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Incorporation of Power Flow Descriptions in an Optimization Model for Multinational Transmission Expansion Planning

A Comparative Analysis of Power Flow
Modeling Using NTCs and PTDFs

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Abstract

Multinational transmission expansion planning (TEP), i.e. investments in cross-border electric power exchange capacity, is an important step towards achieving the ambitious decarbonization targets for the energy sector outlined by the European Commission. Power system flexibility and increased market integration are key elements for ensuring security of supply and avoiding curtailment of power production from renewable energy sources (RES), and is considered vital by the European Network of Transmission System Operators for Electricity (ENTSO-E) to maintain an efficient and secure pan-European power market. However, the most promising RES utilization strategy in Europe, harvesting intermittent solar- and wind energy, is characterized by large utilization potentials located far from onshore load centers, e.g. offshore wind in the North Sea, requiring long-distance transmission cables. To ensure optimal expansion of the interconnected European power grid, it is crucial to coordinate the connection of both future and existing offshore wind farms with the expansion of cross-border exchange capacity. However, offshore grid expansion may evoke unidentified distributional effects in the onshore AC grid, presenting operational system challenges. Hence, it is of great importance to develop decision-making tools that are suited for future market environments outlining the cost recovery of such investments, and to improve the power system modeling within these tools to enable TEP-models to account for distributional effects in the grid.

In light of multinational TEP, this thesis presents a comparative analysis quantifying the effects of expanding the system boundaries of an optimization model for grid investments, and subsequently incorporating different power flow modeling techniques. Considered techniques include a transportation model of the power network using net transfer capacities (NTCs), and a flow-based (FB) methodology utilizing power transfer distribution factors (PTDFs). Analyzes were conducted utilizing the generic TEP optimization model NetOp developed by SINTEF Energy, using mixed integer linear programming (MILP), to quantify the impact of applying the suggested model extensions to the North Seas offshore grid (NSOG). The analyzes were carried out under the four

ENTSO-E 2030 Visions, outlining the future development of the European power system.

The results indicated a great need for expansion of the NSOG to reach EU's climate goals regardless of grid modeling technique and parameter forecast. All scenarios with both methodologies showed that the existing system is constrained by NSOG interconnectors of suboptimal capacity. Furthermore, the two approaches produced different optimal solutions, as expected from theory, with flow-based modeling resulting in greater power flows, stimulating higher investments in transmission capacity. This originates from the fact that FB takes all flows in the system into account, resulting in a more realistic representation of the grid, and differs from NTCs mainly because different laws and characteristics apply to commercial and physical exchange of electricity in an interconnected system. Additionally, there are indications of different utilization strategies for the major interconnectors of the North Seas with the two models, shifting Norway's role from provider of power and balancing services to transportation hub when moving from an NTC- to a PTDF representation. An overall assessment of the results reveals that an NTC-approach might yield suboptimal solutions to TEP, and that FB should be the preferred modeling technique where applicable. However, it is more computationally and analytically demanding.

To the author's knowledge, no similar studies regarding the impact of incorporating different power flow modeling techniques in a TEP-context have been conducted, particularly not for joint operational- and investment optimization of multinational offshore applications representing a mix of both HVAC- and HVDC grids. Two relevant contributions from this work will be improvement of AC grid representation in a MILP-model for multinational TEP, and quantification of investment- and computational effects of using different power flow modeling techniques. In addition, an indirect contribution of this work includes the possibility of enhanced evaluation of distributional effects of large offshore grid investments resulting from the improved AC grid representation.

Sammendrag

Multinasjonal nettutbyggingsplanlegging, kapasitetsinvesteringer i mellomlandsforbindelser for elektrisk kraftoverføring, er et viktig steg mot oppnåelse av energisektorens dekarboniseringsmål utarbeidet av Europakommisjonen. Fleksibilitet i kraftnettet og økt markedsintegrering er sentrale elementer for økt forsyningssikkerhet og redusert begrensning av fornybar produksjonskapasitet, og er av European Network of Transmission System Operators for Electricity (ENTSO-E) ansett som avgjørende for å opprettholde et effektivt og sikkert paneuropeisk kraftmarked. Samtidig er de mest lovende kildene til utvinning av fornybar energi i Nord-Europa, variabel sol- og vindkraft, karakterisert med sitt største utvinningspotensiale lokalisert langt fra lastsentrene på kontinentet, for eksempel offshore vind i Nordsjøområdet, og har dermed et behov for lange kraftoverføringskabler til land. For å sikre optimal ekspansjon av det europeiske kraftnettet er det essensielt å koordinere tilkobling av både eksisterende og fremtidige offshore vindparker med utvidelser av overføringskapasitet mellom prisområder. Dette kan derimot føre til operasjonelle utfordringer da økt overføringskapasitet kan medføre uidentifiserte distribusjonseffekter i det eksisterende AC-nettet. Det er derfor avgjørende å utvikle verktøy for beslutningsstøtte tilpasset fremtidige markedsløsninger for å kartlegge kostnadsdekningen av slike investeringer, samt å forbedre modelleringen av kraftsystemet i disse verktøyene for å muliggjøre avdekking av distribusjonseffektene i nettet.

Denne avhandlingen presenter en komparativ analyse som kvantifiserer innvirkningen av systemgrenseutvidelser av en nettinvesteringsmodell, og deretter effekten av å anvende forskjellige metoder for kraftflytmodellering. De anvendte metodene inkluderer en transportmodell som begrenser kraftflyten til linjenes netto overføringskapasitet (NTC), samt en flytbasert modell (FB) som benytter seg av sensitivitetsfaktorer for effektflytfordeling (PTDF). Analyser ble utført på offshorenettet i Nordsjøområdet ved bruk av den generiske nettinvesteringsmodellen NetOp utviklet av SINTEF Energi, som bruker lineær blandet heltallsprogrammering (MILP), for å kvantifisere påvirkningen av å inkorporere de nevnte modellutvidelsene. Analysene ble

gjort under de fire scenarioene fremlagt av ENTSO-E for utviklingen av det europeiske kraftsystemet frem mot 2030.

Resultatene fremlagt i avhandlingen indikerer et betydelig behov for ekspansjon av Nordsjønettet for å nå EUs klimamål uavhengig av metode for nettmodellering og framtidsprognose. Alle scenarier med både NTC og PTDF viste at driften av det eksisterende Nordsjønettet er begrenset av mellomlandsforbindelser med suboptimal kapasitet. Videre viser resultatene, som forventet fra teori, at de to modelleringsmetodene produserte forskjellige optimale løsninger hvor flytbasert modellering fremkalte større kraftflyt i systemet, noe som videre stimulerte høyere kapasitetsinvesteringer. Dette stammer fra det faktum at FB tar alle kraftflyter i systemet i betraktning, noe som fører til en mer realistisk representasjon av overføringsnettet. Dette skiller FB fra NTC da forskjellige lover gjelder for kommersiell og fysisk utveksling av elektrisk kraft. Videre er det indikasjoner på at de to metodene fremprovoserer forskjellige utnyttelsesstrategier for mellomlandsforbindelsene i Nordsjøområdet, hvor Norges rolle skiftes fra leverandør av kraft og balansetjenester til det europeiske kontinentet med NTC til et knutepunkt for kraftoverføring mellom Kontinentaleuropa og De britiske øyer med PTDF. Summen av dette indikerer at bruk av NTC kan gi suboptimale løsninger på nettutbyggingsplanlegging, og at FB burde være den foretrukne fremgangsmåten. FB er derimot mer både analytisk- og beregningsmessig krevende.

Så langt forfatteren av denne avhandlingen kjenner til, har det aldri tidligere blitt utført studier rundt effekten av inkorporering av forskjellige metoder for kraftflytmodellering i nettutbyggingssammenheng. Spesielt ikke ved samoptimering av både nettdrift og -investeringer i multinasjonale anvendelser sammensatt av både HVAC- og HVDC nett. To relevante bidrag fra dette arbeidet vil være forbedret representasjon av AC nett i MILP-modeller for nettutbyggingsplanlegging, med medfølgende muligheter for forbedret evaluering av resulterende distribusjonseffekter, samt kvantifisering av investerings- og beregningseffekter av forskjellige metoder for effektflytmodellering.

Preface

This a Master's Thesis concluding my Master of Science (M.Sc.) degree in Energy and Environmental Engineering with the Department of Electric Power Engineering at the Norwegian University of Science and Technology (NTNU). The thesis was written in cooperation with SINTEF Energy as a part of their research into electric power transmission expansion planning, under the supervision of Professor Magnus Korpås and PhD Candidate Martin Kristiansen with the Department of Electric Power Engineering at NTNU.

I have gained through this research valuable knowledge and a sound basis for further work within the areas of power markets and transmission expansion planning. It is with great gratitude that I would like to thank my supervisors for the guidance throughout the project, and for their willingness to answer my questions and sharing their knowledge. I would also like to extend my gratitude to PhD Candidate Yonas Tesfay Gebrekiros with the Department of Electric Power Engineering at NTNU and SINTEF Energy for his invaluable assistance on flow-based modeling and PTDFs, and to William Matus with University of Michigan for proofreading.

The thesis is written assuming that the reader has little or no previous knowledge of subjects presented.

Trondheim, June 2016

Lars Åmellem

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Abbreviations

4M MC	4M Market Coupling Project
AAC	Already allocated capacity
AC	Alternating current
AMU	Average mean utilization
ATC	Available transfer capacity
BM	Balancing Markets
CAPEX	Capital expenditure
CET	Central European Time (GMT+1)
CfD	Contracts for Difference
CNE	Critical network element
CNTC	Coordinated net transfer capacity
DAM	Day-ahead market
DC	Direct current
EC	European Commission
ELBAS	Electrical Balancing Adjustment System
EMCC	European Market Coupling Company
EMPS	EFIs Multi-area Power-market Simulator
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
FB	Flow-based
FBMC	Flow-based market clearing
FCR	Frequency Containment Reserves
FM	Financial market
FRR-A	Automatic Frequency Restoration Reserves
FRR-M	Manual Frequency Restoration Reserves
FTR	Financial Transmission Right
GSK	Generator Shift Key
HVDC	High voltage DC
IDM	Intra-day market

MRC	Multi-Regional Coupling Project
MILP	Mixed integer linear programming
NC CACM	Network Code on Capacity Calculation and Congestion Management
NDSG	Network Development Stakeholder Group
NetOp	Network Optimization Tool
NOWITECH	Norwegian Research Center for Offshore Wind Technology
NP	Net position
NPS	Nord Pool Spot
NPV	Net present value
NSOG	North Seas offshore grid
NTC	Net transfer capacity
NTNU	Norwegian University of Science and Technology
NVE	The Norwegian Water Resources and Energy Directorate
OPEX	Operating expenditure
OPF	Optimal power flow
PCI	Projects of Common Interest
PCR	Price Coupling of Regions
PF	Power flow
PTDF	Power transmission distribution factor
PX	Power Exchange
RES	Renewable energy sources
RK	Regulating Power Market
RKOM	Regulating Power Options Market
SMP	System marginal price
T&D	Transmission and distribution
TEP	Transmission expansion planning
TRM	Transmission reliability margin
TSO	Transmission System Operator
TTC	Total transfer capacity
TYNDP	Ten-Year Network Development Plan

Nomenclature

P_i	Net active power injection in node i
Q_i	Net reactive power injection in node i
N	Number of nodes
U_i	Voltage magnitude in node i
δ_i	Voltage angle of node i in radians
G_{ik}	Conductance between node i and k with negative sign
G_{ii}	Sum of all conductances connected to node i
B_{ik}	Susceptance between node i and k with negative sign
B_{ii}	Sum of all susceptances connected to node i
$\boldsymbol{P}$	Vector of net active power injection in all nodes
$\boldsymbol{Y_{bus}}$	Bus admittance matrix, also called B-matrix
$\boldsymbol{Y'_{bus}}$	Bus admittance matrix augmented with reference node
$\boldsymbol{\delta}$	Vector of voltage angle at all nodes
P_{ij}	Active power flow on the line connecting nodes i and j
r_{ij}	Resistance of the line connecting nodes i and j
x_{ij}	Reactance of the line connecting nodes i and j
j	Imaginary unit
$\boldsymbol{Z_{bus}}$	Bus impedance matrix
$\boldsymbol{Z'_{bus}}$	Bus impedance matrix augmented with reference node
$PTDF_{ik,n}$	Sensitivity parameter for flow on line i-k resulting from export from node n
$\boldsymbol{PTDF}$	PTDF-matrix of a system of n nodes and l lines
NP_n	Net position of node n
$\boldsymbol{P_{line}}$	Vector of active power flow on all lines in a system
$\boldsymbol{NP}$	Vector of the net position of all nodes in a system
$PTDF_{ik,A}$	Sensitivity parameter for flow on line i-k resulting from export from area A
GSK_n	Generation Shift Key of node n

€	Euro currency sign
C_{tot}	Total system costs for covering a given demand
I	Set of all nodes in the system
I_i	Subset of all neighboring nodes to node i
G	Set of all generators
G_i	Subset of all generators at node i
S	Set of all states
x_g^s	Power generated by generator g in state s
c_g	Marginal cost of generation for generator g
a	Annuity factor; a factor calculating the present value of an annual payment occurring at the end each period for the duration of the economic lifetime
t	Number of hours during the year that each state represents, $t = \frac{8760}{\lvert S \rvert}$
$x_{\kappa,ij}$	New interconnector capacity between node i and j
c_{ij}	Cost of new capacity between node i and j
y_{ij}	Number of new cables/lines built between node i and j, integer
f_{ij}	Fixed cost of a new cable between node i and j
y_i	Indicates whether a new node i is built or not, binary
f_i	Fixed cost of building node i
x_{ij}^s	Power transmitted from node i to j in state s
l_{ij}	Linear losses on the interconnector between node i and j
b_i^s	Load at node i in state s
$x_{g,min}^s$	Minimum generation capacity for generator g in state s
$x_{g,max}^s$	Maximum generation capacity for generator g in state s
κ_{ij}	Pre-existing capacity between node i and j
$PTDF_{ij,n}^s$	PTDF-factor for line ij due to net position of node n in state s
$x_{ij,max}$	Maximum transmission capacity per cable between node i and j
E_g	Upper limit for annual generation for generator g
M	A sufficiently large number

Chapter 1
Introduction

1.1 Background

Multinational transmission expansion planning (TEP), i.e. investments in cross-border electric power exchange capacity, is an important step towards achieving the ambitious decarbonization targets for the energy sector outlined by the European Commission (EC) [1]. Recent studies conducted by academia and governmental organizations suggest that multinational grid expansion is an absolute necessity to handle the increasing volatility in both electricity prices, and power system balance arising due to the increasing share of intermittent renewable energy sources (RES) in the interconnected European power system [2, 3, 4]. Power system flexibility and increased market integration are key elements for ensuring security of supply and avoiding curtailment of RES production, and is for these reasons considered vital by the European Network of Transmission System Operators for Electricity (ENTSO-E) to maintain an efficient and secure pan-European power market [5]. In many cases, this can be solved by sufficient transmission capacity and interconnection of market areas [6]. However, such grid investments are typically highly capital intensive with a long economic lifetime, and can be classified as sunk costs[1].

In order to achieve the aforementioned goals, the most promising RES utilization strategy in Europe, harvesting intermittent solar- and wind energy, is characterized by large utilization potentials located far from load centers, e.g. offshore wind in the North Seas[2] [8]. However, the optimal development of an adequate power system in order the reach these targets represents multiple challenges, as identified by the ENTSO-E [2]. Some of these wind

[1] A sunk cost is a cost or investment that has already been incurred and thus cannot be recovered. Sunk costs are independent of any future events and utilization strategy, because it has already incurred.

[2] The North Seas are considered to be the Irish, North and Baltic seas, the English Channel, Kattegat and Skagerrak.

farms are located far from shore, requiring long-distance subsea cable connections to the onshore grid. To ensure optimal expansion of the interconnected European power system, it is crucial to coordinate the connection of both future and existing offshore wind farms with the expansion of cross-border exchange capacity, possessing the possibility of creating the world's first supergrid as the North Seas offshore grid (NSOG) are without predefined transmission technology or topology [7, 9]. Thus, TEP can serve the twofold purpose of providing both increased system flexibility and reliability due to efficient dispatch and greater utilization of RES, and increased trading resulting in improved overall market efficiency and socio economic welfare [10].

Modeling of the physical power flows in TEP is a difficult task, mainly because different laws and characteristics apply to commercial and physical exchange of electricity in an interconnected system [11]. This is particularly the case when dealing with alternating current (AC) systems of considerable size, like the European power system, since physical power flows may take multiple paths though a grid, in accordance with Kirchhoff's circuit laws [12]. Increased exchange capacity and generation therefore represents operational challenges for the existing AC transmission system, demanding models that account for the distributional effects in the onshore grid when planning multinational transmission investments [11]. This would enable TEP-models to uncover possible transmission expansion needed to facilitate for the increased power flows in other parts of the interconnected system.

The transmission grid is the backbone of today's power system, and it is of great importance to develop decision-making tools that are suited for future market environments outlining the cost recovery of grid investments, and to improve the power system modeling within these tools [10].

1.2 Previous Work

Due to its importance and priority to the European climate and energy policy, several research projects has been conducted on the NSOG over the past years. These include, among others, the projects of Norwegian Research Center for Offshore Wind Technology (NOWITECH) [13], OffshoreGrid [14], North Sea Transnational Grid [15] and the collaboration between E3G and Imperial College [16]. Despite these, there is still uncertainty as to the optimal design of the grid, and multiple optimization models for multinational TEP have been created [7]. However, most of today's models lack an appropriate representation of the physical grid, precluding the models from calculating realistic power flows and accounting for distributional effects [11]. Models presented by Jaehnert *et al.* utilizing EFIs Multi-area Power-market Simulator (EMPS) [17], Trötcher and Korpås creating Network Optimization Tool (NetOp) [9] (both developed by SINTEF Energy), Akbari *et al.* [18] and Lotfjou *et al.* [19], all use a low degree of detail when modeling the power flows in the system by applying net transfer capacity (NTC)-constraints as described in detail in Section 3.2.1.

The foundation of this thesis is the research conducted by Trötcher and Korpås at SINTEF Energy, resulting in the creation of NetOp. Their research article *A Framework to Determine Optimal Offshore Grid Structures for Wind Power Integration and Power Exchange* of 2011, presents a framework to find optimal offshore grid expansions utilizing a transportation model of the NSOG and its surrounding countries, optimized by using mixed integer linear programming (MILP) [9]. Section 4.3 provides a detailed description of NetOp. A transportation model of the grid is, however, not adequate as it does not account for transit flows and distributional effects, as discussed later in this thesis. Replacing the NTCs with a flow-based (FB) representation of the grid utilizing power transmission distribution factors (PTDFs) as described in Section 3.2.2, could possibly yield a more detailed description of the distributional effects, resulting in solutions closer to the true optimum. Hagspiel *et al.* present such a grid modeling technique in [11], jointly optimizing generation dispatch and transmission capacity through an iterative approach using PTDFs.

The basis of this Master's Thesis is its pre-work conducted by the same author in the fall of 2015. Parts of the resulting report are included in this thesis.

1.3 Scope

In light of multinational TEP, this thesis presents a comparative analysis quantifying the effects of expanding the system boundaries of an optimization model for grid investments, emphasizing on the onshore AC grid, and subsequently incorporating different power flow modeling techniques. Considered techniques include a transportation model of the power network using net transfer capacities (NTCs), and a flow-based (FB) methodology utilizing power transfer distribution factors (PTDFs). Analyzes are conducted utilizing the TEP optimization model NetOp developed by SINTEF Energy, using mixed integer linear programming (MILP), to quantify the impact of applying the suggested model extensions to the North Seas offshore grid (NSOG), revealing possible differences in optimal solutions of the interconnectors. The analyzes are carried out under the four ENTSO-E 2030 Visions, outlining the future development of the European power system.

The topics discussed in this thesis are related to the relevant areas of NetOp, i.e. the North Sea region comprising Norway, Sweden, Denmark, Finland, Germany, Netherlands, Belgium, Great Britain, and their neighboring seas. Hence, discussions are based upon the Nordic and European interconnected power system structure and operation.

1.4 Report Structure

Chapter 1, *Introduction*, introduces the reader to the topics discussed in this thesis as well as a short overview on the previous work within the field of multinational TEP and the scope of the thesis research.

Chapter 2, *Power System Modeling*, provide an introduction to mathematical modeling of the power flows in an electric power system. This is done by introducing the power flow equations, followed by the derivation of the PTDFs. Lastly, some insight into the application of PTDFs is provided, which will be utilized in later chapters.

Chapter 3, *The Nordic Power Markets*, presents an introduction to the structure and operation of the different markets that together create the Nordic and European power markets. This is included because basic insight into the operation of the power markets are important for the creation and application of TEP-models.

Chapter 4, *Transmission Expansion Planning*, provides some insight into the theory behind TEP. It also presents an optimization model that can be used for TEP, and an example utilizing this model with the two different approaches; NTCs and PTDFs, on a simple three-node system.

Chapter 5, *Case Study*, further applies the model presented in the previous chapter to conduct a comparative analysis quantifying the effects of model expansion and modification by presenting and discussing the results.

Chapter 6, *Conclusion*, sums up the results of the analysis of Chapter 5 before presenting some concluding remarks. Finally, some suggestions for future work on the topic of multinational TEP models are given at the end of the chapter.

Chapter 2

Power System Modeling

This chapter is obtained from the pre-work of this thesis [10]. It provides a stepwise derivation of the mathematical approximations of the power flows in a system. The reader should consult the Nomenclature provided in the beginning of the thesis for clarification of symbols used in the equations of this chapter.

2.1 The Power Flow Equations

The basis for mathematical modeling of power flows in a system, is the *AC power flow (PF)* or *load flow* equations, given in Equation 2.1 as denoted in most electrical engineering literature [12]. These non-linear sets of equations describe the steady-state relationship between active and reactive power injections, and voltages in a given system. They result from the physical reality of an electric grid where the power flows always follows the path of least resistance, in accordance with Kirchhoff's circuit laws [12].

$$P_i = U_i \sum_{k=1}^{N} U_k (G_{ik} \cos(\delta_i - \delta_k) + B_{ik} \sin(\delta_i - \delta_k)) \tag{2.1a}$$

$$Q_i = U_i \sum_{k=1}^{N} U_k (G_{ik} \sin(\delta_i - \delta_k) + B_{ik} \cos(\delta_i - \delta_k)) \tag{2.1b}$$

Computation time increase significantly with system complexity, i.e. number of nodes and branches. In order to decrease computational time, linearization of the power flow equations can be of great benefit. It provides the opportunity to use commercial optimization software on a large set of linear equations to analyze an approximation of the non-linear relationship, which are significantly less demanding.

Linearization of the power flow equations is based on a number of assumptions, which are proven to yield results within an acceptable range of the exact solution, as the grid data used for analysis are usually not completely available or reliable [20]. The first approximation is based on the fact that the resistance, R, in the grid usually has a much lower value compared with the reactance, X. A ratio between reactance and resistance of between two to ten is not uncommon [21]. From Equation 2.2 it can be observed that the conductance, G, then can be neglected, and that the susceptance, B can be approximated.

$$R \ll X \Rightarrow Y = G + jB = \frac{1}{Z} = \frac{1}{R + jX} \approx \frac{1}{jX} \Rightarrow \begin{cases} G \approx 0 \\ B \approx -\frac{1}{X} \end{cases} \tag{2.2}$$

Furthermore, the assumption is made that all voltage magnitudes will be approximately equal to the reference voltage in per unit values, typically in the range of 0.95 to 1.05 [21]. This implies that little error is incurred if all voltage magnitudes are approximated to unity.

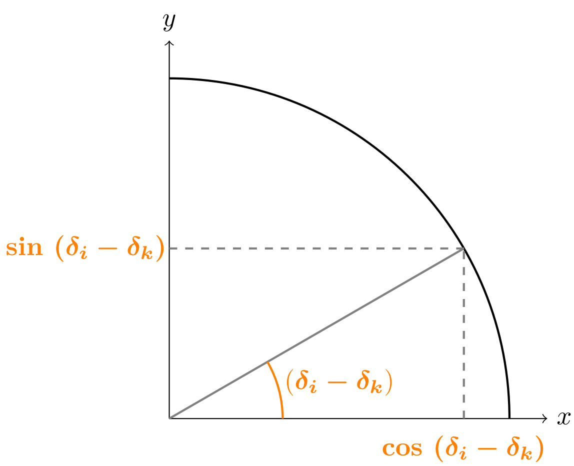


Figure 2.1: First quadrant of a circle indicating the trigonometric functions of an angle.

The difference in voltage angles between two adjacent buses under normal conditions are usually very small, rarely above 15 degrees or 0.26 radians [21]. From Figure 2.1, it is clear that for a small angle, or in this case angle *difference*, the cosine value approaches one. It can also be observed that the sine value of an angle that are approaching zero (in radians) is indeed the angle itself. From this, the approximations given in Equation 2.3 can be made.

$$\sin(\delta_i - \delta_k) \approx \delta_i - \delta_k \tag{2.3a}$$

$$\cos(\delta_i - \delta_k) \approx 1 \tag{2.3b}$$

When combining the approximations given above with Equation 2.1, the AC load flow equations can be reduced down to the linear set of equations given in Equation 2.4.

$$P_i = \sum_{k=1}^{N} B_{ik}(\delta_i - \delta_k) \tag{2.4a}$$

$$Q_i = \sum_{k=1}^{N} -B_{ik} \tag{2.4b}$$

Since the expression for reactive power injection is reduced to a constant term, it will have no impact on the flow in the system. Hence, the reactive power is neglected, i.e. Q_i and Q_{ij} equals zero. This method of linearizing the load flow equations is commonly referred to as *direct current (DC) load flow*, yielding the *DC load flow equations*, providing a method of approximating the physical net power injections in a system with simplified computations. While the term indicates that the method analyzes DC currents and voltages, it is indeed AC flows that are regarded. The term originates from the fact that reactive power is disregarded [20]. DC power flow can also be expressed using matrix notation, as shown in Equation 2.5, which is quite useful both in programmed and written computation.

$$\boldsymbol{P} = \boldsymbol{B\delta} = \boldsymbol{Y_{bus}\delta} \tag{2.5a}$$

$$\boldsymbol{\delta} = \boldsymbol{Y_{bus}^{-1}} \boldsymbol{P} = \boldsymbol{Z_{bus}} \boldsymbol{P} \tag{2.5b}$$

The bus admittance matrix is given by the following entries:

$$Y_{bus,ii} = \sum_{k \in A_i} \frac{1}{x_{ik}} \tag{2.6a}$$

$$Y_{bus,ik} = -\frac{1}{x_{ik}} \tag{2.6b}$$

where A_i is all nodes adjacent to node i.

Due to the interdependency between all sets of equations creating Equation 2.5, an infinite number of solutions exist, and Y_{bus}-matrix is said to be singular. In order to have a unique solution, a reference point has to be created. This is the point in the electric system referred to as the reference node[1], where the voltage angle is set to zero. This can be formulated mathematically by deleting the row and column in Y_{bus} corresponding to the number of the reference node. The augmented matrix is denoted $\boldsymbol{Y'_{bus}}$. This can also be calculated mathematically by adding one to the diagonal element corresponding to the reference node. E.g. if node one is chosen as reference, row one and column one in Y_{bus} is deleted, or one is added to element (1,1) in Y_{bus}. Adding this to Equation 2.5, the following relationship is obtained. The DC power flow equations on matrix notation, augmented to include a point of reference.

$$\boldsymbol{P} = \boldsymbol{B}\boldsymbol{\delta} = \boldsymbol{Y'_{bus}} \boldsymbol{\delta} \tag{2.7}$$

[1] A node in a system, known as the slack, swing or reference node, is chosen as reference where the voltage magnitude and angle is specified. This node supplies the difference between total load and generated power that are caused by the losses in the system [12]

2.2 PTDF

The PTDFs, or the PTDF-matrix, is a useful way of denoting the DC load flow equations of a system. The PTDFs are sensitivity factors expressing the percentage of one unit export from a given node, or an area as described later in Section 2.3, that will flow on a particular line. These parameters are calculated by the Transmission System Operator (TSO) for the entire system, and is the basis for FB market clearing (FBMC), as described in Section 3.2.2, providing the market clearing algorithm with power flow constraints.

The mathematical formulation of a PTDF-matrix is exemplified below for the three node interconnected power system illustrated in Figure 2.2.

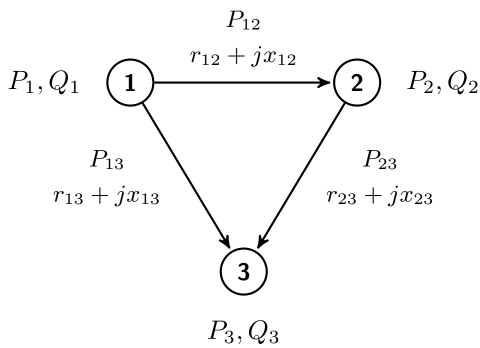


Figure 2.2: Example grid with three nodes.

From Equation 2.7, an expression for the voltage angles in the system can be formulated. These are given in Equation 2.8 with node one chosen as the reference node, resulting in the "+1" of element (1,1) of the admittance matrix, as described in 2.1.

$$\boldsymbol{\delta} = \begin{bmatrix} \delta_1 \\ \delta_2 \\ \delta_3 \end{bmatrix} = \begin{bmatrix} B_{12} + B_{13} + 1 & -B_{12} & -B_{13} \\ -B_{21} & B_{21} + B_{23} & -B_{23} \\ -B_{31} & -B_{32} & B_{31} + B_{32} \end{bmatrix}^{-1} \begin{bmatrix} P_1 \\ P_2 \\ P_3 \end{bmatrix} = \boldsymbol{Z'_{bus}} \boldsymbol{P} \tag{2.8}$$

As mentioned in the beginning of this section, the sensitivity parameters express how a change in net injection in one node affects the flow on a given connection.

Ignoring the reactive power flow, Q, and the conductance, G, by the same arguments as stated in Section 2.1, the power flows in a system can represented as given in Equation 2.9. As denoted in electrical engineering literature, the active power flow between two nodes in a system, P_{ik}, is given as the real term of the complex power flow, S_{ik} [12].

$$P_{ik} = Re(S_{ik}) = Re(U_i I_{ik}^*) = Re\left(\frac{U_i(U_i - U_k(\cos(\delta_i - \delta_k) - j\sin(\delta_i - \delta_k)))}{R_{ik} - jX_{ik}}\right) \tag{2.9}$$

With the approximations mentioned earlier in this chapter, Equation 2.9 can be abbreviated into Equation 2.10.

$$P_{ik} = B_{ik}(\delta_i - \delta_k) \tag{2.10}$$

If it is assumed that additional power, ΔP_1, is injected in node one, the change in voltage angles can be found from Equation 2.8. The change can be expressed as:

$$\Delta\delta_1 = Z'_{bus,11}\Delta P_1 \tag{2.11a}$$

$$\Delta\delta_2 = Z'_{bus,21}\Delta P_1 \tag{2.11b}$$

When applying Equation 2.11 to Equation 2.10, extended to apply for a *change* in active flow on the line between nodes one and two, given a change in injected power in node one, Equation 2.12 can be derived.

$$\Delta P_{12} = B_{12}(\Delta\delta_1 - \Delta\delta_2) = B_{12}\Delta P_1(Z'_{bus,11} - Z'_{bus,21}) \tag{2.12}$$

If ΔP_1 is set to unity, the effect on power flow on line 1-2 can be regarded as the PTDF for line 1-2 per unit net power injection in node one. This is commonly denoted $PTDF_{12,1}$.

$$PTDF_{12,1} = \Delta P_{12} = B_{12}(Z'_{bus,11} - Z'_{bus,21}) \tag{2.13}$$

Based on Equation 2.13 a general expression for the PTDFs can be formulated:

$$PTDF_{ik,n} = B_{ik}(Z'_{bus,in} - Z'_{bus,kn}) \tag{2.14}$$

The PTDFs of a system is, as earlier mentioned, provided to the market clearing algorithm by the TSOs as a matrix, the most convenient way to represent large power grids. The PTDF-matrix of a system of n nodes can be formulated as in Equation 2.15.

$$\boldsymbol{PTDF} = \begin{array}{c c} & \begin{array}{cccc} \text{Node 1} & \text{Node 2} & \cdots & \text{Node n} \end{array} \\ \begin{array}{c} \text{Line 1-2} \\ \text{Line 1-3} \\ \vdots \\ \text{Line i-k} \end{array} & \begin{bmatrix} PTDF_{12,1} & PTDF_{12,2} & \cdots & PTDF_{12,3} \\ PTDF_{13,1} & PTDF_{13,2} & \cdots & PTDF_{13,3} \\ \vdots & \vdots & \ddots & \vdots \\ PTDF_{ik,1} & PTDF_{ik,2} & \cdots & PTDF_{ik,n} \end{bmatrix} \end{array} \tag{2.15}$$

In Appendix A, an algorithm for creating the PTDF-matrix for any given system from line reactance values are provided. The code is implemented in MATLAB® [22].

2.3 Area to Critical Network Element PTDFs

In FB market clearing, complexity increases significantly when dealing with real world problems, especially due to the fact that FB can take every node and every line in the system into account. However, as described in Section 3.1.2, price calculations are done on an area level, hence the system PTDFs has to be aggregated into areas consisting of a number of nodes. In the market clearing algorithm, only connections between bidding areas, referred to as the critical network elements (CNEs), are taken into account. This results in the need of replacing the node-to-CNE PTDFs described in Section 2.2, with area-to-CNE PTDFs. The area-to-CNE PTDFs are used by the market clearing algorithm, and indicates how a change in the aggregated net position in an area affects the flow on a given CNE [23].

As mentioned, to calculate the area-to-CNE PTDFs, the nodal PTDFs has to be aggregated. As the net position (NP) of all nodes in an area influence the flow on a given CNE to varying degree, incorrect weighting of a node could yield inaccurate estimates of the actual flows on a CNEs. One way to cope with this problem, is the use of Generator Shift Keys (GSKs). The GSKs describe how a change in net position of a node affects the net position of the area it is a part of. Different strategies defines how the node-to-line PTDFs should be weighted in accordance to each other, in order to obtain equivalent area-to-line PTDFs [23]. Different shift keys can be used to distinguish between production and consumption, as well as different generation technologies. Correct use of the GSKs provides the opportunity to model which nodes that have generating capacity, and how much they can contribute.

A generic formulation of the area-to-CNE PTDF using GSKs can be expressed as shown in Equation 2.16.

$$PTDF_{ik,A} = \sum_{n \in A} GSK_n \cdot PTDF_{ik,n} \tag{2.16}$$

Where

$$\sum_{n \in A} GSK_n = 1 \tag{2.17}$$

There are several methodologies on how to calculate the GSKs for a system, all with different advantages and disadvantages. Different strategies may be appropriate for different bidding areas, due to variations in generation technology, geographical distribution, and other factors [24]. Gebrekiros *et al.* [24] presents three different schemes with varying degree of complexity and information requirement. They argue that the choice of strategy depends, among other factors, on the quality and possibility of forecasts of net positions, simplicity of PTDF aggregation, and accuracy of the results. The reader is referred to [24] for more in-depth information of the different strategies. One should have in mind that inaccurate GSKs may influence the market extensively, and may be one of the major sources of inaccuracies in FBMC [23].

2.4 Distributional Effects

The sensitivity parameters of each line in a system, represented as the PTDF-matrix, can be used to calculate all physical active power flows in the system, resulting from export from a node. Total export or import from a node is given by the surplus, or deficit, of power in the node when subtracting demand from production. This is referred to as the net injection or net position of the node. The total flow on a particular line can then be calculated as the sum of the contributions from all nodes in the system, as shown in Equation 2.18.

$$P_{ik} = \sum_{n \in N} PTDF_{ik,n} \cdot NP_n \tag{2.18}$$

For a system of n nodes, the power flows can be expressed using matrix notation, as given in Equation 2.19.

$$\begin{bmatrix} P_{12} \\ P_{13} \\ \vdots \\ P_{ik} \end{bmatrix} = \begin{bmatrix} PTDF_{12,1} & PTDF_{12,2} & \cdots & PTDF_{12,n} \\ PTDF_{13,1} & PTDF_{13,2} & \cdots & PTDF_{13,n} \\ \vdots & \vdots & \ddots & \vdots \\ PTDF_{ik,1} & PTDF_{ik,2} & \cdots & PTDF_{ik,n} \end{bmatrix} \begin{bmatrix} NP_1 \\ NP_2 \\ \vdots \\ NP_n \end{bmatrix} \tag{2.19}$$

Equation 2.19 can be a generically expressed for a system of any size, as provided in Equation 2.20.

$$\boldsymbol{P_{line}} = \boldsymbol{PTDF} \cdot \boldsymbol{NP} \tag{2.20}$$

This implies that one can model all active power flows that will occur in the entire system, resulting from import and export between the nodes. The interdependency of the power system can be described, as mentioned earlier, according to Kirchhoff's laws for electric circuits. Hence, multiple paths can be taken by the power flows when transmitting energy from one point to another, and is referred to as transit or loop flows. This phenomena is hard, if not impossible, to predict if the grid is not modeled to some degree of detail.

This is made possible by the use of power flow equations, simplified through the PTDFs, as deduced in this chapter.

The reader is referred to the TEP example of Section 4.4 where the differences in power flow with the two grid modeling techniques are evident. It shows that even for a simple three-node system, as the one presented in Figure 2.2, significant differences in the power flow can occur. The example indicates that a PTDF-representation yields a greater total power flow in the system and gives a more balanced and flexible utilization of the grid, than with NTCs. This is discussed further in the example.

Chapter 3
The Nordic Power Markets

This chapter is obtained from the pre-work of this thesis [10].

Prior to the deregulation of the Nordic power system[1], starting with the Norwegian Energy Act of June 1990, electric power generation, transmission and supply was strongly controlled by the authorities through state- or municipally-owned utilities. They had monopolistic power, an obligation to supply and a requirement of self-sufficiency [25].

Resulting from the privatization, market economy was brought into the power sector to facilitate competition between market participants. Power is in general generated by a producer, financially traded in a market though a Power Exchange (PX), physically delivered via the transmission and distribution (T&D) system, and used by a consumer, as illustrated by Figure 3.1. Power markets are characterized by a high degree of volatility resulting from uncertainties in both production and demand, and, as will be discussed later, that demand always must be met. It is therefore in the interest of all parties that a balance between production and consumption is obtained prior to the hour of operation, where the actual energy is physically delivered, as balancing at a later stage might be costly. System balance is obtained through the use different markets for electric power, that will be described in the following sections.

[1] Deregulation refers to the privatization of parts of the power supply industry, unbundling the competitive activities (production, trading and supply) from the regulated network activities (transmission and distribution).

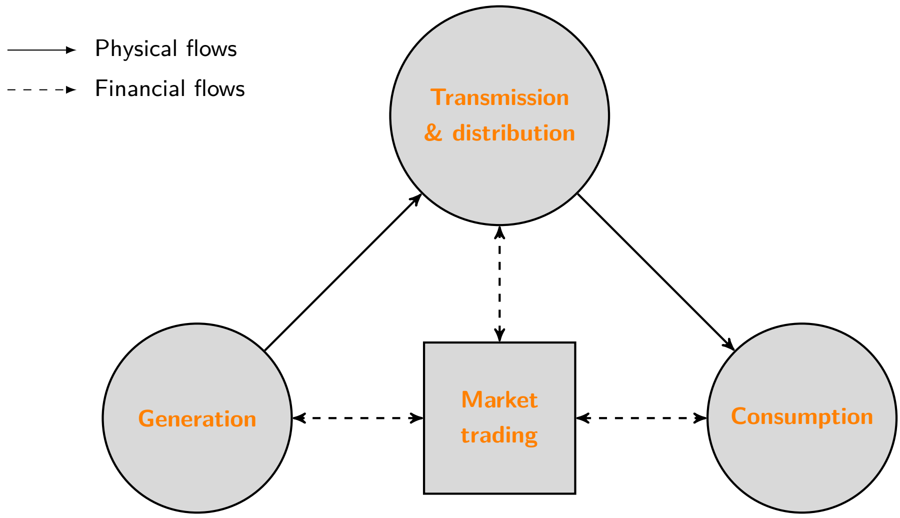


Figure 3.1: Illustration of the power industry structure [26].

3.1 Market Design

The Nordic power market can mainly be divided into two types of different time horizons; a financial and a physical market, as illustrated in Figure 3.2. In the financial markets (FMs), bilateral contracts are traded to secure future energy prices. This is referred to as price hedging, and is commonly used for risk management, further elaborated in Section 3.1.1. Financial trades do not involve an actual physical delivery of energy. In the physical market, however, trades are settled as actual power flows via the transmission grid, as mentioned in the beginning of this chapter.

The physical power market comprises several, integrated markets that are active at different hours; the Day-Ahead Market (DAM), the Intra-Day Market (IDM) and the Balancing Markets (BM). Both DAM and IDM are operated by Nord Pool Spot (NPS), owned by the Nordic and the Baltic TSOs[2] [27]. NPS is Europe's first and largest PX, acting as a counterpart for all trades, guaranteeing settlement.

The above-mentioned physical markets are so-called electricity pools where, in general, trading is centralized through a power exchange, and involves all producers and consumers. This form of commodity trading is an uncommon way of carrying out market transactions.

[2] The Nordic and Baltic TSOs are: Statnett SF (Norway), Svenska Kraftnät (Sweden), Fingrid Oyj (Finland), Energinet.dk (Denmark), Elering (Estonia), Litgrid (Lithuania) and Augstsprieguma Tikls (Latvia)

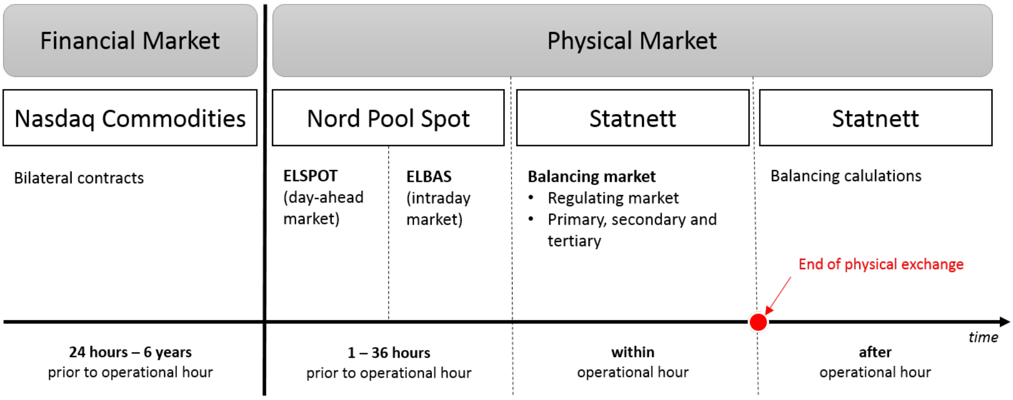


Figure 3.2: An illustration of the Nordic power market structure [28].

However, it is well functioning for electric power as all physical flows are pooled in the interconnected power system, precluding knowledge of origin. Instead of being dependent on repeated, continuous transactions between producers and consumers, pooling provides an efficient way to reach a market equilibrium [29]. Producers submit bids to supply an amount of energy at a given price, mostly corresponding to their marginal cost of production. Consumers submit offers on what price they are willing to pay for a given quantity. From this the supply and demand curve can be constructed by ranking the bids and offers in merit order, as illustrated in Figure 3.3. This is a typical illustration exemplifying the mixture of production and demand in the Nordic power system. In the supply curve, TP stands for thermal production, IM for import, and HP represents hydro power production indicated by its water value function[3]. Non-controllable production in the illustration represents intermittent RES such as run-of-river hydro, wind and solar. As energy from these sources has to be produced when available and the marginal cost of non-controllable production are close to zero, production is bid in at a price close to zero.

A major part of the total demand for electricity is usually considered price-inelastic[4]. This is often referred to as firm demand, and is represented by FD in Figure 3.3. Firm demand can only be reduced by physical rationing[5]. Hence, it is set at a very high price

[3]The water value is the expected opportunity cost of the water in a reservoir. It is needed for hydro power production planning as the marginal costs of production are close to zero, and the amount of resource are limited.

[4]When the price elasticity of demand for a good or service is considered inelastic, demand for the good does not change much when the price changes. I.e. if the price goes up, consumption habits remain unchanged.

[5]Physical rationing refers to a situation during critical deficits of energy where measures, controlled by the authorities, are taken to physically reduce demand, i.e. disconnecting load. This imposes very high costs to society [25].

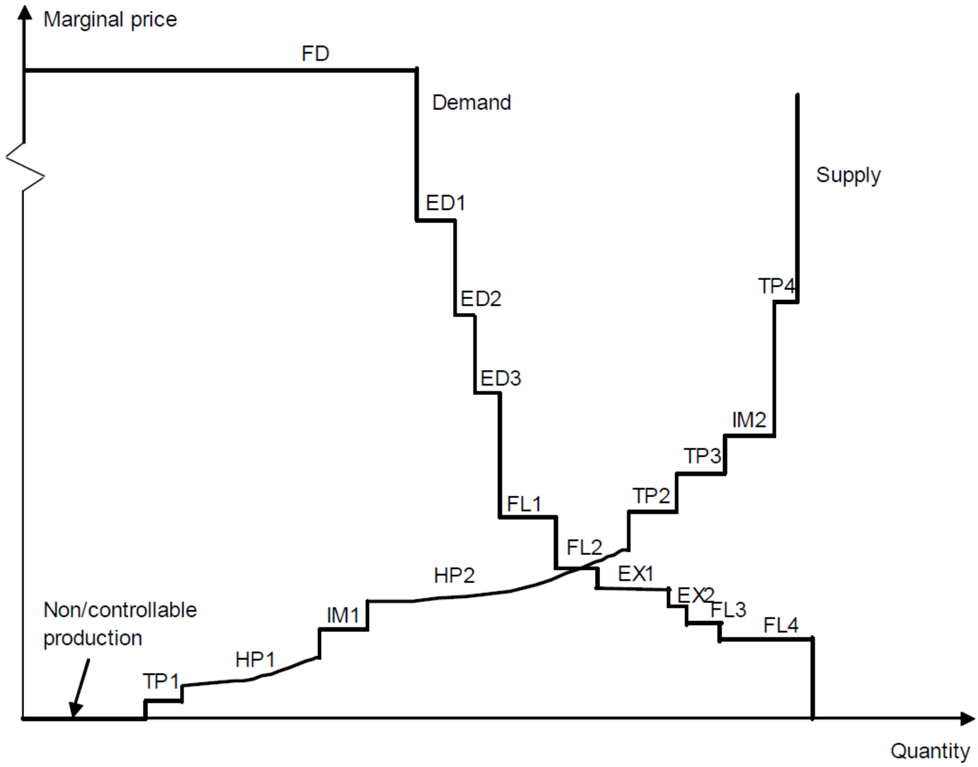


Figure 3.3: Illustration of supply and demand in the Nordic synchronous area [25].

in the demand curve. This is a fair assumption in the Nordic system as demand is more or less constant due to low electricity prices. Prices must be extremely high, or other incentives must be in place, for consumers to change their behavior. Another reason for the inelasticity is that most consumers are unaware of the spot prices at a given time, due to lack of real time metering and billing equipment, and therefore has no reason, opportunity and/or incentive to respond to price fluctuations. However, a certain share of the firm demand is gradually becoming more price elastic as a result of the development towards a more market-oriented system with increasing demand response due to smart metering. Particularly in Norway where consumption is high, and prices have fluctuated greatly the recent years [25]. This behavior can be modeled as an exponential curve, or by a number of discrete steps, as represented by the EDs in the figure, resulting in a near vertical demand curve.

The remaining parts of the total demand, can be considered as flexible demand, FL, and export to other markets, EX. Flexible demand can be loads like dual fuel boilers, that can run on different sorts of fuel, e.g. oil and electricity, and industry loads that can handle operation during curtailment. Hence, load curtailment can be used as way of balancing the system, as discussed in Section 3.1.4 and Section 3.1.5. The quantity of flexible load is highly exaggerated in the illustration for the purpose of clarification.

The market equilibrium is found in the intersection between these two curves, and the market price and total quantity, or turnover, is set. All producing bids submitted equal to or below the market price are accepted, and producers are instructed to supply the amount of energy corresponding to their bid. Producers will receive the market price, or the system marginal price (SMP), for every unit of energy generated. The SMP reflects the marginal production cost of the last generator that has to be used, i.e. the most expensive accepted bid, while disregarding transmission capacity constraints. Hence, the SMP is the price of an additional unit of produced energy in the system. Similarly are all consuming offers equal to or greater than the market price accepted, and consumers are provided information on the amount of energy they are allowed to consume. They will then pay the SMP regardless of their offer [29]. This is referred to as clearing the market according to the *marginal pricing principle*.

In the following sections, more information is provided on how these markets are structured and operated in the Nordic power system.

3.1.1 Financial Markets

As uncertainty and variations in future electricity prices may result in unacceptable variations in revenues, many power producers and consumers choose to hedge parts of their production or demand in the financial markets. The main objective of hedging is managing the risk associated with price fluctuations [25]. Trade-offs between expected revenues and risk can be obtained through trading of bilateral contracts in the FMs. In the Nordic region, market participants can trade contracts through NASDAQ Commodities with a time horizon of up to six years [30]. Most of the trades are comprised of private long-term contracts between two parties; the buyer and the seller (not necessarily the producer and consumer) [29]. Financial trades does not represent physical power flows, i.e. the participants are only hedging against future price expectations, not trading in physical delivery of energy. Grid congestions and transmission capacity allocations are not taken into consideration in financial contracts [30], hence the SMP calculated by Nord Pool Spot, as described in Section 3.1.2, is used as the reference price. Price hedging is therefore a way of reducing the impact of the volatility in the spot market, creating an opportunity for risk management for both producers and customers.

Financial products that can be traded include futures, forwards, Financial Transmission Rights (FTRs), options and Contracts for Differences (CfDs). Futures and forwards are contracts to buy or sell at a fixed price, used to hedge against system price volatility, hence providing risk management. Options provide the *option* to buy or sell at a fixed price against a fee, and can be used as an insurance. FTRs, on the other hand, are products for price hedging energy transmission. It provides market participants the opportunity to attain an increased price *certainty* when delivering or receiving energy across the grid. The holder of an FTR is entitled to receive a value corresponding to the congestion rent[6] [32], as established by differences in the day-ahead hourly area prices, described in Section 3.1.2. Thus, a holder of a FTR between a generator in one area serving a load in another area, would be indifferent to any difference in area prices. The FTR would reimburse the holder the same amount it pays in congestion fees [32]. CfDs are forward contracts with a premium covering the difference between two underlying assets, for example system- and area price, e.g. enabling participants to bet on the area prices exceeding the system price, or not.

3.1.2 The Day-Ahead Market

The DAM in the Nordic power system is called ELSPOT and is operated by NPS. It is the market for electric power trading the day ahead of production, i.e. power is traded during one day, for delivery on the next day. ELSPOT was established in 1993 as the spot market for electric power in Norway, today comprising all NPS countries shown in Figure 3.4, creating Europe's largest day-ahead market for power trading with a total traded volume of 361 TWh in 2014 [33].

The area covered by ELSPOT is divided into fifteen bidding areas, or ELSPOT areas,

[6] Congestion rent occurs in situations with insufficient transmission capacity between bidding areas, resulting in different area prices. Revenue is then made by the power exchange due to the different prices that producers receive and consumers pay when power flows from a surplus area to a deficit area. In the Nordic region, the congestion income is shared between the TSOs [31]

as a result of the TSOs estimates of grid transfer capacity constraints [34]. Figure 3.4 shows the geographical locations and names of the different areas. If there were sufficient transfer capacity between bidding areas, the price would become equal, creating one price area. This happened 15th of May 2014, where uniform prices occurred from The North Cape to Gibraltar.

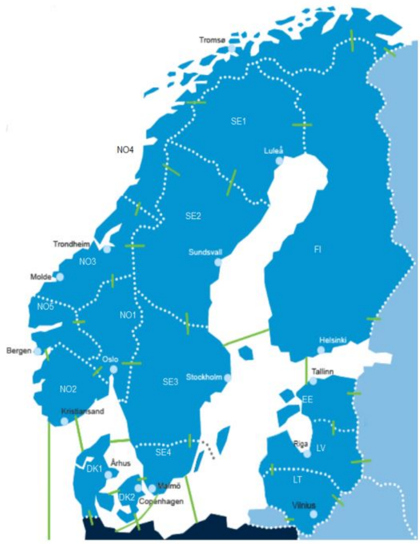


Figure 3.4: Map of the price areas in ELSPOT [34].

ELSPOT is operated as an electricity pool as described in Section 3.1 where members place their bids and offers on an hourly basis. The orders can be placed from 12 to 36 hours ahead of the hour of operation, with the window closing at 12:00 CET the day ahead. The time delay between market clearing and physical delivery provides thermal and nuclear power plants sufficient time for up- and down-regulation of production [35]. The TSOs require all market participants to place bids to the spot market expecting no imbalances within the given price area, and to be able to fulfill the obligations following the acceptance of a bid, c.f. §8 in Statnetts *The Practice of System Responsibility.* If a market participant acts in a way that causes significant imbalances over time, the TSOs have the authority to revoke the concession to produce [34].

After all bids and offers are received, the system price is calculated as described in Section

3.1 for each operating hour the following day. This price is the reference for the entire market, including trading and clearing of the majority of financial contracts, taking import and export into account [33].

In the case of transmission capacity constraints[7] between price areas, different area prices are calculated to avoid or relieve congestions. An increased price in a deficit area will, according to basic economic theory, result in increased production and decreased consumption. Similarly will a decreased price in a surplus area, result in decreased production and increased consumption. The area prices is set so that the interconnection capacities between the price areas are fully utilized. Power flow will then naturally occur from surplus areas with lower prices to deficit areas with higher prices [36]. It is important to note that bidding in the spot market is portfolio based for a given price area [34]. I.e. if a producer owning multiple generating units gets a bid accepted for a given bidding area, the producer is free to determine which of the individual units to run within that area. A large-scale producer owning units in multiple bidding areas, has to place different bids for the different areas, and fulfill its obligations within that area.

3.1.3 The Intra-Day Market

The balance between supply and demand, also referred to as the NP, of electric power is mostly ensured in the DAM. However, the time span between the clearing of ELSPOT and the actual hour of delivery can be quite long (12-36 hours), and market participants may need to adjust their portfolio before the physical delivery of energy. Weather-related fluctuations in production and consumption, breakdowns in production facilities, or outages in the transmission system is examples of situations that will cause changes in NPs. In the IDM, buyers and sellers are provided the opportunity to use market incentives to adjust their positions closer to the hour of operation, if their production and/or consumption schedules deviates from their ELSPOT bidding.

The Electrical Balancing Adjustment System (ELBAS) is the IDM in the Nordic synchronous area[8], operated by NPS. It was opened in 1999 by Finland and Sweden, and is today a provider of intra-day power trading services in and between ten countries.

[7] More information on how the transmission capacity constraints are calculated are provided in Section 3.2.

[8] A synchronous area is defined as an area covered by interconnected TSOs with a common system frequency in a steady-state [37].

With the launch of ELBAS 4 in November 2014, the users are the Nordic area, the Baltics, Germany, Belgium, the Netherlands and the newly included United Kingdom [38, 39]. With a total volume traded of 5.85 TWh in 2014, ELBAS is a small market compared to ELSPOT. However, it is of increasing importance as the share of intermittent production, specially wind power, is increasing in the European power system [39]. The remaining cross-border transfer capacities after clearing ELSPOT, is provided to ELBAS, making it an after-market for ELSPOT.

Figure 3.5: Map the countries included in ELBAS 4 [39].

These markets are open every hour of every day throughout the year, offering 15 minute, 30 minute, hourly and block products providing the flexibility needed to meet the needs of each market.

Trading in ELBAS commences at 14:00 CET after the closure of ELSPOT, and the market is open around the clock, 365 days of the year, until one hour prior to delivery. The market offers 15 minute, 30 minute, hourly and block products providing the flexibility needed to meet the growing needs of the market [39]. The process works as in a stock market where bids are placed into a trading system, consisting of price and volume for a given time and price area [34]. The price is set based on a first-come, first-served principle where the highest buying price and the lowest selling price is cleared first [39]. This is a so-called *Pay As Bid*-market where the price received by the producer is based on their actual bids. It is obliged that all trades in ELBAS are reported to the TSO [34].

Trading in the IDM provides the participants the opportunity to balance their positions prior to the hour of operation, reducing the possibility of facing the higher prices of the BM [34].

3.1.4 Balancing Markets

There must always be reserves available in a power system, and with increasing shares of intermittent power production that offer little or no contributions to system support services, the coordination of reserves is increasingly important.

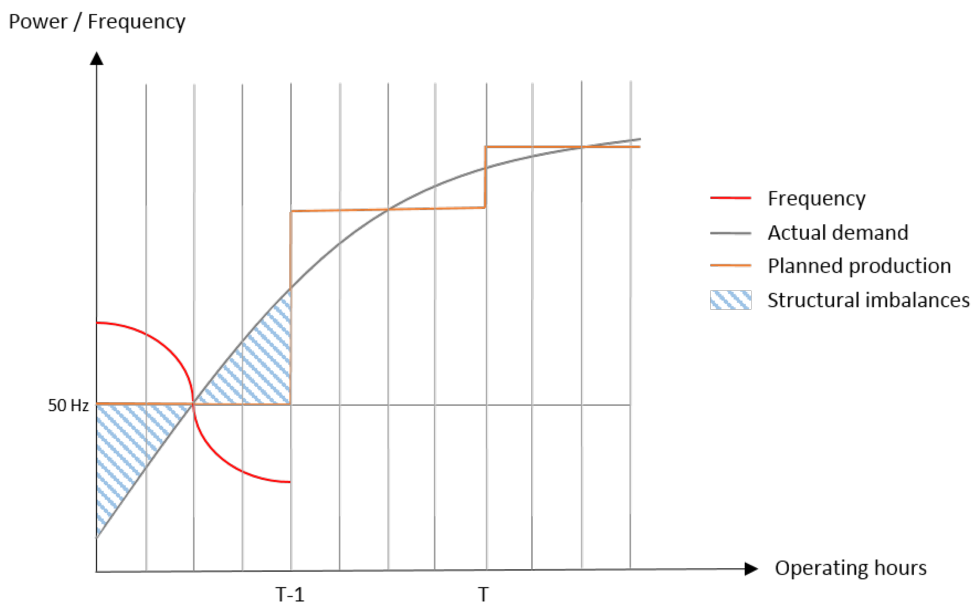


Figure 3.6: Illustration of the meaning structural imbalances.

Even though the market creates a balance during the planning phase through the DAM and the IDM, the system is continuously exposed to factors that may disturb this balance as mentioned in Section 3.1.3. Such stochastic imbalances may also occur during the hour of operation, after the closure of the IDM. However, the main reason for occurrence of imbalances in the system is due to planning mismatch between production and consumption, as a result of the hourly (or longer) resolution on market trades. As demand is assumed constant throughout the hour of operation, deviations might occur as demand in reality varies continuously. This is referred to as *structural imbalances* or deterministic frequency deviations, as they occur a regular and repetitive basis. Structural imbalances will increase even further with increasing HVDC interconnector capacity, further reducing frequency quality[9] [40]. Figure 3.6 illustrates the basics behind structural imbalances.

To be able to handle such unforeseen events, it is essential that there are sufficient and geographically distributed reserves in the power system [41]. All such reserves are acquired through market solutions. The structure of the balancing markets differ between the countries, and in the Nordic synchronous area the four TSOs are responsible for the reliability and net balance in the power system at all times [34].

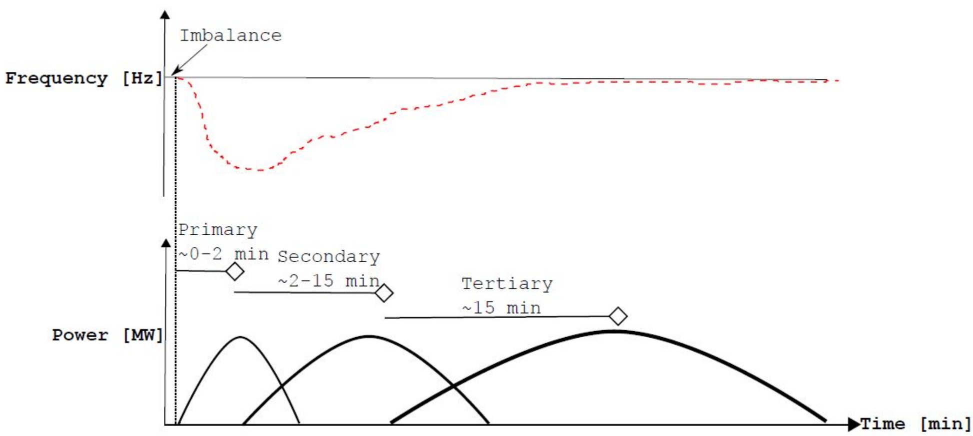


Figure 3.7: Illustration of the activation sequence of the reserves during a deficit situation [34].

The operational reserves in the Norwegian system are handled by Statnett and are generally divided into three different types of reserves: primary, secondary and tertiary. The three types of reserves are used sequentially, as shown in Figure 3.7, to restore the balance in the system. The primary reserves, or the Frequency Containment Reserves (FCR), are automatically activated upon frequency deviations due to the counteraction of the inertia

[9]The frequency of a synchronous grid, is a good indicator of system balance. As illustrated in Figure 3.6, the frequency will rise above its nominal value in a surplus situation and fall below in a deficit situation. The nominal value of frequency in the European system is 50 Hz.

of the rotating mass in the system, resulting from sudden power imbalances in the system. In an hydro power-dominated system, like the Nordic, these reserves are easily obtained as hydro power plants have their highest efficiency at a production level below maximum capacity, leaving some of the capacity available for quick up- and down-regulation even during normal operation [34]. The FCRs are obtained through the automatic response of turbine controllers of active generators [42]. That is why the primary reserves are often referred to as *spinning reserves*.

FCRs are acquired, as all other reserves, through market solutions. The primary reserves market in Norway was established by Statnett in 2008 and is divided in two; a weekly and daily market. The weekly market is cleared prior to the opening of ELSPOT, while the daily market is cleared after to cover the remaining need. This division is done following an agreement between Statnett and the producers to avoid significant changes in the production plan after clearing of ELSPOT, while at the same time securing adequate reserve capacity [41]. The products traded in the two markets are divided into reserves for normal operation (FCR-N) and for contingencies (FCR-D). Only FCR-D are traded in the weekly market, while FCR-N are traded in both. Producers may participate in one or both markets by placing bids, and both markets are primarily cleared according to the marginal pricing principle as described in Section 3.1 [34]. However, situations may occur after clearing the daily market, resulting in Statnett acquiring FCRs for prices higher than the marginal price [43].

The secondary reserves, or the Automatic Frequency Restoration Reserves (FRR-A), is automatically activated upon frequency deviations that occur for several minutes without the primary reserves restoring balance. The goal of the FRR-As is to release the primary regulation making them available for new frequency deviations, and to restore the grid frequency to its nominal value [41]. The activation of the secondary reserves is managed centrally by Statnett by adjusting the controller set points of the generators contributed to the FRR-A market [42]. Thus, producers wanting to contribute with secondary reserves has to equip their generators with the appropriate control systems.

Reservation of capacity is done through weekly actions in the FRR-A-market, and is cleared according to the marginal pricing principle [34]. However, the market was established in 2013 and the design is still under development. The goal is to establish a common

Nordic market for FRR-A [43]. Today, only production units are suppliers of the 300 MW capacity that is acquired in the Nordic system for times with significant load fluctuations. However, consumers with the correct control systems are being included in the market as well [41].

The tertiary reserves are called Manual Frequency Restoration Reserves (FRR-M), or most commonly known as *regulating power*. The FRR-Ms has a dual purpose; it can be used both to reduce any imbalances in the system freeing up the primary and secondary reserves for long-lasting frequency deviations, and to manage congestions [41]. The regulating power is manually activated by the TSO.

The tertiary reserves market is referred to as the FRR-M-market, or more commonly as the Regulating Power Market (RK). The RK is a common balancing market for the entire Nordic power system, established in 2002, where both producers and consumers can offer their services. Participants have to be able to respond within 15 minutes and deliver the service for at least one hour [34]. All bids end up in a common Nordic pool where the cheapest is activated first. When managing congestions, the cheapest resource on the geographically correct location is activated. All the Nordic countries are obliged to have FRR-M corresponding to the dimensioning fault[10] in their part of the system. In Norway this is 1200 MW, but Statnett is considering an increase in regulating power of an additional 500 MW [41]. The TSOs use RK to balance production and demand in real time, and one could argue that the prices in this market is the actual spot price for electric power [34]. RK is normally cleared according to the marginal pricing principle, and this price is also used when pricing activated energy in the FRR-A market [34].

3.1.5 Capacity Markets

There is a growing concern for the inadequacy[11] of future generating capacity to cover demand in all situations. This is mainly due to the low flexibility, or high inelasticity, of demand as described in Section 3.1, and the fact that flexible and controllable generation capacity is being increasingly replaced by intermittent renewable capacity [44]. This results in power market clearing prices not rising high enough to justify high investment

[10]The dimensioning fault in a power system is defined as the most severe outage in production or import as the system is designed to tolerate.

[11]Capacity adequacy can be defined as a system's ability to establish market equilibrium in the day-ahead market, while providing sufficient balancing capacity, even in situations of critical shortage.

cost in new generating capacity. Particularly, during times of critical shortages and blackouts where additional capacity is needed the most, the market might not be able to determine a clearing price at all. This was proven true by He *et al.* who conducted an ex post analysis of the Nordic system during the shortage period of the winter 2002-2003 [45]. Hence, market failure occurs and no incentives for future capacity investments are provided by the market. Therefore, several European countries have implemented, or consider implementing separate capacity markets, or mechanisms in the existing markets, to provide additional incentives for long-term investments in generating capacity [46].

RKOM

No such long-term capacity markets exist in the Nordic power market, but Statnett established the more short-term Norwegian Regulating Power Options Market (RKOM) in 2000 to secure sufficient amounts of regulating power being bid into the Norwegian part of RK. RKOM is a capacity market for up-regulation in RK open to both consumers and producers where the participants are paid to guarantee their commitment to RK. This provides Statnett the option to activate the reserves if necessary. By introducing RKOM, Statnett has succeeded in including a considerable amount of consumer reserves into the tertiary reserves market as RKOM stimulates flexible power intensive industry to contribute with rapid load curtailment. Consequently, load reduction from power intensive industry is regularly bid into RKOM [34].

RKOM is divided into two sub markets; seasonal and weekly. In RKOM-season, options are purchased for the duration of the winter season, and in RKOM-week options is bought for day or night. Trades in the weekly market is based on the actual situation in the power system, i.e. production and demand forecasts, cross-border exchange, and probable congestions [41].

3.2 Day-Ahead Market Clearing

In order for NPS to set the market price, they need to know the anticipated transfer capacities between the bidding areas for every hour of the following day. This is provided by the TSOs.

The market-clearing algorithm that is used in the DAM can be expressed as a generic optimization problem. The objective of this problem, or the objective function, is to maximize the total welfare, also known as the economic surplus, while balancing the supply and demand in the market and considering transmission constraints. The total welfare is a term that refers to the total surplus received by all market participants, both producers and consumers, i.e. the sum of consumer and producer surplus, and congestion rent [23].

The consumer surplus is defined as the total benefit that consumers receive by paying a market price lower that what they are willing to pay, providing a measure for the total net benefit to consumers. The producer surplus is an analogous measure for the producers, defined by the benefit of receiving a market price higher than the cost of providing the good [47].

The constraints of the optimization problem are, as earlier mentioned, given by the balance of supply and demand, also referred to as the NP, and the transmission constraints of the grid. These capacity restrictions can be calculated based on two different approaches; a NTC and a flow-based approach. There is a drive in the European electricity transmission industry towards a change in methodology to the latter. An introduction to the two methodologies are given in the following sections.

3.2.1 Net Transfer Capacity Market Clearing

The NTC, or rather the available transfer capacity (ATC) obtained when subtracting the already allocated capacity (AAC) as shown in Equation 3.1, is the maximum allowed commercial exchange between two adjacent bidding areas that complies with the security standards of the given synchronous area, and takes into account the technical uncertainties on future grid conditions [48]. These limits are determined by the TSOs to facilitate the market transactions while safeguarding the grid. The NTC is defined as total transfer capacity (TTC) less the transmission reliability margin (TRM) [49]. The TRM is a part of the total capacity that is withheld from the market by the TSO in order to manage possible congestions and the physical flows, including transit flows, that will occur in the interconnected system. The transit flows are not taken explicitly into account in the NTC market clearing approach, also known as coordinated net transfer capacity (CNTC). As a result of this, inefficient allocation of the total capacity might occur if the allocated TRMs is not fully utilized. As transit flows are hard to predict, capacity calculation in an interconnected grid becomes complex and might lead to suboptimal or inefficient capacity allocations [23].

$$\mathrm{ATC} = \mathrm{NTC} - \mathrm{AAC} = (\mathrm{TTC} - \mathrm{TRM}) - \mathrm{AAC} \tag{3.1}$$

In CNTC, the transmission constraints in the market optimization model are given by these NTC capacity calculations, and can be formulated generically as shown by Equation 3.2.

$$\begin{aligned} &\text{maximize} && \text{socioeconomic surplus} \\ &\text{subject to} && \mathrm{NP} = 0 \ , \ \forall \text{ nodes} \\ & && \text{NTC capacity constraints} \end{aligned} \tag{3.2}$$

3.2.2 Flow-Based Market Clearing

In the FBMC approach, capacity allocation is no longer a choice of the TSO that is made in advance, but it is an outcome of the market clearing, hence the allocation is market driven, creating a stronger connection between the power markets and the physical system [49]. This provides the market with the opportunity to prioritize the most economically efficient solutions, hence a more efficient and flexible use of the grid is obtained. For this reason, FB market clearing is the preferred approach in the Network Code on Capacity Calculation and Congestion Management (NC CACM) developed by the ENTSO-E[12]. It states the a FB approach should be used unless its added value can be disproved compared to an NTC approach [23].

[12]The ENTSO-E represents 41 TSOs from 34 countries across Europe and is working for closer cooperation to support the implementation of EU energy policy and achieve Europe's energy and climate objectives.

As the entire power system is physically interconnected, an action in one part of the system will in principle affect the entire system, in the form of transit flows as mentioned in Section 2.4. As the NTC-approach sees power flows as fully controllable, divergence between financial and physical flows will occur, creating uncertainties. It is these uncertainties that create the need for reliability margins, as described in Section 3.2.1.

The use of a flow-based model allows a more precise modeling of the physical flows, as the constraints of the FB optimization problem are simplified grid models, reflecting the impact of changing net positions on the flows in the network [49]. This leads to a more efficient capacity allocation as the market takes all flows in the system into account and no transfer capacity has to be withheld from the market. Transit flows can then be monitored and possible congestions are taken care of in the market clearing algorithm directly [23]. For trades that are settled through DC connections, all trades directly translate into physical flows. This is due to the fact that, when assuming point-to-point connections equipped with converter stations[13], all flows can be perfectly controlled [11]. However, FB market clearing can lead to non-intuitive situations, e.g. flows from high-price to low-price areas. The reason is that some non-intuitive exchanges free up capacity, allowing even larger exchanges between other markets, which can yield higher total social welfare [50].

$$
\begin{aligned}
\text{maximize} \quad & \text{socioeconomic surplus} \\
\text{subject to} \quad & \text{NP} = 0 \ , \ \forall \text{ nodes} \\
& \text{FB capacity constraints}
\end{aligned} \tag{3.3}
$$

It is important to note the objective function of the optimization problem remains unchanged, as can be observed by comparing Equations 3.2 and 3.3. The only difference is within the constraint formulation. Because there is no need for pre-allocation of capacity in advance of the market clearing, a larger solution domain can be obtained by the algorithm, still containing all possible solutions of the CNTC [23]. This implies that FBMC might contain solutions outside the solution domain of CNTC, providing a greater number of trading opportunities with the same level of security of supply [49]. This is illustrated in Figure 3.8.

[13]This is the common technological approach today, although the future probably is meshed or multi-terminal DC grids. A technology under development.

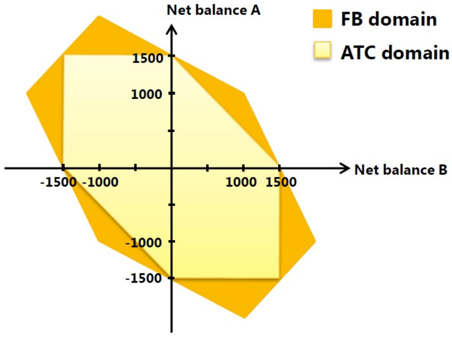


Figure 3.8: Illustration of NTC (ATC) compared with FB solution domain [49].

3.3 European Day-Ahead Market Coupling

Prior to market coupling in 2009, internal price calculations were conducted separately on the different power exchanges, while exchange to other areas where handled by explicit daily auctions. The highest bidding participant won the entire transmission capacity, possibly resulting in sub-optimal socioeconomic allocation of transmission capacity as wrong forecasts might give power flow in the wrong direction, or no use at all [51].

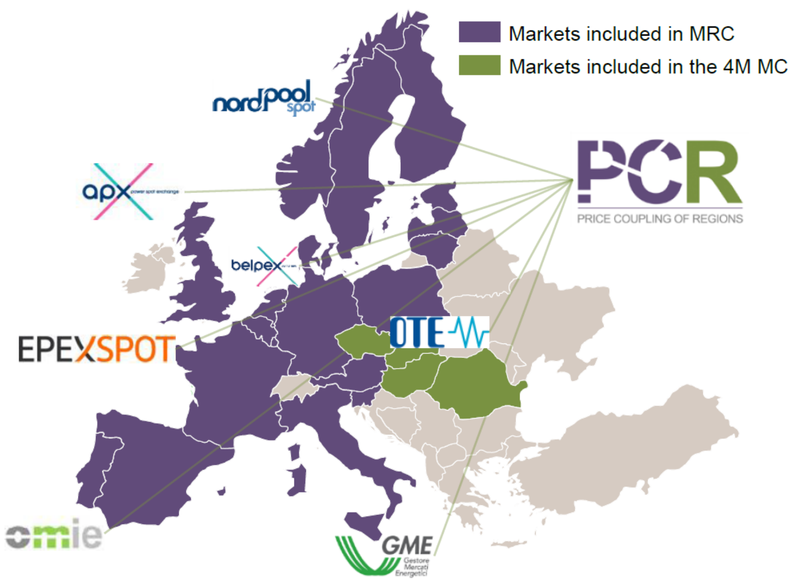


Figure 3.9: Map of PCR regions [50].

Market coupling refers to the process where multiple day-ahead markets are cleared together, simultaneously calculating prices and volumes in all bidding areas. When markets are coupled, orders and bids are no longer confined to a given bidding area or country. Trades can now be settled between buyers and sellers from different, possibly distant, geographical areas, only restricted by the underlying grid constraints. This leads to an improved market liquidity[14], resulting in less volatile spot prices, as supply and demand can be met by a greater number of market players. Integration of the European power markets increases the efficiency of the allocation of interconnector capacities between bidding areas and countries, hence optimizing the overall social welfare.

The European Market Coupling Company (EMCC) is a coordination organ for the market coupling of Europe, and is currently running the Price Coupling of Regions (PCR) project. The PCR was initiated by seven European power exchanges; APX, Belpex, EPEX SPOT, GME, NPS, OMIE and OTE, covering both the Multi-Regional Coupling Project (MRC) and the 4M Market Coupling Project (4M MC) countries (see Figure 3.9). The PCR PXs represent more than 75 % of the European power market [50]. One of the key achievements of the PCR-project is the development of a common European clearing algorithm, called Euphemia. Market clearing in Euphemia starts with market participants submitting their orders to their respective PX, as described in Section 3.1.2. All orders are then submitted to the algorithm that decides which are accepted. The acceptance of a bid is based on maximizing social welfare while taking capacity restrictions into account. Price calculations are conducted in accordance with the marginal pricing principle. Both NTC and FB capacity constraints are handled by the algorithm [50]. The development of Euphemia is a step towards a common European power market [51].

[14]In economics, market liquidity is a market's ability to facilitate the purchase or sale of an asset without causing drastic change in the asset's price.

Chapter 4
Transmission Expansion Planning

An interconnected power system in a restructured environment enables several generators to compete in an aggregated market, as described in Chapter 3. Inadequate transmission capacity will, however, result in reduced competitiveness for some market participants compared with an optimal scenario, decreasing overall efficiency of the electric power markets and energy trading opportunities [52]. The latter phenomena arise mainly due to the reduced flexibility of generation, resulting in transmission from surplus areas with low marginal generation costs, to deficit areas with high marginal generation costs [9]. Increased grid capacity through construction of new lines and cables, or by upgrading the existing infrastructure, would further result in reduced congestions and increased stability and security of supply, providing increased socio-economic benefits. Multinational transmission expansion is identified as the most important step towards achieving the ambitious decarbonization goals outlined by the EC [1, 2].

As mentioned in the introductory chapter, increased cross-border exchange capacity would also facilitate increased renewable energy production, as the best sites for harvesting energy from RES often are located far from load centers and existing infrastructure. Offshore wind power is most relevant in the context of the Nordic power system, due to the large and stable wind potential of the North Seas. On a global level, great unutilized potential exists within the vast desserts areas of the world. Around 90 percent of the world's population lives within 3000 kilometers of an utilizable dessert. With today's technology, exploiting one percent of these areas for RES development would supply the world's energy demand. The only *technological* barrier for further development of these projects, is long-distance transmission capacity [53].

The ENTSO-E 2014 Ten-Year Network Development Plan (TYNDP) recognizes about 100 major grid investments needed in the European power system, doubling the interconnection capacity, in order to cope with existing and predicted bottlenecks [5]. With a total investment cost of approximately € 150 billion by 2030, divided as illustrated in Figure 4.1, these projects represent substantial financial commitments for the European TSOs [5]. Furthermore, the EC has identified 195 key energy infrastructure projects, known as Projects of Common Interests (PCIs), to promote cross-border exchange investments [54]. These are essential for the integration of the European energy markets, as discussed in Section 3.3, and for reaching European Union (EU)'s climate goals. Making correct investment decisions are crucial to power transmission companies and grid investors, as most transmission assets are unable to be redeployed and generally have an economic lifetime of a minimum 50 - 60 years.

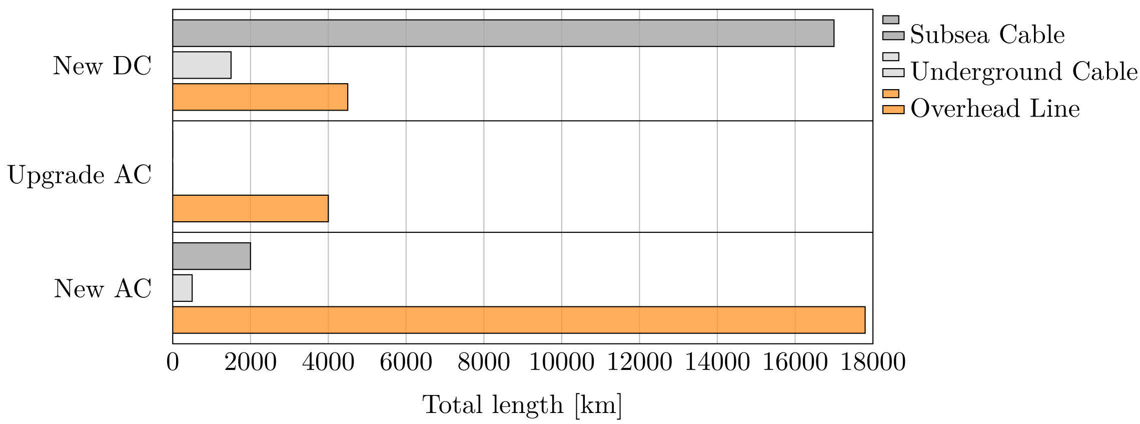


Figure 4.1: ENTSO-E TYNDP 2014 investment portfolio [5].

There are two, possibly complementary, approaches to investment decision making in a T&D grid; market-driven and regulatory, divided on the grounds for investment.

4.1 Market-Driven Transmission Investments

In the rare case of merchant-, or market-driven transmission investments, the investment decision is made by a company based on the fundamental function of all transportation businesses; buy a good at low price in one market, and sell it at a higher price in another market, exploiting an arbitrage opportunity between the markets [52]. This is a viable business if the cost of transportation and the necessary investments are lower than the income generated from the price difference, creating profit for the transporter. The foundation of price differences in the Nordic power system, is the principle of area spot pricing described in Section 3.1.2, where different price areas are created to relieve congestions due to transmission capacity constraints, and account for some of its widespread effects [52]. An investor expecting a considerable and stable price discrepancy between two areas, might invest in interareal transmission capacity, exploiting that price difference; charging high prices for power imported from low-price areas.

A transmission user may buy either physical or financial transmission rights for congestion charge hedging. Physical rights entitle the holder to a given portion of the transmission capacity, while financial rights provide the holder a financial benefit equal to the congestion rent, as described in Section 3.1.1. Another principle of market-driven TEP is that an efficient grid investment should generate revenue from the sale of such transmission rights at a high enough margin to provide a reasonable return for the investor [52].

4.2 Regulated Transmission Investments

Regulated TEP is based on the fact that electric power transmission is a natural monopoly due to the physical nature of the infrastructure and its importance to society. Hence, regulatory agencies have to create proper incentives rewarding economically efficient investment decision making[1], while simultaneously avoiding over-investment and encouraging efficient operation [29, 52]. This is a difficult task to execute due to conflicting interests of different stakeholders [55]. In Norway, the TSO is a state enterprise, thus controlled by the authorities through the Norwegian Water Resources and Energy Directorate (NVE). Annually, a permitted revenue is established based on the assumption that the transmission grid is operated, utilized and developed in an efficient way, meant to cover the costs of grid investments and maintenance, and to provide a reasonable return on grid assets [56]. The price difference between two price areas is incurred as an additional cost by the parties involved in the financial transaction and is part of the TSO revenue, as described in Section 3.1.1. This is referred to as *congestion rent*, and is supposed to provide an economic incentive for the TSO to relieve congestions by transmission expansion [52].

Despite the potential benefits obtained from multinational coordination of interconnector capacity and onshore connection of offshore wind farms, as discussed in the introduction, all grid investments today are led nationally [7]. Interconnection of the European countries is conducted bilaterally by the involved TSOs, while the regulation of connection of offshore wind farms varies throughout the region, either placing the responsibility with the TSO, the generator, or a third party [7].

[1] A monopolist has, according to basic economic theory, complete market power and will set prices higher than the competitive market price in order to maximize profit. Hence, a monopoly is economically inefficient.

4.3 Optimization Model - NetOp

Transmission expansion planning in a restructured environment covers both economical and engineering aspects. This creates the need for TEP models to include, in addition to economics of the grid investments, models of both the commercial power market and the physical grid, thus capturing the improved system operation due to increased transmission capacities [52]. The models also need to cover the fundamental requirement of a power system; balance supply and demand of power while taking into account the capacity restrictions of the underlying power system, as described in Section 3.2. Power market models are commonly modeled as a linear optimization problem. This is a fair assumption for most applications, especially when large systems are analyzed [11]. Combined with the methodology deducted in Chapter 2, load flow- and grid investment-calculations can be explicitly included in one linear optimization problem. This provides the opportunity to jointly optimize generator dispatch and interconnector capacities, while taking into account the underlying physics constraining system operation. Model linearity is important to keep computational power and time within reasonable limits with increasing system size.

There are numerous ways to model a TEP-problem. One approach is the MILP optimization model described by Trötscher and Korpås [9], as mentioned in Section 1.2. The investment model assumes a hypothetical TSO charged with the coordination and construction of an offshore power grid in the North Seas. The goal for this top-level, strategic investor is maximizing social economic welfare, i.e. achieving a cost efficient supply at a given demand assuming perfect market competition [9]. This implies that electric power is always supplied by the generator with the lowest marginal cost, and that no market participants exercise market power[2]. Despite being constructed for the NSOG, the model is completely generic and can by applied to any power system of arbitrary size.

The optimization model is formulated mathematically as provided in Equation 4.1 (the reader is referred to the Nomenclature for explanation of symbols). The objective is equivalent with minimizing total system costs including both operational- and investment costs [6]. This can be seen by the objective function, given in Equation 4.1a, which sums

[2]Market power is referred to as the ability of a market participant to manipulate the price of a good or service by influencing its supply, demand or both. In perfectly competitive markets, participants have no market power, equating marginal costs and price [57].

up all costs that incur during the planning period, i.e. the net present value (NPV)[3] of production costs, fixed and capacity-dependent costs for transmission and the costs of new nodes. The first restriction (Equation 4.1b) handles the power balance in each node, restriction c the generating capacity, and d and e restricts the power flow on each line. These equations, together with restriction f, handling the maximum capacity per cable, create the aforementioned connection between the power market, generator dispatch and interconnector capacity expansion. Restriction g covers the construction of new nodes.

As the model does not provide the possibility of modeling hydro power reservoir constraints, thus disregarding optimal hydro power dispatch, a restriction on annual generation (energy constraint) is added to all generators in the model, given as Equation 4.1h. This is necessary in order to limit the utilization of low cost hydro production, as the average utilization times[4] of Norwegian hydro power plants are between 3500 and 5000 hours [59], and around 3000 hours for Norwegian onshore wind power plants [60]. The utilization time for offshore wind can be considerably higher. The utilization of wind- and solar power are limited through the production time series described in Section 4.3.3.

[3]The NPV is the total cost in terms of year zero's value of money, where all costs are discounted to present value by a given discount rate [58].

[4]Utilization time for a power plant is generally defined as the amount of hours the plant has to run at full capacity to produce the total annual production. For a hydro power plant, it is defined as the time it will take to produce one year of average inflow at maximum capacity. It can be calculated as annual production divided by installed capacity.

$$
\begin{aligned}
\min \quad C_{tot} = \sum_{s\in S}\sum_{g\in G} x_g^s c_g a t + \sum_{i\in I}\sum_{j\in I_i}(x_{\kappa,ij}c_{ij} + y_{ij}f_{ij}) + \sum_{i\in I} y_i f_i \qquad && && && \text{(a)} \\
\text{s.t.} \quad \sum_{g\in G_i} x_g^s - \sum_{j\in I_i} x_{ij}^s + \sum_{j\in I_i} x_{ji}^s l_{ij} &= b_i^s && \forall i \in I, s\in S && \text{(b)} \\
x_{g,min}^s \le x_g^s &\le x_{g,max}^s && \forall g \in G, s \in S && \text{(c)} \\
x_{ij}^s - x_{\kappa,ij} &\le \kappa_{ij} && \forall i \in I, j \in I_i, s \in S && \text{(d)} \\
x_{ji}^s - x_{\kappa,ij} &\le \kappa_{ij} && \forall i \in I, j \in I_i, s \in S && \text{(e)} \\
x_{\kappa,ij} - x_{ij,max} y_{ij} &\le 0 && \forall i \in I, j \in I_i && \text{(f)} \\
\sum_{j\in I_i} y_{ij} - M y_i &\le 0 && \forall i \in I && \text{(g)} \\
\sum_{s\in S} x_g^s t &\le E_g && \forall g \in G && \text{(h)} \\
y_{ij} &\in \mathbb{Z}^+ && \forall i \in I, j \in I_i && \text{(i)} \\
y_i &\in \{0,1\} && \forall i \in I && \text{(j)}
\end{aligned}
\tag{4.1}
$$

4.3.1 Assumptions and Simplifications

Electric power is commonly considered to be supplied by generating units with a maximum capacity and an associated marginal generation cost function [9]. In NetOp, marginal production costs are considered constant (for linearity), and the entire production capacity of each generator is available at that given cost. To model more realistic behavior, while maintaining linearity, marginal production costs can be represented as piecewise linear functions, or sampled from time series as described in Section 4.3.3, to represent optimal hydro dispatch through the use of water values. Furthermore, demand is considered completely inelastic, which is a minor simplification from what was discussed in Section 3.1. Constraints like ramping rates[5], minimum up/down regulation times and water reservoir limits are ignored. Further, generator capacities and locations are assumed known and fixed. In principle, grid investments should be co-optimized with investments in generating capacity, but this is considered out of scope. It is, however, a fair assumption as the

[5]The rate, expressed in megawatts per minute, that a generator or a DC cable is able to change its output or flow due to physical restrictions.

initial focus of NetOp was offshore grids and wind farm connection where plant siting and capacity are mainly determined by external factors [9]. The model does, however, allow for sampling from time series of generating capacity, as done for the wind- and solar production described in Section 4.3.3, enabling the model to account for variations in non-RES generation.

4.3.2 Grid Modeling

In the original version of NetOp, a transportation model of the grid was used, simply modeling branches as transmission capacity constraints, expressed as the NTCs described in Section 3.2.1, ignoring branch impedances. However, due to the limitations of NTCs, as described in Section 3.2, sensitivity factors, expressed as the PTDFs deducted in Section 2.2, can be utilized to model the interconnected power flows of the entire grid. The NTCs only restrict flow on each connection, while the PTDFs are used to translate market transactions into physical power flows in the system, creating a stronger coupling between the power market and the physical system. This method provides a better, more realistic description of the grid than using a transportation model, while still maintaining linearity [9].

To account for the flow-based capacity restrictions and the use of PTDFs, the optimization model has to be augmented with the additional constraints given in Equation 4.2. They take into account all power flows in the interconnected system resulting from the net positions of all nodes. The PTDF-matrix can be used both statically and dynamically, implying that the latter is iteratively updated whenever the investment model adds additional transmission capacity. This is, however, not utilized in NetOp as grid capacities are not iteratively upgraded. Optimal capacities are calculated once per sample, assuming all years throughout the planning horizon to be equal. Additionally, the choice was made not to include optimization and expansion of the onshore AC grid in the model due to the increase in computation time further discussed in Section 5.4.2. Therefore no investment variables are included for the PTDF-branches.

$$\sum_{n\in I} PTDF_{ij,n}^{s} \left(\sum_{g\in G_n} x_g^s - b_n^s\right) \leq x_{ij}^s \qquad ,\forall i \in I, j \in I_i, s \in S \tag{4.2}$$

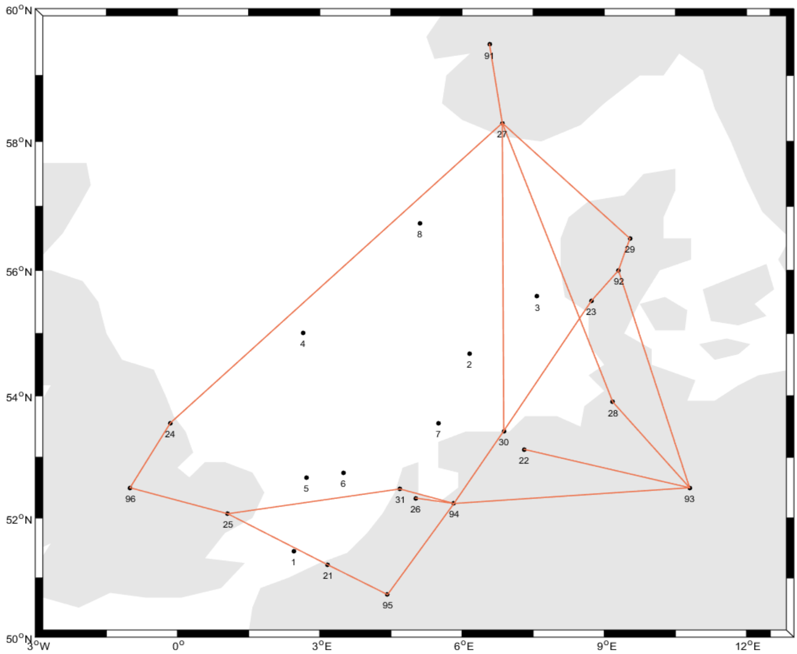


Figure 4.2: The initial grid of NetOp with offshore wind farms represented as nodes numbered 1-8.

4.3.3 Sampling

Many TEP-models tend to use a single state-representation of the power system operating conditions, commonly described by system peak values. This is a valid assumption with regards to thermal systems where power flows from large generating units to consumers in a predictable pattern [9]. As the increasing share of wind power in the European power system is distributed over a large area, and when taking into account the uncorrelated relationship between load- and RES generation patterns, the assumption becomes invalid and will lead to suboptimal results [9].

To account for this inadequacy, NetOp has the functionality to sample from hourly correlated time series over a year, as illustrated by Figure 4.3 [6]. This allows for the inclusion of variability in both load and renewable energy production, improving the degree of detail in the model. Ideally, the optimization model should use the full data set containing 8760 samples per year, for a near perfect modeling of actual system behavior. This would, however, yield unreasonably long computation times [9]. Hence, the number of states should be kept as low as possible without compromising computational accuracy.

Resulting from this, the model created random samples of matching subsets, as illustrated by Figure 4.3. The model then optimizes the system for each of them, indicated by the s's in Equation 4.1. Determining the sufficient number of states that have to be used in order to attain a certain precision of the results, is not a straightforward task. However, Trötscher and Korpås found by experimental testing, that there were diminishing gains from increasing the number of states beyond 200 samples, and that improvement in performance with a greater number of samples was negligible [9].

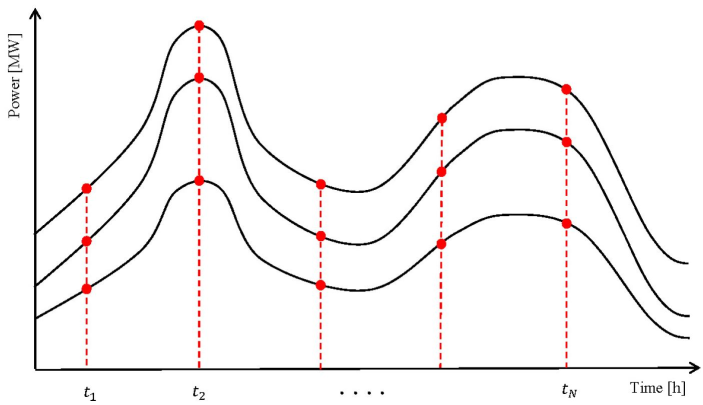


Figure 4.3: Illustration of creating state subsets by sampling from different time series [61].

The reader is referred to [9] for a more comprehensive explanation of the NetOp-model.

4.4 Three Node TEP Example

This example is based upon the pre-work of this thesis [10]. It uses the simple three node system shown in Figure 2.2 to illustrate the use of optimization models for transmission expansion planning, and to conduct a simple analysis of the differences of using the NTCs and PTDFs for power flow modeling.

For this example, a simplified version of the NetOp-model presented in Equation 4.1 was implemented in Mosel using Xpress [62] as given in Appendix B. The model was initially implemented using the NTC-methodology, and later extended to use the FB approach, adding Equation 4.2 as an additional constraint, as described in Section 3.2 and Section 4.3.2. As input to the FB constraints, a PTDF-matrix for the three node system is needed. This can be calculated using a generic formula as presented in Equation 2.14, or by applying the generic MATLAB [22]-script provided in Appendix A on the system impedance matrix. The PTDF-matrix for this example is given in Equation 4.3, with node 3 chosen as the reference node, or slack bus, as it has the highest generating costs. The input data, as presented in Table 4.1, was based on [19] and modified to yield significant results for illustrative purposes, and might therefore be unrealistic. The system was optimized assuming no restrictions on total energy production.

$$\boldsymbol{PTDF} = \begin{array}{r} \\ \text{Line 1-2} \\ \text{Line 1-3} \\ \text{Line 2-3} \end{array} \begin{array}{c} \begin{array}{ccc} \text{Node 1} & \text{Node 2} & \text{Node 3} \end{array} \\ \begin{bmatrix} 0.4127 & -0.3175 & 0 \\ 0.5873 & 0.3175 & 0 \\ 0.4127 & 0.6825 & 0 \end{bmatrix} \end{array} \tag{4.3}$$

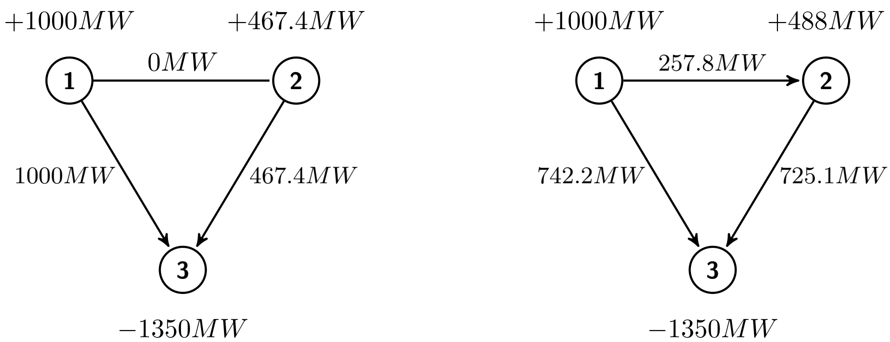
Parameter name			**Value**
Discount rate			5.00 %
Economic life [years]			10
Average AC losses			8.00 %
AC expansion capacity cost [m €/MW]			0.30
AC expansion fixed cost [m €/interconnector]			2.33
Maximum capacity per interconnector [MW]			500
Number of states per year, $\|S\|$			1
Time per state, $\frac{8760}{\|S\|}$ [h]			8670
	Node 1	Node 2	Node 3
Demand [MW]	200	100	1350
Maximum generating capacity [MW]	1200	600	300
Generating cost [€/MWh]	10	20	40
	Line 1-2	Line 1-3	Line 2-3
Reactance [p.u.]	0.017	0.026	0.020
Pre-existing capacity [MW]	500	600	0

Table 4.1: Three node example input data.

The results of the optimization are presented in Table 4.2, and illustrated graphically in Figure 4.4. In the figure, the numbers above or below the nodes represent the net position of the node, i.e. production less demand in the node. A plus sign indicates a positive NP, i.e. the node is in surplus and exports power. Correspondingly, a minus sign indicates a deficit node in need of import to cover demand. The numbers at the lines indicates the magnitude of the power flow in the direction of the arrow.

Variable		**NTC**	**FB**
CAPEX [m €]		264.9	267.2
OPEX [m €]		1579.3	1607.2
Total losses [MW]		117.4 / 6.64 %	138.0 / 7.72 %
New capacity built [MW]	Line 1-2	0	0
	Line 1-3	400	142.2
	Line 2-3	467.4	725.2
Number of new interconnectors	Line 1-2	0	0
	Line 1-3	1	1
	Line 2-3	1	2
Line flow [MW]	Line 1-2	0	257.8
	Line 1-3	1000	742.2
	Line 2-3	467.4	725.2
Generation [MW]	Node 1	1200	1200
	Node 2	567.4	588
	Node 3	0	0

Table 4.2: Three node example results.



(a) NTC (b) FB

Figure 4.4: Results from the three node AC TEP case.

From the results, one can clearly see that the approaches yield different results in optimal power flow, giving rise to different optimal grid expansion. The flow-based approach gives a more balanced and flexible utilization of the grid, representing the distributional effects in the system in greater detail. As mentioned in Section 3.2.2, this results from taking into account transit flows, which are flows that occur in an interconnected system according to Kirchhoff's laws when settling trades between two nodes. As can be seen from the results in Table 4.2, line 1-3 is utilized to full capacity in the NTC case. In order to manage possible congestions and unpredictable (when using NTCs) transit flows, the TSO allocates part of the transmission capacity as a reliability margin, the TRM, and withholds this from the market, as described in Section 3.2.1. When adding this constraint, the model has to build additional capacity in the NTC-case in order to account for the margin. In this example, a TRM of 5.9 percent of the total transmission capacity, increases the transmission expansion of the NTC-case beyond that of the flow-based case.

From Table 4.2 one can observe that the FB model has a higher capital expenditure (CAPEX). Since the FB model takes into account all flows, the resulting total flow in the system is higher than in other modeling scenario, requiring additional CAPEX when expanding transmission capacity. Furthermore, increased power flow leads to higher losses, which is assumed linearly increasing with the power flow, and that has to be covered by increased production, increasing the operating expenditure (OPEX) as well.

The results of this example comply with the theory presented earlier in this thesis. However, no greater capacity expansion is required by the FB approach. This is due to a better utilization of the existing capacity.

Chapter 5

Case Study

NetOp was originally designed for analyzing the grid interconnecting a two-node aggregation of the countries surrounding the North Seas, as shown in Figure 4.2. A case study was conducted with a primary goal of examining the effects of expanding the original area, into a grid resembling that of the EMPS [17]. That included the addition of a six-node representation of Sweden and a one-node representation of Finland, together with an augmented eleven-node representation of Norway, creating a grid as shown in Figure 5.1. The secondary goal was examining the effects of using a FB approach to onshore AC grid modeling, utilizing PTDFs, as described in Section 4.3.2. The key parameters that were monitored throughout the case study included; the exchange flows, model computation time, utilization hours and capacity expansion of the interconnectors. Furthermore, the distributional effects in the PTDFs-represented grid were examined by observing the accumulated flow in that part of the system. These parameters were chosen as the foundation for comparison of both model performance and results. However, the most important parameter for comparison was the power flow, as it is the governing factor of both capacity expansion and utilization.

The load and generation data used in the case study were based on the 2030 Visions outlined by ENTSO-E, as presented in the Scenario Outlook and Adequacy Forecast 2014-2030 included in the TYNDP 2014 package. An introduction and overview of the Visions are provided in Section 5.1 and Appendix C. The aggregated winter peak values were distributed among the price areas according to the 2014 total ELSPOT volume distribution [33], and divided between the nodes to resemble the situation of the Nordic power system, i.e. high demand and low production in the Oslo area etc. All other exogenous model parameters, i.e. expansion costs, branch losses and so forth, were used as predefined in NetOp, and used in other research [6, 9].

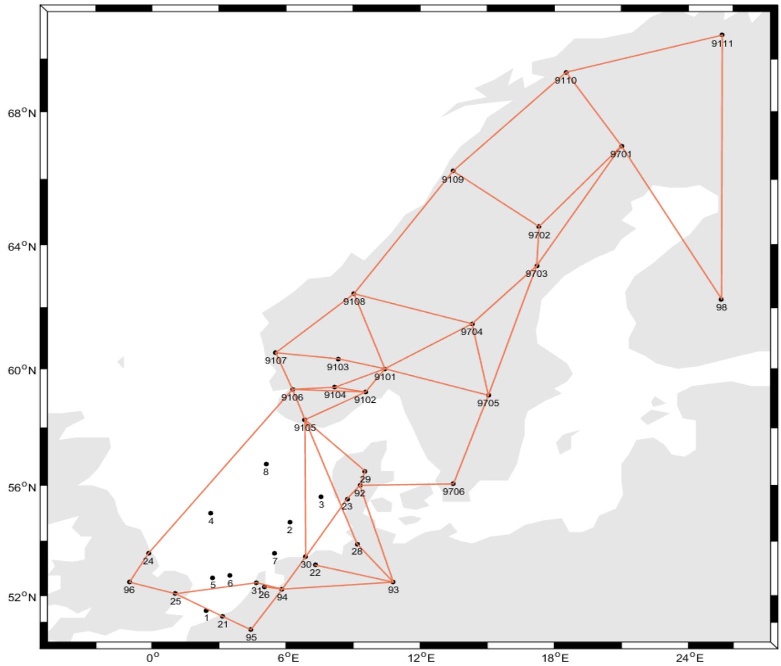
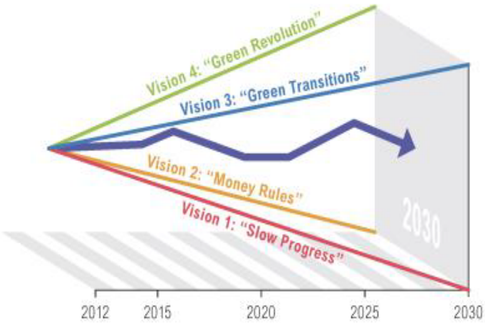


Figure 5.1: The grid of the expanded NetOp with offshore wind farms represented as nodes numbered 1-8.

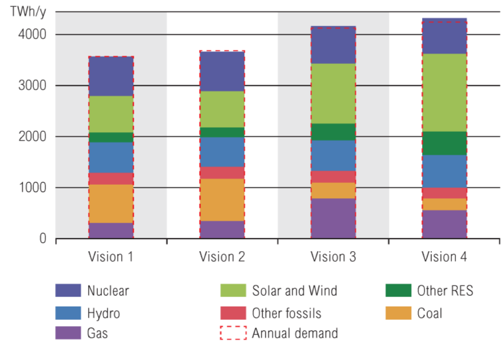
5.1 The ENTSO-E 2030 Visions

The Visions cover four scenarios estimating different extremes defining the borderlines of expected development of the European power system towards 2030, with a high level of certainty [5]. This is represented graphically in Figure 5.2a, with the purple line illustrating a parameter development limited by the four Visions. These expected boundary conditions, developed by the ENTSO-E, are results of collaboration with stakeholders, through the Network Development Stakeholder Group (NDSG) and a public consultation. It provides a midpoint between the short-term goals of EU's 2020 package, and the long-term goals of Energy Roadmap 2050 outlined by the EC [5].

The scenarios differ with respect to alignment with the Energy Roadmap 2050, and generation mix development strategy [5]. Aggregated production and demand for the ENTSO-E-area are given in Figure 5.2b, where one can observe both an increasing share of RES and increasing demand from Vision 1 to Vision 4, together with a decreasing share of non-renewable power production, coal in particular. Production and demand data is provided on an aggregated country basis for the North Sea area in Appendix C.



(a) Illustration of expected development.



(b) Total annual production and demand.

Figure 5.2: ENTSO-E 2030 Visions [5].

Vision 1 and 3 are created using a bottom-up strategy, based on each country's energy policy provided by the TSOs. Vision 2 and 4 are top-down strategies developed to meet EU's climate objectives on a European level, derived from the other two visions [5].

Vision 1 is called *slow progress*, reflecting a gradual development towards a green power system, with economic and financial conditions considered less favorable [5]. This scenario fails to meet EU's climate goals for 2030, and is considered a plausible scenario during a long term economic recession, resulting in a lower growth in consumption compared to the other Visions, entailing a moderate need for further market integration and interconnection capacity [5].

The second scenario is named *money rules*. This estimate reflects a cautious progress towards the Energy Roadmap 2050, driven by high rates of return on investments[1] [5]. Vision 2 is similar to Vision 1 with respect to consumption and generation mix, another plausible scenario during economic recession. However, it considers a higher level

[1] The rate of return is the gain, or loss, on an investment over a specified period, expressed as a percentage of the initial investment cost [58].

of European cooperation since it is a top-down strategy, resulting in increased market integration [5].

Vision 3 is referred to as *green transition.* This scenario reflects an ambitious development towards the European energy goals for 2050, assuming that all nations work towards achieving an overall 50 % load supply from RES on a European level by 2030 [5]. Hence, Vision 3 is in line with EU's climate goals for 2030. However, a low degree of inter-European cooperation results in over-investments in generating assets, as countries tend to secure their own supply independently [5].

Vision 4 is called *green revolution* and it reflects an aggressive strategy towards the achievement of the 2050 European energy goals. This scenario meets the EU goals by 2030 with 60 % of load supplied by RES in 2030 [5]. Compared to Vision 3, a high level multinational cooperation is assumed, resulting in optimization of power supply on a European level, taking advantage of every country's situation and interconnection capacity [5].

Both political- and economic frameworks, and generation- and demand frameworks of the four scenarios are summarized in Figure C.1 in the appendices.

5.2 The PTDF-matrix

When using a flow based approach to TEP, a PTDF-matrix is needed to translate market transactions into physical flows, as described in Section 2.2. The PTDF-matrix used for the Nordic region in the case study was provided by PhD Candidate Yonas Tesfay Gebrekiros with the Department of Electric Power Engineering at NTNU and SINTEF Energy. The matrix was constructed as part of his distinguished doctoral research into balancing market integration in Northern Europe, and is therefore used in this thesis without further consideration.

5.3 Model Implementation

The original code for the NetOp algorithm, written by Trötscher and Korpås, was used as a starting point for the model implementation. Different spreadsheets were created for each scenario, containing all input parameters. Input and output handling, together with optimization problem formulation and creation, was implemented in MATLAB [22]. The optimization problem itself was solved utilizing the MATLAB-interface of Gurobi Optimizer [63]. The optimizations were conducted on a Dell Latitude E6430 laptop computer with Intel® Core™ i7 CPU of 2.9 GHz and 8 GB RAM.

The expansion of the grid was accomplished through changing the input files as the program code is written completely generic. When the model was expanded to utilize PTDFs, additional code was written to take into account the added constraints. Flow based constraints was included for the onshore AC-grid interconnecting Norway, Sweden, Denmark and Finland. All DC connections in this area were disregarded.

Due to the length of the code and the multiple script interaction, the complete implementation of the NetOp-algorithm is only provided in the digital appendices. However, a simple flow chart of the algorithm is provided in Figure 5.3 to illustrate the algorithm procedure.

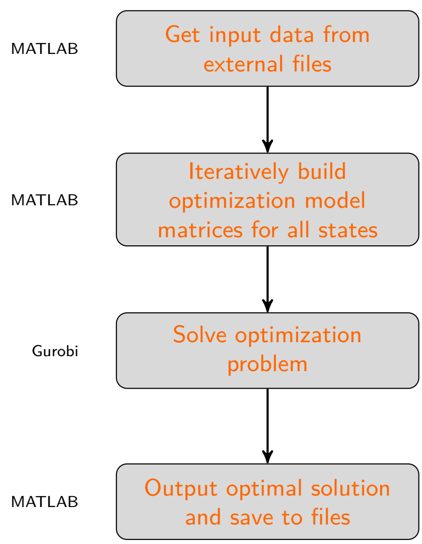


Figure 5.3: Simple flow chart of the NetOp algorithm.

5.4 Case Study Results

The optimal values of the case study are provided in Appendix D. Additionally, some figures are included in the following subsections providing graphical comparisons of the aforementioned key parameters. Average mean utilizations (AMUs)[2] are used as a comparative measure of interconnector utilization.

Maps of the different optimal grid solutions are provided in the following sections. The numbers on the lines in these maps are given on the format; *a:b*, where *a* indicates the number of new lines to be built, and *b* the resulting total transmission capacity. The color coding of the branches indicates the branch type, according to Table 5.1. The onshore grid with PTDF-representation is not included in the figures as these branches are not optimized and will remain unchanged throughout the analysis.

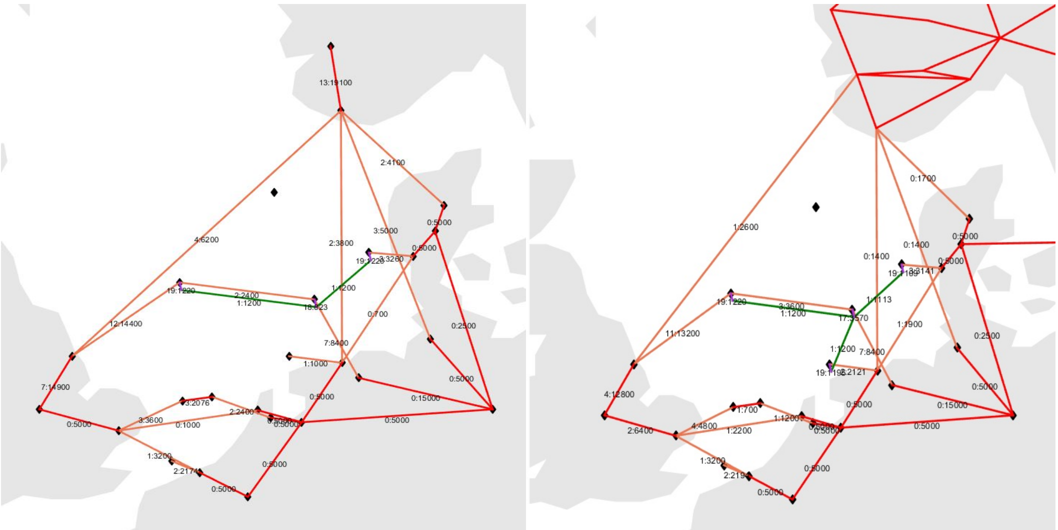
Color	**Branch type**
Blue	Meshed AC with PTDF-representation
Red	Meshed AC without PTDF-representation
Orange	Radial DC
Green	Meshed DC

Table 5.1: Color coding of the optimal grid maps.

5.4.1 Grid Expansion Analysis

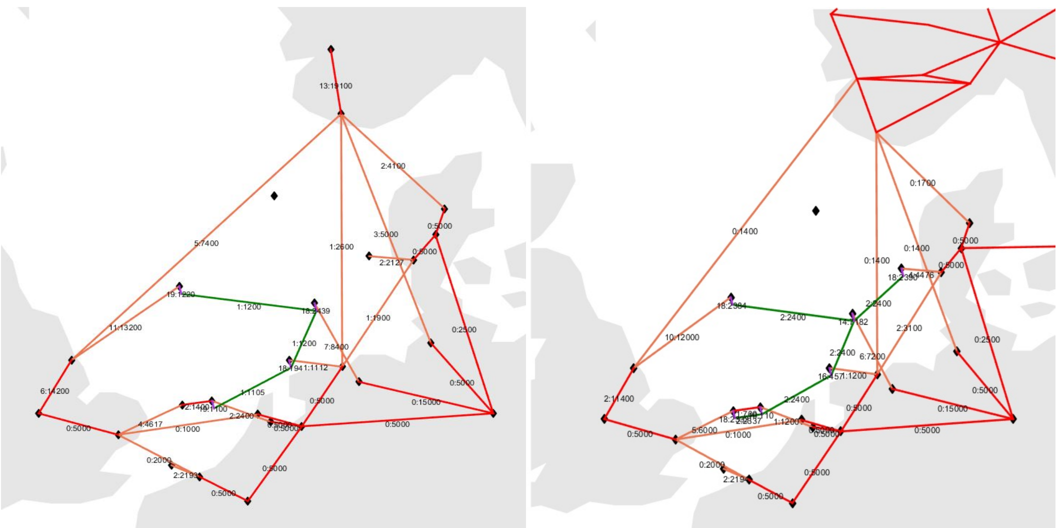
A summary of the optimization results are listed in Table D.1 for the analysis of the model grid expansion. Figure 5.11 shows the optimal cross-border exchange to and from Norway, and is included to illustrate the effect of including the possibility of onshore power transmission on the offshore interconnectors.

[2]Mean utilization time is the mean of the utilization time for all samples (given as a percentage of a year), calculated for a given interconnector. Average mean utilization referrers to the average of that percentage for a number of interconnectors.



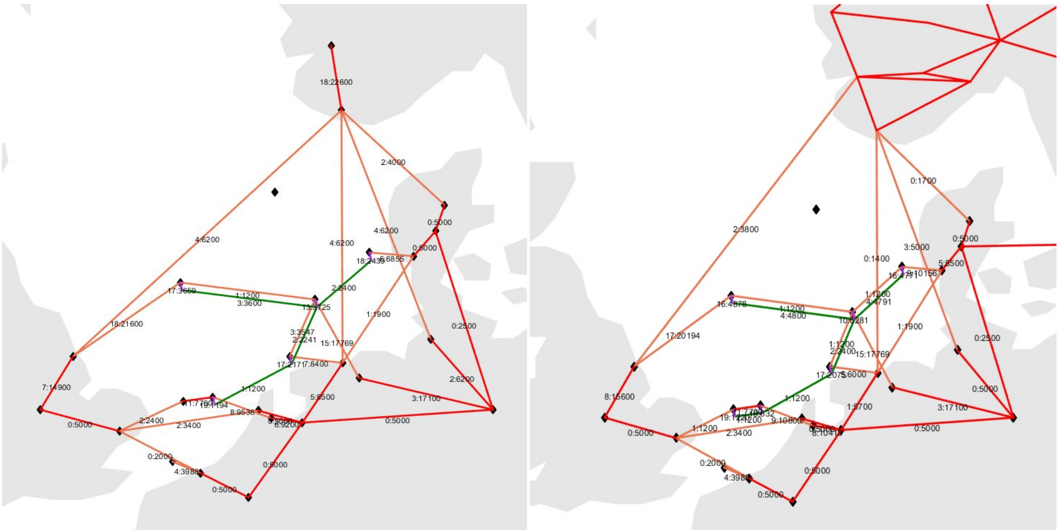
(a) Original (b) Expanded

Figure 5.4: Optimal grids under Vision 1.



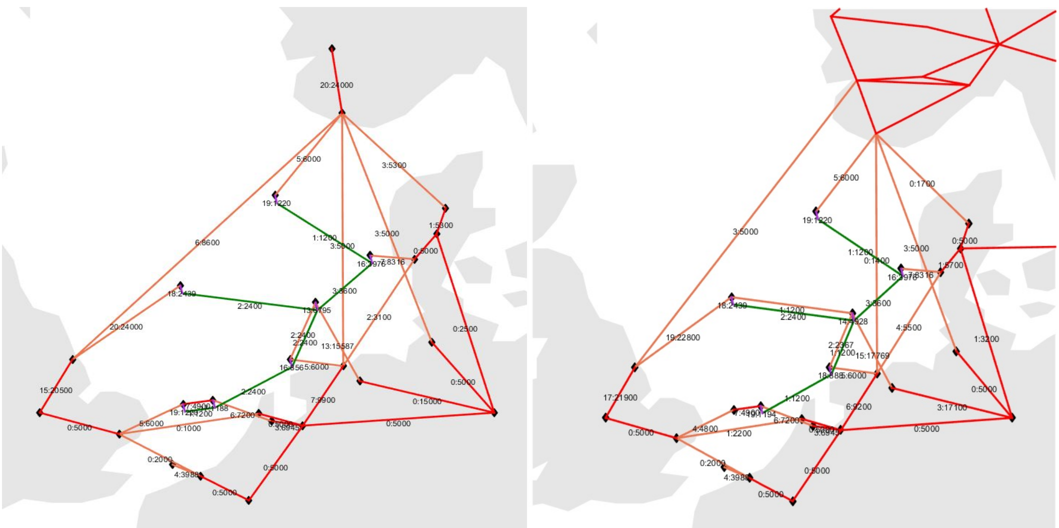
(a) Original (b) Expanded

Figure 5.5: Optimal grids under Vision 2.



(a) Original (b) Expanded

Figure 5.6: Optimal grids under Vision 3.



(a) Original (b) Expanded

Figure 5.7: Optimal grids under Vision 4.

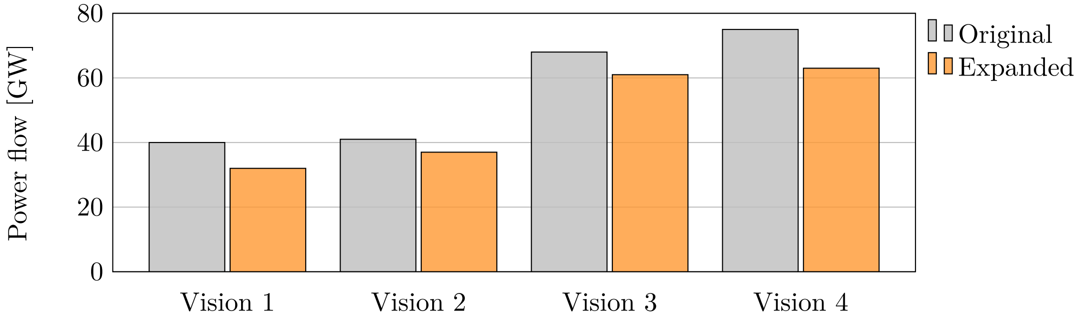


Figure 5.8: Graphical comparison of the accumulated interconnector exchange of the expansion-analysis.

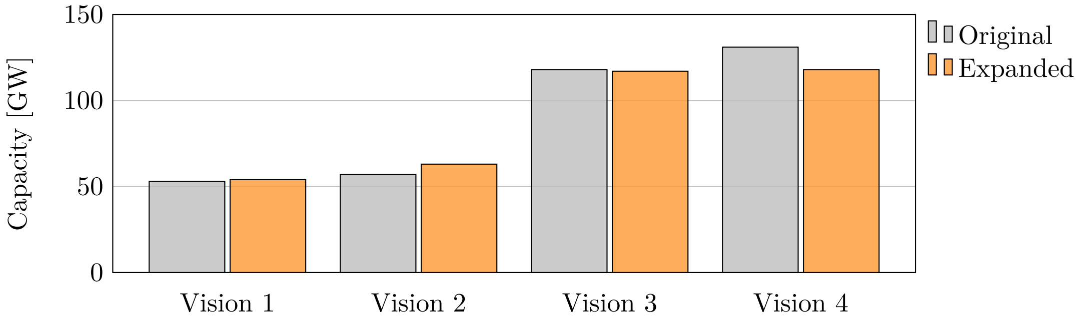


Figure 5.9: Graphical comparison of the accumulated interconnector capacity expansion of the expansion-analysis.

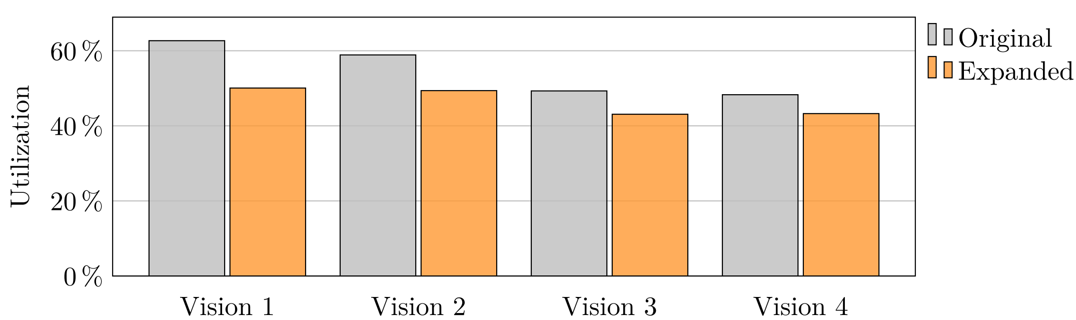


Figure 5.10: Graphical comparison of AMU of all interconnector of the expansion-analysis.

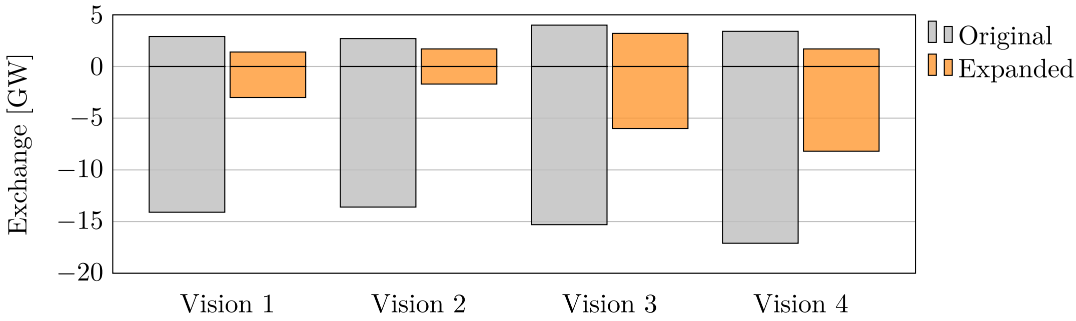


Figure 5.11: Graphical comparison of the accumulated interconnector exchange to and from Norway of the expansion-analysis (import +, export ÷).

Discussion of Results

From the data presented, it is clear that the expansion of the NetOp grid had a considerable impact on the optimal solutions. There is a definite trend of over-estimation of the interconnector exchange in the original model, as indicated by Figure 5.8. This is also the case for the exchange to and from Norway, as presented in Figure 5.11. It is evident that several of the major interconnectors of the North Seas might be excessively emphasized in the original NetOp model. The over-simplification of the onshore grid leads to highly overestimated DC exchange flows, both import and export. It is a clear trend that when the model has the opportunity to transfer power through the onshore AC grid, a higher emphasis is put on this part of the system, reducing the exchange flows of the interconnectors, i.e. different approaches are taken to solving the problem. This results in reduced interconnector expansion costs when the grid is expanded, as seen in Table D.1. From the same table, one can also observe increased production costs. This is a result of the increased losses that occur in the system due to grid expansion, and is not covered by the reduced curtailment of low-cost RES observed in most scenarios.

As seen in Figure 5.9, there is a stepwise increase in the accumulated interconnector capacity under the different Visions, for both cases. This is due to the assumption of an increasing level of pan-European cooperation towards achieving EU's climate goals, as described in Section 5.1. Increased cross-border exchange capacity facilitates the utilization of the best energy source available at all times, in a greater geographical area. This results in reduced curtailment of wind- and solar power production, as observed in

Table D.1. Hence, it has a higher priority in Visions 2 and 4, as they build upon top-down strategies. Furthermore, the larger steps in multiple variables from Vision 2 to Vision 3 than between the others are worth noting. This can be explained by the large increase both in demand and RES penetration between these two scenarios, as reflected by Figure 5.2b, resulting in a greater need for cross-border exchange and lower production costs. However, even though the two models yield comparable optimal solutions for power flows, it seems that they differ, to some extent, in the optimal solution of exchange capacity. There is no clear trend for this parameter, as observed in Table D.1. This might be because the expanded model allows for a greater range of solutions. This can observed from Figures 5.4 - 5.7 where the cables connecting Norway and Denmark, are utilized (expanded) to a greater extent by the original model than the expanded NTC-model, which favors the onshore grid for import to Denmark. While the peak-flow on the interconnectors remains high, the base-flow decreases, resulting in the need for high capacity even though the accumulated flow are reduced. This can also explain the reduction in AMUs for the expanded model observed in Figure 5.10, as they are calculated from flow and capacity.

It might be counter-intuitive that the elapsed optimization time decrease when the model increase in size. After all, several new flow variables with interrelated constraints are added. This is, however, explained by the relaxed transmission constraints of the onshore grid, as described in Section 5.3, enabling the optimizer to solve the problem in fewer iterations.

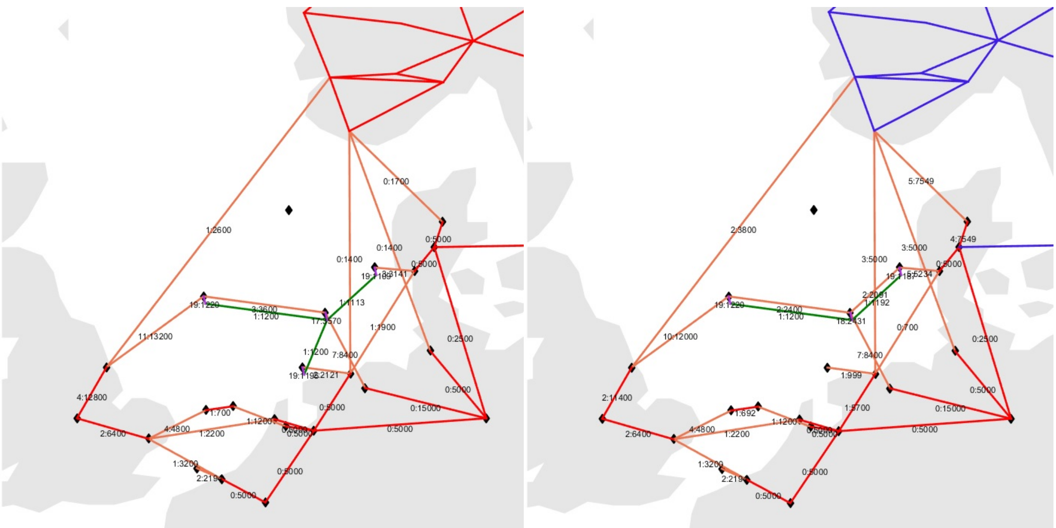
5.4.2 Analysis of Introducing Flow Based Constraints

A summary of the optimization results are listed in Table D.2 for the analysis of the model grid expansion, together with graphical comparisons of the key parameters provided in Figures 5.16 - 5.19. Additionally, a closer look is taken on some of the major cross border, subsea high voltage direct current (HVDC) interconnectors of the NSOG, i.e. NSN, NorNed, NordLink and Skagerrak. The Skagerrak transmission system comprises several HVDC links providing a total exchange capacity of 1700 MW between Norway and Denmark [64], and NorNed is a 700 MW[3] cable connecting Norway and the Netherlands [65]. NordLink is a 1400 MW cable between Norway and Germany currently under construction for commencement of commercial operation in 2020 [66]. The NSN link is a

[3]The pre-existing capacity is incorrectly sat to 1400 MW in NetOp.

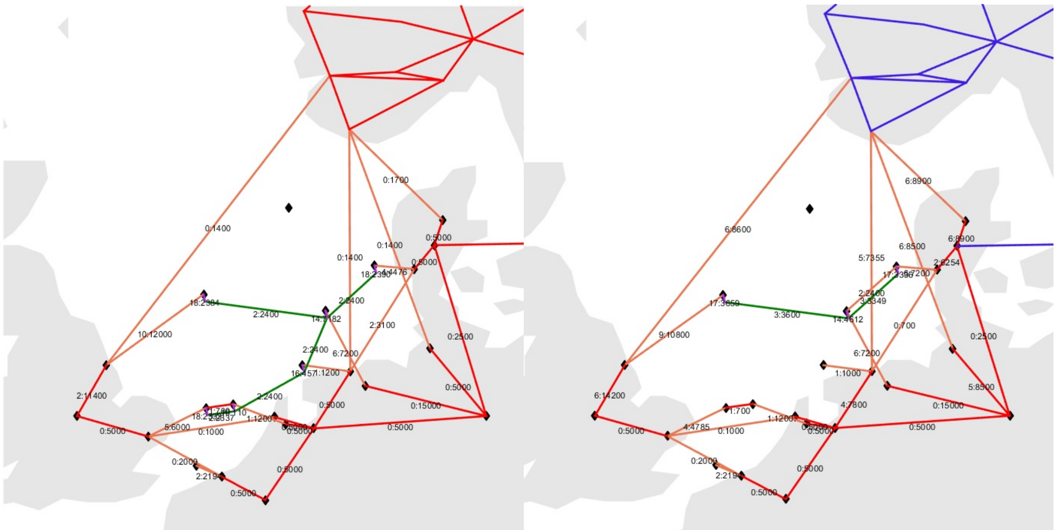
planned 1400 MW cable connecting Norway and Great Britain, aimed at being operational in 2021 [67]. A comparative analysis was conducted quantifying the effects of flow based modeling of the onshore grid on these interconnectors, compared to the NTC-approach. The results are presented in Tables D.3 - D.6.

Initially, all branches of the expanded model were optimized. However, due to unreasonably long computation times (more than seven days when using the PTDF-approach), optimization of onshore AC transmission system capacity was excluded from the algorithm, as the emphasis of the analysis was on the offshore interconnectors. Existing capacity on these branches were then set high enough so that no constraints were put on these power flows. Capacity on all PTDF-branches were reduced, representing the TRM discussed in Section 3.2.1, when the NTCs were utilized compared to PTDFs.



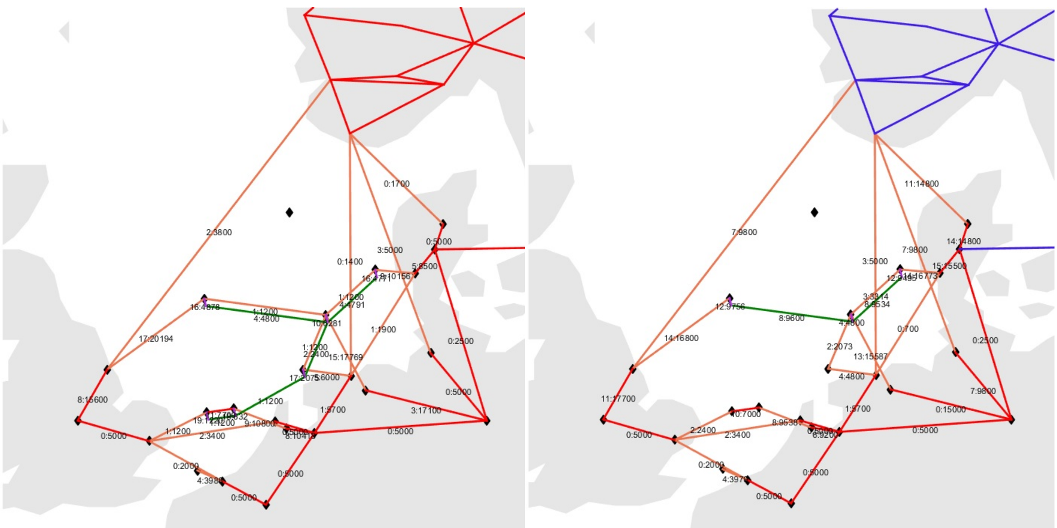
(a) NTC (b) PTDF

Figure 5.12: Optimal grids under Vision 1.



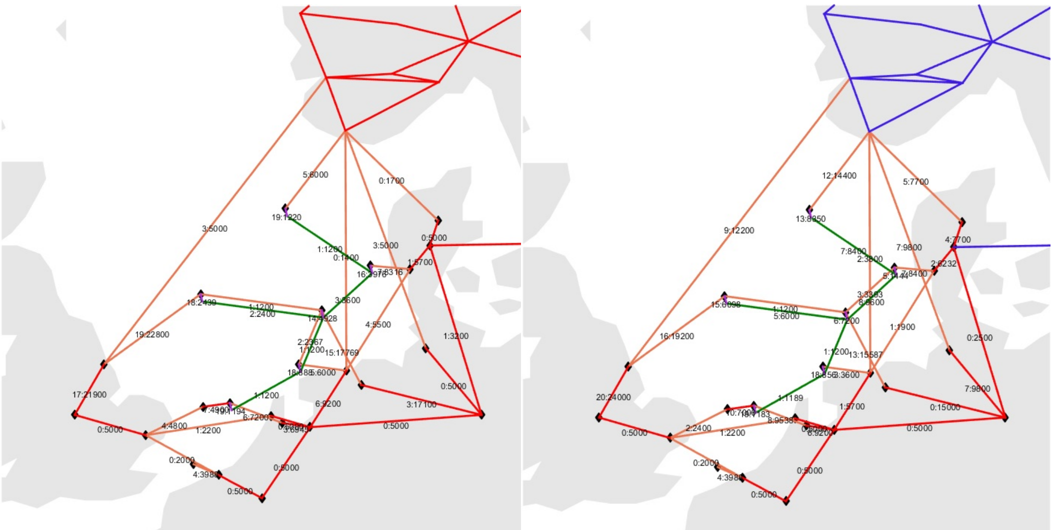
(a) NTC (b) PTDF

Figure 5.13: Optimal grids under Vision 2.



(a) NTC (b) PTDF

Figure 5.14: Optimal grids under Vision 3.



(a) NTC (b) PTDF

Figure 5.15: Optimal grids under Vision 4.

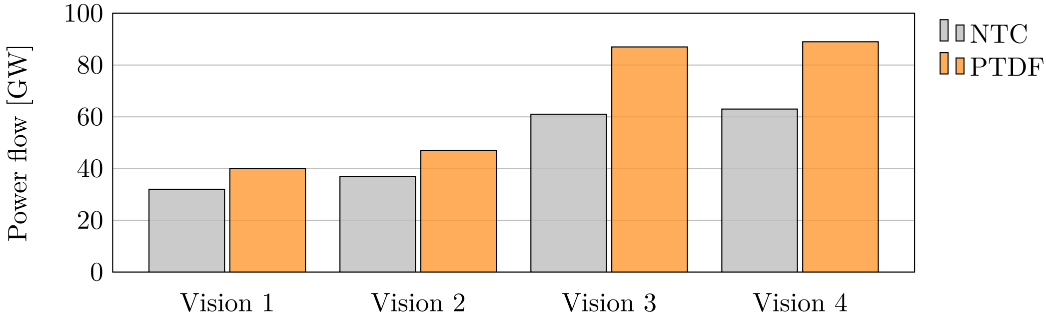


Figure 5.16: Graphical comparison of the accumulated interconnector exchange of the NTC-FB-analysis.

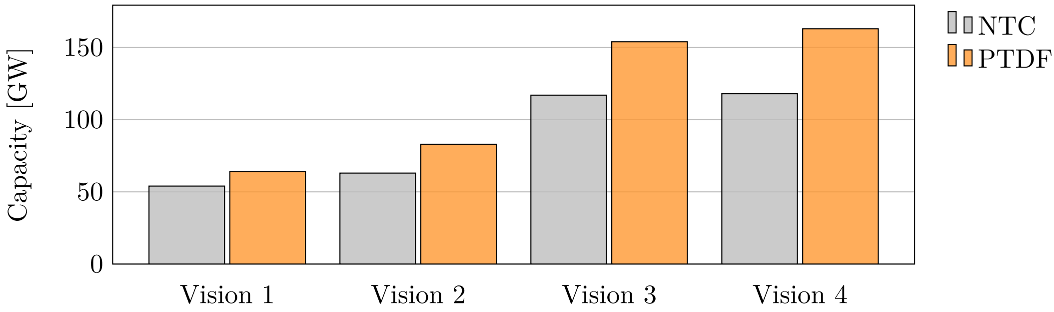


Figure 5.17: Graphical comparison of the accumulated interconnector capacity expansion of the NTC-FB-analysis.

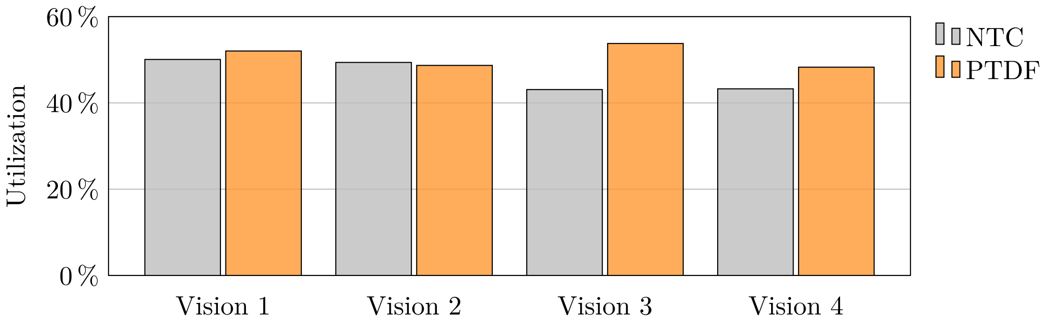


Figure 5.18: Graphical comparison of AMUs of all interconnectors of the NTC-FB-analysis.

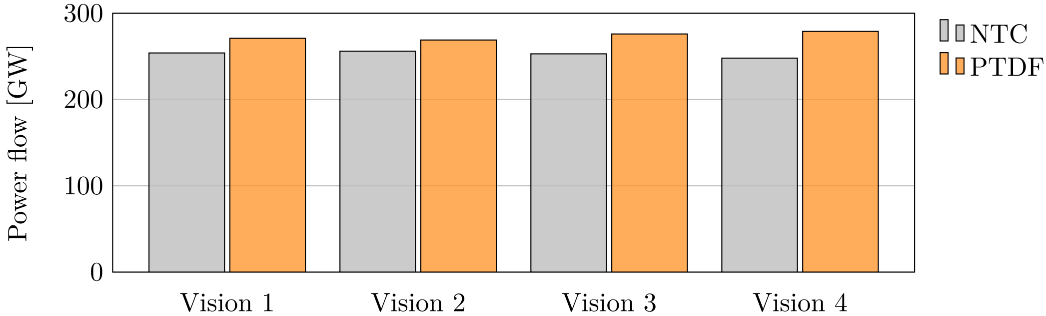


Figure 5.19: Graphical comparison of the accumulated active power flows on PTDF branches of the NTC-FB-analysis.

Discussion of Results

Considering the data presented, one can clearly observe differences in the results of the two methodologies as well.

From Figure 5.16, an increase in optimal interconnector exchange is observed, for all Visions, when the flow-based methodology was used. This results in the capacity expansion following the same trend, as indicated by Figure 5.17, in order to facilitate for these flows. This is also observed on all the major interconnectors, illustrated by Tables D.3 - D.6, where the FB approach yields optimal total exchange greater than that of the NTC, for all scenarios. This is in compliance with the theory presented in Section 3.2, stating that the solution domain of a flow based market clearing is greater than, and containing all the solutions of, the solution domain obtained when using NTCs. When examining the optimal interconnector exchange for the different Visions, the same discussion as the expansion analysis, provided in Section 5.4.1, applies. With increasing pan-European cooperation, the cross-border exchange increases, with a significant increase from Vision 2 to Vision 3. This is true for both approaches, and is clearly gleaned from Figure 5.16.

However, there does not seem to exist any trend in utilization of the interconnectors. As observed in Table D.2 for the system, and in Tables D.3 - D.6 for the interconnectors, the change in utilization varies to a great extent. This results from infrequent, high magnitude power flows, as seen in the power flow time series of Figure 5.21, which will be discussed in more detail in the next section. These power flows result in the construction of high capacity cables, while the average power flows are considerably lower. As the AMUs are defined as the average power flow divided by the total capacity, decreased utilization is the result of large exchange capacity, rather than an actual low degree of utilization.

The optimal accumulated power flow in the onshore AC grid with a PTDF-representation, is illustrated in Figure 5.19. As indicated by the graph, there is an increasing trend in the difference between the accumulated flow in the NTC-case and the FB-case. This is compliant with the theory presented in Section 2.4, stating that an NTC-approach does not account for the distributional effects in an AC system. The PTDFs, however, calculate all transit flows, resulting in a higher accumulated flow in that part of the system. Furthermore, this results in increased production costs in the PTDF-case, as shown in Table D.2, due to the fact that a higher accumulated flow in the system entails increased losses[4] that has to be supplied by a generator. This phenomenon is also observed in the example of Section 4.4. Another explanation for the increased production costs, is the increased curtailment of RES generation with the flow based modeling under Visions 3 and 4, observed in Table D.2. Curtailment is often a result of inadequate transmission capacity, restricting production dispatch, resulting in demand being supplied by generators of higher marginal costs. Under Visions 1 and 2, the production costs are almost equal with the two methodologies, indicating that the reduction of curtailment covers the increased costs due to losses. Whereas, with the increasing RES penetration under Visions 3 and 4, curtailment increases when using PTDFs, entailing an increased production cost.

The elapsed optimization time is a crucial parameter for the performance of the model. In order to be practicable, the model can not be highly time consuming. As seen in Table D.2, the optimization times increased drastically when the PTDF-constraints were introduced, as they added additionally two constraints for every branch of the PTDF-representation. However, as explained in Section 5.3, after disregarding the optimization of the PTDF-branches, the optimal solution was still obtained within reasonable limits for all optimizations, as the PTDF-representation of Vision 4 had the longest duration of approximately 45 minutes.

5.4.3 Power Flow Analysis of the Major Interconnectors of NSOG

The optimization results for the aforementioned interconnectors are provided in Tables D.3 - D.6. The time series for the 50 first samples under Vision 4 of power flow on the given interconnectors and offshore wind power production in the southern parts of NSOG, are provided in Figures 5.20 and 5.21. Figures 5.22 and 5.23 provide an illustration of the time series of the 50 first samples under Vision 4 for the wind power production in and power flow between the Dogger Bank wind farm and the offshore wind farms off the northern coast of Germany. All figures are provided for both methodologies and offers a more comprehensible representation of the complete time series given in the appendices, without any reduction in information. Vision 4 is chosen since it is the most impactful scenario on grid expansion. Additionally, an overview of the correlation coefficients[5]

[4]NetOp assumes losses of a line or cable to be linearly increasing with its power flow.

[5]Correlation describes the linear relationship between to variables. The strength of this relationship can be described by the correlation coefficient, $-1 \leq \rho \leq 1$, ranging from perfect negative to perfect positive correlation [68].

between exchange on all interconnectors and wind power production.

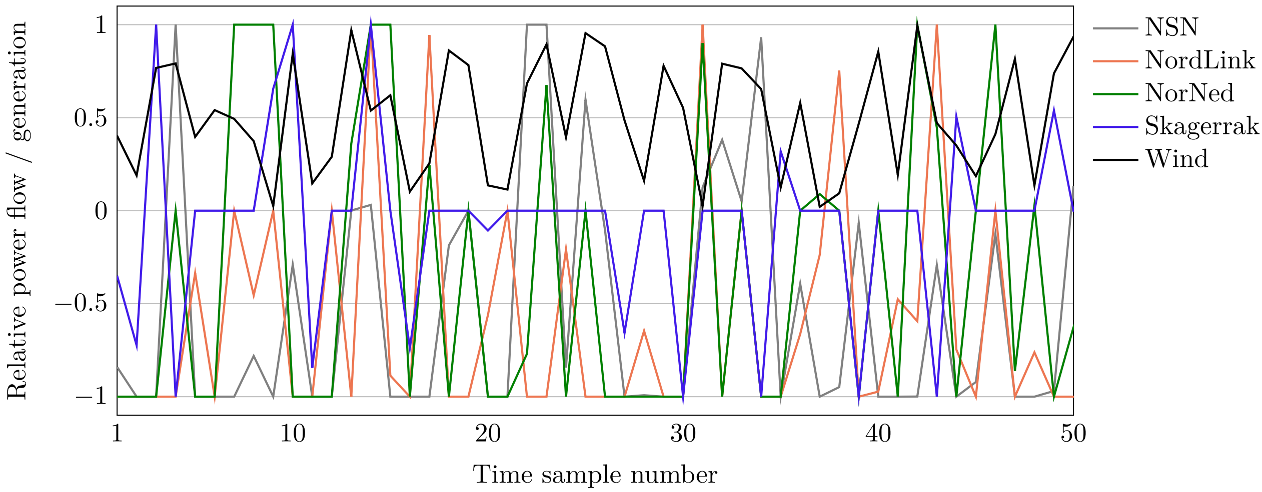


Figure 5.20: Power flow time series for some of the major interconnectors under Vision 4 using NTCs with Norway as reference (import +, export ÷, relative to max value).

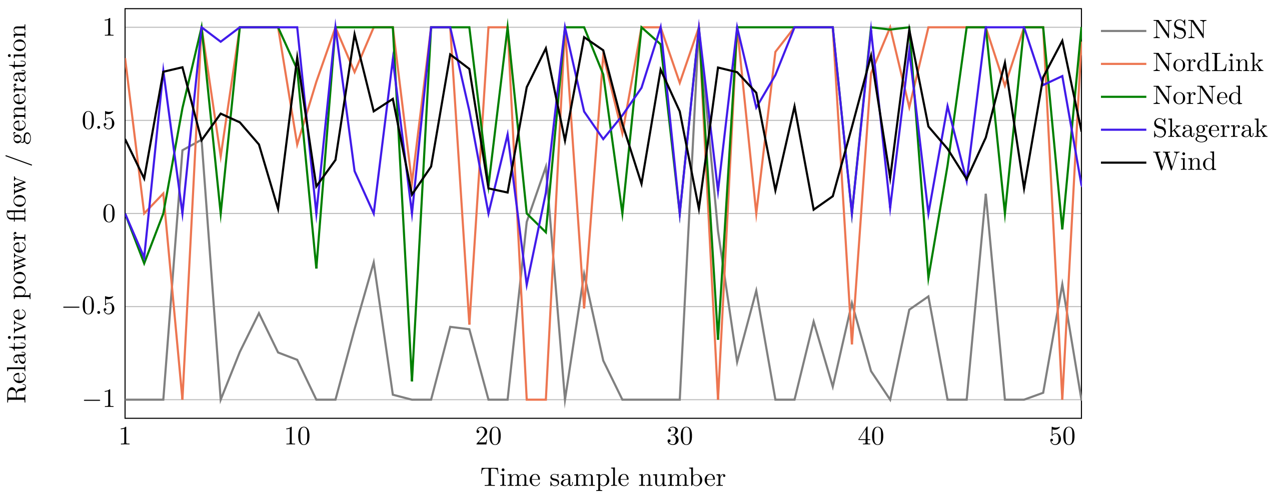


Figure 5.21: Power flow time series for some of the major interconnectors under Vision 4 using the PTDFs with Norway as reference (import +, export ÷, relative to max value).

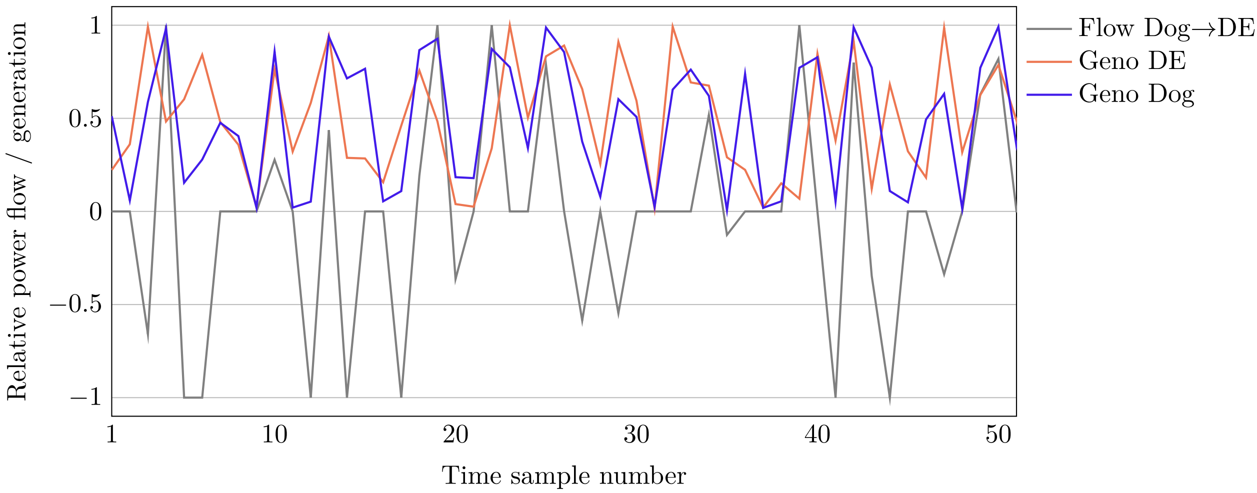


Figure 5.22: Time series of generation in and power flow between Dogger Bank (Dog) and the offshore wind farms off the northern coast of Germany (DE) under Vision 4 using NTCs, relative to max value.

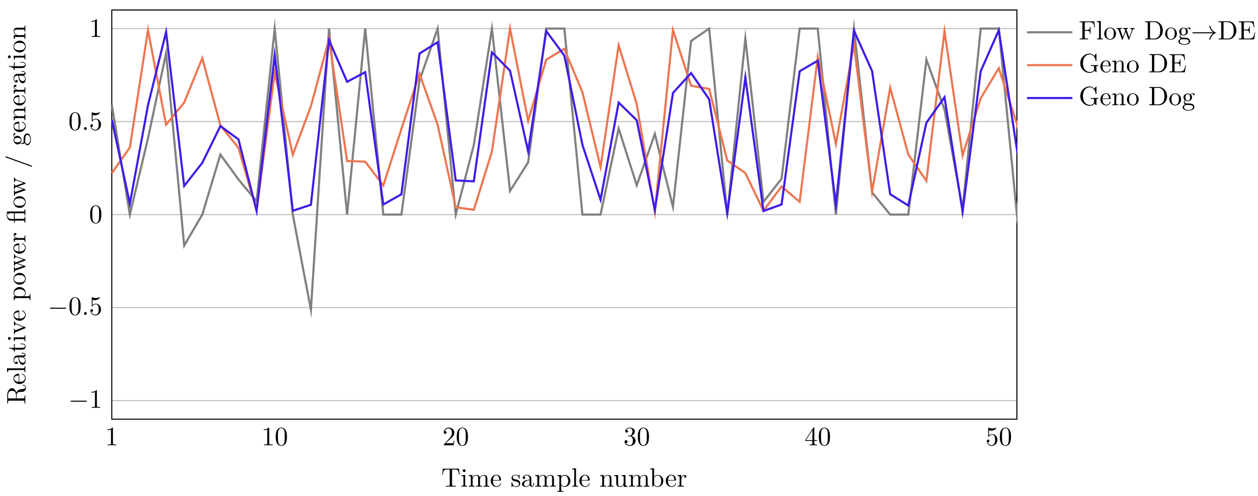


Figure 5.23: Time series of generation in and power flow between Dogger Bank (Dog) and the offshore wind farms off the northern coast of Germany (DE) under Vision 4 using PTDFs, relative to max value.

Discussion of Results

When examining the power flow time series, there is an indication of the flow based modeling of the grid resulting in a different utilization strategy of the major NSOG interconnectors, compared with using NTCs.

From Figure 5.20, there are indications of correlation between some of the time series. This can also be observed from the correlation coefficients of Table D.7. Most importantly, there seems to be a positive correlation, i.e. both variables increase simultaneously, between offshore wind production in the southern parts of NSOG, and exchange on NSN. That is, import to Norway increases with increasing wind production, and export increases with decreasing wind production. This is further indicated by a positive correlation coefficient of 0.51. Furthermore, there is an indication of a negative correlation between wind production and exchange on NordLink, i.e. import on NordLink increases with decreasing wind production. This is also indicated by a moderately negative correlation coefficient of -0.43. All these effects, combined with no correlation between the power flows in the different interconnectors, gives ground to say that Norway does not serve as a hub for transportation of power between continental Europe, and the UK. The fact that power is exported in times of high offshore wind production to the feed-in areas indicates that Norway rather serves the role of providing power and balancing services to continental Europe. This is needed due to the volatility of RES production, and is easily obtained in the hydro-dominated Norwegian system as hydro power provides the opportunity for fast regulation, exporting balancing power whenever needed.

From Figure D.1a, a similar utilization strategy as indicated for the NTC-model, can be observed for the original model. That is expected considering the equivalence of the power flow modeling.

From Figure 5.21, one can firstly observe greater variations and magnitudes of power flows when using PTDFs. This results from, as discussed in Section 5.4.2, the fact that a flow based grid modeling accounts for all power flows in a system. Furthermore, both Table D.7 and Figure 5.21 indicate a decrease in the correlation between offshore wind production and exchange on NSN. However, the correlation between wind production and exchange on NordLink remains unchanged (-0.46). Moreover, the significantly negative correlation between export on NSN and NordLink, together with a clear indication of positive correlation between exchange on NordLink, Skagerrak and NorNed, emphasized by significantly positive correlation coefficients, indicates a different utilization strategy for the interconnectors. It appears that, in the PTDF-model, Norway acts as a hub for transportation of power to and from continental Europe, and the UK. This is also indicated by Figures 5.12 - 5.15 where a shift in the interconnector expansion-strategy can be observed, putting more emphasis on the northern cables with the PTDF-approach.

On the interconnector between the British wind farm zone, Dogger Bank and the offshore wind farms off the northern coast of Germany, there is a strong correlation between the power flow and the accumulated generation in the wind farms as observed from Figures 5.22 and 5.23. This is emphasized by a strongly positive correlation coefficients between the difference in the two sites' generation and the flow between them, for both models as provided in Table D.8. This is an indication that the flow on the given interconnector is governed by the wind power production in the area, and not largely influenced by other factors such as area prices.

It is important to note that even though there indications of Norway's role in the European power system shifting away from supplier of balancing power, such services are still provided with PTDF-model. Otherwise, offshore interconnection of Norway would not be necessary as power could be routed through the southern corridor of NSOG, directly from continental Europe to UK, reducing the need for capacity expansion. These results correspond to those obtained by the Twenties project [3], where a shift in utilization strategy is observed when a more detailed flow-based analysis used compared to a more simple NTC-approach.

Chapter 6
Conclusion

In this thesis, the conducted research regarded multinational transmission expansion planning and the effects of incorporating power flow descriptions in a TEP optimization model, using different methodologies with a varying degree of model comprehensiveness. The investigated system was the prospective supergrid of the North Seas, optimized under the assumptions of the ENTSO-E 2030 Visions. It is evident from the research conducted that, from an engineering and optimization point of view, a great expansion of the NSOG is needed to lay the groundwork for the future European power system and meet the climate goals outlined by the European Commission, regardless of the grid modeling methodology and parameter forecast. However, varying optimal solutions were obtained under the different power flow constraints presented in this thesis.

As observed in both the three node example of Chapter 4, and in the case study of Chapter 5, a flow-based model yields a greater optimal expansion of the existing capacity, resulting from increased power flows in the system, than the more commonly used NTC methodology. This is because FB takes all flows, including the transit flows, in the system into account, resulting in a more realistic representation and efficient utilization of the grid. Moreover, the changes in utilization strategies observed on the major interconnectors of the NSOG is a further indication that the modeling techniques yield significantly different results, and that a more detailed and realistic representation of the grid results in variations in distributional effects in both the onshore and the offshore grid.

Based on the analysis, several of the major interconnectors of the NSOG, both commissioned and planned, are of suboptimal capacity, constraining the system from optimal operation. However, interconnector expansion entails high investment cost. As seen from Table D.3, the optimal expansion of the NSN link under Vision 4 single-handedly represents an additional investment cost of € 6.39 billion on top of the existing € 2 billion budget. Even though such an investment are considered cost efficient by the optimization model, it still has to be incurred by a TSO, and covered by congestion rent. This is probably considered unprofitable by the TSOs, explaining the capacity chosen in the existing solution. The model also assumes one hypothetical TSO in charge of NSOG TEP, disregarding the effects of multinational cooperation and the resulting distribution of both costs and benefits. This might be a major limitation of the model as interconnector investments are conducted bilaterally by the involved TSOs, as described in Section 4.2. It is, however, a difficult feature to include in an optimization model due to the conflicting objectives of market participants mentioned in Section 4.2.

The use of an expanded FB model is, however, more computationally demanding, and sets higher requirements to the input to the optimization model. The PTDFs will also change for every expansion of the system, and must be continuously updated and recalculated whenever an iterative approach is undertaken. This will lead to, possibly significantly, increased computational times, depending on GSK-strategy, and will be disadvantageous to the flow-based methodology in a decision-making process.

As the theory and research presented in this thesis indicates, one can state that the FB approach to power flow modeling using PTDFs is the superior of the two methodologies. Particularly for larger, more complex, interconnected systems where inadequate modeling of the distribution effects might have a significant impact on the power flows in the system. This implies that modeling a power system using NTCs in a TEP optimization model, might yield suboptimal solutions. Hence, flow-based modeling of interconnected systems should be the preferred approach to transmission expansion planning where possible, as stated in the ENTSO-E Network Codes. Future research should use expanded models to the greatest extent possible and further consider the use of PTDFs as the results of the comparative analysis were significantly different for several parameters.

6.1 Limitations and Sources of Error

In addition to the possible limitation of disregarding investor cooperation as described in the previous section, another major limitation of the model potentially results from the assumption of perfect market competition. In reality, factors such as transmission capacity constraints can restrict optimal behavior for a market participant. Furthermore, the consideration of all generators as price-takers can be inaccurate in some systems due to the existence of large-scale producers possessing some market power, i.e. the power to alter the price by changing their behavior. Both these factors violate the assumption of perfect competition.

Another feature of NetOp creating possible deviations and limitations from realistic behavior is the deterministic nature of the model, assuming known future parameters, disregarding uncertainty. However, some of these effects are accounted for in the case study by conducting analyzes using the ENTSO-E Visions. As mentioned in Section 5.1, the European power system is expected, with a high level of certainty, to develop somewhere within the boundaries of these four extremes. The reader should therefore consider the presented results as different extremes, in between which a realistic optimal solution exists.

Furthermore, the assumption of all years throughout the planning horizon being equal as defined by the 2030 scenarios, may represent additional model limitations. NetOp discounts an annuity of a given number of equal operational years to present value, resulting in the model not taking an iterative approach to infrastructure expansion, allowing for reinvestments and cost distribution over the years. Allowing variations between the operational years would enable uncovering of potential chronological changes in necessary capacity. Nevertheless, this would necessitate the inclusion of iteratively updated PTDF-matrices, increasing complexity of the model.

Inaccuracies and errors might have occurred in the formulation of the optimization model, and the inclusion of exogenous parameters. The implementation of NetOp is a collection of multiple comprehensive and interrelated scripts of computer code, written and modified by several researchers, creating the possibility of misinterpretations.

A possibly significant source of error may occur through the inclusion of exogenous parameters, particularly within the calculation of the PTDF-matrix, despite being a result of distinguished doctoral research. As the PTDFs describe the interdependency of the power flows, imprecise sensitivity factors will affect the entire system and might yield inaccurate results that can be hard, if not impossible, to detect, particularly with increasing system complexity. Imprecise calculation of aggregated area PTDFs using GSKs is therefore a major source of inaccuracies in flow-based market clearing, as described in Section 2.3. All other exogenous parameters were used as predefined in NetOp, and no further research was conducted on this topic, with the exception of load and generation data. The potentially unrealistic nodal distribution of the aggregated values provided in the ENTSO-E Visions, might induce further inaccuracies in the solutions.

Furthermore, little is known about the consequences of the choice of not optimizing the PTDF-branches of the system, other than the time consumption of the optimizations. This might affect the solution as the model has to additionally account for limited capacity in the onshore grid and solve it cost efficiently. Additionally, disregarding optimal hydro power dispatch and other assumptions made by the model, might prove to have an impact on the optimal solution. Particularly in the hydro power dominated Nordic power system.

It also important to discuss the correlation coefficients used for the time series analysis. As mentioned in Section 5.4.3, the coefficients range from perfect negative (-1) to perfect positive (+1) correlation. However, one must be careful in the interpretation of any value within that interval. These values only provide indicative information on the strength of the linear relationship between the samples of the two populations, which again might deviate from the actual relationship between the variables.

The process of creating matching subsets of the generation and load time series through sampling can also be the cause of inaccuracies. Important input data can be lost in this process if the sampling algorithm does not include extreme values. However, as mentioned in Section 4.3.3, Trötscher and Korpås does experimentally prove in [9] that a 200 sample-representation of one operational year is adequate, at least for the original model. No sensitivity analysis was conducted to identify possible impacts different numbers of samples would have on the extended models. Furthermore, the sampling procedure present the possibility of variations in the optimal solutions occurring due to differences in the random input data. Nevertheless, Trötscher and Korpås addressed this topic in [9], concluding that the given sample size yield small variations.

6.2 Future Work

Going forward, continued research is needed within the topic of incorporating detailed grid representations and power flow modeling in a TEP-context. Particularly because, to the author's knowledge, no similar studies of joint operational- and investment optimization has previously been conducted in a TEP-context, especially not for multinational offshore applications representing a mix of both HVAC- and HVDC grids.

For the investment model NetOp, further development is needed to make sure it is suited for future market environments. Perhaps the most important step would be the use of stochastic optimization, e.g. as the two-stage model developed by van der Weijde and Hobbs with the University of Cambridge [69]. The inclusion of probabilities to input parameters associated with uncertainty, such as production costs, demand et cetera would be a valuable extension to improve realistic modeling. Additionally, inclusion of uncertainty and risk for the investors, as discussed in [55], could prove to be an interesting addition to the model. This would be particularly relevant if investor competition and conflicting objectives between investors are modeled, allowing for trade-offs between risk and profit.

Furthermore, an expansion of the system would be interesting, comprising of both augmenting the aggregated nodal representation of all the included countries with their corresponding PTDF-matrices, modeling the grid in greater detail, and extension of the system boundaries beyond the model presented in this thesis. Another interesting development would be the inclusion of system flexibility in the form of energy storage and demand-side management, as presented by Kristiansen *et al.* in [6].

Although TEP-models should be as comprehensive and realistic as possible, every extension to the model would increase the elapsed optimization times, and must be evaluated against its benefits prior to incorporation in a final model.

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Appendix A

MATLAB®-Code for Creating the PTDF-Matrix

create_PTDF.m

```
function PTDF = create_PTDF(X)
clc

[row,col] = size(X);
nNodes = row;

if (row ≠ col)
    error('Reactance matrix must be square')
end

% Creating vectors of start- and end node for each line and printing them
n=1;
for i=1:nNodes
    for j=1:nNodes
        if (X(i,j) ≠ 0 && i<j)
            node_from(n) = i;
            node_to(n) = j;
            fprintf('Line %1.0f: %1.0f-%1.0f\n',n,i,j)
            n=n+1;
        end
    end
end

nLines = n-1;

fprintf('\nTotal number of lines: %2.0f\n',nLines);

% Getting slack bus number from user
ref_bus = input('\nSlack bus number: ');
disp(' ')

% Creating bus admittance matrix
Y_bus = zeros(nNodes,nNodes);

for i=1:nNodes
    for j=1:nNodes
        if (i == j)
            for n=1:nNodes
                if (X(i,n) ≠ 0)
                    Y_bus(i,j) = Y_bus(i,j) + (1/X(i,n));
                end
            end
        elseif (X(i,j) ≠ 0)
```

```
            Y_bus(i,j) = -1/X(i,j);
        end
    end
end

Y_bus(ref_bus,ref_bus) = Y_bus(ref_bus,ref_bus) + 1;

% Creating bus impedance matrix
Z_bus = inv(Y_bus);

% Creating PTDF matrix
PTDF = zeros(nLines,nNodes);

for n=1:nLines
    for i=1:nNodes
        PTDF(n,i) = 1/X(node_from(n),node_to(n))*(Z_bus(node_from(n),i) - Z_bus(node_to(n
    end
end

end
```

Appendix B
Mosel-Code for AC TEP Optimization Models

multinode_TEP.mos

```
model multinodeTEP

options explterm
options noimplicit
uses "mmxprs";

!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!

declarations
    nNodes          :   integer;
    nLines          :   integer;
end-declarations

initializations from "3node_data.txt"
    nNodes;
    nLines;
end-initializations

declarations
    I               :   set of integer;
    L               :   set of integer;
end-declarations

    I               :   = 1 .. nNodes;
    L               :   = 1 .. nLines;


declarations
    genCost         :   array(I)                of real;
    discountRate    :   real;
    life            :   real;
    anuityFactor    :   real;
    totalTime       :   integer;
    capCostCable    :   real;
    fCostCable      :   real;
    cableCap        :   integer;
    loss            :   real;
    relMargin       :   real;
    Load            :   array(I)                of real;
    genMax          :   array(I)                of real;
    genMin          :   array(I)                of real;
    preCap          :   array(I,I)              of integer;
```

```
    PTDF            :   array(L,I)              of real;
    totalLoss       :   real;
    n               :   integer;
    connection      :   array(I,I)              of integer;
end-declarations

initializations from "3node_data.txt"
    genCost;
    discountRate;
    life;
    totalTime;
    capCostCable;
    fCostCable;
    cableCap;
    loss;
    relMargin;
    Load;
    genMax;
    genMin;
    preCap;
    PTDF;
    connection;
end-initializations

    anuityFactor    :   = (1/discountRate)*(1-(1/(1+discountRate)^life));

declarations
    totalCost       :   linctr;
    balanceCon      :   dynamic array(I)        of linctr;
    maxGenCon       :   dynamic array(I)        of linctr;
    transToCon      :   dynamic array(I,I)      of linctr;
    transFromCon    :   dynamic array(I,I)      of linctr;
    nCablesCon      :   dynamic array(I,I)      of linctr;
    PTDFcon         :   dynamic array(I,I)      of linctr;
    generation      :   dynamic array(I)        of mpvar;
    flow            :   dynamic array(I,I)      of mpvar;
    newCapacity     :   dynamic array(I,I)      of mpvar;
    numberCables    :   dynamic array(I,I)      of mpvar;
end-declarations

forall (i in I, j in I | connection(i,j) = 1) do
    create(flow(i,j));
    create(newCapacity(i,j));
    create(numberCables(i,j));
    numberCables(i,j) is_integer;
end-do

forall (g in I) do
    create(generation(g));
    generation(g) is_semcont genMin(g);
end-do

!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!

totalCost := sum(g in I) generation(g)*genCost(g)*anuityFactor*totalTime +
    sum(i in I, j in I) (newCapacity(i,j)*capCostCable +
    numberCables(i,j)*fCostCable);

forall (i in I) do
    balanceCon(i) := generation(i) -
        sum(j in I | connection(i,j) = 1) flow(i,j) +
        sum(j in I | connection(j,i) = 1) (flow(j,i)*(1-loss)) =
```

```
        Load(i);
end-do

forall (g in I) do
    maxGenCon(g) := generation(g) ≤ genMax(g);
end-do

forall (i in I, j in I | connection(i,j) = 1) do
    nCablesCon(i,j) := newCapacity(i,j) ≤ cableCap*numberCables(i,j);
end-do

! NTC constraints
forall (i in I, j in I | i < j and connection(i,j) = 1) do
    transToCon(i,j) := flow(i,j) ≤ (1-relMargin)*(newCapacity(i,j) +
        preCap(i,j));
    transFromCon(i,j) := flow(j,i) ≤ (1-relMargin)*(newCapacity(i,j) +
        preCap(i,j));
end-do

! FB constraints, comment out when using NTCs
n := 1;
forall (i in I, j in I | connection(i,j) = 1) do
    PTDFcon(i,j) := flow(i,j) ≥
        sum(m in I) (PTDF(n,m)*(generation(m)-Load(m)));
    n := n+1;
end-do


minimize(totalCost);

!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!

procedure print_status
    declarations
        status: string;
    end-declarations

    case getprobstat of
        XPRS_OPT: status:="Optimum found";
        XPRS_UNF: status:="Unfinished";
        XPRS_INF: status:="Infeasible";
        XPRS_UNB: status:="Unbounded";
        XPRS_OTH: status:="Failed";
        else status:="?";
    end-case

    writeln("Problem status: ", status);
end-procedure

print_status;
writeln('');

writeln('Optimal total cost is: EUR ', getobjval);

writeln('');
writeln('New capacity:');
writeln('Total: ',sum(i in I, j in I) getsol(newCapacity(i,j)));
forall(i in I) do
    forall(j in I) do
        write(getsol(newCapacity(i,j)), '       ');
    end-do
    writeln('');
```

```
end-do

writeln('');
writeln('# new cables:');
forall(i in I) do
    forall(j in I) do
        write(getsol(numberCables(i,j)), '      ');
    end-do
    writeln('');
end-do

writeln('');
writeln('Flow:');
writeln('Total: ',sum(i in I, j in I) getsol(flow(i,j)));
forall(i in I) do
    forall(j in I) do
        write(getsol(flow(i,j)), '      ');
    end-do
    writeln('');
end-do

writeln('');
writeln('');
writeln('Max generation capacity:');
forall(g in I) do
    write(getsol(genMax(g)), '      ');
end-do

writeln('');
writeln('Generation:');
forall(g in I) do
    write(getsol(generation(g)), '      ');
end-do

writeln('');
writeln('');
writeln('Load:');
forall(g in I) do
    write(getsol(Load(g)), '        ');
end-do

writeln('');
writeln('');
writeln('Net position:');
forall(i in I) do
    write(getsol(generation(i))-Load(i), '      ');
end-do

writeln('');
writeln('');
totalLoss := sum(g in I) getsol(generation(g)) - sum(i in I) Load(i);
writeln('Total losses: ',totalLoss,' MW, ',
    totalLoss/(sum(g in I) getsol(generation(g)))*100,'%');

!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!

end-model
```

Input Data File

3node_data.txt

```
nNodes      :       3
nGenerators :       3
nLines      :       3

genCost     :     [ 10      18      38 ]
discountRate:       0.05
life        :       10
totalTime   :       8760
capCostCable:       300000
loss        :       0.08
fCostCable  :       2330000
relMargin   :       0
cableCap    :       800
maxProd     :       9000000
Load        :     [ 200     100     1350 ]
genMax      :     [ 1200    600     300 ]
genMin      :     [ 0       0       0 ]
preCap      :     [ 0       500     600
                    500     0       0
                    600     0       0 ]
PTDF        :     [ 0.4127  -0.3175 0
                    0.5873  0.3175  0
                    0.4127  0.6825  0 ]
connection  :     [ 0       1       1
                    1       0       1
                    1       1       0 ]
```

Appendix C

ENTSO-E 2030 Visions Data

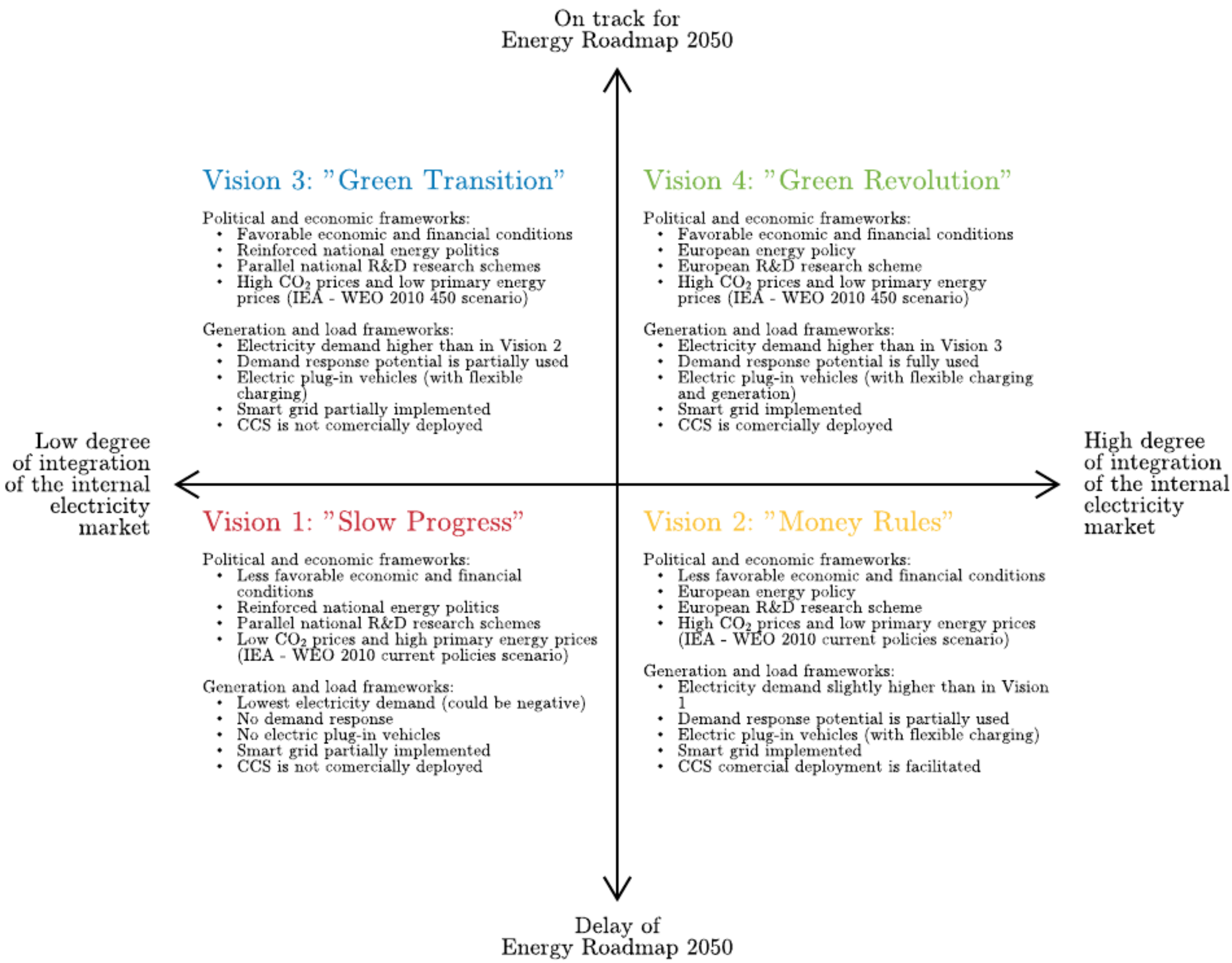


Figure C.1: ENTSO-E 2030 Visions described [5].

Production Costs

	Vision 1	Vision 2	Vision 3	Vision 4
Offshore wind	0.5	0	0	0
Onshore wind	0.5	0	0	0
Gas		70	70	70
Oil	160	160	160	160
Bio-mass	50	50	50	50
Hydro	0/20	0/20	0/20	0/20
Solar	0	0	0	0
Nuclear	11	20	20	20
Lignite and hard coal	60	60	60	60

Table C.1: ENTSO-E 2030 Visions production costs in €/MW [4].

Norway

	Vision 1	Vision 2	Vision 3	Vision 4
Winter peak load	22400	23000	23400	23400
Offshore wind	0	0	0	6400
Onshore wind	2750	3500	5000	5000
Gas	1300	1300	1300	900
Oil	0	0	0	0
Bio-mass	0	0	0	0
Hydro	36800	37500	38000	52000
Solar	0	0	0	0
Nuclear	0	0	0	0
Lignite and hard coal	0	0	0	0

Table C.2: ENTSO-E 2030 Visions generation and load data in MW for Norway [2].

Sweden

	Vision 1	Vision 2	Vision 3	Vision 4
Winter peak load	23500	24740	25440	26110
Offshore wind	160	160	1100	5000
Onshore wind	6090	6090	10000	14000
Gas	0	0	0	0
Oil	660	660	660	660
Bio-mass	5340	5340	5300	5300
Hydro	16200	16200	16200	16200
Solar	0	0	1000	1000
Nuclear	9950	8160	9950	9950
Lignite and hard coal	1150	1150	670	670

Table C.3: ENTSO-E 2030 Visions generation and load data in MW for Sweden [2].

Denmark

	Vision 1	Vision 2	Vision 3	Vision 4
Winter peak load	6210	6660	7620	8130
Offshore wind	2140	2140	4540	5540
Onshore wind	4710	4710	5920	5920
Gas	3170	3100	2010	2010
Oil	0	0	0	0
Bio-mass	560	560	4140	4690
Hydro	10	10	10	10
Solar	1110	1110	3430	3430
Nuclear	0	0	0	0
Lignite and hard coal	2760	2830	0	0

Table C.4: ENTSO-E 2030 Visions generation and load data in MW for Denmark [2].

Finland

	Vision 1	Vision 2	Vision 3	Vision 4
Winter peak load	12020	13540	14880	15280
Offshore wind	950	950	2350	2350
Onshore wind	1850	1850	2550	2550
Gas	200	200	1700	0
Oil	1360	1360	1360	1360
Bio-mass	1870	1870	3230	7050
Hydro	3740	3740	3740	3740
Solar	10	10	40	40
Nuclear	4890	4890	6490	6490
Lignite and hard coal	2920	2920	2550	2050

Table C.5: ENTSO-E 2030 Visions generation and load data in MW for Finland [2].

Great Britain

	Vision 1	Vision 2	Vision 3	Vision 4
Winter peak load	46040	58540	50380	64640
Offshore wind	20030	19220	35150	42310
Onshore wind	8290	11350	14000	18060
Gas	44270	43080	37050	39190
Oil	750	500	780	610
Bio-mass	2290	3800	3430	11150
Hydro	3870	5010	4480	5270
Solar	0	1870	0	5800
Nuclear	9250	10920	12710	13910
Lignite and hard coal	0	3450	4580	9520

Table C.6: ENTSO-E 2030 Visions generation and load data in MW for Great Britain [2].

Belgium

	Vision 1	Vision 2	Vision 3	Vision 4
Winter peak load	14190	14390	15550	15790
Offshore wind	2200	2200	4000	4000
Onshore wind	2590	2590	4540	5370
Gas	15590	15240	15590	15130
Oil	0	0	0	0
Bio-mass	1710	1710	2290	2510
Hydro	1440	1440	2020	1440
Solar	4050	4050	5740	6740
Nuclear	0	0	0	0
Lignite and hard coal	0	0	0	0

Table C.7: ENTSO-E 2030 Visions generation and load data in MW for Belgium [2].

Germany

	Vision 1	Vision 2	Vision 3	Vision 4
Winter peak load	89060	93420	102760	108160
Offshore wind	9800	9800	23600	23600
Onshore wind	49500	49500	61400	89500
Gas	18520	15930	41260	39300
Oil	1200	1200	1200	1200
Bio-mass	8800	8800	11100	13500
Hydro	15650	15650	15650	15650
Solar	55100	55100	68800	68800
Nuclear	0	0	0	0
Lignite and hard coal	43640	43640	35800	31690

Table C.8: ENTSO-E 2030 Visions generation and load data in MW for Germany [2].

Netherlands

	Vision 1	Vision 2	Vision 3	Vision 4
Winter peak load	16760	17420	22880	22980
Offshore wind	2000	2000	6000	6800
Onshore wind	4000	4000	6000	6000
Gas	19300	19220	22230	20710
Oil	0	0	0	0
Bio-mass	2540	2540	2900	3100
Hydro	200	200	200	200
Solar	4000	4000	8000	9100
Nuclear	490	480	0	490
Lignite and hard coal	3310	3310	3310	3230

Table C.9: ENTSO-E 2030 Visions generation and load data in MW for Netherlands [2].

Appendix D
Case Study Results

Grid Expansion Analysis

Vision	Parameter	Original	Expanded	Difference
1	Accumulated interconnector expansion [GW]	53.34	54.06	1.37%
	AMU of interconnectors [%]	62.68	50.07	-20.11%
	Accumulated flow on interconnectors [GW]	40.43	32.17	-20.42%
	Elapsed optimization time (sec)	421.54	200.47	-52.44%
	Accumulated interconnector import NO [GW]	2.94	1.44	-51.13%
	Accumulated interconnector export NO [GW]	14.15	3.03	-78.57%
	Interconnector expansion costs [bn €]	13.63	9.52	-30.11%
	NPV of total production costs [bn €]	417.68	563.80	34.98%
	Mean total curtailed RES [MW]	51.84	87.10	68.00%
2	Accumulated interconnector expansion [GW]	56.90	63.46	11.52%
	AMU of interconnectors [%]	58.88	49.38	-16.13%
	Accumulated flow on interconnectors [GW]	40.47	36.91	-8.80%
	Elapsed optimization time (sec)	148.57	82.77	-44.28%
	Accumulated interconnector import NO [GW]	2.72	1.71	-37.31%
	Accumulated interconnector export NO [GW]	13.62	1.75	-87.16%
	Interconnector expansion costs [bn €]	13.23	8.63	-34.76%
	NPV of total production costs [bn €]	512.84	666.99	30.06%
	Mean total curtailed RES [MW]	28.52	15.94	-44.10%
3	Accumulated interconnector expansion [GW]	118.22	117.55	-0.56%
	AMU of interconnectors [%]	49.30	43.09	-12.59%
	Accumulated flow on interconnectors [GW]	68.14	60.57	-11.11%
	Elapsed optimization time (sec)	649.23	271.40	-58.19%
	Accumulated interconnector import NO [GW]	4.04	3.19	-21.09%
	Accumulated interconnector export NO [GW]	15.27	6.07	-60.24%
	Interconnector expansion costs [bn €]	23.26	19.22	-17.36%
	NPV of total production costs [bn €]	352.32	484.92	37.64%
	Mean total curtailed RES [MW]	588.31	421.52	-28.35%

4	Accumulated interconnector expansion [GW]	130.78	117.88	-9.86%
	AMU of interconnectors [%]	48.29	43.26	-10.41%
	Accumulated flow on interconnectors [GW]	74.60	63.08	-15.44%
	Elapsed optimization time (sec)	557.08	109.98	-80.25%
	Accumulated interconnector import NO [GW]	3.36	1.73	-48.39%
	Accumulated interconnector export NO [GW]	17.13	8.18	-52.27%
	Interconnector expansion costs [bn €]	24.97	21.42	-14.24%
	NPV of total production costs [bn €]	432.78	558.69	29.09%
	Mean total curtailed RES [MW]	410.56	320.56	-21.92%

Table D.1: Comparison of the optimal results of the analysis of NetOp grid expansion. A positive difference indicates an increase from the original model to the expanded.

Analysis of Introducing Flow Based Constraints

Vision	Parameter	NTC	PTDF	Difference
1	Accumulated interconnector expansion [GW]	54.06	64.39	19.11%
	AMU of interconnectors [%]	50.07	52.03	3.91%
	Accumulated flow on interconnectors [GW]	32.17	39.67	23.30%
	Accumulated flow on PTDF branches [GW]	253.95	270.89	6.67%
	Elapsed optimization time (sec)	200.47	514.21	156.50%
	Accumulated interconnector expansion costs [bn €]	9.52	14.2	48.92%
	NPV of total production costs [bn €]	563.80	567.50	0.66%
	Accumulated interconnector import NO [GW]	1.44	7.18	399.13%
	Accumulated interconnector export NO [GW]	3.03	6.97	129.74%
	Mean total curtailed RES [MW]	87.10	43.60	-49.94%
2	Accumulated interconnector expansion [GW]	63.46	82.79	30.45%
	AMU of interconnectors [%]	49.38	48.69	-1.4%
	Accumulated flow on interconnectors [GW]	36.91	46.71	26.55%
	Accumulated flow on PTDF branches [GW]	256.14	268.90	4.97%
	Elapsed optimization time (sec)	82.77	849.35	926.15%
	Accumulated interconnector expansion costs [bn €]	8.63	19.42	125.02%
	NPV of total production costs [bn €]	666.99	673.82	1.02%
	Accumulated interconnector import NO [GW]	1.71	12.12	610.60%
	Accumulated interconnector export NO [GW]	1.75	7.79	345.59%
	Mean total curtailed RES [MW]	15.94	9.33	-41.50%

3	Accumulated interconnector expansion [GW]	117.55	154.34	31.29%
	AMU of interconnectors [%]	43.09	53.77	24.78%
	Accumulated flow on interconnectors [GW]	60.57	87.18	43.93%
	Accumulated flow on PTDF branches [GW]	252.81	275.52	8.98%
	Elapsed optimization time (sec)	271.40	2200.91	710.94%
	Accumulated interconnector expansion costs [bn €]	19.22	29.84	55.24%
	NPV of total production costs [bn €]	484.92	515.39	6.28%
	Accumulated interconnector import NO [GW]	3.19	15.49	385.42%
	Accumulated interconnector export NO [GW]	6.07	8.30	36.67%
	Mean total curtailed RES [MW]	421.52	444.35	5.41%
4	Accumulated interconnector expansion [GW]	117.88	163.22	38.46%
	AMU of interconnectors [%]	43.26	48.28	11.61%
	Accumulated flow on interconnectors [GW]	63.08	88.56	40.38%
	Accumulated flow on PTDF branches [GW]	248.22	279.07	12.42%
	Elapsed optimization time (sec)	109.98	2699.32	2354.37%
	Accumulated interconnector expansion costs [bn €]	21.42	32.37	51.14%
	NPV of total production costs [bn €]	558.69	606.84	8.62%
	Accumulated interconnector import NO [GW]	1.73	12.43	616.91%
	Accumulated interconnector export NO [GW]	8.18	10.37	26.78%
	Mean total curtailed RES [MW]	320.56	401.17	25.15%

Table D.2: Comparison of optimal results of the analysis of introducing PTDFs to the NetOp onshore AC grid. A positive difference indicates an increase from NTC to PTDF.

NSN

Vision	Parameter	NTC	PTDF	Difference
1	Capacity expansion [MW]	1200	2400	100.00%
	Mean utilization [%]	82.00	69.89	-14.76%
	Import to Norway [MW]	266.38	302.79	13.66%
	Export from Norway [MW]	1865.66	2353.05	26.12%
	Expansion cost [bn €]	0.71	1.42	100.00%
2	Capacity expansion [MW]	0	7200	inf
	Mean utilization [%]	85.11	72.00	-15.40%
	Import to Norway [MW]	315.89	469.28	48.55%
	Export from Norway [MW]	875.73	5722.94	553.50%
	Expansion cost [bn €]	0	4.27	inf
3	Capacity expansion [MW]	2400	8400	250.00%
	Mean utilization [%]	90.07	69.70	-22.61%
	Import to Norway [MW]	1589.35	771.27	-51.47%
	Export from Norway [MW]	1833.35	6059.33	230.50%
	Expansion cost [bn €]	1.42	4.98	250.00%
4	Capacity expansion [MW]	3600	10800	200.00%
	Mean utilization [%]	84.00	74.82	-10.93%
	Import to Norway [MW]	907.42	427.03	-52.93%
	Export from Norway [MW]	3293.05	8701.43	164.23%
	Expansion cost [bn €]	2.13	6.39	200.00%

Table D.3: Optimization results of NSN of the NTC-FB-analysis.

NorNed

Vision	Parameter	NTC	PTDF	Difference
1	Capacity expansion [MW]	0	3600	inf
	Mean utilization [%]	80.22	77.76	-3.06%
	Import to Norway [MW]	216.79	1279.41	490.14%
	Export from Norway [MW]	906.42	2608.99	187.83%
	Expansion cost [bn €]	0	1.59	inf
2	Capacity expansion [MW]	0	5955	inf
	Mean utilization [%]	68.26	47.49	-30.42%
	Import to Norway [MW]	239.76	2078.96	767.08%
	Export from Norway [MW]	715.88	1414.04	97.52%
	Expansion cost [bn €]	0	2.64	inf
3	Capacity expansion [MW]	0	3600	inf
	Mean utilization [%]	79.38	57.38	-27.71%
	Import to Norway [MW]	371.37	2246.46	504.90%
	Export from Norway [MW]	739.99	622.59	-15.86%
	Expansion cost [bn €]	0	1.59	inf
4	Capacity expansion [MW]	0	2400	inf
	Mean utilization [%]	76.60	62.81	-18.00%
	Import to Norway [MW]	200.38	2159.22	977.55%
	Export from Norway [MW]	872.11	227.74	-73.88%
	Expansion cost [bn €]	0	1.06	inf

Table D.4: Optimization results of NorNed of the NTC-FB-analysis.

NordLink

Vision	Parameter	NTC	PTDF	Difference
1	Capacity expansion [MW]	0	3600	inf
	Mean utilization [%]	46.97	78.80	67.75%
	Import to Norway [MW]	465.10	2740.06	489.13%
	Export from Norway [MW	192.49	1199.79	523.29%
	Expansion cost [bn €]	0	1.51	inf
2	Capacity expansion [MW]	0	7100	inf
	Mean utilization [%]	53.73	76.02	41.47%
	Import to Norway [MW]	663.52	5906.71	790.20%
	Export from Norway [MW	88.70	554.66	525.29%
	Expansion cost [bn €]	0	3.01	inf
3	Capacity expansion [MW]	3600	8400	133.33%
	Mean utilization [%]	77.73	67.55	-13.10%
	Import to Norway [MW]	536.69	5047.54	840.50%
	Export from Norway [MW	3350.00	1572.05	-53.07%
	Expansion cost [bn €]	1.51	3.52	133.33%
4	Capacity expansion [MW]	3600	8400	133.33%
	Mean utilization [%]	79.73	74.10	-7.06%
	Import to Norway [MW]	414.98	5895.72	1320.72%
	Export from Norway [MW	3571.33	1365.80	-61.75%
	Expansion cost [bn €]	1.51	3.52	133.33%

Table D.5: Optimization results of NordLink of the NTC-FB-analysis.

Skagerrak

Vision	Parameter	NTC	PTDF	Difference
	Capacity expansion [MW]	0	5849	inf
	Mean utilization [%]	32.80	48.49	47.83%
1	Import to Norway [MW]	489.77	2855.43	483.01%
	Export from Norway [MW	67.79	804.80	1087.19%
	Expansion cost [bn €]	0	1.42	inf
	Capacity expansion [MW]	0	7200	inf
	Mean utilization [%]	35.58	42.26	18.77%
2	Import to Norway [MW]	486.42	3664.92	653.44%
	Export from Norway [MW	67.46	96.18	42.57%
	Expansion cost [bn €]	0	1.73	inf
	Capacity expansion [MW]	0	13100	inf
	Mean utilization [%]	49.56	50.47	1.83%
3	Import to Norway [MW]	693.85	7425.61	970.20%
	Export from Norway [MW	148.66	44.54	-70.03%
	Expansion cost [bn €]	0	3.15	inf
	Capacity expansion [MW]	0	6000	inf
	Mean utilization [%]	38.36	52.23	36.15%
4	Import to Norway [MW]	211.24	3949.50	1769.67%
	Export from Norway [MW	440.92	72.52	-83.55%
	Expansion cost [bn €]	0	1.44	inf

Table D.6: Optimization results of Skagerrak of the NTC-FB-analysis.

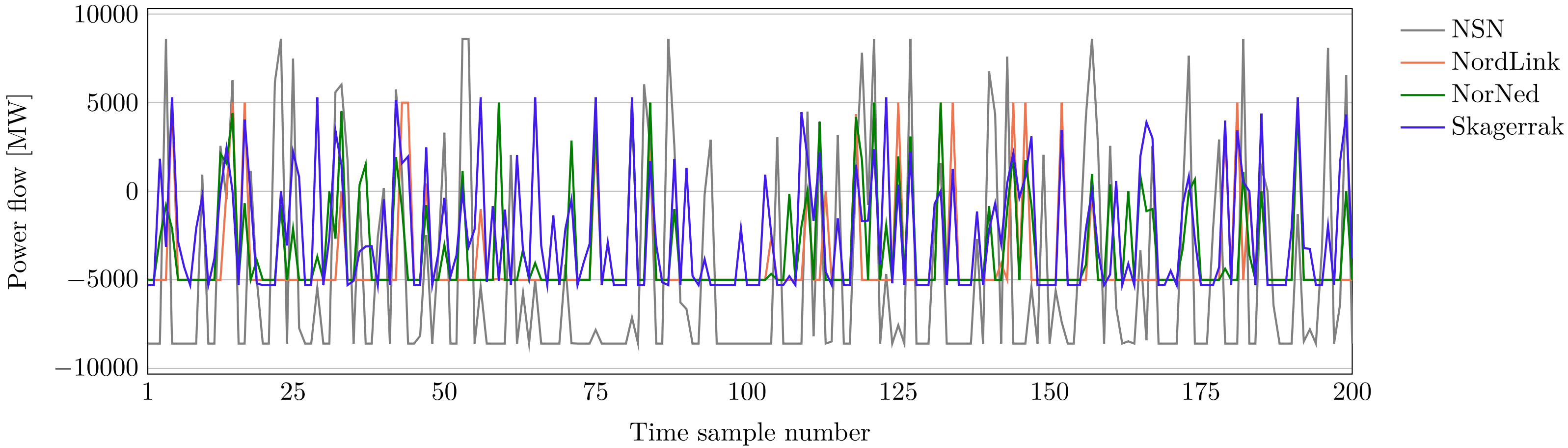
Power Flow Analysis of the Major Interconnectors of the NSOG

		Wind	NSN	NordLink	Skagerrak
NTC	**Wind**	1.00			
	NSN	0.51	1.00		
	NordLink	-0.43	-0.09	1.00	
	Skagerrak	0.10	-0.15	0.15	1.00
	NorNed	0.03	0.17	0.50	0.17
PTDF	**Wind**	1.00			
	NSN	0.19	1.00		
	NordLink	-0.46	-0.40	1.00	
	Skagerrak	0.02	-0.08	0.44	1.00
	NorNed	-0.04	0.02	0.51	0.60

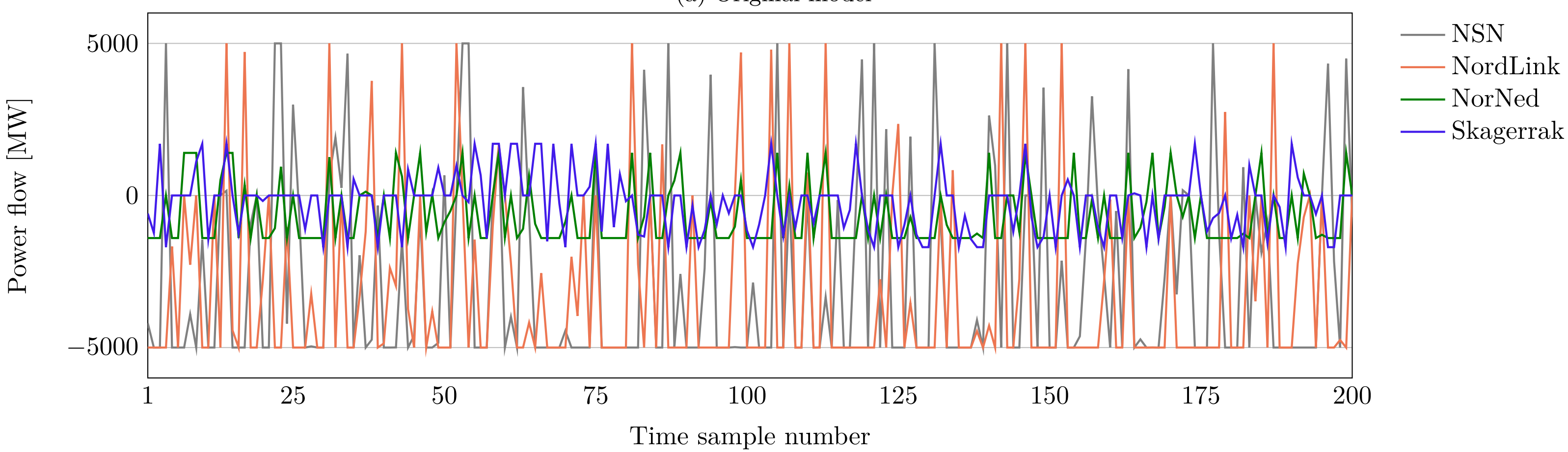
Table D.7: Correlation coefficients of interconnector exchange and offshore wind production under Vision 4.

		Flow 4→2	Geno2	Geno4
NTC	**Flow 4→2**	1.00		
	Geno2	0.00	1.00	
	Geno4	0.62	0.44	1.00
	Geno 4-Geno 2	0.63	-0.42	0.63
PTDF	**Flow 4→2**	1.00		
	Geno2	0.27	1.00	
	Geno4	0.81	0.52	1.00
	Geno 4-Geno 2	0.67	-0.31	0.65

Table D.8: Correlation coefficients of exchange and offshore wind production in southern NSOG. Geno2 is wind power production in node 2, representing the offshore wind farms off the northern coast of Germany. Node 4 represents the Dogger Bank area under Vision 4.



(a) Original model



(b) Expanded NTC model

Figure D.1: Complete power flow time series for some of the major interconnectors under Vision 4 for the original model and the expanded NTC with Norway as reference (import +, export ÷).

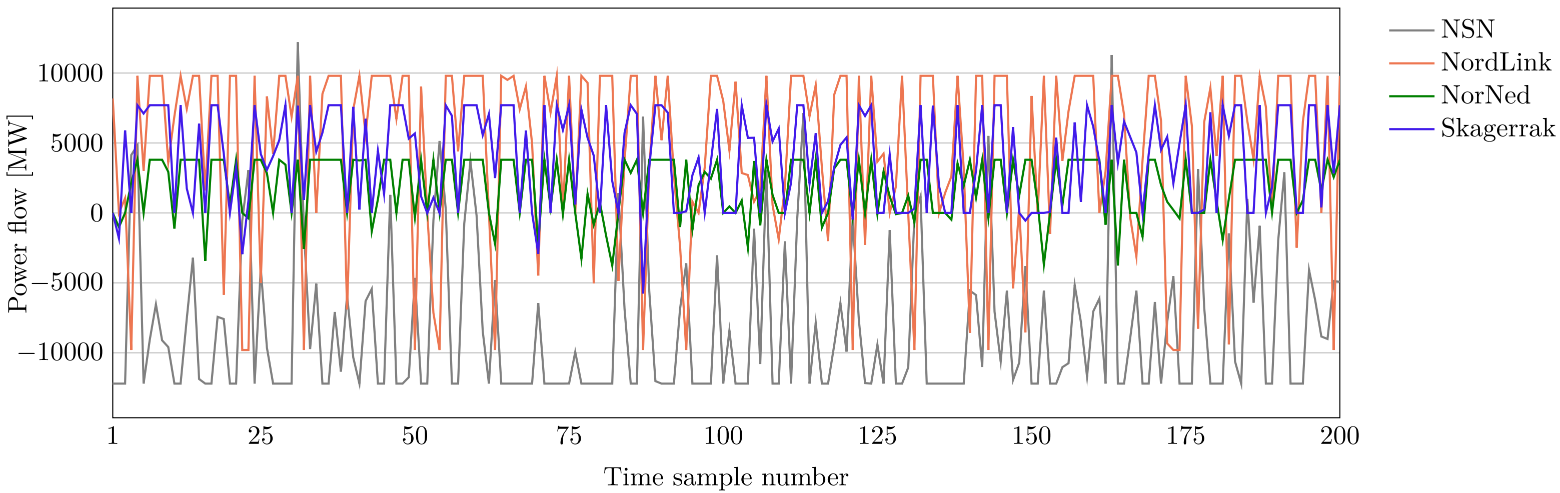
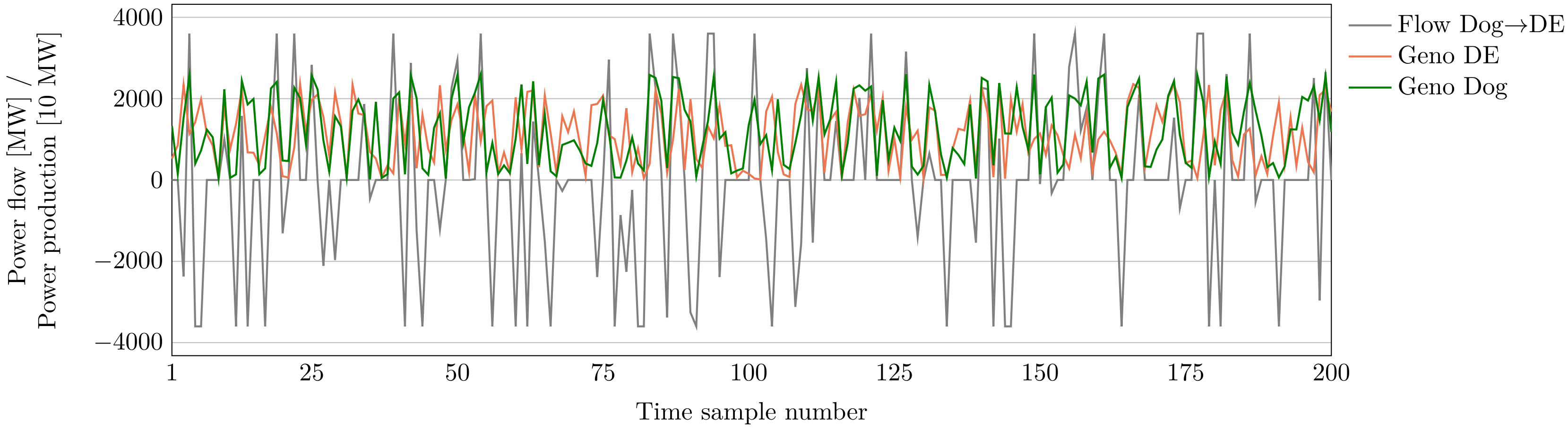
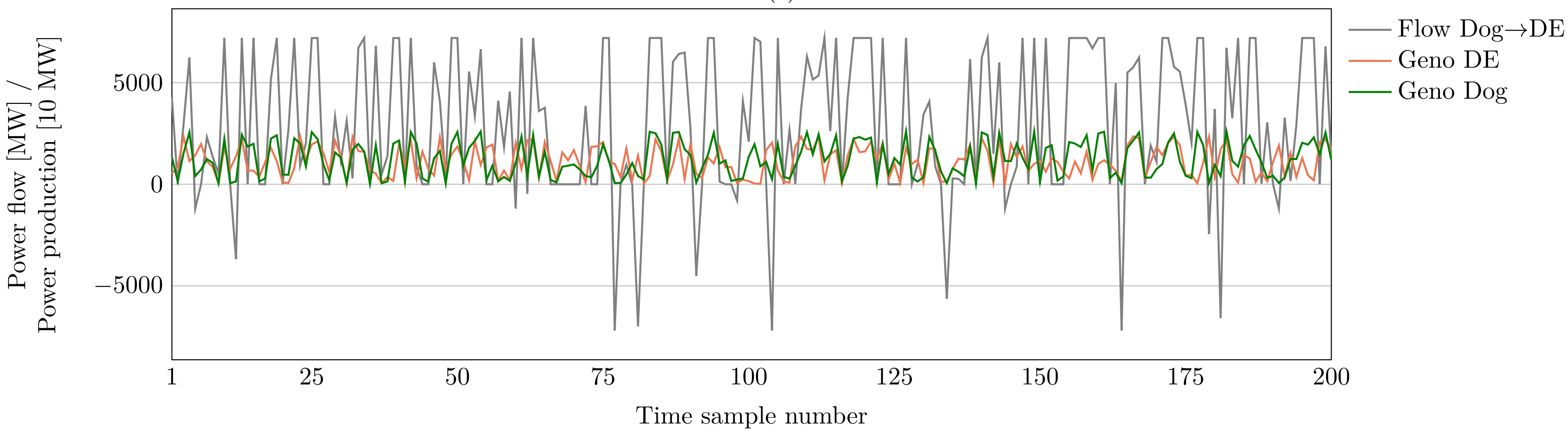


Figure D.2: Complete power flow time series for some of the major interconnectors under Vision 4 using the PTDF-representation with Norway as reference (import +, export ÷).



(a) NTC



(b) PTDF

Figure D.3: Complete time series of generation in and power flow between Dogger Bank (Dog) and the offshore wind farms off the northern coast of Germany (DE) under Vision 4.