of storage in Greenland is to reduce the size of the HVDC links between the different regions. By reducing the size, the goal is to increase the capacity factor of the interconnections. This could potentially increase their interest. In our model, the storage device is considered as an enormous and unique entity.

To integrate storage, the installation cost of an additional MWh of storage needs to be added to the objective function. Let us define $\mathit{\Delta}_{ST}$, C_{ST}, $P_{ST} \in \mathbb{R}$ respectively the lifetime, the installation cost and the installed capacity of storage. The additional term in the objective function associated with the storage is given by Equation 4.30. The total size of the storage system is an unknown of the system when a sizing approach is chosen. Again, there is no discount rate, because C_{ST} is only an approximation.

$$\frac{P_{ST} \cdot C_{ST} \cdot T}{8760 \cdot \mathit{\Delta}_{ST}} \tag{4.30}$$

The storage is constrained by the following ones.

4.1. Storage limit The energy stored $E_{ST}(t) \in \mathbb{R}$ is constrained by the installed capacity of the storage device. In our case, it could be discharged up to E_{ST}^{min} or be charged up to the maximum level of energy. The maximum level of energy is limited by the size of the storage unit, which is defined by the installed capacity P_{ST}. This constraint is imposed by Equation 4.31.

$$E_{ST}^{min} \leq E_{ST}(t) \leq P_{ST} \quad \forall t \in \tau \tag{4.31}$$

4.2. Storage actions The storage unit can be charged or discharged. The optimisation problem needs to choose between one of these actions. This could be done using the discrete variable $\beta \in \{0, 1\}$. This variable is equal to 0 if the storage device is being discharged or equal to 1 if the storage device is being charged. $P_{ST}^{c} \in \mathbb{R}$ and $P_{ST}^{d} \in \mathbb{R}$ are respectively defined as charged and discharged power. They are restricted by their respective transfer capability $P_{ST}^{c,max}$ and $P_{ST}^{d,max}$.The Equations 4.32 and 4.33 impose the charge and discharge limit.

$$0 \leq P_{ST}^{c}(t) \leq P_{ST}^{c,max}\beta(t) \quad \forall t \in \tau \tag{4.32}$$

$$0 \leq P_{ST}^{d}(t) \leq P_{ST}^{d,max}(1 - \beta(t)) \quad \forall t \in \tau \tag{4.33}$$

$$\beta(t) \in \{0, 1\} \quad \forall t \in \tau \tag{4.34}$$

4.3 Storage dynamic The storage dynamic describes the evolution of the energy stored in function of the actions of the storage unit. As these actions induced losses, efficiency factors are added to the storage dynamics. η_c and η_d are respectively the efficiency of the charge and the discharge. The time horizon for this equation is slightly different. The storage level at the time t=0 is initialised to zero.

$$E_{ST}(t) - E_{ST}(t-1) = \eta_c \cdot P_{ST}^{c}(t) - \frac{1}{\eta_d} P_{ST}^{d}(t) \quad \forall t \in \tau \tag{4.35}$$

4.4 Update of Power Balance The power balance in the region where the storage unit is installed need to be modified. For our study, the storage device is only installed in Greenland. The original power balance in Greenland is represented by Equation 4.25. The terms $P_{ST}^{d}(t)$ and $P_{ST}^{c}(t)$ need to be added to this power balance. $P_{ST}^{d}(t)$ could be seen as an additional power generation and $P^c_{ST}(t)$ as an additional load. The resulting power balance is given by Equation 4.36.

$$P_G^{(GR)}(t) + \sum_{i \in \Theta_z} \alpha_i^{Z \to GR} P_{Z \to GR,i}(t) + \sum_{j \in \Theta_n} \alpha_j^{N \to GR} P_{N \to GR,j}(t) + P^d_{ST}(t) = \sum_{i \in \Theta_z} P_{GR \to Z,i}(t) + \sum_{j \in \Theta_n} P_{GR \to N,j}(t) + P^c_{ST}(t) \ \forall t \in \tau \quad (4.36)$$

5. Analysis in terms of CO_2 emissions One potential advantage of the Global Grid is the reduction of CO_2 emissions. To solve the hybrid pricing multi-period problem in order to minimise the CO_2 emissions, the total emission of each generator replaces the total cost of the system as objective function. The new objective function is given by Equation 4.37. This equation is the sum of all CO_2 emitted by each generator and the CO_2 emissions for the installation of the HVDC links. The emissions related to the installation of the wind farms are not taken into account in the objective function because the emissions per kWh produced are considered. These emissions already consider the impact of the construction phase. $CO_{2,Tr} \in \mathbb{R}$ is defined as the total CO_2 emissions related to the production and the installation of the HVDC links in kg per MW and per km. The length of the cables between the Greenland and the CWE region and between the Greenland and the PJM regions are given by the vectors $L^{(Gr-z)} \in \mathbb{R}^{N_z^{(z)}}$ and $L^{(Gr-n)} \in \mathbb{R}^{N_n^{(n)}}$. $CO_{2,G}^{(n)} \in \mathbb{R}^{N_G^{(n)}}, CO_{2,G}^{(z)} \in \mathbb{R}^{N_G^{(z)}}, CO_{2,G}^{(Gr)} \in \mathbb{R}$ are the CO_2 emissions per MWh produced by the generators belonging to the nodal, zonal and Greenlandic regions.

$$\sum_{t \in \tau} \left(\sum_{i \in \Omega_n} CO_{2,G_i}^{(n)} P_{G_i}^{(n)}(t) + \sum_{i \in \Omega_z} CO_{2,G_i}^{(z)} P_{G_i}^{(z)}(t) + CO_{2,G}^{(Gr)} P_G^{(Gr)}(t) \right) + \sum_{i \in \Lambda_n} \frac{P_{Tr,i}^{(Gr-n)} \cdot L_i^{(Gr-n)} \cdot T \cdot CO_{2,Tr}}{\Delta_{Tr} \cdot 8760} + \sum_{i \in \Lambda_z} \frac{P_{Tr,i}^{(Gr-z)} \cdot L_i^{(Gr-z)} \cdot T \cdot CO_{2,Tr}}{\Delta_{Tr} \cdot 8760} \quad (4.37)$$

The constraints are unchanged. The constraints of the model are linked to the operational point of view to ensure that the production meets the demand under production and transmission limits.

5 Description of the models

The CWE model stands for the zonal model. This zonal model is representative of the Central Western Europe (CWE). The reference countries are Belgium, Germany, France and the Netherlands. The PJM model stands for the nodal model. This nodal model is representative of the area covered by the PJM TSO. The last model is the Greenland model. The Greenland model is used as an intermediate hub between the zonal and the nodal models.

The CWE and PJM models are chosen because they have almost the same size. The total consumption in 2017 is respectively 1034 and 890 TWh. One potential advantage of connecting directly the CWE and PJM models is the jet lag between the two areas. Therefore, the peak demand doesn't happen at the same time as shown by Figure 3.

In general, during off-peak hours, less expensive generators are used. If the peak hours don't happen at the same time, the production of the available generators can be sent to the other areas to avoid the use of more expensive generators. A large price difference is nevertheless required to overcome the losses in the HVDC links and cover the investment to build the transmission cables.

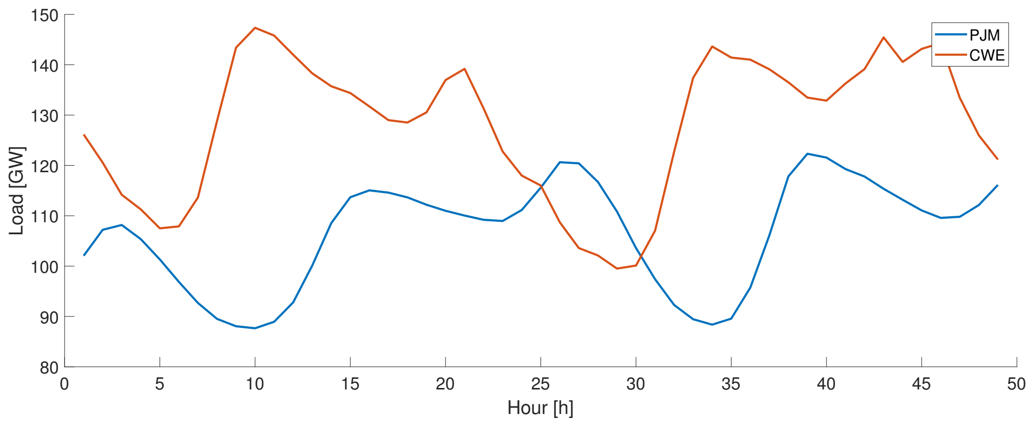

Figure 3 – Load for two specific days for the PJM and CWE regions

5.1 PJM model

The reference model used to represent the North America is the part of the network operates by the PJM TSO.

5.1.1 Assumptions

The general simplifications used in order to perform the simulations, as well as the source of the data that will be necessary for these are listed below. The reference year for the data is 2017.

- The region under study has any other interconnection that the one with the Greenland.
- The load is assumed to be perfectly inelastic to the price.
- As there is no available nodal model for this area. No network constraints are considered for the simulations. This implies a unique price for the whole area.
- All generation bids are made at the LCOE of the power plant. All these costs are provided by the following study [21]. The LCOE are supposed to be constant through the year. Note that the cost of the CO_2 is equal to 30€ per tonne.
- The information about the load and energy production by renewable energies are gathered from PJM data miner 2[1].
- The installed capacity is gathered from the market report of PJM[2].

1. `https://dataminer2.pjm.com/list`
2. `https://pjm.com/-/media/committees-groups/committees/mc/20180322-state-of-market-report-review/20180322-2017-state-of-the-market-report-review.ashx`

- The different power plants can be used during the whole year, so no scheduled stop periods are considered.
- As the installed capacity is negligible, this model doesn't consider hydro power plant.
- The marginal cost of renewable energies inside the PJM region is supposed to be equal to zero. This is an important approximation because renewable energies have non-zero marginal cost (maintenance costs). To perform the simulations, the total production of renewable energies that are already installed inside the PJM region will be simply subtracted from the total load.

5.1.2 Installed capacity and marginal cost

The Table 1 shows the installed capacity and LCOE considered in this study for the PJM model. The power plants with the same production type are aggregated to form only one equivalent power plant. The LCOE is the same for the whole equivalent power plant.

Power Plant ID	1	2	3	4
Type	Coal.	Gas	Nucl.	Oil
Capacity [MW]	66622	65110	33043	6733
LCOE [€/MWh]	74	54	48	120

Table 1 – Power plant ID, type, installed capacity and LCOE for the power plants belonging to PJM region.

5.2 CWE model

As a reference zonal market, a part of the Central Western Europe (CWE) is considered. The reference countries for this study are Belgium, Germany, France and the Netherlands. The reference year for the data is 2017.

5.2.1 Assumptions

This subsection aims at describing the general simplifications that will be used in order to perform the simulations, as well as the source of the data that will be necessary for these.

- The countries under study are not supposed to interact with any other country. The only interactions that we consider are through the transmission lines between these countries and the HVDC links between these countries and the Greenland.
- The demand is assumed to be perfectly inelastic to the price.
- The transmission lines are lossless inside the zonal model. Losses are only considered between the different regions.

- All the data regarding the installed capacity, the total load and the generation per production type are gathered from Entsoe [22].
- All renewable energies are considered to be identical. Their production is estimated as the total energy produced from renewable energies for each country. The total energy is computed thanks to the data provided by Entsoe [22].
- All generation bids are made at the LCOE of the power plant. All these costs are provided by the following study [21]. The LCOE are supposed to be constant through the year. Note that the cost of the CO_2 is equal to 30€ per tonne.
- The different power plants can be used during the whole year, so no scheduled stop periods are considered.
- The marginal cost of renewable energies is supposed to be equal to zero. This is an important approximation because renewable energies have non-zero marginal cost (maintenance costs). To perform the simulations, the total production of renewable energies that are already installed will be simply subtracted from the total load of the country (for the RE production inside the zone). The resulting annual load for Belgium, Germany, France and the Netherlands are respectively equal to 79.4, 406.4, 441.2 and 107.7 TWh.
- Considering the total installed capacity for run-of-river and hydro reservoir power plant, only 25%[1] of this can be used. No seasonal change is considered in this study. The remaining capacity can be used at full capacity during the entire year.
- The full installed capacity of the hydro pumped storage is only used 1000 hours per year. The installed capacity of these kinds of power plant is deduced from the load at the highest peak hours of the year. The hydro pumped storage unit could be considered as a storage unit in the model using the equations described for the integration of storage. Nonetheless, this simplification is used to decrease the number of variables in our model.

5.2.2 Installed capacity and LCOE

As said previously, only a few number of different types of power plants are considered for each country. The power plants with the same type are aggregated. The Table 2 shows the installed capacity and the LCOE considered in this study for the CWE model.

Country	Belgium			Germany				France			Netherlands		
Power Plant ID	1	2	3	4	5	6	7	8	9	10	11	12	13
Type	Nucl.	Gas	Biom.	Nucl.	Hydro	Coal	Gas	Nucl.	Gas	Hydro	Nucl.	Coal	Gas
Capacity [MW]	5919	6095	720	10793	3400	53654	31596	63130	18075	6000	486	4631	18433
LCOE [€/MWh]	46	87	130	46	18	59	87	44	82	18	46	65	82

Table 2 – Power plant ID, type, installed capacity and LCOE for power plants belonging to CWE region.

1. https://www.edf.fr/groupe-edf/espaces-dedies/l-energie-de-a-a-z/tout-sur-l-energie/produire-de-l-electricite/l-hydraulique-en-chiffres

5.2.3 Cross-border capacity allocation

The cross-border capacity allocation for this model is based on the Flow Based Market Coupling. The determination of the two parameters RAM and PTDF is made by the TSO. The values of these parameters are gathered directly from JAO [14].

To compute the flow in each critical branch, the PTDF matrix is multiplied by the net export of each zone. The flow in the critical line cannot exceed the RAM.

The RAM is computed via Equation 5.1. The value given by JAO is directly the RAM. The drawback is that the data about the other values for the year 2017 are not available on the website. Therefore, the simulations are performed with the RAM. This is a non-negligible assumption, because in our model the F_l^{ref} should be equal to zero as all the electricity is sold on the day-ahead market. Therefore, the transfer capacities between the different zones can be underestimated. To quantify the impact of this assumption, a sensitivity analysis of the RAM will be performed. The sensitivity analysis permits to evaluate the impact of the underestimation of the RAM and the possible future upgrade of the network.

$$RAM = F_l^{max} - F_l^{ref} - FAV_l - FRM_l \tag{5.1}$$

where :

- F_l^{max} is the maximum power flow in the critical line l [MW]
- F_l^{ref} is the reference flow in the critical line l [MW], this flow is caused by the commercial transactions outside the day-ahead market
- FAV_l is the final adjustment value in MW, this value is determined by the TSO
- FRM_l is the flow reliability margin on critical branch l in MW. This is a security margin.

5.3 Greenland model

The Greenland could be seen as an intermediate hub for the interconnection between the PJM and the CWE regions. The main advantage of Greenland is the possibility to harvest high quality renewable energy. The interest in harvesting wind energy in Greenland was brought to light by [10].

The data collection of wind signals in Greenland at hourly resolution is achieved via the regional MAR (Regional Atmosphere Model) model. This model was developed to simulate climatic conditions of polar regions. The main advantage of MAR is that this model takes into account the contribution of the Katabatic winds [23]. The boundary conditions of the MAR model are determined by the ERA5 reanalysis model [24]. These winds lead to mean load factor over the year up to 49% if the cut-off speed of the wind turbine is equal to 25m/s and up to 64% if no cut-off speed is considered for onshore wind farm [10].

Offshore wind farms in Greenland are not considered in our study, because the installation costs of offshore wind farms are much more important than the installation costs of onshore wind farms. The mean annual capacity factor is generally higher for offshore wind farms, but the cost difference is prohibitive compared to the increase related to the capacity factor.

One of the MAR output at hourly resolution is the wind speed at 100 metres of altitude. These wind speeds are used as a wind pattern for the Greenland model.

The next step is to transform the wind speeds given by the MAR model to capacity factor. This could be done using the transfer function of a wind farm. For this study, a multi-turbine power curve approach is used to simulate the dynamics of a wind farm composed of identical wind turbine [25]. The wind turbines considered is the 8 MW - aerodyn SCD 8.0/168.

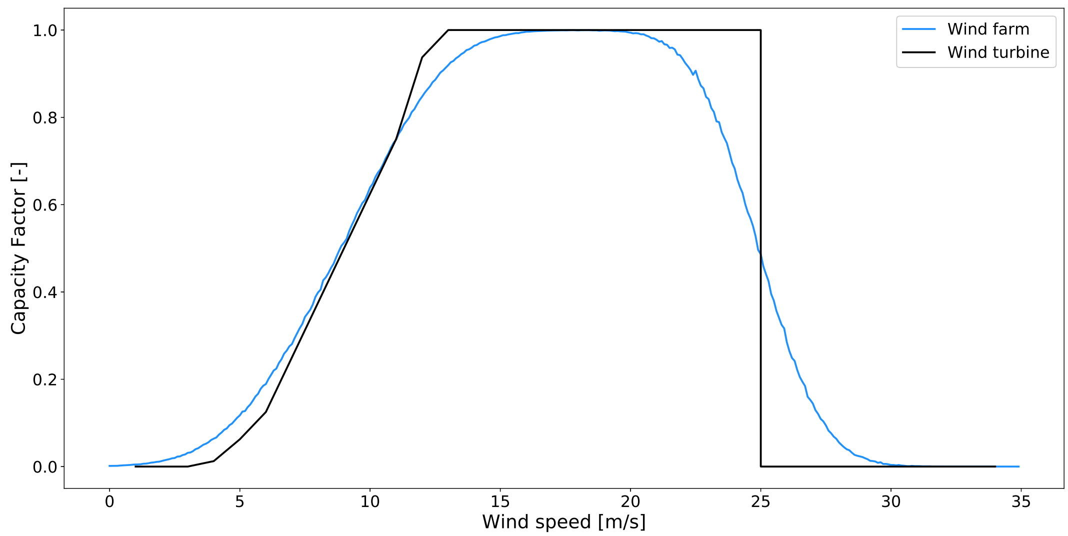

Figure 4 – Single turbine and wind farm transfer functions.

The resulting transfer function is shown in Figure 4. This transfer function is used to calculate the output power. The total output power of the wind farm $P_G^{(Gr)}$ is given by the Equation 5.2.

$$P_G^{(Gr)} = CF(W_{wind}^{(Gr)}) \cdot P_{inst}^{(Gr)} \quad [MW] \tag{5.2}$$

where $P_{inst}^{(Gr)}$ is the installed capacity in Greenland [MW] and CF is the capacity factor [-] which is a function of the wind speed $W_{wind}^{(Gr)}$ [m/s].

The Table 3 shows an overview of the capacity factor for the wind farms in Greenland. These data are interesting to explain the future results. 50% of the time, the capacity factor is higher than 50%. The mean capacity factor through the year is equal to $49,9\%$.

Interval	[0,0.25[	[0.25,0.5[	[0.5,0.75[	[0.75,1]
time [%]	0.39	0.11	0.11	0.39

Table 3 – Percentage of the time that the capacity factor is within a specific interval

The CAPEX and OPEX assumptions for this study are given in the Table 4. These values are provided by ELIA and NREL studies [26],[27]. No marginal cost is considered for wind energy in Greenland. The real installation cost is set by the combination of the CAPEX and the OPEX. The most expensive CAPEX and OPEX (NREL values) are considered. The cost is unchanged despite the fact that the wind turbines are going to be installed in Greenland. This choice is motivated by the fact that enormous installed capacity is expected. So economy of scale is believed.

	NREL	ELIA
CAPEX [k€/MW]	1690	1500
OPEX [k€/MW/yr]	45.8	29

Table 4 – CAPEX and OPEX for wind turbine

5.4 Hybrid model

The hybrid model is the combination of the zonal, nodal and the Greenland models. The nodal model is the nodal representation of the network holds by PJM. The zonal model is the zonal representation of the CWE model. These models are connected together through the Greenland. The Greenland model consists of an intermediate hub where wind farms and storage units could potentially be installed.

The size of the HVDC links, the wind farms or the storage units can be fixed or determined during the resolution of the optimisation problem when a multi-period problem is considered.

The Figure 5 shows how the model is interconnected. The different regions are interconnected together via HVDC links.

5.5 Facilities

The hybrid model has the possibility to install wind farms in Greenland, new transmission cables between the different regions and storage capacities in Greenland. The characteristics of wind farms in Greenland were discussed in previous subsection. In this subsection, the two other facilities (transmission and storage) and the CO_2 emissions are discussed.

5.5.1 Interconnection

High Voltage Direct Current links are chosen instead of High Voltage Alternative Current (HVAC). HVDC links have a lot of advantages [28]. Among them, they can perform asynchronous interconnection, which is an important point because the frequencies in North America and in Europe are different. Furthermore, they have no technical limits to the potential length of the cables. This is a non-negligible, because the length of the cable is enormous in our study (more than 3000 km).

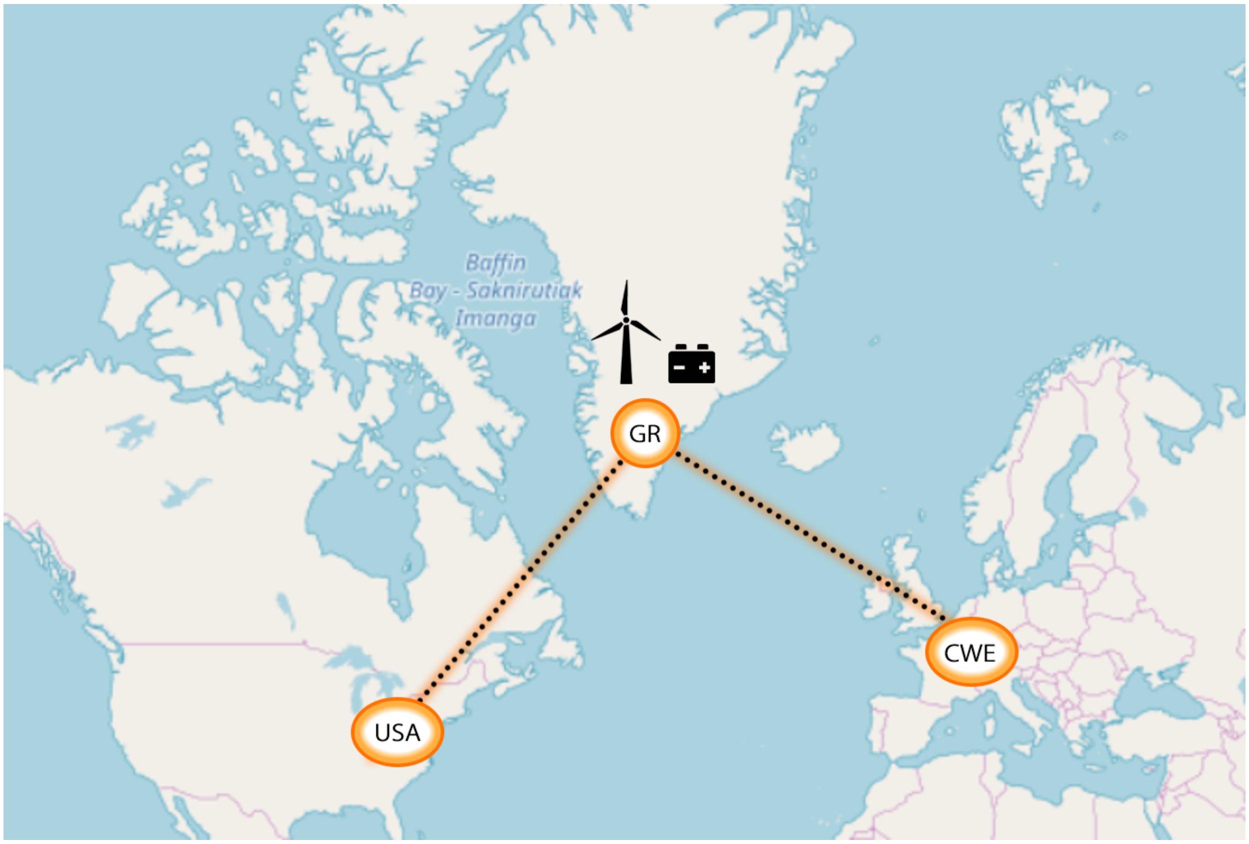

Figure 5 – Hybrid model representation

Another important advantage is the cost for long transmission. The Figure 6 shows the investment costs in function of the distance. Above a critical distance, investing in HVDC is cheaper than HVAC. The critical distance is around 50 km for undersea cable [3]. There are other advantages (controllability, low short circuit current, ...) but they are not discussed in this study.

The data about the two interconnections considered are taken from the CIGRE study [29]. The data about the losses and the cost are given in Table 5. The assumed lifetime of such cable Δ_{Tr} is 50 years.

Interconnection	GR-CWE	GR-USA
Losses [% flow]	12,1	7.7
Cost max [10^6€/GW]	4 347	2 579
Cost min [10^6€/GW]	2 846	1 648

Table 5 – Losses and costs data for the interconnections between the Greenland, the CWE region and the North America.

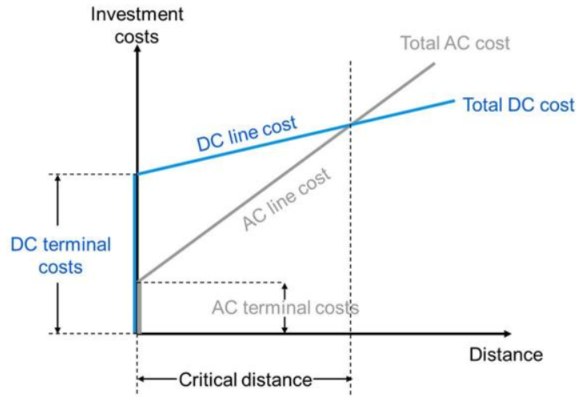

Figure 6 – HVDC vs HVAC transmission costs [3]

5.5.2 Storage

There are different storage methods such as flywheels, chemical batteries (NaS, Lead-Acid, Flow batteries, lithium ...), Compressed Air Energy Storage (CAES), Pumped-storage or high temperature storage (Molten Salt). In our case, the storage has to be shaped to allow energy management. Only CAES and Pumped-storage technologies are invoked in our study.

The size of the storage unit is going to be enormous, even to store a few hours of production, because the wind farms installed capacity in Greenland is about many GW. Currently, the largest storage project is about 2.68 GWh[1](CAES with a round trip efficiency equals to 54%).

For the storage unit in Greenland, we are looking for a technology which is able to have a large installed capacity and a huge number of cycles. To don't decrease their interest, a good round-trip efficiency is required. As the storage unit would have to store a lot of energy in a small lapse of time, the rated power has to be sufficient too.

The study [30] estimates the investment, the round-trip efficiency, the lifetime for CAES and Pumped-storage (PS) in 2030. For both, the lifetime could be above 100 years. The initial investment cost per kWh is respectively 70 USD/kWh and 100 USD/kWh for CAES and PS. The round-trip efficiency is respectively 70% and 80%. These two technologies are able to answer the basic criterion required.

For this study, the technology for the storage is not fixed. Only some main characteristics are imposed to the system. The round trip efficiency is 81%, the efficiency of the charge and the discharge are both equal to 90%. The rated power is not constrained. The lifetime is approximated to 50 years. The installation cost is fixed to 200 k€ per MWh installed. But most of the simulations including storage are run using a sensitivity approach for the cost of storage.

5.5.3 CO_2

The emission levels for the different power plants are estimated by the following study [31]. This study gives three levels of emission (min, median and max) for the whole Life Cycle of the

1. `https://en.wikipedia.org/wiki/List_of_energy_storage_projects`

energy generator. The median values are chosen. The emissions are given in g of $CO_{2,eq}$ per kWh. The Table 6 resumes the emissions for the available generators. Note that there is no information about the emissions of oil power plant in the study. The same level of emission as biomass is used instead. The impact of this choice is limited due to the small installed capacity of oil power plant.

The emissions for the wind onshore in Greenland are unknown. The median emissions proposed in the study is for projects that are certainly closer than Greenland. Therefore, higher emissions are expected for a wind farm in Greenland. But on the other hand, the capacity factor is larger in Greenland than for other onshore wind farms. The unchanged median value is chosen as the reference.

Gen. type	Nucl.	Gas	Biomass	Hydro	Coal	Oil	Wind Onshore
$CO_{2,eq}$ [g/kWh]	12	490	740	24	820	740	11

Table 6 – $CO_{2,eq}$ [g per kWh] per generation type

The estimation of the Lyfe Cycle Assessment (LCA) for the submarine cable is much more complex because there is no similar project. To choose a realistic hypothesis, the following study [32] is used. In [32], the authors estimated the carbon footprint of an export cable (HVDC, 450 kV, 2790 - mm^2 Cu) at 215 t of CO_2 equivalent per km. But they use different hypothesis that the one used in this study (other lengths, other depths,..). Our own hypothesis for this study is 500 t of $CO_{2,eq}$ per km and per GW of transmission cable. The length of the cable between the CWE region and Greenland is estimated at 3500 km and the one between the PJM region and Greenland is estimated at 3000 km.

6 Simulations

Before analysing the different simulations, the criteria used to describe the simulations are defined. The simulations are mainly described in terms of the total cost, the price at each zone/node and the Total Equivalent Hour of each power plant.

The total cost of the system is given by the objective function. The value of the objective function at the end of the resolution of the optimisation problem is the total cost of the system. This total cost depends on the situation. The total cost could depend on the total generation cost and the investment costs. The investment costs are only considered if the optimisation problem considers wind farms in Greenland, HVDC links and/or storage units.

The second criterion is the price of the electricity at a specific node/zone. This price brings to light at which price the producers are paid and the price paid by the consumers. The derivation of the price is given in the Appendix A.

The last main criterion is the Total Equivalent Hour (TEH). The Total Equivalent Hour gives an overview of how much a specific power plant is used during the year. The total equivalent hour of a power plant is calculated using the Equation 6.1.

$$TEH = \frac{E_{prod}}{P_{inst} \cdot T} \tag{6.1}$$

where P_{inst} is the installed capacity (in MW), E_{prod} is the total energy produced during the whole year (in MWh) and T is the number of hours considered.

6.1 Zonal pricing model

In this subsection, the coupling of the CWE and the Greenland regions is analysed. First, we run the reference case, which is the simulation of the isolated CWE model. After, the CWE model is coupled with the Greenland. One simulation is performed for which the size of the transmission capacity and the installed capacity are imposed. The other simulations aim to size the installed capacity in Greenland, the transmission capacity and the storage capacity.

6.1.1 CWE model isolated

RAM The zonal pricing model runs for one complete year without any other interconnection. The RAM is unchanged. The Table 7 brings to light the main statistics about the price for the isolated CWE model. The price is mainly set in Belgium and in the Netherlands by their respective gas power plant. Most of the time, the price is set by the nuclear power plant in France and by the coal power plant in Germany.

Zone	Belgium	Germany	France	Netherlands
Minimum price [€/MWh]	42	46	44	46
Annual mean price [€/MWh]	84.19	59.28	46.77	81.73
Maximum price [€/MWh]	87	83	82	82

Table 7 – Maximal, annual mean and minimum price per zone for the zonal pricing model when the CWE model is isolated

The Figure 7 shows the total equivalent hour for the generators in the zonal model. The biomass power plant in Belgium and the gas power plant in Germany are never used. The price in Belgium is mainly set by the gas power plant, but the total equivalent hour for this unit is only 27%. This could be explained by the huge installed capacity of the gas power plant in Belgium. Indeed, even if only a small part of the aggregated power plant is used most of the time, the gas power plant is rarely used at high capacity. The same argumentation is applicable to the Dutch case. The gas power plant in France is almost never used due to the huge nuclear installed capacity. The French nuclear power plant covers the major part of the local load.

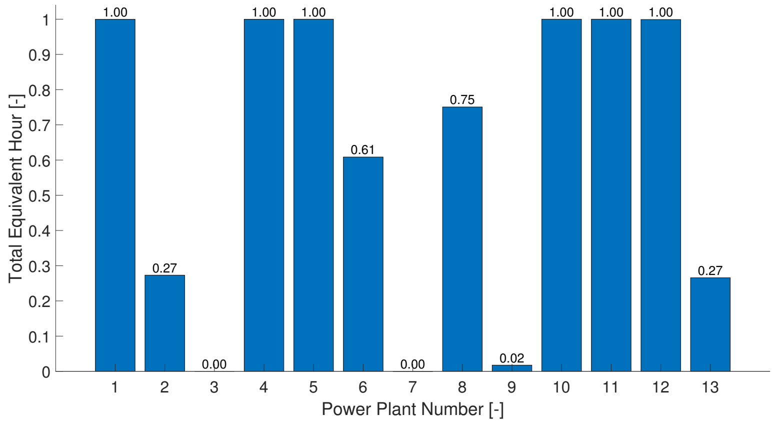

Figure 7 – Total Equivalent Hour for the isolated zonal model

The total cost of the system for the whole year is equal to $5.1203 \cdot 10^{10}$ €. This total cost is equal to the total production cost. This is the reference cost for the zonal model. In the next subsections, this total cost is used to compare the potential interest to build an interconnection between the CWE region and the Greenland.

RAM muliplied by 2 The RAM is underestimated because the term F_l^{ref} is not added to the RAM. To give a general overview of the impact of the underestimation of the RAM, the zonal pricing model is run when the RAM is multiplied by 2. This implies additional possibilities for the coupling inside the CWE model.

The Table 8 shows the main statistics about the price for the different countries inside the CWE model. The main difference compared to the Table 7 is the mean price in Belgium and in the Netherlands. These countries are more expensive than Germany and France. As the RAM is multiplied by 2, less expensive countries export more to more expensive countries. So the price in Belgium and the Netherlands decrease, because these countries use less their most expensive generators. In contrast, the price in France increases, because more expensive generators are more used to cover the load in more expensive countries. This could be seen in Figure 8.

Zone	Belgium	Germany	France	Netherlands
Minimum price [€/MWh]	46	46	44	46
Annual mean price [€/MWh]	75.27	59.79	48.00	78.46
Maximum price [€/MWh]	87	87	87	82

Table 8 – Maximal, annual mean and minimum price per zone for the zonal pricing model when the model is considered isolated and the RAM is multiplied by 2

As the coupling between the market increases, the total cost of the system decreases. Indeed, more expensive generators are less used and so the total cost decreases. The total cost is equal to $5.0113 \cdot 10^{10}$ €.

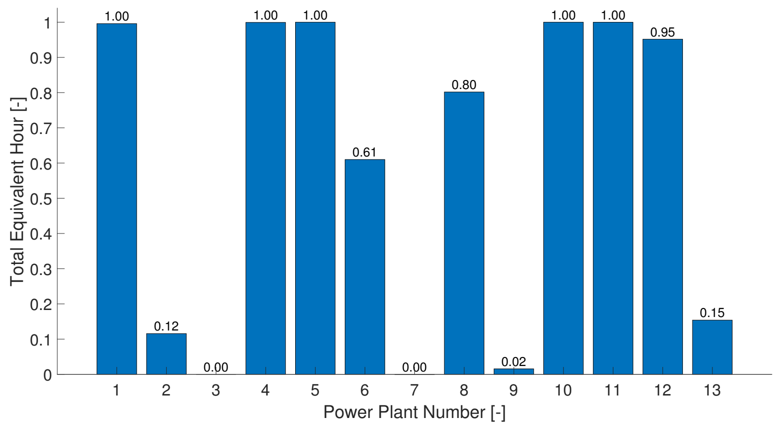

Figure 8 – Total Equivalent Hour for the isolated zonal model when the RAM is multiplied by 2

6.1.2 Taking Greenland into account

In this configuration, the CWE model is coupled with the Greenland model. Each country is connected to the Greenland by a 2500 MW submarine cable. The size of the wind farms in Greenland is 10 GW. So all the submarine cables could be fully used when the production in Greenland is maximal.

The Table 10 shows the information about the price for each country. The annual mean price in Belgium decreases by more than 10%. The impact for the other countries is less important.

Zone	Belgium	Germany	France	Netherlands
Minimum price [€/MWh]	42	46	44	46
Annual mean price [€/MWh]	72.75	59.26	47.06	79.13
Maximum price [€/MWh]	87	83	82	82

Table 9 – Maximal, annual mean and minimum price per zone for the countries inside the CWE when this model is connected to Greenland. The installed capacity in Greenland is 10 GW and each country is connected to Greenland by a cable of 2.5 GW.

The decrease in the annual mean price in Belgium could be explained by the decrease of 22% in the total equivalent hour for the gas power plant. The reason why Belgium is more impacted than the Netherlands can be explained by the LCOE of the next marginal generator in both countries. The nuclear power plant in Belgium bids at 46€ and the coal power plant in the Netherlands bids at 65€. Therefore, the total cost of the system decreases more if the nuclear in Belgium is used instead of the Dutch coal power plant. So there is a higher interest for Belgium to import "free" energy from Greenland.

The Table 10 brings to light the power flows between Greenland and the zonal model. Surprisingly, even if there is 12.1% of losses per trip, the two least expensive countries (Germany and

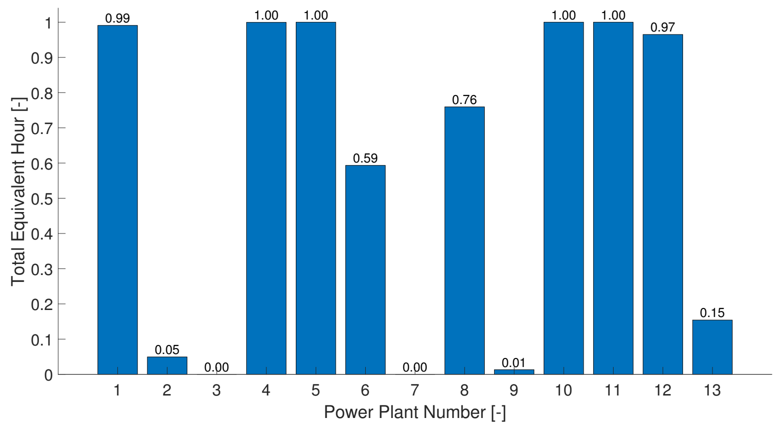

Figure 9 – Total Equivalent Hour for the zonal model when it is connected to Greenland with four 2500 MW cables. The installed capacity in Greenland is 10 GW.

France) send energy to Greenland. This energy is sent to more expensive countries (Belgium or the Netherlands). If the MWh transmits in the HVDC links is produced by the French nuclear power plant. The total production cost is $44 \cdot 1.24 = 54.56$ €/MWh if losses are taken into account. If the French nuclear power plant produced the MWh instead of another power plant with a LCOE higher than 54.56 €/MWh, there is an interest from an economic point of view.

Zone	Belgium	Germany	France	Netherlands
$GR \rightarrow Z$ [TWh]	18.5	11.58	7.06	20.57
$Z \rightarrow GR$ [TWh]	0	5.368	10.541	0

Table 10 – Flows between Greenland and the zonal models. The installed capacity in Greenland is 10 GW and each country is connected to Greenland by a cable of 2.5 GW.

Compared to their respective load, the Netherlands and Belgium import much more than the two other countries. The interest of these imports is to avoid the utilisation of the gas power plants, which have higher LCOE than the other power plants.

The total cost of the system for one year is equal to $4.8310 \cdot 10^{10}$ €. This cost doesn't take into account the costs of the installed capacity in Greenland and the installation of the HVDC links.

6.1.3 Taking Greenland into account : multi-period approach

RAM The Greenland and the zonal models are coupled. The installed capacity in Greenland and the size of the HVDC links are variables of the multi-period optimisation problem. Therefore, the costs of such installations/interconnections are taken into account in the objective function. For the following simulations, the maximum price for the interconnection and the NREL data for the wind farms are chosen.

From the whole year simulation, the installed capacity in Greenland is equal to 63 GW. The total transmission capacity is equal to 62 GW (developed in Table 11). The flows between the two regions are shown in the Table 11. The Netherlands imports from Greenland more than 95% of its resulting total load. Belgium imports approximately a quarter of its total resulting load. The reason why Belgium imports less could be explained by the fact that Belgium needs to import less to don't use its gas power plant. Germany imports 40% of its resulting total load. This huge import is mainly used to decrease the utilisation of the coal power plant. The import of France is negligible compared to its resulting total load. The LCOE of French nuclear power plants is so low that it is less expensive to produce with nuclear power plant than import energy from Greenland. The installed capacity in France is surprising compared to the annual import via this HVDC link. This is just due to the huge export from France to Greenland. Taking into account export and import, the capacity factor of the link is more than 70%.

Zone	Belgium	Germany	France	Netherlands
P_{Cable} [GW]	4	34	10	14
$GR \rightarrow Z$ [TWh]	22.37	159	27.8	101.32
$Z \rightarrow GR$ [TWh]	0	4.86	37.47	0

Table 11 – Flows and size of the cable between Greenland and the zonal models. Multi-period approach with the size of the HVDC links and the installed capacity as variables.

The Table 12 shows the information about the price for the CWE model. The mean price decreases for each country, because these countries can import "free" energy from Greenland. The most affected countries are Belgium and the Netherlands. This is surprising that Germany is not affected more, because this is the country that imports the most in terms of quantity. But the price is still mainly set by the coal power plant, even if the capacity factor of this unit is decreased. The total production cost of German power plants is decreased due to this import,but this import doesn't affect directly the price, because the installed capacity of the coal power plant is enormous (53 GW). France is almost not affected. The minimum price in Germany and in the Netherlands is equal to zero. This means that all the loads of these countries are covered by the wind farms in Greenland at some specific time.

Zone	Belgium	Germany	France	Netherlands
Minimum price [€/MWh]	22	0	44	0
Annual mean price [€/MWh]	57.48	54.96	47.26	57.47
Maximum price [€/MWh]	87	83	82	82

Table 12 – Maximal, annual mean and minimum price per zone for the countries inside the CWE for the multi-period approach

The total cost of the system (taking into account the cost of the interconnections and wind farms in Greenland) is equal to $4.8603 \cdot 10^{10}$ €. The total cost of the system is 5% lower than the reference total cost. The Figure 10 brings to light that the most expensive generators (mostly the gas power plant in each country) are less used.

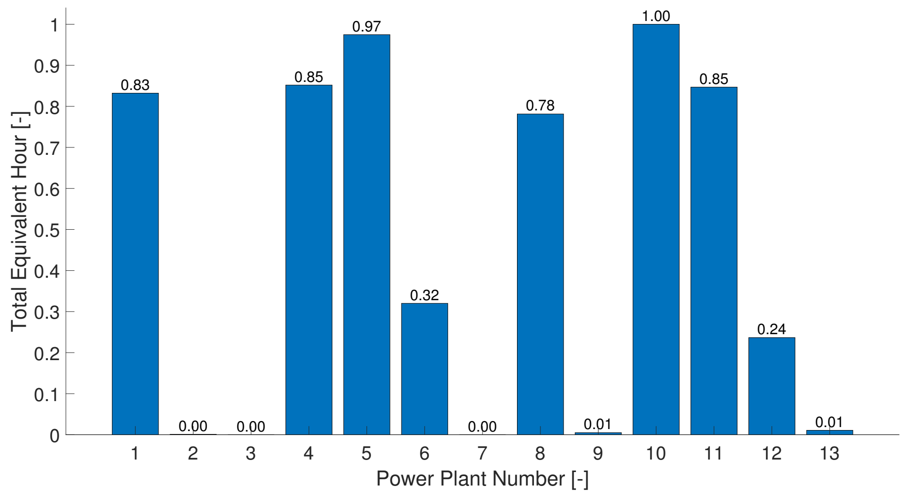

Figure 10 – Total Equivalent Hour for the multi-period problem interconnecting the zonal and the Greenland models. The size of the transmission cables and the installed capacity in Greenland are variables.

RAM multiplied by 2 The same model (Greenland and zonal models coupled together) is evaluated but the RAM is multiplied by 2. The installed capacity and the size of the cables are still variables.

The Table 13 shows the installed capacity of the HVDC links. The total installed capacity is equal to 58 GW. The total installed capacity of wind farms in Greenland is equal to 59 GW. The total energy imported from Greenland decreases from 310 TWh (previous case) to 282 TWh. The system imports less from Greenland, because the most expensive generators are already less used due to the higher transmission capacities between the countries inside the CWE.

Zone	Belgium	Germany	France	Netherlands
P_{Cable} [GW]	2	33	8	15
$GR \rightarrow Z$ [TWh]	8.44	156.1	21.83	96.59
$Z \rightarrow GR$ [TWh]	0	2.17	26.9	0

Table 13 – Flows and size of the HVDC links between Greenland and the zonal models. Multi-period approach with the size of the HVDC links and the installed capacity of wind farms as variables. The RAM is multiplied by 2.

The main lesson that can be seen in the Figure 11 is the fact that the production of the French nuclear is increased by 5% compares to the case when the RAM is intact. This is due to the relaxation of the network constraints inside the CWE model.

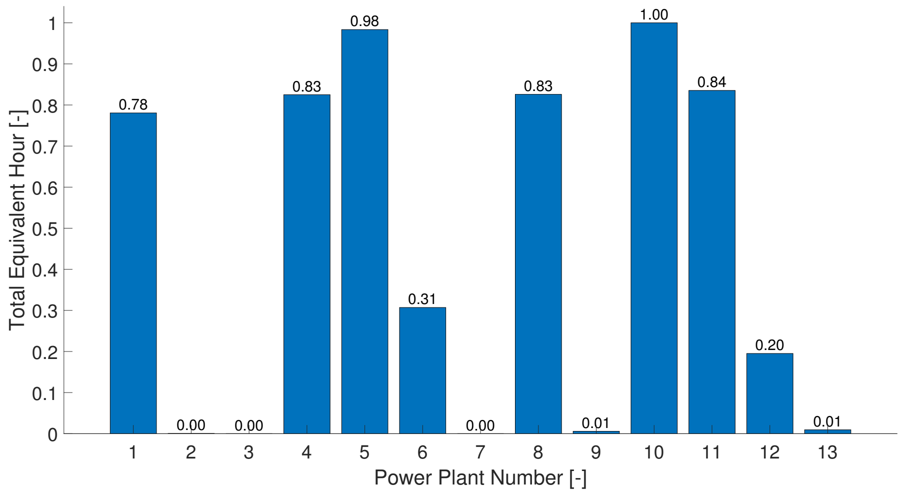

Figure 11 – Total Equivalent Hour for the multi-period optimisation problem interconnecting the Greenland and the zonal models. The RAM is multiplied by 2

The total cost is equal to $4.8182 \cdot 10^{10}$ €. So the total cost in slightly lower than the previous case. The impact of multiplying the RAM by 2 is not so significant in terms of the total cost. Therefore, the basic RAM is used as reference for the rest of this report.

6.1.4 Taking Greenland into account : multi-period approach with storage

The main idea is to give the possibility to the system to add storage in Greenland. The approach is slightly different. The installed capacity of the wind farms in Greenland is fixed. The objective function depends on the total generation cost, the installation cost of an additional MWh of a storage capacity and the installation cost of an additional GW of transmission cable.

Instead of giving a fixed cost for the additional MWh of storage or an additional MW of transmission cable, the cost varies from a minimum value to a maximum value. The cost of the storage capacity varies from 0 to $0.5 \cdot 10^6$ € per MWh installed. The lifetime is assumed to be 50 years. As no discount rate is considered, the reader can easily compute the annual cost per MWh installed. The cost of transmission cable varies from 0 to the maximum value given by the CIGRE. The simulations are performed for an installed capacity in Greenland equals to 20 GW and 50 GW. Note that when the cost of the transmission cable is 0, the size of the HVDC links is imposed by the maximum flow through the cables.

For this kind of problem (storage and transmission), there is clearly a trade-off between the installation of storage capacities and transmission capacities. Especially above a certain value of transmission capacities, because the transmission capacities need to be sufficient to transmit the energy stored or the energy stored is lost. The storage can increase the capacity factor of the transmission cables and so increase their profitability. On the other hand, the installed capacity for the storage has to be enormous to decrease the installed capacity of the transmission cables.

Installed capacity in Greenland is 20 GW The next simulation is performed with an installed capacity in the Greenland set to 20 GW. The results are given in the Table 14.

C_{ST}[k€/MWh] / C_{TR}[M€/GW]	0		100		200		300		400	
0	92	3274	93	0	93	0	93	0	93	0
2846	11	3218	19	34	20	4	20	0	20	0
3596	11	3249	18	52	19	16	20	0	20	0
4347	10	2852	16	93	19	16	20	0	20	0

Table 14 – The installed capacities for the transmission cables (in GW)|for the storage unit (in GWh). The installed capacity of the wind farms in Greenland is equal to 20 GW.

The maximum size of the transmission cables is 93 GW. This is more than four times the size of the wind farm in Greenland. This is due to two factors. The first factor is that each country can be connected by a 20 GW cable to import this amount of power at a specific hour. The second factor is that other countries can export a part of their own production to other countries (especially France). Therefore, the maximum size of the transmission cables can exceed 20 GW.

When the storage cost is zero, the installed capacity has a maximum value of 93 GW for the reasons described before. For the other cases, the installed capacity is around half of the installed capacity in Greenland. This could be justified by the capacity factor of the wind farms in Greenland. Above 11 GW, there is no irrecoverable need to build additional transmission cable to transmit the energy produced in Greenland. The installed capacity when the C_{TR} is maximum is interesting. More storage capacity was expected, but as the transmission cable is optimised for 10 GW, the storage capacity cannot be too large or too much power will be lost due to the inability of the transmission cables to transmit more than 10 GW.

There are two different trends in the results when the cost of storage is different from 0 k€. The column where C_{ST} = 100k€ per MWh installed is considered, it can be seen that the installed capacity for storage increases when the cost of the cable increases. For this storage cost, there is really a trade-off between storage and transmission. On the other hand, the trend is different when C_{ST} = 200k€ per MWh installed. The installed capacity doesn't change too much when the transmission cost increases. The trade-off between the storage and the transmission capacity is not interesting anymore at this price. Note that above this price, there is no storage. The storage is 'replaced' by a cable with the same size as the wind farm installed capacity. The size of the cables reaches 20 GW each time. Proof that this is interesting to import all the "free" power produced in Greenland.

When the storage cost is higher than 0, the total transmission capacity has almost the same size as the installed capacity in Greenland. This could be explained by the Table 3. The capacity factor is 39% of the time comprises between 0.75 and 1. So if the cables are undersized, a huge part of the production is simply lost. If a part of the production of the wind farms is lost due to transmission limitations, the interest of harvesting renewable energies in remote locations decreases.

Installed capacity in Greenland is 50 GW The second simulation is run with an installed capacity in Greenland set to 50 GW.

C_{ST}[k€/MWh] / C_{TR}[M€/GW]	0		100		200		300		400		500	
0	130	8022	130	0	130	0	130	0	130	0	130	0
2846	26	7087	47	62	49	12	50	0	50	0	50	0
3596	25	6622	42	150	48	20	49	6	49	4	50	0
4347	25	6622	39	213	45	53	48	13	49	4	49	2

Table 15 – The installed capacities for the transmission cables(in GW)|for the storage unit (in GWh). The installed capacity of the wind farms in Greenland is equal to 50 GW.

The results for the case with 50 GW installed in Greenland are similar to the previous results. The main difference is that the installation of additional storage capacity is economically profitable for installation costs higher than 200 k€. However, the installed capacity is smaller compared to the size of the wind farms.

The trend is similar for both $C_{ST} = 100$k€ and $C_{ST} = 200$k€. This could be explained by the higher production in this case. In the free storage case, the transmission capacity is still around 50% of the installed capacity.

The interest of the storage is clearly limited by the huge installed capacity that needs to be installed to limit the installed capacity of the transmission cables. Such huge storage unit could only be considered if the installation cost of storage is low. With the cost assumption considered in this study, if there is no storage, the installed capacity of the transmission cables is almost equal to the installed capacity of the wind farms.

6.2 Nodal pricing model

Due to lack of available data, the nodal model of the USA is really simplified. The PJM region is modelled, but there is no network constraints. This lead to a uniform price final price for the whole region.

In this subsection, as the nodal pricing model is very simple, only two simulations are analysed. The first one is the PJM model isolated. The second one is the multi-period optimisation problem of the PJM model interconnected with Greenland. Only the installed capacity and the transmission cables are variables.

6.2.1 Without taking Greenland into account

The first simulation of the nodal pricing model represents the PJM model isolated. There is no interconnection with Greenland. The aim of this simulation is to describe the reference situation for the PJM model, especially computes the total cost of the system.

The Figure 12 brings to light that the nuclear power plant is always used. This is expected as it is the least expensive power plant. Shortly after, the gas power plant is almost always used. The coal power plant has only a total equivalent hour of 15%. The oil power plant is never used.

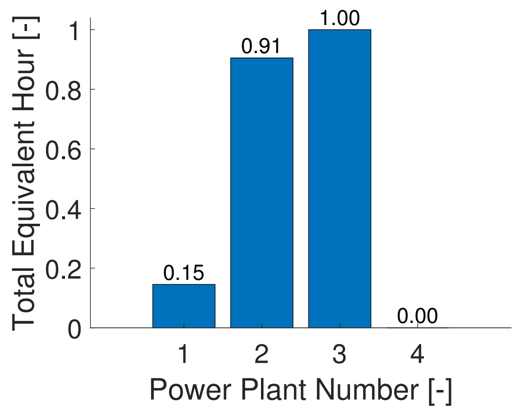

Figure 12 – Total Equivalent Hour for the economic dispatch of the nodal model when there is no other interconnection.

The mean price is 64.84 €. The maximum price is 120 €. This implies that the oil power plant is used at a moment of the year. But its utilisation is so small that the total equivalent hour is rounded at 0 instead of 0.01. The minimum price is 54 €. This means that there is always at least a part of the gas power plant that is used and so the price is never set by the nuclear power plant.

The total cost for the PJM model is $4.8056 \cdot 10^{10}$€. This is the reference cost of the PJM model.

6.2.2 Taking Greenland into account : multi-period approach

The following simulation is performed when the PJM model could be interconnected with Greenland. This is a multi-period optimisation problem for which the size of the HVDC links and the installed capacity of the wind farms are variables.

The resolution of the multi-period problem leads to an installed capacity in Greenland of 99 GW of wind farms and 97 GW of transmission capacity. This results in the import of 421 TWh from the Greenland. Such import has a non-negligible impact of the generation dispatch inside the PJM model.

The Figure 13 shows the impact of the interconnection on the total equivalent hour. The use of the gas and nuclear power plants is largely reduced.

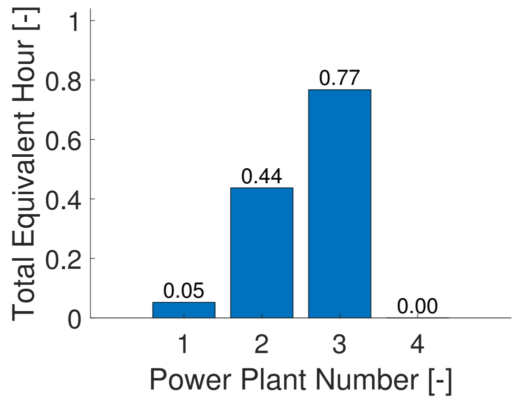

Figure 13 – Total Equivalent Hour for the multi-period problem of the PJM model when it is interconnected with Greenland.

The total cost is $4.27 \cdot 10^{10}$€. This represents a decrease of more than 10% of the total cost.

The total installed capacity of the wind farms in Greenland is impressive. Some additional simulations are performed to determine above which price there is an interest to install wind farm and transmission cable between the PJM model and the Greenland. To perform such simulation, the generation cost of each generator in the PJM region is forced to be identical. The goal of this approach is just to determine the price above which there is an interest to install cable and wind farms in Greenland.

The generation cost is decreased until there is no generation unit installed in Greenland. The tipping price is 41 €/MWh. Below this price, there is no generation capacity in Greenland. Above this price, there is a huge generation capacity in Greenland. In our case, the PJM model has the lowest generation cost equal to 48 €/MWh. So there is directly an interest to install huge wind farms.

6.3 Hybrid pricing model

The zonal and the nodal models are interconnected via the Greenland. Only multi-period simulations are performed for the hybrid model. The potential interest of the hybrid model is that energy could be sent from Europe to the USA and vice versa. Furthermore, the wind farms could be used to send some power to Europe and the USA. Therefore, higher revenues are expected for the wind farms holders in Greenland, because they would be able to sell their production at peak price more often.

6.3.1 Only interconnection

For this simulation, there is only the possibility for the model to add interconnection between CWE-Greenland and PJM-Greenland. So the PJM and the CWE models could be connected. No wind farm in Greenland is considered for this simulation. The aim is to determine if there is a business case to interconnect both countries when there is no wind farms in Greenland.

The total cost of the system for this simulation is equal to $9.9259 \cdot 10^{10}$ €. This is simply the addition of the total cost of the isolated CWE and PJM models. There is no business case for a direct interconnection. The optimisation problem doesn't build HVDC links.

6.3.2 Interconnections and wind farms

In this case, the optimisation problem can add interconnections between Greenland and the two other regions. Furthermore, wind farms could be installed in Greenland.

There is a business case in Greenland for this simulation. The Table 16 shows the installed capacity for the transmission and the flows between Greenland and the other regions. The total installed capacity of the wind farm is 170 GW. The total installed capacity of the transmission cable is 168 GW.

Zone	Belgium	Germany	France	Netherlands	PJM
P_{Cable} [GW]	5	35	14	14	100
$GR \rightarrow Z$ [TWh]	24.7	185.7	36.4	100.4	427.8
$Z \rightarrow GR$ [TWh]	0	14.8	36.4	0	0.8

Table 16 – Flows and size of the cables between Greenland, the CWE and the PJM models. Multi-period optimization problem with the installed capacity in Greenland and the size of HVDC links as variables.

In this case, there are power flows directly between the PJM and the CWE models. The sum of the power flows between the two regions is equal to 14.6 TWh. This total flow is negligible compared to the production of the wind farms. France and Germany are the main exporter. The size of the cables is almost the same as the size of the cables when the PJM and the CWE models are connected separately with Greenland.

The Figure 14 shows the total equivalent hour. Compared with the case CWE-Greenland, the generators in the CWE model produces in total 2.6 GWh less. Compared with the case PJM-Greenland, the generators of the PJM model produces in total 0.6 GWh less. The difference is almost negligible.

What is surprising is the fact that the total capacity installed in Greenland is almost equal to the sum of the installed capacity when the two models are separately connected. This could be expected with the previous analysis. There is not really a business case for connecting directly both countries under the cost assumptions made.

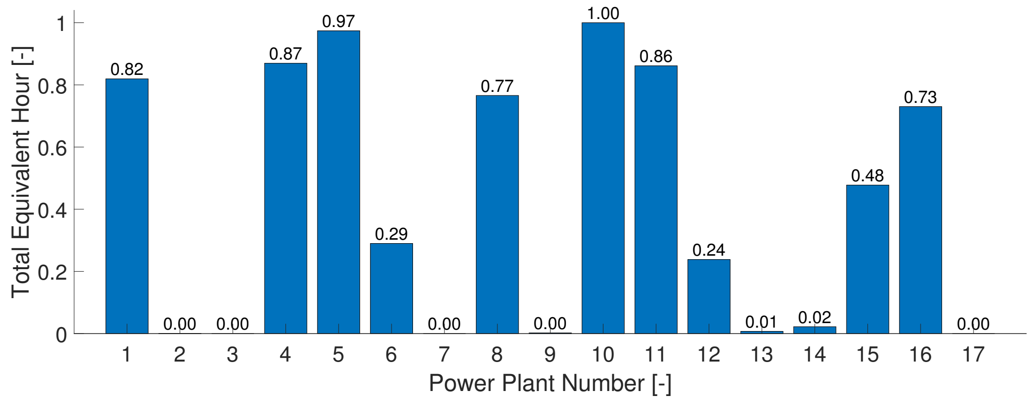

Figure 14 – Total Equivalent Hour for the multi-period problem of the hybrid model when there is interconnection with Greenland and the possibility to install wind farms in Greenland. 1-13 : Generators of the CWE model. 14-17 : Generators of the PJM model

The total cost of the system is $9.1038 \cdot 10^{10}$ €. The reduction is non-negligible (more than 8%). The total cost is surprisingly low regarding the installed capacity in Greenland. As the installation cost of cables and wind farms in Greenland are only approximations, sensitivity analysis are performed.

6.3.3 Interconnections and wind farms : Sensibility analysis

The real price for building some interconnections or wind farms in Greenland is unknown. The aim of this section is to perform a sensitivity analysis in order to see the impact of the installation costs. The Table 20 shows the results of the sensitivity analysis. The OPEX cost of the wind farms is fixed, but the CAPEX cost is modified.

The basic case ($C_{WF} = 1690$ k€/MW,$C_{TR} = 4347$ M€/GW) is the one treated previously. The total installed capacity in Greenland is 170 GW and the total size of the transmission cables is 168 GW. As there is no direct business case to transmit electricity from the PJM region to the CWE region, the installed capacity of the cables depends strongly on the size of the wind farms. This is evidenced by the installed capacity in Greenland in the case $C_{WF} = 3380$ k€/MW,$C_{TR} = 4347$ M€/GW. The installed capacity of the transmission cables is maximal with respect to the size of the wind farms to transmit as much power as possible. The size of the cables is limited by the cost of building an additional MW of wind farms.

If the cost of the interconnections increases up to 8694 M€/GW, the installed capacity plummeted to 76 GW when the cost of wind farms is $C_{WF} = 1690$ k€/MW. The decrease of the installed capacity is less important than the one for which the installation cost of the wind farms is double. There is no business case in Greenland when the cost of both facilities is double.

To understand better these results, it is valuable to compute the price to produce a MWh in function of the installation cost. If the OPEX cost of the wind farms is not taken into account and if the capacity factor is roughly rounded to 0.5, the cost to produce an additional MWh could be approximated. First, the total cost per year needs to be computed. The cost per year is the division of the installation cost by the lifetime of the installation. The next step is to compute the

<table>
<tr><td colspan="3"></td><td colspan="2">C_{TR}[M€/GW]</td></tr>
<tr><td colspan="3"></td><td>4347</td><td>8694</td></tr>
<tr><td rowspan="4">C_{WF}[k€/MW]</td><td rowspan="2">1690</td><td>$P_{inst,GR}$ [GW]</td><td>170</td><td>76</td></tr>
<tr><td>P_{Cable} [GW]</td><td>168</td><td>73</td></tr>
<tr><td rowspan="2">3380</td><td>$P_{inst,GR}$ [GW]</td><td>40</td><td>0</td></tr>
<tr><td>P_{Cable} [GW]</td><td>40</td><td>0</td></tr>
</table>

Table 17 – Size of the wind farms and the transmission cables installed in Greenland in function of their respective cost.

number of MWh produced per year. As the capacity factor is 0.5, the number MWh produced per year is $\frac{8760}{2} = 4380$.

The cost to transmit 1 MWh when C_{TR} is equal to 4347 and 8694 M€/GW is respectively 19.5 and 39 €/MWh. The cost to produce 1 MWh when C_{WF} is equal to 1690 and 3380 k€/MW is respectively 15 and 30 €/MWh. By combination of the costs, it is possible to have an overview of when it could make sense to build such connection. When the price is double, the cost per MWh is 69 €/MWh. This cost is higher than most of the LCOE of the generators and so there is no business case.

6.3.4 Interconnections, wind farms and storage

The cost of the storage is another unknown, a cost of 200k€ per MWh installed is assumed for this simulation (lifetime is 50 years). No discount rate is considered.

The size of the wind farm increases to 211 GW. But the total installed capacity of the HVDC links decreases to 162 GW. This decrease is due to the large storage installed in Greenland. The size of the storage is 0.99 TWh. The total energy imports by the PJM model is very impressive. But this could be explained by the fact that there is a business case to import energy from Greenland in the PJM area when the price of the generator is higher than 41 € as said previously. As all generators in this area have higher LCOE, the optimisation problem tries to maximise the import from Greenland.

As seen in Table 18, the North American region imports more. The size of the HVDC links connected to France is reduced thanks to the storage in Greenland. The excess of energy is stored when the production is higher than the total size of the transmission cable and transmit when the wind is not sufficient in Greenland.

The total cost of the system for this configuration is $8.9549 \cdot 10^{10}$€. The total cost continues to decrease compared to the previous simulations. The storage increases the possibility to use less the most expensive generators.

Zone	Belgium	Germany	France	Netherlands	PJM
P_{Cable} [GW]	5	37	5	14	101
$GR \rightarrow Z$ [TWh]	26.8	231	13.6	108.7	518.9
$Z \rightarrow GR$ [TWh]	0	5.39	9.5	0	15.6

Table 18 – Flows and size of the HVDC links between Greenland, the CWE and the PJM models. Multi-period optimization problem with the installed capacity in Greenland, the size of the interconnection cable and the storage capacity as variables.

6.3.5 Interconnections and storage : Sensibility analysis

The approach is the same as the one for the CWE model. The installed capacity of the wind farms is fixed (50 GW). The objective function depends on the total generation cost, the cost of installed an additional MWh of storage capacity and the installation cost of an additional GW of transmission cable.

Instead of imposing a fixed price for the installation of storage capacity or transmission capacity. The cost for storage varies from 0 to $0.5 \cdot 10^6$ € per MWh installed. The lifetime is assumed to be 50 years. Again, there is no discount rate, so the reader can easily estimate the annual cost of such installation. For the transmission capacity, the cost varies from 0 to 2 times the maximum price given by the CIGRE study.

The main trends are the same as for the study for which only the CWE region is connected to Greenland. The transmission capacity is almost the same as the installed capacity in Greenland when the installation costs of additional transmission capacities are too important compared to the storage costs.

The business case for the storage is limited. The installed capacity of the storage unit is negligible compared to the installed capacity of the wind farms. Furthermore, there is only huge installed capacity of storage when the installation cost of transmission capacity is above the maximum value given by the CIGRE and the storage cost below 300 k€/MWh.

The storage capacity when $C_{TR} = 6520.5$ M€/GW is surprising compared to the other capacities when $C_{ST} = 0$ k€/MWh. The transmission capacity connected to the zonal model $C_{TR} = 6520.5$ M€/GW is higher than the one connected to the zonal model when $C_{TR} = 8694$ M€/GW. This is the contrary for the capacity connected to the nodal model. As both cases have the same total installed capacity, the energy management is different for both cases and this explains the difference in the storage capacity installed.

6.4 Hybrid model pricing - Installed capacity / Revenues

In the previous simulations, the objective function was to minimise the total cost of the whole system. In this subsection, the approach is different. We consider the investor point of view. The

C_{ST}[k€/MWh] \ C_{TR}[M€/GW]	0		100		200		300		400		500	
0	217	5401	211	0	211	0	211	0	211	0	211	0
2173.5	35	6144	52	22	52	0	52	0	52	0	52	0
4347	31	6719	45	101	49	10	50	0	50	0	50	0
6520.5	25	9867	38	233	46	40	48	12	49	4	49	2
8694	25	6978	36	298	42	88	45	35	47	14	48	5

Table 19 – The installed capacities for the transmission cables(in GW)|for the storage capacity (in GWh). The installed capacity of the wind farms in Greenland in equal to 50 GW.

investor doesn't care about the minimisation of the total cost of the system. The only goal of this investor is to maximise his benefit.

In our case, the investor is defined as the person who provides the initial investment for the wind farms and the transmission cables. After this initial investment, the investor has no impact on the market. At any moment, he can deflect from the optimal strategy. The optimal strategy is the one set by the optimisation problem. The goal of the optimisation problem is still to minimise the total cost of the system. The investor decided the installed capacity of the wind farms in Greenland.

To generate the results, the wind farms installed capacity in Greenland varies from 20 GW to 260 GW by steps of 20 GW. The size of the transmission capacity is determined by the optimisation problem. The revenues of the investor are determined by the revenues generate by the transmission cables. The first source of revenues is the sum of all the power produced by the wind farms in Greenland that is sold to another region. The revenues are therefore the total energy that arrived to the other region at the time t multiply by the price of the region at the same time t. The other source of revenues is when some energy is sent from one region to another region. The revenue generated is the money gets when the energy is sold to the receiving region minus the money pay when the energy is bought at the sending region. Note that some money is lost due to the losses in the HVDC links.

The Figure 15 shows the total profit in function of the wind farms installed capacity in Greenland. Under the cost assumption made, there is a possible interest to invest in Greenland until 180 GW of wind farms. Above this installed capacity, the investor loses money.

The revenues depend on two main factors. The first factor is the total energy that is sold by the holder of the HVDC links. This energy sold mainly depends on the installed capacity of the wind farms. So as the installed capacity in Greenland increases, the export energy increases and the price in each region begins to decrease too. The revenues begin to decrease when the increase in production is not sufficient to compensate the decrease of the price in each region.

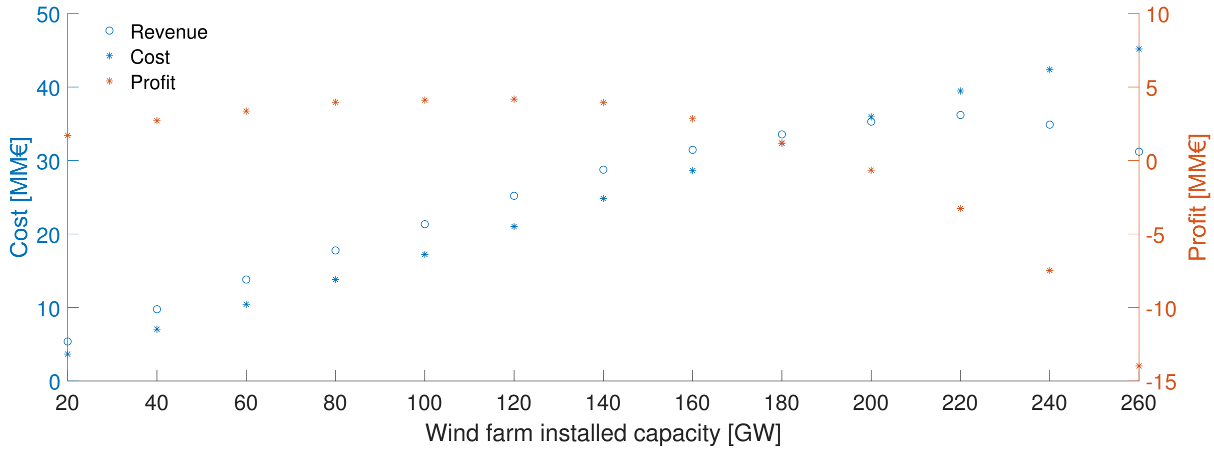

Figure 15 – Costs for the installation of the wind farms and the transmission cables in Greenland, revenues and resulting profit in function of the installed capacity of the wind farms

For information, the mean annual price in the PJM region varies from 61.8€/MWh (for 20 GW installed) to 30.29€/MWh (for 260 GW installed).

The profit is maximum when the installed capacity is 120 GW. The annual profit is 4.1774 MM€. Therefore, the best option for the investor is to install this capacity. The profit is minimum, but positive for 180 GW installed. The total cost of the system is minimised when the installed capacity is between 160 and 180 GW. The option for which there is no profit for the investor is the best option for the model because the total cost is minimised for this choice.

6.5 Hybrid model pricing - CO_2 approach

In this section, the optimisation problem aimed CO_2 emissions is analysed. This means that the objective function only depends on the CO_2 emissions. The aim is to assess one of the benefits of the global grid : the mitigation of CO_2 emissions.

The first model simulated is the model without any interconnection between PJM - Greenland - CWE. As there is no interconnection, there is no wind farms in Greenland. $5.26 \cdot 10^8$ t of CO_2 is emitted for the whole year. This case is the reference case.

The second model allows interconnections to be built, but forbid the construction of wind farms. Under these assumptions, there is a business case in terms of CO_2 to build 176 GW of transmission cables. These cables are built to allow the PJM region to import energy from Europe. This could be expected, because the generators in the PJM region emitted more CO_2 than the one in Europe (mainly less coal in Europe). $4.574 \cdot 10^8$ t of CO_2 is emitted for the whole year. This is already 15% less than the reference case. In terms of CO_2 emissions, there is a clear interest of building transmission, but from an economic point of view, there is no interest when no wind farms are installed in Greenland.

The next model allows interconnections and wind farms to be built. The optimisation problem is slightly modified. In the objective function, the maximum production of the wind farms $P_{inst,GR} \cdot$

$CF(W_{wind}(t))$ is considered instead of the production that is really used by one of the other regions. The goal of this is to limit the size of the wind farms as the CO_2 emission depends only on the production of the energy and not of the installed capacity. But the main CO_2 emissions for a wind farm is during the production/installation and not necessarily during the production.

Even with this hypothesis, the installed capacity of wind farms in Greenland is completely oversized (790 GW). Only 40% of the total energy produced is really used. The size of the cables is really impressive (265 GW in total). The total CO_2 emissions fall to $1.654 \cdot 10^8 t$. This reduction represents a decrease of more than 68% compared to the reference case.

The main drawback of the last simulation is that the model only used a small part of the total energy produced by the wind farms in Greenland. To overtake this drawback, two other simulations are performed. For the first one, the installed capacity in Greenland is fixed to 265 GW. The aim of this simulation is to increase the total energy really used by the system. The second one represents a more realistic installation size, for example 50 GW.

If 265 GW of wind farms are installed in Greenland, 89.1% of the energy produced is used. All the energy produced cannot be used because the installed capacity of the cable is lower than 265 GW. In this case, the wind farms are not completely oversized. The CO_2 emissions still fall drastically (−63.8%).

If 50 GW of wind farms are installed in Greenland, 100% of the energy produced is used. The size of the cables is greater than the size of the wind farms. This is due to power exchanges directly between Europe and North America. The impact on the CO_2 emissions is lower but there is already a decrease of 32.1%.

Model	P_{cable} [GW]	$P_{inst,GR}$ [GW]	CO_2 [10^8 t]
No Int	-	-	5.26
Int	96	-	4.574
Int + Wf	265	790	1.654
Int + Wf 265 GW	242	265	1.904
Int + Wf 50 GW	127	50	3.568

Table 20 – Installed capacities for the transmission cables and the wind farms and the total CO_2 emissions for the whole year.

As demonstrated by the simulations, this interconnection of the Global Grid can lead to an important reduction of CO_2 emissions. Therefore, there is a real interest of developing such solution if the main goal is to mitigate CO_2 emissions.

7 Greenland vs Offshore

In the previous section, simulations were performed to determine if there is a possible interest to harvest high quality renewable energy in Greenland and repatriate this energy to supply Europe and/or North-Eastern America. Under different cost assumptions, the total installed capacity of wind farms in Greenland was determined though a hybrid pricing multi-period model. The results show a clear interest to invest massively in Greenland to supply Europe and/or North America.

From the European point of view, there is an interest to invest in Greenland under the cost assumptions considered. But behind the numbers, there are still huge barriers to overcome. The distance between Europe and Greenland and the huge potential depth are still problematic for HVDC links. The main advantage of the Greenland is that onshore wind farms could be built with very good capacity factor. But Europe has huge offshore wind potential. Actually, 12.6 GW of offshore wind energy is operating in Europe. This is only a small fraction of the resource potential available in the European sea basins. Offshore wind could in theory generates $2600 - 6000$ TWh per year at a competitive price (65€/MWh or below (costs for 2030))[33]. The potential is there and the capacity factor of these offshore sites could be better than the one in Greenland. This lead to the main question of this section : Is a massive investment in the offshore wind near the European continent more profitable than a massive investment in Greenland?

To answer this question, it is important to note that building offshore wind farms is much more expensive than onshore wind farms. On the other hand, the transmission costs would be smaller for offshore wind farm sites in Europe due to the proximity. The idea is to upgrade the hybrid pricing multi-period model in order to allow the system to choose between building onshore wind farms in Greenland and/or building offshore wind farms in Europe.

7.1 The offshore model

To allow the optimisation problem to build offshore wind farms in European sea basins, some upgrades need to be performed. First, the nodal model is not considered anymore. Only the interconnections between the zonal model, the European sea basins sites and the Greenland are studied. The superscript (o) denotes the variables referring to offshore if there is an ambiguity with the variables defined previously.

Considering $N_n^{(o)}$ offshore locations, each site could be connected to one of the four zones, there are $N_n^{(o)} \cdot N_z^{(z)}$ possible transmission cables. Let $P_{Tr}^{(o)} \in \mathbb{R}^{N_n^{(o)} \times N_z^{(z)}}$ be the installed capacity of the associated cables. $C_{Tr}^{(o)} \in \mathbb{R}^{N_n^{(o)} \times N_z^{(z)}}$ is the corresponding cost for the MW of cable installed between the offshore sites and the zones to which it is connected. $P_{inst}^{(o)} \in \mathbb{R}^{N_n^{(o)}}$ is the installed capacity of the offshore wind farms for each possible site. The production limits of each site $P_G^{min(o)} \in \mathbb{R}^{N_n^{(o)}}$ are known and the wind speeds $W_{wind}^{(o)}(t) \in \mathbb{R}^{N_n^{(o)}}$ is known over the time horizon.

The objective function is modified to take into account the additional cost induced by the offshore wind farms and the cost of the interconnections. Three new terms are added to the objective function. The first two terms incorporate the CAPEX and the OPEX cost of the offshore wind farms. The last term comprises the installation cost induced by the transmission cables. Again, any marginal cost is taken into account for the offshore wind farm, the LCOE of the offshore wind is only induced by the CAPEX ($C^{(o)}_{capex} \in \mathbb{R}$) and the OPEX ($C^{(o)}_{opex} \in \mathbb{R}$).

$$\sum_{i=1}^{N_n^{(o)}} \frac{P^{(o)}_{inst,i} \cdot T \cdot C^{(o)}_{capex}}{\Delta_W \cdot 8760} + \sum_{i=1}^{N_n^{(o)}} \frac{P^{(o)}_{inst,i} \cdot T \cdot C^{(o)}_{opex}}{8760} + \sum_{i=1}^{N_n^{(o)}} \sum_{j=1}^{N_z^{(z)}} \frac{P^{(o)}_{Tr,ij} \cdot T \cdot C^{(o)}_{Tr,ij}}{\Delta_{Tr} \cdot 8760} \tag{7.1}$$

The integration of the offshore sites in the optimisation problem leads to additional constraints. The first one is the production limits of the different offshore wind farms. The production limits are imposed by Equation 7.2. The production of each wind farm $P^{(o)}_G(t) \in \mathbb{R}^{N_n^{(o)}}$ is limited by the product of the installed capacity by the capacity factor at this location. The capacity factor is, of course, a function of the wind speed.

$$P_G^{min(o)} \leq P^{(o)}_G(t) \leq P^{(o)}_{inst} \cdot CF(W^{(o)}_{wind}(t)) \quad \forall t \in \tau \tag{7.2}$$

The exports from the wind farms to one of the four countries constituting the zonal model cannot exceed the thermal limit of the HVDC links between this wind farm and the considered country. Let $P_{O\to Z}(t) \in \mathbb{R}^{N_n^{(o)} \times N_z^{(z)}}$ be the power flows through the different HVDC links. This constraint could be express as:

$$0 \leq P_{O\to Z,ij}(t) \leq P^{(o)}_{Tr,ij} \quad \forall i \in \{1, ..., N_n^{(o)}\}, \forall j \in \{1, ..., N_z^{(z)}\}, \forall t \in \tau \tag{7.3}$$

The next constraint that is added to the optimisation problem is the power equilibrium of each wind farm. The total production of the wind farm $P^{(o)}_G(t)$ has to be equal to the total energy sent to the connected countries. This constraint is simply written as :

$$P^{(o)}_{G_i}(t) = \sum_{j=1}^{N_z^{(z)}} P_{O\to Z,ij}(t) \quad \forall i \in \{1, ..., N_n^{(o)}\}, \forall t \in \tau \tag{7.4}$$

Two constraints of the original optimisation problem need to be modified to take into account this new source of production. First, the Equation 4.26 needs to take an additional term into account. This term is the total power send to each zone j: $\sum_{i=1}^{N_n^{(o)}} \alpha^{O\to Z}_{ij} P_{O\to Z,ij}$. Furthermore, the power equilibrium of the zonal model has to take this additional variable into account (Equation 4.23). $\alpha^{O\to Z} \in \mathbb{R}^{N_n^{(o)} \times N_z^{(z)}}$ are the losses in the associated transmission cables.

In our case, the system is allowed to build offshore wind farms in the sea near the European continent. Each the possible spot could be seen as a production hub. The potential cables that connect one offshore wind farm with two different zones cannot be used to transmit power between the two zones that are connected together via the production hub. This choice is motivated by computational constraints. As losses are considered in the HVDC cables, two variables need to be defined if the flows in both directions are considered. So twice more variables are needed. As each production hub could be connected to each zone, the number of variables becomes considerable.

7.2 Model creation

The additional variables and equations were described in the previous subsection. In the subsection, the explanation of how the data are collected and treated is described.

Wind data collection The wind signals from Europe at hourly resolution are achieved via the ERA-V model [24]. Within the scope of the current report, the ERA-V data provided the 100-metre wind speed and direction. The area under consideration scans the latitude belonging to $\{35°, 60°\}$ and the longitude belonging to $\{-10°, 30°\}$ with a resolution of $1°$ for both directions (see Figure 16[1]). A large part of this area is onshore, the onshore locations are eliminated from the data to only save the offshore locations. The offshore locations are sorted later.

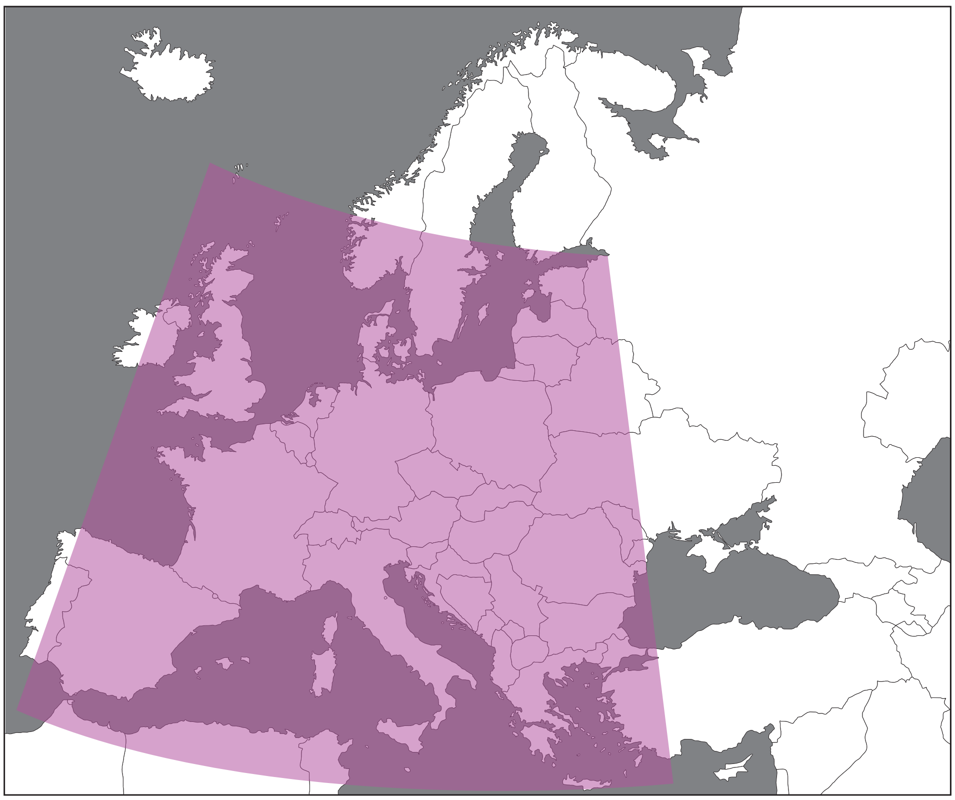

Figure 16 – Area under consideration

From the ERA-V model, the eastward wind value at 100-metre-high U_{100m} and the northward wind value at 100-metre-high V_{100m} for the location under study are obtained. To compute the resultant wind signal R_{100m}, the Equation 7.5 is used for every offshore location and for every time t over the time horizon considered.

$$R_{100m} = \sqrt{U_{100m}^2 + V_{100m}^2} \tag{7.5}$$

When the resultant wind signals R_{100m} is determined for each offshore location, the associated capacity factor can be computed. To compute the capacity factor, the same transfer function as

1. `https://www.gps-coordinates.net/`

the one used for Greenland is used. Again, the multi-turbine approach is considered, because huge wind farms are expected.

The capacity factor for each offshore location and for each time step computed, the total output power of the corresponding wind farm could be calculated by multiplying the installed capacity at a specific offshore location by the associated capacity factor.

Interconnection point The total production of a specific offshore location determined, this energy needs to be exported to a specific zone (Belgium, Germany, France or the Netherlands in our case). The zones considered are large, so each zone is represented by a number of possible interconnection points. An interconnection point is represented by a specific coordinate. The coastline of each zone under study is swept by several possible interconnection points. These possible points are uniquely geographical choice, no study of the network at these points are made. For information, there are 3, 6, 12 and 5 possible interconnection points respectively for Belgium, Germany, France and the Netherlands.

A *Matlab* function is created to determine the closest interconnection point with each country. The function calculates the distance between the offshore wind farm coordinates and the coordinates of the possible interconnection points along the coastline of the different countries. All possibilities are computed and the smallest distance is retained. The formula to calculate the distance between two geographical points (lat_a,$long_a$) and (lat_b,$long_b$) is given by :

$$dist = \arccos(\sin(lat_a) \cdot \sin(lat_b) + \cos(lat_a) \cdot \cos(lat_b) \cdot \cos(long_a - long_b)) \cdot R_{earth} \tag{7.6}$$

R_{earth} is the radius of the earth and is equal to 6371km.

Losses Once the distance between the potential wind farm and the interconnected country is calculated, the losses in the cable need to be computed. As High Voltage Direct Current links are considered, the losses are approximated as 3% of the transmitted power per 1000 km.

Wind farm Construction The cost of building an offshore wind farm is assumed to be independent of the localisation. The technology envisaged being fixed-bottom offshore. The cost for installing one MW is provided by [27]. The CAPEX and the OPEX are given in the Table 21. The installation cost of offshore wind farm is obviously higher than the installation cost of onshore wind farm.

	NREL
CAPEX [k€/MW]	4615
OPEX [k€/MW/yr]	179

Table 21 – CAPEX and OPEX for offshore wind turbine

Cost of transmission The determination of the transmission costs is very difficult in our case, because there are a lot of variable parameters about which we have no information (depth, exact length,interconnecting points). There is a paper [34] about the general estimation of the cost for HVDC links. The drawback of the approach in this paper is that the installed capacity is not linearly dependant with the total cost. This implies that the objective function is not linear anymore and so the computation time increases heavily. To avoid this, a linear estimation is used.

To find a linear relation between the installed capacity of the cable and the grid connection cost, the following study [35] is used. The estimation of costs of grid connection is based on the information from Energinet. They collected this information on their last four projects (HR2, Rødsand 2, Anholt and HR3). The total cost for grid connection is the sum of two main components. The first one is due to the cost of the transformer, the offshore platform and the environmental assessment. The total cost of these components is equal to 340 k€/MW. The second one is the sea cable cost per km. This cost is equal to 2680 € per km per MW.

Sites selection From the wind data collection, only the offshore sites are retained. In total, 427 potential sites exist for the area under consideration. A lot of these sites don't have to be considered. Indeed, some sites have too depth water to consider the installation of a wind farm. Only the sites for which the depth is smaller than 100 m are considered admissible in our model.

The necessity to reduce the number of potential sites is linked to the number of variables of the optimisation problem. The multi-period problem connecting the Greenland and the zonal model without considering the storage already counts 192725 variables (for one year). But if all the offshore locations are considered, 18704735 variables are added to the system. The optimisation problem becomes much more time consuming.

For the previous reason, only few offshore sites are considered. The main criterion is the depth. The depth is checked using the EMODnet database[1]. The used of depth as decision criteria reduced the number of potential sites to 70. This number of locations even though is already highly reduced takes still too much computation time. Therefore, additional criterion has to be taken into account.

To reduce the number of potential sites, three criteria are going to be defined. Simulations are going to be performed using the offshore sites selected by these criteria. The criteria are the following :

- 5 best sites in terms of capacity factor
- 5 best sites in terms of complementarity
- 5 best sites in terms of LCOE

Determine the 5 best sites in terms of capacity factor is the easiest criterion that could be chosen. The capacity factor for the whole year is simply derived by taking the mean of the capacity factor over the whole year. The main advantage of this choice is that the 5 best sites in terms of production are chosen. Unfortunately, this criterion doesn't take into account the distance

1. `http://portal.emodnet-bathymetry.eu/?menu=19`

between the site and the consumption point. The Table 22 shows the coordinates of the 5 sites retained, the mean capacity factor and the minimum distance between the wind farm site and the closest interconnection point.

Coordinate	CF [%]	Dist [km]
(60;-2)	0.6289	885
(60;-1)	0.6200	855
(59;-2)	0.6080	795
(57;7)	0.6048	376
(57;6)	0.6009	395

Table 22 – Coordinates, capacity factor and distance between the offshore location and the closest interconnection point for the 5 sites selected using capacity factor as criterion.

As expected, more than half of the wind farms are far away from the continent. The capacity factors are higher 10% higher than the one in Greenland (50%).

Determine 5 best sites in terms of complementarity is not easy due to the lack of meaning when we deal with complementarity. The methodology to derive the most complimentary sites is inspired from [10].

Let $\alpha \in \{0, 1\}$ be a certain threshold. From the 70 remaining possible locations, 5 have to be selected. To determine the 5 best in terms of complementarity, all possible combinations have to be created. Let Θ_S be the set containing all combinations. The combination containing 5 sites are created using the Matlab function *combnk*.

Each combination of 5 sites is a subset $\Theta_S(j)$ of Θ_S. The subset $\Theta_S(j)$ is considered critical for a specific time t if all the capacity factors of the 5 sites of the subset are simultaneously below the threshold α. Let $b_j(t)$ be a binary variable associated to a specific time t and to a specific subset of Θ_S. This variable is equal to 0 if the subset is considered critical for a specific time t and is equal to one 1 if it is not critical.

$$b_j(t) = \bigcup CF_i(t) > \alpha, \quad \forall t \in \tau, \forall j \in \Theta_S, \forall i \in \Theta_S(j) \tag{7.7}$$

The best subset $\Theta_S(j)$, which contains the 5 best complementary sites, is the one for which $\sum_{t \in \mathcal{T}} b_j(t)$ is maximal. The characteristics of the 5 best complementary sites are given in the Table 23. The threshold α is equal to 0.5.

Determine the 5 best sites in terms of LCOE is easier than the previous selection. The LCOE is computed without taking the losses in the transmission cable into account. For the offshore wind farm, there are four costs to take into account :

Coordinate	CF [%]	Dist [km]
(56;2)	0.5858	385
(56;3)	0.5752	352
(55;2)	0.5802	304
(55;3)	0.5739	259
(55;4)	0.5716	224

Table 23 – Coordinates, capacity factor and distance between the offshore location and the closest interconnection point for the 5 sites selected using complementarity as criterion.

- The CAPEX cost for the wind turbine $C^{(o)}_{capex} = 4.615$ M€/MW
- The OPEX cost for the wind turbine $C^{(o)}_{opex} = 179$ k€/MW/yr
- The fixed cost associated to the transmission cable $C^{(o)}_{Tr,fixed} = 340$ k€/MW
- The variable cost associated to the length of the transmission cable $C^{(o)}_{Tr,var} = 2680$ €/km/MW

Using all these costs and denoting by L the length of the transmission cable, the LCOE of the wind farm taking into account the interconnection is given by the total cost of the installation per year divided by the total production of the installation in one year :

$$LCOE = \frac{\left(\frac{C^{(o)}_{capex}}{\Delta_W} + C^{(o)}_{opex} + \frac{C^{(o)}_{Tr,fixed}}{\Delta_{Tr}} + \frac{C^{(o)}_{Tr,var} \cdot L}{\Delta_{Tr}}\right)}{(CF \cdot T)} \tag{7.8}$$

The Table 24 shows the selected sites and their main information. The sites are closer with this criterion. The LCOE of the different wind farms is such that these wind farms could replace the gas power plant in Europe.

7.3 Simulations

7.3.1 Offshore

For the following simulations, the system cannot build a wind farm in Greenland. The system can only build wind farms in the 5 locations chosen by the criterion considered. The simulations are performed with the wind farm cost described previously (Simulation A) and with the CAPEX and the OPEX cost divided by 2 (Simulation B).

The business case is limited for Simulation A. The installed capacity is small compared to the installed capacity in CWE model. This could be expected as the LCOE of the best wind farm is 73.72 €/MWh. Compared to the LCOE cost in Table 2, there is only an interest if the wind farm production can replace the gas power plant production. Previously (see Table 7), we bring

Coordinate	LCOE [€/MWh]	CF [%]	Dist [km]
(57;7)	73.72	60.48	376
(56;6)	74.40	60.09	395
(60;-2)	75.84	62.89	885
(55;2)	76.09	58.02	304
(56;2)	76.20	58.58	385

Table 24 – Coordinates, LCOE, capacity factor and distance between the offshore location and the closest interconnection point for the 5 sites selected using LCOE as criterion.

	Criterion		
	CF	COM	LCOE
Simulation A	7	5.7	7
Simulation B	95	95	100

Table 25 – Total installed capacity in GW of offshore wind farms when the Greenland is not considered. For the simulation B, the CAPEX and the OPEX of the offshore wind farm are divided by 2.

to light that the gas power plants in Germany and in France are almost never used. This implies that there is no business case to connect an offshore wind farm to Germany and France.

The total equivalent hour of the gas power plant in Belgium and in the Netherlands decreases, respectively from 0.27 to 0.14 and from 0.27 to 0.13 for the case for which 7 GW is installed in the European sea basins. The decrease for the Dutch gas power plant is smaller (0.27 to 0.16) when only 5.7 GW is installed.

On the other hand, the interest to invest in offshore wind farms logically increases when the CAPEX and the OPEX cost are divided by 2. The LCOE is not divided by 2 because a part of the LCOE is due to the cost of the transmission which is not affected. The LCOE of the best site decreases to 39.4 €/MWh. The potential becomes enormous, because the LCOE is lower than the LCOE of all generators in the CWE model except the hydro power plants.

The installed capacity of offshore wind farms increases from 95 GW up to 100 GW. The installed capacity is, of course, limited by the availability of renewable energy. An explanation of the results is only done for the complementarity criterion, the difference with the other simulations is small.

For the simulation based on the complementary criterion, the installed capacity is 95 GW. The total transmission capacities between the offshore locations and Belgium, Germany, France and the Netherlands are respectively 8.5, 38.7, 34.7 and 13.8 GW.

The Figure 17 shows the Total Equivalent Hour. The hydro power plants are the most used, because they are the least expensive. The total equivalent hour for the other power plants decreases severely. The total cost of the system is $4.4845 \cdot 10^{10}$ €.

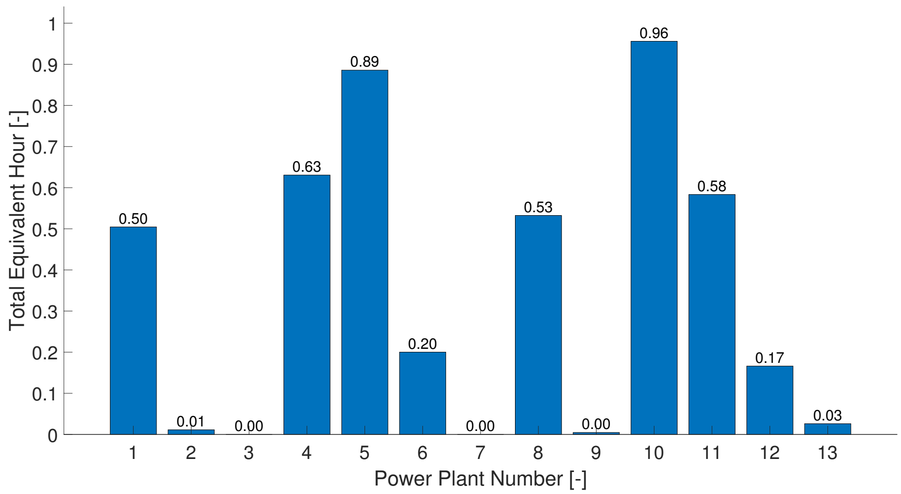

Figure 17 – Total Equivalent Hour for the zonal model when the model is allowed to build offshore wind farms (Complementary criterion)

7.3.2 Offshore vs Greenland

For the following simulations, the system can build wind farms in Greenland and in the 5 locations chosen by the criterion considered. The simulations are performed with the wind farm cost described previously (Simulation C) and with the CAPEX and the OPEX cost divided by 2 (Simulation D). The costs for the Greenland model are unchanged.

	Criterion					
	CF		COM		LCOE	
	GR [GW]	Off [GW]	GR [GW]	Off [GW]	GR [GW]	Off [GW]
Simulation C	62	0	62	0	62	0
Simulation D	0	95	0	95	0	100

Table 26 – Total installed capacity (in GW) of offshore wind farms when the Greenland is considered. For the simulation D, the CAPEX and the OPEX of the offshore wind farms are divided by 2.

The Table 26 shows the results for simulations C and D. There is clearly two different results. When the basic cost is considered for the offshore wind farm, only wind farm in Greenland is installed. The business case for the offshore wind farm is cancelled by the Greenland. Indeed, the production of the gas power plants are reduced by the energy imported from Greenland. There is no possibility for offshore wind farms.

The opposite trend is observed when the CAPEX and the OPEX are divided by 2. All the wind farms are installed in the European sea basins. The benefit of the wind farms in Greenland is reduced, because the most expensive generators are already less used due to the energy imports from offshore wind farms. Furthermore, this is less expensive to invest in offshore wind farms.

7.3.3 Offshore wind farm : optimal cost

The aim is to determine the installed capacity in Greenland and in European sea basins when the CAPEX and the OPEX of the offshore wind farm are multiplied by a factor. This factor varies from 0 to 1. The CAPEX for the wind farm in Greenland is unchanged, but two OPEX costs are considered. The usual value and the same value multiplied by 2. The OPEX costs are multiplied by 2 in the second case to bring to light the impact on an increase of the operational cost due to harder conditions in Greenland. The selection criterion is the complementary criterion.

The case for which the multiplier is equal to zero is not brought to light by the Figure 18, because the offshore installed capacity reaches $4.39 \cdot 10^7$ GW. If this case is added, the Figure 18 becomes unreadable.

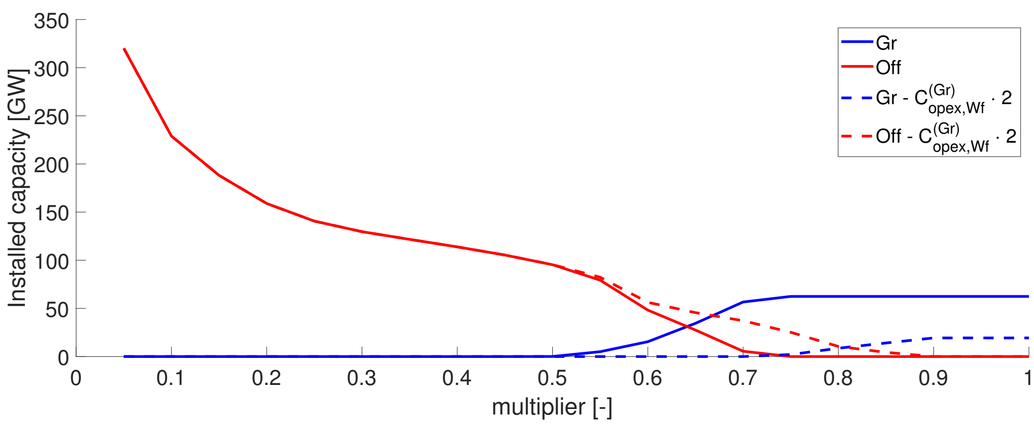

Figure 18 – Installed capacity in Greenland and for the offshore sites when the CAPEX and the OPEX of the offshore wind turbines are multiplied by a corrective factor. The OPEX for the wind farms in Greenland is equal to the 45.8 or 91.6 k€/MW/year.

The case for which the OPEX in Greenland is equal to 45.8 k€/MW/year is considered. More than 300 GW of offshore wind farms are installed when the multiplier is equal to 0.05. The corresponding LCOE is around 5 €/MWh. Some wind turbines are installed (5 GW) in Greenland when the multiplier is equal to 0.55. The corresponding LCOE for offshore wind farm is around 40€/MWh. The installed capacity in Greenland increases rapidly above this value. The maximum installed capacity in Greenland is 62 GW. This maximum is already reached for multiplier equals to 0.75. This implies that there is no interest to invest in offshore wind farms instead of Greenland wind farms if the LCOE is above 54.46 €/MWh. For LCOE of offshore wind farm belonging to {40;54.46} €/MWh, there is interest to invest both in Greenland and in offshore wind farms. Of course, the interest for an investment in offshore wind farms decreases as the LCOE increases.

When the OPEX cost is equal to 91.6 k€/MW/year, the maximum installed capacity in Greenland falls to 19 GW. The installed capacity for the offshore sites is more important than 10 GW until a LCOE equals to 58 €/MWh. Above 61.54 €/MWh, the installed capacity is zero. For LCOE of offshore wind farm belonging to {54.46;61.54} €/MWh, there is interest to invest both in Greenland and in offshore wind farms.

8 Conclusion

The current study evaluates the potential to harvest high quality renewable energy in Greenland through a hybrid pricing multi-period model. The hybrid model connects the PJM and the CWE models via the Greenland, defined as a potential production hub. The aim of the optimisation problem is to minimise the total cost of the system. The total cost of the system includes the installation costs of the HVDC links and of the wind farms in Greenland and the production costs of all the generators.

The reference case for the hybrid model is defined as the total cost of the system when the zonal and the nodal models are isolated. Other simulations are performed for which there is the possibility to invest in Greenland (HVDC links, wind farms and/or storage units). Simulations show that, under certain assumptions, the total cost of the system can be reduced by more than 8% when the Greenland is used as a production hub. As the installation costs in Greenland are assumptions, sensibility analysis are performed to study the evolution of the installed capacity in function of the installation costs. The investor point of view was considered too, simulations show that there is a potential benefit to invest in Greenland until a total wind farm installed capacity of 180 GW.

Another benefit of the Global Grid approach is highlighted via a CO_2 analysis. The objective of the optimisation problem is modified. The total CO_2 emissions replace the total cost of the system. The global CO_2 emissions are widely reduced thanks to the Global Grid approach for two main reasons : The CO_2 emissions of the wind farm in Greenland is negligible compared to the most polluting generators and the HVDC links allow to use less the most polluting units. When 50 GW of wind farms are installed in Greenland, the CO_2 emissions of the system are already reduced by 32%.

Finally, as there is also a wind potential in the European sea basins, the compromise between investing in Greenland and/or in European sea basins is studied. The optimisation problem is upgraded in order to allow the system to build offshore wind farms near the European continent. Simulations show that, under certain cost assumptions, there is interest to invest simultaneously in Greenland and in European sea basins if the LCOE of the offshore wind farms is reduced at least up to 61.54€/MWh.

Regarding further research directions, perform similar simulations with another wind turbine whose the cut-off speed is higher could still increase the interest of wind farms in Greenland. The aggregated power plants can be split to small units in order to add start up cost and other constraints on the generation to obtain more realistic results. A realistic representation of a nodal model is required in order to add the possibility to consider the additional costs linked to the network reinforcement after the installation of HVDC links.

A Derivation of the LMP for the Hybrid model

Using the DC-OPF for the Hybrid model, the Lagrangian can be derived. The derivation is done at a specific time t.

$$
\begin{aligned}
&\mathrm{L}(\mathrm{P}_G^{(z)}, P_G^{(n)}, P_G^{(GR)}, P_{Tr}^{(GR-z)}, P_{Tr}^{(GR-n)}, P_{inst}^{(GR)}, P_{Z\to GR}, P_{GR\to Z}, P_{N\to GR}, P_{GR\to N},\\
&\mu^{(z)}, \mu^{(n)}, \mu^{(GR)}, \lambda^{(z)}, \lambda^{(n)}, \lambda^{(GR\to Z)}, \lambda^{(GR\to N)}, \nu^{(z)}, \nu^{(n)}, \nu^{(GR)})\\
&= \textstyle\sum_{i\in\Omega_z} C_{G_i}^{(z)} P_{G_i}^{(z)} + \sum_{i\in\Omega_n} C_{G_i}^{(n)} P_{G_i}^{(n)} + C_G^{(GR)} P_G^{(GR)}\\
&+ \nu^{(z)} \left(\textstyle\sum_{i\in\Theta_z} \left(P_{A_i}^{(z)} - P_{D_i}^{(z)} + \alpha_i^{GR\to Z} P_{GR\to Z,i} - P_{Z\to GR,i}\right)\right)\\
&+ \nu^{(n)} \left(\textstyle\sum_{i\in\Theta_n} \left(P_{A_i}^{(n)} - P_{D_i}^{(n)} + \alpha_i^{GR\to N} P_{GR\to N,i} - P_{N\to GR,i}\right)\right)\\
&+\nu^{(GR)} \left(P_G^{(GR)} - \textstyle\sum_{i\in\Theta_n} P_{GR\to N,i} - \sum_{i\in\Theta_z} P_{GR\to Z,i} + \sum_{i\in\Theta_z} \alpha_i^{Z\to GR} P_{Z\to GR,i} + \sum_{i\in\Theta_n} \alpha_i^{N\to GR} P_{N\to GR,i}\right)\\
&+ \textstyle\sum_{i=1}^{N_L^{(z)}} \lambda_i^{(z),+} \left(\sum_{j\in\Theta_z} PTDF_{i,j}^{(z)} \left(P_{A_j}^{(z)} - P_{D_j}^{(z)} + \alpha_j^{GR\to Z} P_{GR\to Z,j} - P_{Z\to GR,j}\right) - RAM_i\right)\\
&+ \textstyle\sum_{i=1}^{N_L^{(z)}} \lambda_i^{(z),-} \left(\sum_{j\in\Theta_z} -PTDF_{i,j}^{(z)} \left(P_{A_j}^{(z)} - P_{D_j}^{(z)} + \alpha_j^{GR\to Z} P_{GR\to Z,j} - P_{Z\to GR,j}\right) - RAM_i\right)\\
&+ \textstyle\sum_{i=1}^{N_L^{(n)}} \lambda_i^{(n),+} \left(\sum_{j\in\Theta_n} PTDF_{i,j}^{(n)} \left(P_{A_j}^{(n)} - P_{D_j}^{(n)} + \alpha_j^{GR\to N} P_{GR\to N,j} - P_{N\to GR,j}\right) - F_i^{max}\right)\\
&+ \textstyle\sum_{i=1}^{N_L^{(n)}} \lambda_i^{(n),-} \left(\sum_{j\in\Theta_n} -PTDF_{i,j}^{(n)} \left(P_{A_j}^{(n)} - P_{D_j}^{(n)} + \alpha_j^{GR\to N} P_{GR\to N,j} - P_{N\to GR,j}\right) - F_i^{max}\right)\\
&+ \textstyle\sum_{i=1}^{N_L^{(GR\to Z)}} \lambda_i^{(GR\to Z),+} \left(P_{GR\to Z,i} - P_{Z\to GR,i} - P_{Tr,i}^{(GR-z)}\right)\\
&+ \textstyle\sum_{i=1}^{N_L^{(GR\to Z)}} \lambda_i^{(GR\to Z),-} \left(-P_{GR\to Z,i} + P_{Z\to GR,i} - P_{Tr,i}^{(GR-z)}\right)\\
&+ \textstyle\sum_{i=1}^{N_L^{(GR\to N)}} \lambda_i^{(GR\to N),+} \left(P_{GR\to N,i} - P_{N\to GR,i} - P_{Tr,i}^{(GR-n)}\right)\\
&+ \textstyle\sum_{i=1}^{N_L^{(GR\to N)}} \lambda_i^{(GR\to N),-} \left(-P_{GR\to N,i} + P_{N\to GR,i} - P_{Tr,i}^{(GR-n)}\right)\\
&+ \textstyle\sum_{i=1}^{N_G^{(z)}} \mu_i^{(z),-} \left(P_{G_i}^{min,(z)} - P_{G_i}^{(z)}\right) + \sum_{i=1}^{N_G^{(z)}} \mu_i^{(z),+} \left(P_{G_i}^{(z)} - P_{G_i}^{max,(z)}\right)\\
&+ \textstyle\sum_{i=1}^{N_G^{(n)}} \mu_i^{(n),-} \left(P_{G_i}^{min,(n)} - P_{G_i}^{(n)}\right) + \sum_{i=1}^{N_G^{(n)}} \mu_i^{(n),+} \left(P_{G_i}^{(n)} - P_{G_i}^{max,(n)}\right)\\
&+ \mu^{(GR),-} \left(P_G^{min,(GR)} - P_G^{(GR)}\right) + \mu^{(GR),+} \left(P_G^{(GR)} - P_G^{max,(GR)}\right)
\end{aligned}
$$

Per definition, the Locational Marginal Price is given by the marginal change in the cost function for a marginal change in the load ξ :

$$LMP = \frac{\partial \mathbb{L}}{\partial \xi} \tag{A.1}$$

The derivation of the Locational Marginal Price for the zonal and the nodal model is equivalent because the optimization problem for both models is identical in this study. Therefore, the following derivation is applicable for both models.

If we derive the LMP for the nodal model, the very small change in the load is added to the vector P_D^n. So this vector becomes $\tilde{P}_D^n = P_D^n + \Xi$ where each element of Ξ is equal to zero except for the first element. The first element is equal to ξ_1.

The Lagrangian will be rewritten take into account this change. To simplify the calculation, only the term of the Lagrangian that content the auxiliary variable ξ is existent.

$$\mathrm{L}(\mathrm{P}_G^{(z)}, P_G^{(n)}, P_G^{(GR)}, P_{Tr}^{(GR-z)}, P_{Tr}^{(GR-n)}, P_{inst}^{(GR)}, P_{Z\to GR}, P_{GR\to Z}, P_{N\to GR}, P_{GR\to N},$$
$$\mu^{(z)}, \mu^{(n)}, \mu^{(GR)}, \lambda^{(z)}, \lambda^{(n)}, \lambda^{(GR\to Z)}, \lambda^{(GR\to N)}, \nu^{(z)}, \nu^{(n)}, \nu^{(GR)})$$

$$+ \nu^{(n)} \left(\sum_{i\in\Theta_n} \left(P_{A_i}^{(n)} - (P_{D_i}^{(n)} + \xi_i) + \alpha_i^{GR\to N} P_{GR\to N,i} - P_{N\to GR,i}\right)\right)$$

$$+ \sum_{i=1}^{N_L^{(n)}} \lambda_i^{(n),+} \left(\sum_{j\in\Theta_n} PTDF_{i,j}^{(n)} \left(P_{A_j}^{(n)} - P_{D_j}^{(n)} + \alpha_j^{GR\to N} P_{GR\to N,j} - P_{N\to GR,j} - \xi_i\right) - F_i^{max}\right)$$
$$+ \sum_{i=1}^{N_L^{(n)}} \lambda_i^{(n),-} \left(\sum_{j\in\Theta_n} -PTDF_{i,j}^{(n)} \left(P_{A_j}^{(n)} - P_{D_j}^{(n)} + \alpha_j^{GR\to N} P_{GR\to N,j} - P_{N\to GR,j} - \xi_i\right) - F_i^{max}\right)$$

So the LMP can be derived :

$$LMP = \frac{\partial \mathbb{L}}{\partial \xi_1} = -\nu^{(n)} - \lambda_1^{(n),+} PTDF_1^{(n)} + \lambda_1^{(n),-} PTDF_1^{(n)} \tag{A.2}$$

Using the same methodology for the Greenland :

$$\mathrm{L}(\mathrm{P}_G^{(z)}, P_G^{(n)}, P_G^{(GR)}, P_{Tr}^{(GR-z)}, P_{Tr}^{(GR-n)}, P_{inst}^{(GR)}, P_{Z\to GR}, P_{GR\to Z}, P_{N\to GR}, P_{GR\to N},$$
$$\mu^{(z)}, \mu^{(n)}, \mu^{(GR)}, \lambda^{(z)}, \lambda^{(n)}, \lambda^{(GR\to Z)}, \lambda^{(GR\to N)}, \nu^{(z)}, \nu^{(n)}, \nu^{(GR)})$$

$$+ \nu^{(GR)} \left(P_G^{(GR)} - \sum_{i\in\Theta_n} P_{GR\to N,i} - \sum_{i\in\Theta_z} P_{GR\to Z,i} + \sum_{i\in\Theta_z} \alpha_i^{Z\to GR} P_{Z\to GR,i} + \sum_{i\in\Theta_n} \alpha_i^{N\to GR} P_{N\to GR,i} - \xi\right)$$

As the variable Ξ only have an impact on the power balance in the Greeland region, the LMP for Greenland is given by :

$$LMP = \frac{\partial \mathbb{L}}{\partial \Xi} = -\nu^{(GR)} \tag{A.3}$$

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