Master's thesis

NTNU
Norwegian University of Science and Technology
Faculty of Information Technology and Electrical Engineering
Department of Electric Power Engineering

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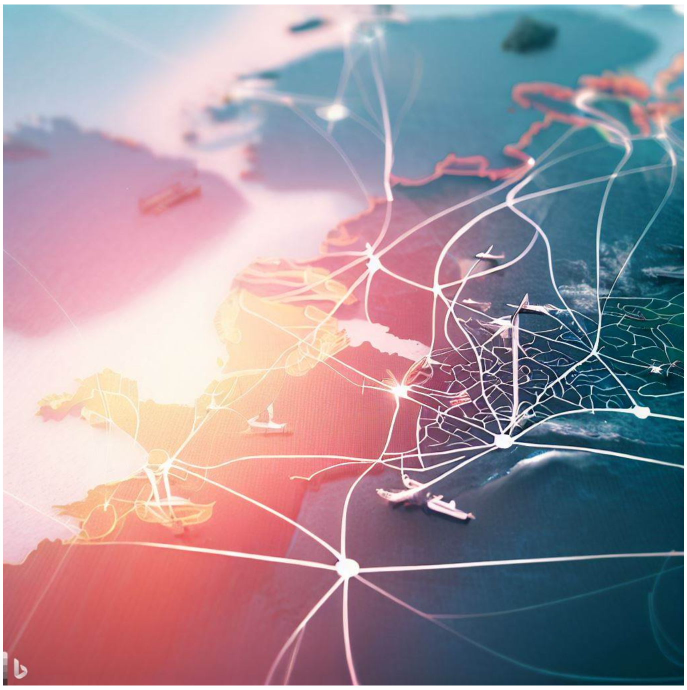
Exploring the Effects of Integrating Power Link Island into the North Sea through Transmission Expansion Planning

Master's thesis in Energy and Environmental Engineering
Supervisor: Salman Zaferanlouei
June 2023



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Abstract

As the transition towards a carbon-neutral society accelerates, the North Sea has been identified as a key region for harnessing offshore wind energy. This shift necessitates significant enhancements to the transmission system to accommodate intermittent energy production. Transmission expansion planning (TEP) comes forward as a key tool to solve this challenge.

Three case studies were conducted to assess the potential benefits of integrating power link islands (PLIs) into the North Sea through optimal investment and operational strategies, including power flow analysis, transmission capacity expansions, cost allocation among participating countries, and determination of area prices. The optimization model PowerGIM was used to minimize total system costs and maximize socio-economic welfare.

To obtain insight into various directions for the European energy market, three datasets for future storylines were used in the simulations, each based on the TYNDP2022 report published by ENTSO-E. National Trends turned out to be the storyline with the lowest average area price, remarkably lower than Distributed Energy and Global Ambition. This was primarily due to the low electricity demand, but it also reflected the extensive transmission expansion that was displayed during simulations. Global Ambition had the highest total costs due to its high electricity demand and emphasis on centralized generation, which demanded extensive transmission expansion. Distributed Energy proved to have the lowest investment cost as the spatial distribution of generation sources implied a reduced dependency on long-distance transmission lines.

Specifically, the case studies analyzed the impact of the PLI transmission capacity and the number of PLIs. The results displayed a clear economic advantage of investing in the PLI. The scenario that introduced a 50 GW PLI showcased the most significant cost reduction, with investment costs reduced to less than half compared to the base case scenario without a PLI, across all storylines. The implementation of multiple PLIs resulted in higher investment costs compared to installing a single PLI with the same capacity as all the PLIs combined. However, the operational costs remained the same for both scenarios. Therefore, building high-capacity PLIs in the North Sea emerges as the most cost-effective option given the model configuration.

This thesis contributes to the framework for optimal PLI implementation by performing TEP. Furthermore, it explores the significance of considering future scenarios with varying generation capacities and demands. By incorporating such considerations, the research enhances the accuracy and effectiveness of the implementation process.

Sammendrag

I overgangen mot et karbonnøytralt samfunn har Nordsjøen blitt pekt ut som en strategisk lokasjon for utnyttelse av havvind. For å håndtere den variable energiproduksjonen kreves betydelige forbedringer i transmisjonssystemet. Planlegging av transmisjonssystemets kapasitet (TEP) vil spille en avgjørende rolle i å takle denne utfordringen.

Tre casestudier ble gjennomført for å vurdere potensielle fordeler ved å integrere krafttilkoblingsøyer (PLIer) i Nordsjøen. Dette ble gort ved å optimalisere investerings- og driftsstrategier, kraftflyt, utvidelse av overføringskapasitet, kostnadsfordeling mellom deltakende land og fastsettelse av områdepriser. Optimeringsmodellen PowerGIM ble brukt for å minimere totale systemkostnader og maksimere samfunnsøkonomisk velferd.

For å få innsikt i de ulike retningene for det europeiske energimarkedet, ble det benyttet tre datasett med fremtidige scenarier i simuleringene. Disse datasettene er basert på TYNDP2022-rapporten utgitt av ENTSO-E, og gir verdifulle perspektiver på potensielle utviklinger og trender i energisektoren. I simuleringene viste det seg at scenarioet med nasjonale trender hadde den laveste gjennomsnittlige områdeprisen, betydelig lavere enn Distributed Energy og Global Ambition. Dette skyldtes hovedsakelig lav kraftetterspørsel, men det gjenspeilte også den omfattende utvidelsen av overføringskapasiteten som ble utført i simuleringene. Global Ambition hadde de høyeste total kostnadene på grunn av den høye etterspørselen og vektleggingen av sentralisert kraftproduksjon, som krevde omfattende utvidelse av overføringssystemet. På den andre siden viste Distributed Energy seg å ha den laveste investeringskostnaden på grunn av en jevn fordeling av energikilder, noe som reduserte behovet for lange transmisjonslinjer med høy kapasitet.

I casestudiene ble virkningen av overføringskapasiteten til PLIer og antallet PLIer grundig analysert. Resultatene tydeliggjorde en klar økonomisk fordel ved å investere i PLIer. Spesielt viste scenariet med en 50 GW PLI den mest betydelige kostnadsreduksjonen, med investeringskostnader redusert til under halvparten sammenlignet med scenarioet uten PLI. Implementering av flere PLIer førte til høyere investeringskostnader sammenlignet med en enkelt PLI med samlet kapasitet, men driftskostnadene ble det samme. Dermed framstår bygging av høykapasitets PLIer i Nordsjøen som det mest kostnadseffektive alternativet basert på modellkonfigurasjonen.

Denne avhandlingen bidrar til utviklingen av rammeverket for optimal implementering av PLIer ved bruk av TEP. Videre undersøker den betydningen av fremtidige scenarier med variasjoner i genereringskapasitet og etterspørsel. Ved å inkorporere slike hensyn forbedrer denne forskningen nøyaktigheten og effektiviteten i implementeringsprosessen.

Preface

This master's thesis was written at the Department of Electric Energy at the Norwegian University of Science and Technology (NTNU) during the spring semester 2023.

Sincere thanks are extended to our supervisor at NTNU, postdoc Salman Zaferanlouei, for consistently being available to provide professional insights, engaging in valuable discussions, and honest feedback throughout the semester. Additionally, we would like to give a big thanks to senior researcher Dr.Harald Svendsen from SINTEF Energi, for giving essential help and guidance in relation to the functionality of PowerGIM.

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Tobias:
It has been an honor to write my master's thesis with Daniel. Through hard work and dedication, we have learned to know each other's strengths and weaknesses, which has been a pure pleasure from start to finish. Appreciation is shown towards all my boys in Huset; Erlend Annfinsen, Sean Condon, Sivert Forbord, and Birk Hestvik, which have made the last four years unforgettable. A big thanks to all my fellow students and friends in EMIL 18'; you are amazing. Lastly, I would thank my family for always supporting me.

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I express my heartfelt appreciation to my friends, family, and girlfriend for their amazing support throughout my journey towards my Masters degree. I would also like to thank my fellow students for making these five years in Trondheim unforgetable. Lastly, I would like to express my sincere gratitude to Tobias. It has been an absolute pleasure collaborating with you, and your dedication has been truly inspiring. Working alongside you has not only made me a better professional but also a better person.

Trondheim, June 8^{th} 2023
Tobias Sjøli & Daniel Steinar Holt

Contents

List of Figures

List of Tables

Abbreviations

- **HVAC** - High Voltage Alternating Current
- **BE, DE, DK, NL, NO, UK** - Belgium, Germany, The Netherlands, Norway, The United Kingdom
- **DE** - Distributed Energy
- **DSM** - Demand Side Management
- **EC** - European Commission
- **ENTSO-E** - European Network of Transmission System Operators for Electricity
- **EV** - Electric Vehicles
- **GA** - Global Ambitions
- **GTEP** - Generation Transmission Expansion Planning
- **HVDC** - High Voltage Direct Current
- **LCOE** - Levelized Cost Of Energy
- **MILP** - Mixed Integer Linear Programming
- **NSEC** - The North Seas Energy Cooperation
- **NSOG** - North Sea Offshore Grid
- **OWP** - Offshore Wind Power
- **NT** - National Trends
- **PLI** - Power Link Island
- **PowerGIM** - Power Grid Investment Module
- **RES** - Renewable Energy Sources
- **TEP** - Transmission Expansion Planning
- **TSO** - Transmission System Operators
- **TYNDP** - Ten-Year Network Development Planning

1 Introduction

The transition towards a zero-emission society has accelerated rapidly in recent years. The European Commission has outlined a target to reduce greenhouse gas emissions by 80-95 % by 2050 compared to 1990. This ambitious target aims to limit the global average temperature rise to below 2 °C [1]. The energy sector accounts for more than 75 % of the EU's emissions [2]. To address this challenge, the European Commision has established the Renewable Energy Directive, which aims to increase the share of renewable energy sources (RES) in the energy mix. The directive has set a target of 32 % reduction, with the possibility of upward revision [2].

Studies conducted by ENTSO-E highlight the increasing volatility in electricity prices due to the integration of RES into the power system. To reduce these fluctuations, grid expansion will be essential [3][4], with TEP playing a key role in addressing this challenge. The growing proportion of RES also presents challenges in effectively transmitting energy from the production sites to the demand centers. Interconnections are essential for facilitating the transmission of electricity over these long distances while facilitating enhanced system reliability [5].

The north sea offshore grid (NSOG) has been identified by the European Commission as a strategic region for offshore wind power (OWP) [6]. With several countries bordering the North Sea setting ambitious targets for offshore wind deployment [7], new solutions are required to accommodate the growing production in the region. A key development in this regard is the concept of power link islands (PLIs), which serve as distribution hubs and enable efficient harnessing and transmission of OWP [8]. The consortium of TSOs leading the development of the NSOG is aiming to establish transmission infrastructures to facilitate this [9]. Ongoing PLI projects, such as Belgium's project in the North Sea and Denmark's initiatives in the Baltic Sea and the North Sea[10][11].

1.1 Research objective

In this master thesis, the primary objective is to investigate the benefits of integrating a PLI in the North Sea and optimizing the corresponding transmission grid. The research aims to optimize the transmission grid to maximize social welfare using the PowerGIM optimization model. Datasets from the most recent TYNDP report will be utilized, which introduces projected storylines[1] for the trends within energy supply and demand in the coming years. By exploring a range of case studies with different scenarios and storylines, the ripple effect on the power market and assessment of the PLI feasibility

[1] The term "storyline" will be used throughout the report and refer to the three storylines; Distributed Energy, Global Ambition, and National Trends. This terminology is utilized to avoid misunderstanding between storylines and the scenarios presented for the case studies

will be examined. The case studies will investigate how a gradual integration of PLI, the transmission capacity size[2], and the number of PLIs will influence the total system cost and transmission expansion in 2030. Furthermore, the effects on power flows, average area prices, and the allocation of investment costs among the participating countries will be examined.

1.2 Motivation

The motivation for this master's thesis is propelled by the expansion of offshore wind energy. NSEC projects 193 GW of wind power in the North Sea by 2040 and 250 GW by 2050 [12]. Currently, the necessity for grid connections greatly exceeds the current state of the system [13]. The offshore grid is a relatively new concept, accompanied by numerous uncertainties regarding its economic and technological feasibility [14]. These uncertainties contribute to increased risks associated with initiating new offshore grid projects. Consequently, it is imperative to lay the groundwork - akin to building the tracks before the train is operational - to ensure a successful transmission grid in the future. To ensure strong cooperation and coordination between the stakeholders, several initiatives and projects have been launched in recent years to support the development and integration of RES. Initiatives within the EU and the North Sea area specifically are briefly discussed below.

- After the Russian invasion of Ukraine in February 2022, the European Council joined forces and established REPowerEU. The initiative's main purpose is to reduce the EU's dependency on Russian oil and gas by accelerating RES penetration [15].

- The North Seas Energy Cooperation (NSEC) serves as a collaborative platform among the countries bordering the North Sea, with the objective of establishing a sustainable and integrated energy system in the region. The cooperation focuses on exploiting the synergies arising from the OWP available, enabling utilization across borders. NSEC involves the development of joint infrastructure projects, the sharing of knowledge and best practices, and the coordination of energy policies and regulations [12].

- North Seas Countries Offshore Grid Initiative (NSCOGI) is a collaborative effort to optimize the transmission infrastructure in the North Sea. By promoting cross-border cooperation, NSCOGI facilitates the efficient utilization of OWP, which minimizes costs and paves the way to overcome challenges related to grid integration [6].

- The Esbjerg Offshore Wind Declaration is a joint initiative by several European countries, including Denmark, Germany, the Netherlands, and the United Kingdom,

[2]Note that PLI capacity refers to the transmission capacity of the island, and not generation capacity

to promote OWP development in the North Sea region. The Declaration sets out a framework for cooperation and coordination between the participating countries to accelerate OWP deployment [16].

- The European Commission is the executive branch of the European Union. It plays a critical role in developing and implementing energy policies and regulations at the European level. The Commission is responsible for setting the framework for developing RES and promoting the integration of renewables into the energy system. The Commission also provides funding for research and innovation in energy [2].

The abovementioned initiatives underline the significance of NSOG in the context of RES and transmission investments for the upcoming years. These collaborative efforts demonstrate a shared recognition among the North Sea countries of the immense potential and benefits that can be realized through cross-border cooperation. This serves a strong motivation for further research on the field, including the focus of this thesis.

1.3 Contribution

The present study makes a contribution to the field of TEP in NSOG through its analysis and discussion of some key challenges related to the topic. The contributions of this master's thesis can be summarized as follows:

- By utilizing the most up-to-date datasets from TYNDP, this study provides a comprehensive analysis of the newly introduced storylines and their implications for the transmission grid in NSOG. The insights gained from this analysis contribute to a deeper understanding of the evolving energy landscape.

- The study contributes to the growing body of research on PLIs. Examining the feasibility of PLIs within the offshore grid provides valuable insights into the benefits, obstacles, and key considerations. This contributes to ongoing discussions and efforts by stakeholders to explore and harness the potential of PLIs.

- The utilization of an open-source code in this study enhances the transparency and reproducibility of the research. By working with open-source tools and sharing the developed code, the study contributes to the broader research community by providing a valuable resource for further development and refinement of TEP methodologies. This facilitates collaboration and enables future researchers to build upon the findings and methodology of this study.

1.4 Thesis structure

The structure of this thesis allows for a clear understanding of the research process and findings. Section 1 provides an introduction to the importance of TEP and the NSOG as significant area for grid development. It also highlights the motivation and objective for this study, including the contributions to the topic.

Section 2 and 3 provide relevant literature and background on the topic, such as energy economics, TEP, MILP, and integration of PLI. The sections provide an overview for the reader to understand the implications of the study better.

Section 4 and 5 present the methodology and case studies conducted in the thesis. This includes the configuration of the PowerGIM optimization model and the presentation of the datasets from TYNDP2022. The sections will describe how the model was used to simulate and optimize the NSOG.

Section 6 presents the results from the case studies, which examine the effect of PLI. The following is Section 7, where the results, limitations, and possible improvements will be discussed. Lastly, Section 8 serves as the concluding segment of the thesis, summarizing the research findings, discussing their implications, and highlighting potential directions for future research.

2 Literature review

The literature review for this thesis has been essential in gaining an understanding of multinational transmission expansion. It provided an overview of current research and practices in the field and helped identify successful methods and approaches used in previous studies. The four selected articles offer a comprehensive understanding of state-of-the-art research.

2.1 Assessing the economic benefits and power grid impacts of the power link island project [17]

The article examines the economic advantages and impact on the power grid of the PLI project, focusing on the NSOG consisting of six countries: Great Britain, Belgium, the Netherlands, Germany, Denmark, and Norway. The PowerGIM tool was utilized to optimize grid investments in the case studies. The research encompasses three distinct case studies to explore project costs, transmission investments in specific areas, power exchange facilitated by the island, and area prices to evaluate the benefits of implementing a PLI.

The initial case study assesses the increasing level of PLI in the offshore grid. In the second case study, a predetermined percentage of onshore renewable energy production is transitioned to offshore nodes within the power system. The final case study investigates the optimal location of additional offshore wind farms. The investment model incorporates datasets based on future-oriented visions for the European power system obtained from TYNDP2016, published by ENTSO-E. Each case study incorporates two simulations, representing the most pessimistic and optimistic visions.

The outcomes of the initial case indicate that the PLI investment was implemented across all scenarios, irrespective of the futuristic vision utilized in the simulations. The progressive expansion of the offshore power grid, entailing the construction of an artificial island and associated transmission lines, demonstrated its cost-effectiveness for the future European power grid in case 1. In the second case study, it became evident that shifting a portion of RES from onshore to offshore nodes could enhance overall cost savings for the PLI project. This shift would involve augmenting the proportion of offshore wind power. This approach further reduced operational expenses but necessitated additional investments in the decentralized offshore power grid. The final case study had the least impact on the project's total costs.

2.2 Towards a fully integrated North Sea offshore grid: An engineering-economic assessment of a power link island [8]

This article presents a feasibility study of a PLI as a key component of a fully integrated offshore grid in the North Sea. The article provides a comprehensive overview of the technical aspects of a PLI, including the technical design of the island, the layout of the interconnections, and the electrical infrastructure needed to connect the island to the surrounding offshore wind farms. The authors also consider the potential revenue streams from electricity sales and carbon credits.

The optimization program used to conduct the transmission expansion planning is PowerGIM. This research aims to co-optimize investment decisions and market operations for the considered case studies over an economic lifetime of 30 years starting in the year 2030. There are nine scenarios in total, branching from three groups of case studies. The first case examines varying degrees of PLI integration, and the second investigates the impact of reallocating onshore wind capacity into OWP. A stress test on the system is conducted in the third case. The case studies are simulated with two sets of input data from TYNDP 2016, comprising Vision 1 ("slow progress") and Vision 4 ("green revolution").

The results of the study suggest that a PLI is a technically feasible and economically viable option for the integration of offshore wind farms. The PLI can potentially reduce the overall cost of the offshore grid by enabling the connection of multiple wind farms to a single point, which reduces the need for expensive subsea cables, presented in Figure 2.1. Furthermore, the PLI can provide additional benefits such as improved system flexibility, increased system stability, and reduced carbon emissions.

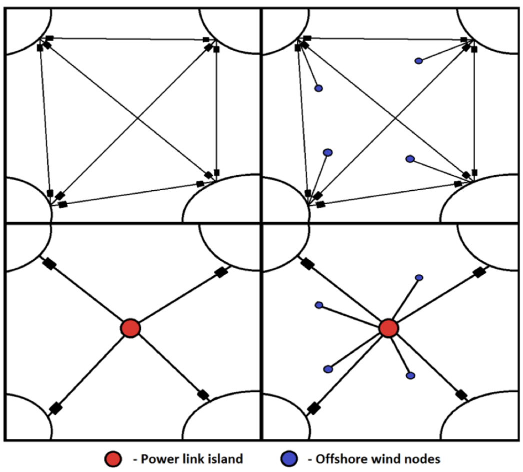

Figure 2.1: Illustration of different levels of grid integration ranging from radial solutions (in the two upper brackets) to integrated, or meshed, solutions (in the two lower brackets). The solution depicted in the lower-right corner represents a full PLI integration.

2.3 A generic framework for power system flexibility analysis using cooperative game theory [18]

The third article is a further analysis of the previous literature. It proposes a generic framework for analyzing power system flexibility using cooperative game theory. PowerGIM is utilized to obtain the results and calculate the Shapley Value to allocate the cost of investments in power system flexibility measures. Shapley Value is a method within cooperative game theory that calculates a fair allocation of costs or benefits.

The proposed framework can be applied to different contexts and scales, from local to national and regional power systems. The authors demonstrate the model's applicability in a case study involving a regional power system connected to the NSOG and testing the system's flexibility. The flexibility options evaluated in the article are grid investments, CCS from gas plants, DSM, and capacity expansion of hydropower. Furthermore, these options were combined in different groups as well.

The study evaluates the risk and benefits of implementing the mentioned flexibilities, and the results show that the prices will be reduced in general. By using Shapley value on the results, it provides a fair and efficient solution for allocating the costs of power system flexibility measures among different stakeholders, promoting cooperation among them. The framework provides a valuable tool for policymakers and other stakeholders involved in the planning and managing of power systems, facilitating the implementation of flexible and sustainable energy systems. Overall, the paper contributes to the ongoing effort of developing sustainable and flexible power systems and supporting the transition towards a low-carbon economy.

2.4 Efficient Allocation of Monetary and Environmental Benefits in Multinational Transmission Projects: North Sea Offshore Grid Case Study [19]

The fourth article proposes an efficient allocation model to distribute the benefits of multinational transmission projects, specifically the NSOG. By highlighting the importance of allocating both monetary and environmental benefits, the authors argue that the current allocation methods (50/50 split) are not satisfactory regarding fairness and efficiency. The proposed model uses cooperative game theory, specifically the Shapley value, to allocate the monetary benefits based on the contributions of each country. To allocate the environmental benefits, the authors use a marginal abatement cost approach, which calculates the cost per unit of reduction in CO_2 emissions for each country.

The paper uses a portfolio of three projects that are planned in the North Seas area, comprised of the following cross-border cables; North Sea Link (NO-GB), NordLink (NO-DE), and Viking (DK-GB). The transmission cables are assumed to be in operation within 2030 under TYNDP2014 scenario vision 4. The model tests all combinations of the investments and the corresponding benefit for each country. The preferred portfolio for each country would differ since all countries will maximize their benefit. The latter leads to an unfair allocation, which may hinder all countries to join the grand coalition of transmission expansion.

The results show that the proposed allocation method is more efficient and fair than the current. The paper also suggests that the proposed model could be used for other multinational transmission projects and other types of projects where benefits are shared among different stakeholders. Overall, the paper contributes to the ongoing discussions and research on the efficient allocation of benefits in multinational transmission projects. The proposed model provides a practical and feasible solution to the challenges of allocating monetary and environmental benefits.

2.5 Conclusion of literature review

In conclusion, the first two articles present a broad examination of the economic advantages and power grid impact of the PLI project within the NSOG. However, there are certain research gaps that motivate further exploration. Firstly, the datasets used in the articles are outdated and do not represent today's energy trends. The scenarios explored in TYNDP2014 and TYNDP2016 are substantially different from what the recent studies present. Considering the rapid transition in the power system and the political situation in Europe, more recent data should be investigated to enhance the accuracy of the results.

The articles lack sensitivity analysis of the PLI transmission capacity and the impact of implementing multiple PLIs, which could provide insights into optimal sizing, topology, and increased reliability. An interesting study would be to conduct a detailed analysis of a multi-terminal DC grid incorporating the PLI and offshore project. Addressing these research gaps will augment our understanding of the PLI project's feasibility, scalability, and potential impact on the broader European power system.

The two last papers [18] [19] address the allocation of investment costs, which becomes an increasingly more important challenge. As more OWP is built in the North Sea, the need for cooperation increases dramatically, and assessing the cost allocation by incorporating the Shapley value may be a feasible solution. This thesis will utilize the 50/50 allocation method but opens the possibility for further analysis and exploration of the results. Implementing Shapley value and re-allocating the costs found in the research is possible as the code will be open source.

3 Background

3.1 Energy economics

Energy economics has become increasingly essential in today's global landscape, where energy consumption and trade are critical factors affecting economies worldwide [20]. The decision-making process for energy investment hinges on a cost-benefit analysis, where stakeholders must consider the potential gains against the associated costs [21]. However, the question arises whether it is feasible to achieve a win-win situation for all parties involved, or if sacrifices need to be made to achieve net benefits by 2050. Given the complexity and uncertainties surrounding energy investment decisions, careful analysis is required to identify the most optimal investments for the future. Thus, this section explores the fundamental concepts of energy economics necessary to build realistic models for energy investment analysis [22].

3.2 Supply, demand, and market balance

The electricity market balances power generation and consumption while optimizing resource utilization. Its primary role is to determine electricity prices and facilitate efficient planning and operation of the power system [23]. The market maintains balance by continuously matching electricity supply with demand. This is illustrated in Figure 3.1, which represents the demand curve from households and industry, and the supply curve from the producers. The intersection between the curves is called the market cross, and it is the point where both consumers and producers are satisfied with quantity and price. This real-time information exchange occurs between producers and consumers every hour. The suppliers indicate the amount of electricity the consumers require, while the producers specify their available production capacity. This information forms the basis for determining the precise price of electricity. Thus, the electricity market plays a crucial role in coordinating and optimizing the operation of the power system [24].

The European power market operates across distinct areas and zones, each with its own production and demand [25]. However, to enable power exchange, the transmission system interconnects these areas, facilitating the import and export of electricity. Despite the advantages, transmission lines face limitations in terms of thermal capacity, voltage stability, and system stability, resulting in congestion and bottlenecks [26]. The congestion leads to price differences between the connected areas. To manage the bottlenecks, optimal congestion management techniques adjust prices to align the transferred power with available capacity [24]. This results in a congestion rent, which is paid to the TSOs. The congestion rent leads to a total welfare loss due to insufficient transmission capacity. Thus the regulators play a crucial role in monitoring and incentivizing grid companies to maintain an efficient transmission system [27].

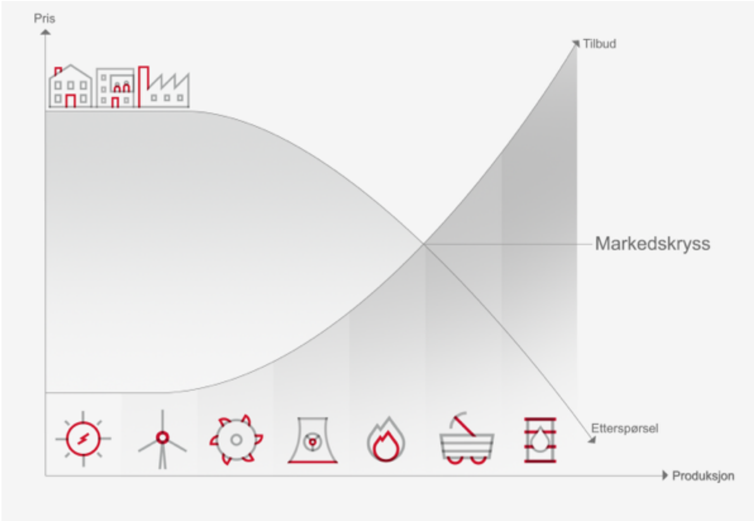

Figure 3.1: Supply-demand curve. [23]

3.3 Transmission expansion planning

TEP in power systems involves identifying the optimal configuration of transmission lines and other infrastructure to meet the current and future demand for electricity in a given region. This process typically involves monitoring the electricity price and analyzing data on existing transmission lines, projected electricity demand, and potential generation sources. When this information is gathered, mathematical optimization techniques are used to determine the most cost-effective and efficient expansions. [3]

TEP can be seen as a co-optimization problem, where both investment and operational costs need to be balanced effectively [29]. If no investments are made, operational costs will remain high due to limitations in the infrastructure. Conversely, excessive investments to minimize operational costs can lead to redundant costs due to underutilized capacity. Finding the optimal equilibrium is essential to ensure cost-effectiveness and maximize the utilization of resources [30].

An illustrative approach for determining whether to make a large investment involves utilizing a price-duration curve and monitoring investment signals. This signal, referred to as a price spike in the curve, represents the area in the price-duration curve that surpasses the average variable cost, as shown in Figure 3.2. This spike can be characterized by either a substantial height or a prolonged duration, signaling a requirement for investments. Further insights on investment criteria can be explored in [31].

[3]This paragraph is taken from an unpublished work from the authors [28]

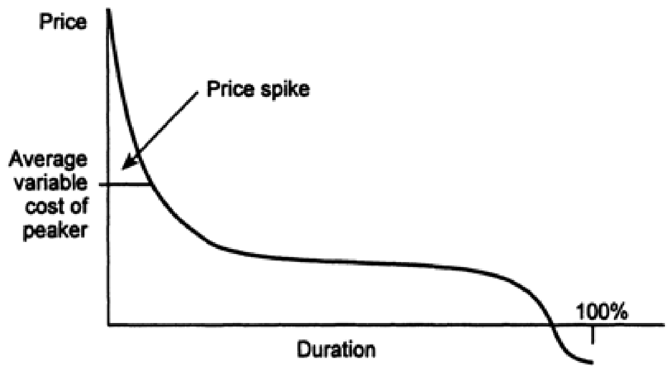

Figure 3.2: The Price-duration curve provides a visual representation of the electricity price variation over time, displaying the duration of prices ranging from the highest to the lowest [31]

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3.3.1 Mixed Integer Linear Programming

MILP is a mathematical optimization technique that involves finding the optimal solution to a problem with a combination of continuous and discrete variables. MILP aims to maximize or minimize an objective function subject to constraints. These constraints may include limits on the values of the variables, as well as relationships between the variables. MILP solvers use algorithms such as branch and bound or cutting planes to search for the optimal solution to a problem. In addition to continuous and discrete variables, MILP can also handle logical constraints, which can be used to represent complex real-world situations. Overall, MILP is a powerful tool for optimization and decision-making in a wide range of applications [32] [4]. The MILP formulation used in the TEP model will be presented in 4.2 in the methodology.

3.3.2 Expansion of the offshore grid

The development of offshore grids presents unique challenges compared to onshore grids. The offshore expansion involves considerably higher costs, primarily attributed to the long distances, extreme weather conditions, and required resources such as personnel, vessels, and the electrical components necessary to operate an HVDC system. By utilizing HVDC technology offshore, power can be transmitted over long distances with minimal power losses and improved stability [33]. The limitations of the electricity grid are often found within the internal grid of the continental power system [34]. Therefore, it is important to consider the internal grid's capabilities when designing and sizing offshore HVDC grids to avoid unnecessary expenses and ensure optimal performance.

The break-even point where HVDC becomes more economically viable than HVAC de-

[4]This paragraph is taken from an unpublished work from the authors [28]

pends on factors such as the transmission distance, power capacity, and the surroundings. However, a general rule is that HVDC becomes more advantageous for longer transmission distances, with overhead lines showing a break-even point at around 500 kilometers, while subsea cables reach the break-even point at approximately 40 kilometers [35]. The power flow control in HVDC cables has some challenges due to the difficulty in interrupting the flow, necessitating costly breakers. These HVDC breakers are required for both meshed DC grids and multi-terminal DC links [36]. Additionally, since the existing onshore grid is primarily based on AC systems, integrating HVDC necessitates the deployment of AC/DC converters at both ends of the cables. This contributes to higher fixed costs compared to AC transmission systems [37].

The number of existing offshore nodes is limited, which requires large investments in new nodes. Given the complexity and the numerous stakeholders involved in the expansion of the grid, it is a long process that requires a thorough analysis of the future energy market and a well-negotiated agreement with all participating parties. Therefore, expansion planning plays a crucial role in determining the grid investment.

3.3.3 Power Link Island

The concept of PLI projects is relatively new, with Belgium and Denmark as the first countries to construct these islands [38][39]. The primary objective is to leverage the PLIs to enable wind turbines to be positioned farther from the coast and enhance the efficient distribution of generated power across multiple countries [11]. This approach has the potential to reduce the necessity for expensive long-distance grid expansions and optimize the overall operation of the power system. Additionally, there are future ambitions to utilize the islands for energy conversion, known as power-to-x, where excess energy can be transformed into alternative forms such as ammonia or hydrogen, potentially serving as fuel for offshore vessels [40].

A study conducted by COWI in 2021 [41] claims the construction of an artificial island that may cost approximately €1.5bn without any electrical components. The cost covers the island's construction with caisson, stones, and sand, including infrastructures such as a landing zone for helicopters, ports for vessels, and facilities for people to operate on the island. Figure 3.3 illustrates what the PLI may look like.

Figure 3.3: Illustration of a potential PLI [42].

4 Methodology

4.1 PowerGIM

PowerGIM, or Power Grid Investment module, is an expansion planning model for optimizing generator- and transmission investments. It was originally a TEP model incorporated into the market model, PowerGAMA, made by SINTEF Energy Research [43]. PowerGAMA is a deterministic LP optimization model, while PowerGIM is formulated as a two-stage MILP model [44]. PowerGIM utilizes Pyomo, a collection of software packages for Python [45]. The advantage of integrating Pyomo objects within Python is the simplified breakdown of complex problems into smaller components and the utilization of parallel communication libraries. This makes the model more efficient and effective [44]. The Gurobi solver was employed to solve the optimization problems [46].

4.2 Mathematical modeling

This subsection presents the deterministic formulation for the optimization problem formulated within PowerGIM. The formulation and description presented in this subsection are obtained from [17][47].

The objective function (1) is to minimize the investment costs (2) and operational costs (3) while complying with the constraints. The investment cost consists of fixed and variable costs, represented in equation (4) and (5). The fixed costs are dependent on mobilization costs (B), cable distance ($B^d D_b$), and voltage transformers/power electronics needed at each end of a cable (CS_b). They are multiplied by an integer variable (y_b^{num}) representing the number of cables. The variable costs include a power-distance parameter ($B^{dp} D_b$) and a power-dependent cost parameter (CS_b^p) multiplied by the new branch capacity parameter (y_b^{cap}). The operational costs are calculated for one representative year. Hence, it is multiplied with an annuity factor, α, in order to get the net present value (NPV). The operational costs depend on the marginal cost (MC_i) and CO2 cost ($CO2_i$) and are multiplied with the generated power (g_i) from the corresponding node. Further, the model considers the value of lost load (VOLL). This is a high penalty price for not delivering sufficient power, and it is multiplied with the amount of shedded load (s_{nt}).

The binary variable (z_n) represents the installation of a non-existing node. This variable is multiplied by the installation cost (CZ_n). Equation (6) is the energy balance constraint, which ensures the generated power always equal the demand at every timestep, even when taking transmission losses into account. The next constraint is the generation capacity and expansion constraint (7), which ensures that a generator's production is never below its minimum or above its maximum. A generator can expand its capacity by adding the variable x_i. The same yields for constraint (9), which gives a branch a minimum and maximum limit in addition to the possibility to be expanded if needed. Constraint (10) is formulated to build multiple branches in parallel instead of relying on one large branch.

Hourly profiles for a full year, obtained from historical weather data, represent fluctuations in the availability of RES as well as changes in the system load. The hourly generation profiles are reflected with a factor, γ_{it}, which varies between 0 and 1 and is multiplied by the installed capacity of the generator P_i^e. In order to reduce the model size, a clustering technique is applied to reduce the number of time steps. The factor ω_t is introduced to account for the downsizing.

Table 4.1: Notations for the generation and transmission expansion planning model. Source: [47]

Type	Notation	Description
Set	$n \in N$	Nodes
	$i \in G$	Generators
	$b \in B$	Branches
	$l \in L$	Loads, Demand, Consumers
	$i \in G_n, l \in L_n$	generators/load at node n
	$n \in B_n^{in}, B_n^{out}$	Branch in/out at node n
Parameter	α, ω_t	Factors for annuity and sample size hour t [h]
	$VOLL$	Value of lost load (cost of load shedding) [€/MWh]
	MC_i	Marginal cost of generation, generator i [€/MWh]
	CO_{2i}	CO_2 emission costs, generator i [€/MWh]
	D_{lt}	Demand at load l, hour t [MW]
	C_b^{fix}, C_b^{var}	Fixed- and variable costs, branch b [€, €/MW]
	B, B^d, B^{dp}	branch mobilization, fixed- and variable cost [€,€/km,€/km MW]
	CS_b, CS_b^p	onshore/offshore switchgear (fixed and variable cost), branch b [€,€/MW]
	CX_i	Capital cost for generator capacity, generator i [€/MW]
	CZ_n	Onshore/offshore node costs (e.g. platform costs), node n [€]
	P_i^{min}, P_i^e	Minimum and maximum existing generation capacity, generator i [MW]
	γ_{it}	Factor for available generator capacity, generator i, hour t
	P_b^e, P_b^{max}	Factor for available generator capacity, generator i, hour t
	D_b	Distance/length, branch b [km]
	l_b	Transmission losses (fixed + variable w.r.t. distance), branch b
	E_i	Yearly disposable energy, generator i [MWh]
	M	A sufficiently large number
Variable	IC, OC	Investment- and operational costs [€]
	y_b^{num}	Number of new transmission lines/cables, branch b
	y_b^{cap}	New transmission capacity, branch b [MW]
	z_n	new platform/station, node n
	x_i	New generation capacity, generator i [MW]
	g_{it}	Power generation dispatch, generator i, hour t [MW]
	f_{bt}	Power flow, branch b, hour t [MW]
	s_{nt}	Load shedding, node n, hour t [MW]

Optimization problem

$$\text{Minimize} \quad IC + \alpha \cdot OC \tag{1}$$

where

$$IC = \sum_{b \in B} C_b^{fix} y_b^{num} + C_b^{var} y_b^{cap} + \sum_{n \in N} CZ_n z_n + \sum_{i \in G} CX_i x_i \tag{2}$$

$$OC = \sum_{t \in T} \omega_t \left(\sum_{i \in G} (MC_i + CO2_i) g_{it} + \sum_{n \in N} VOLL \cdot s_{nt} \right) \tag{3}$$

$$C_b^{fix} = B + B^d D_b + 2CS_b \quad \forall b \in B \tag{4}$$

$$C_b^{var} = B^{dp} D_b + 2CS_b^p \quad \forall b \in B \tag{5}$$

Subject to

$$\sum_{i \in G_n} g_{it} + \sum_{b \in B_n^{in}} f_{bt}(1 - l_b) - \sum_{b \in B_n^{out}} f_{bt} + s_{nt} = \sum_{l \in L_n} D_{lt} \qquad \forall n, t \in N, T \tag{6}$$

$$P_i^{min} \leq g_{it} \leq \gamma_{it}(P_i^e + x_i) \quad \forall i, t \in G, T \tag{7}$$

$$\sum_{t \in T} \omega_t g_{it} \leq E_i \quad \forall i \in G \tag{8}$$

$$-(P_b^e + y_b^{cap}) \leq f_{bt} \leq (P_b^e + y_b^{cap}) \quad \forall b, t \in B, T \tag{9}$$

$$y_b^{cap} \leq P_b^{n,max} y_b^{num} \quad \forall b \in B \tag{10}$$

$$\sum_{b \in B_n} y_b^{num} \leq M z_n \quad \forall n \in N \tag{11}$$

$$\begin{array}{cc} x_i, y_b^{cap}, g_{it}, s_{nt} \in \mathbb{R}^+, & f_{bt} \in \mathbb{R}, \\ y_b^{num} \in \mathbb{Z}^+, & z_n \in \{0, 1\} \end{array} \tag{12}$$

4.3 TYNDP

Developed by the ENTSO-E, TYNDP provides crucial insights into the current state of the European power grid and offers a strategic roadmap for the development of transmission infrastructure in the next decade. It serves as a valuable resource for policymakers, regulators, industry stakeholders, and researchers, guiding their decision-making processes [48].

TYNDP2022, the latest edition of the report, presents an analysis based on the most up-to-date data and assumptions. The report introduces three storylines; Distributed Energy (DE), Global Ambition (GA), and National Trends (NT). DE and GA are the two COP21-compliant storylines where the overarching ambition is to fulfill the emission reduction goals in the Paris Agreement. NT is a bottom-up storyline where a more simplified methodology is utilized, with predefined demand and capacity data from the TSOs [49].

4.3.1 Distributed Energy

DE illustrates a pathway where carbon emissions will be reduced by 55% in 2030 compared to 1995, and carbon neutrality will be reached by 2050. It adopts a decentralized approach to the energy transition, emphasizing the active role of energy consumers (prosumers) in driving decarbonization. Prosumers actively participate in the energy market and contribute to the system's decarbonization by investing in small-scale renewable energy solutions and adopting circular approaches. This scenario prioritizes European energy independence above importing low-carbon energy from other markets. This focus disregards the potential advantages in terms of economic or competitiveness in favor of a geopolitical desire to be more independent [50].

4.3.2 Global Ambition

GA aligns with the COP21 agreement and aims to achieve the 1.5°C target and the EU's climate targets for 2030. It focuses on a combination of centralized energy generation technologies, including large-scale renewable projects such as offshore wind and solar power, alongside conventional centralized power plants. The emphasis is on cost-effective solutions, with a shift towards energy-efficient technologies, smart grids, and the adoption of electric vehicles and heat pumps. The GA scenario considers both domestic renewable energy sources and the potential for importing energy from competitive sources to achieve greenhouse gas emissions reduction and environmental sustainability [48][50].

4.3.3 National Trends

NT considers the individual energy and climate plans of the European countries, reflecting their specific policies and targets. It recognizes the diversity of energy mixes and energy progress across nations. RES deployment is a key focus, with countries leveraging their available resources to increase the share of RES in their energy mix. NT emphasizes cross-border cooperation, interconnections, and regional collaboration to optimize energy resources and enhance system flexibility. It aligns with the EU's 2030 Climate and Energy Framework and the agreed long-term climate target for CO_2 reduction [50]. Table 4.2 presents some of the key takeaways from the storylines[5].

Table 4.2: Comparison of storylines in TYNDP

Parameter	**DE**	**GA**	**NT**
Demand	Medium	High	Low
Installed capacity	High	Low	Medium
Offshore wind	Medium	High	High

[5]These trends may not necessarily represent the same trends observed in the complete dataset with all European countries included, as the case study focuses on a subset of countries

4.4 Input data

PowerGIM is a powerful modeling tool that offers a wide range of outputs and possible analyses. However, the integration of appropriate input data is crucial to obtain accurate and meaningful results. In the case of this study, it was necessary to make certain adjustments to the data obtained from TYNDP [48] in order to ensure its compatibility with the PowerGIM model. As a result, multiple operations were undertaken, which outplayed an important role in establishing the level of detail and accuracy in the simulation. In order to streamline the analysis and focus on the key countries in the North Sea basin, the study narrowed down the scope to six countries: Norway (NO), Denmark (DK), Germany (DE), Netherlands (NL), Belgium (BE), and the United Kingdom (UK). To meet the input requirements of PowerGIM, the generation of four quantitative data files, namely "nodes.csv," "generators.csv," "branches.csv," and "consumers.csv," was necessary. Furthermore, to ensure accurate and realistic simulations, time series data and a set of cost parameters were generated.

4.4.1 Nodes

The representation of transmission grid topology required balancing accuracy and computational efficiency. The North Sea and surrounding areas contain several thousand generators and demand nodes in reality. However, incorporating all nodes in the model would lead to impractically high computation times. In the North Sea system context, a streamlined model with 23 nodes was employed. The majority of countries in the region were represented with three nodes each.

The *main node*, denoted with a m on the node, was located in the respective country's load center and included all forms of generation except offshore wind. The *coast node*, denoted with a c on the node, served as a distribution hub connecting the offshore nodes to the generation centers and facilitated interconnections to other countries. Countries with geographically distant connection points were allocated two coastal nodes. The implementation included the option for nodes to be either DC or AC. The main and coastal nodes were modeled as AC and connected using AC branches.

To represent the offshore wind generation, the production was consolidated into wind nodes, denoted w. The dispersed location of wind farms in the North Sea made the determination of the precise location a challenge. Data for existing and planned farms were utilized to aggregate the generation into realistic locations [51][52]. To further enhance the model's precision, countries with widely spread wind production, namely the UK and the Netherlands, were represented by two wind nodes. The offshore wind nodes were assumed to be fully developed and represented as DC nodes in the model. This approach eliminated the need to consider converter costs for connecting DC branches, as the converters were already present in the existing infrastructure.

A separate node type was introduced specifically for the PLI. The inclusion of PLI in the model required incorporating the investment cost. This cost represents the expenses associated with the construction of the artificial island, including the materials such as sand and stone. The same cost was applied consistently to all PLIs in the study, independently of capacity. The power electronic components required for branch connections are incorporated into the branch costs, as further explained in 4.4.4.

Figure 4.1 provides a visual representation of all nodes in the model, including existing and potential nodes, showcasing the geographical distribution of the system. It is important to note that the simulation assumes the existence of offshore nodes at the beginning, thereby excluding any investment costs associated with the wind nodes. This assumption is based on the consideration that offshore wind generation is already outlined in TYNDP, and the focus of this thesis is not on generation expansion. To ensure that the nodes did not become the limiting factor for power flow, the capacity of the nodes was set at 1000 GW, allowing for adequate power transmission throughout the system.

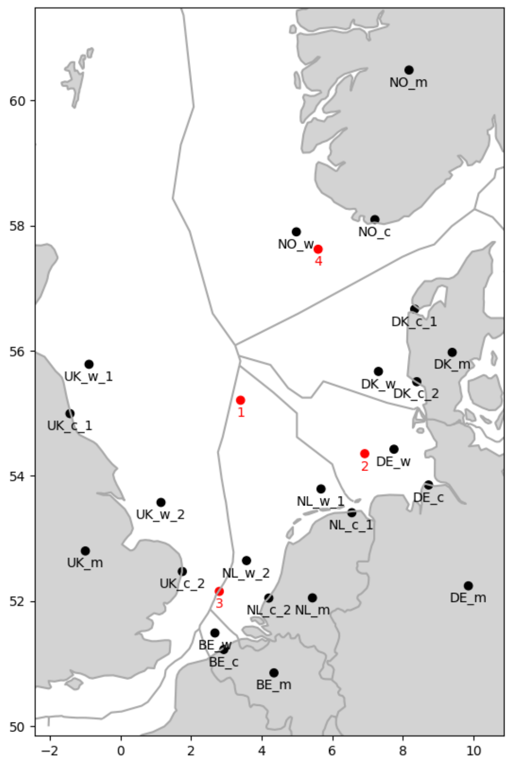

Figure 4.1: Overview of all nodes in the North Sea

4.4.2 Consumers

The demand projections for 2030 were obtained from TYNDP2022 [48]. These projections enabled the aggregation of individual country loads into a single representative node, which served as an approximation for the overall energy demand. The peak demand is a crucial parameter as it represents the maximum power consumption during the most extreme hour of the year. Incorporating the peak demand in the model makes the analysis more robust, which is vital for assessing the capacity expansion necessary. Figure 4.2 presents the peak demand for all countries and storylines.

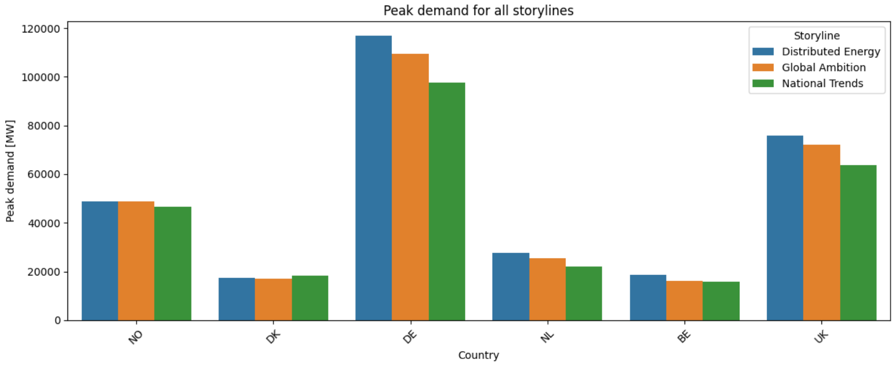

Figure 4.2: Peak demand for all countries and storylines

To capture the realistic demand characteristics, the peak demand is multiplied by a time series. The demand profiles are given in Figure 4.3, and Section 4.4.5 gives a more in-depth explanation of how the time series are constructed.

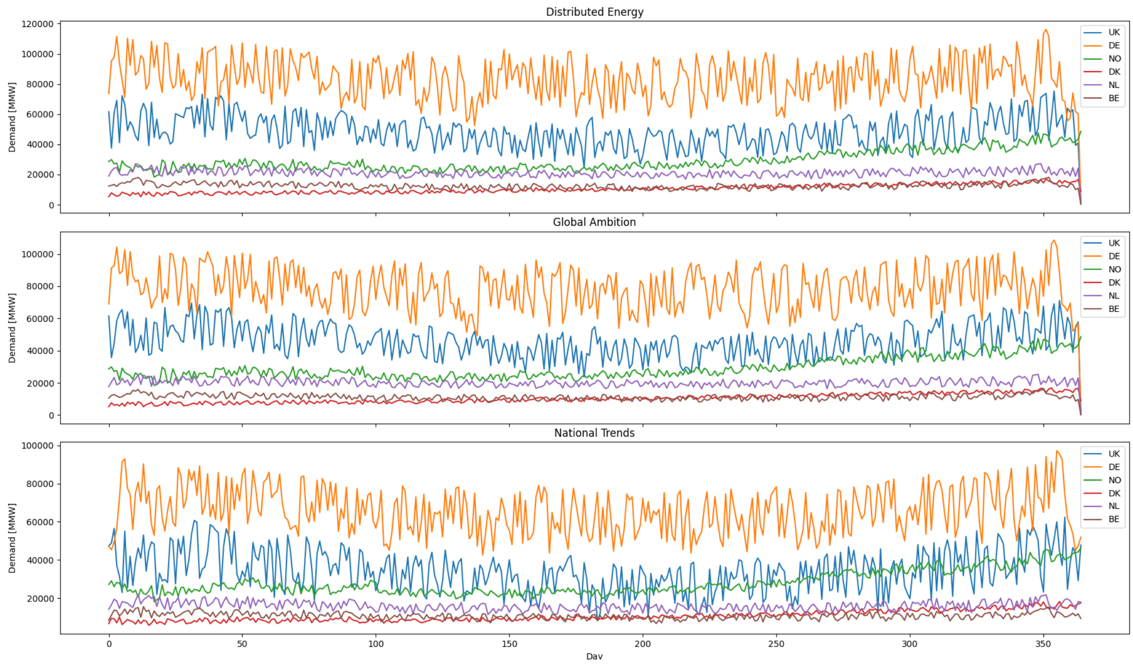

Figure 4.3: Demand time series for all storylines

It is important to note that the demand was assumed to be inelastic, meaning that it does not significantly change in response to price or other factors, and demand-side management was not considered in the model.

4.4.3 Generators

The TYNDP data provides generation capacities based on different climate years, namely 1995, 2008, and 2009. For computational efficiency, the year 2009 was chosen as the basis for the simulations in this study. This particular year is considered the most representative in terms of normalized weather conditions [49]. The TYNDP dataset offers a comprehensive overview of the planned installed capacity for various generation technologies. However, to streamline the modeling process, all generation types, except for the offshore wind, were aggregated into the main node for each country. This simplification allows for a more efficient and manageable representation of the generation mix. Figure 4.4 provides a visual depiction of the projected installed capacity for all generator types in 2030.

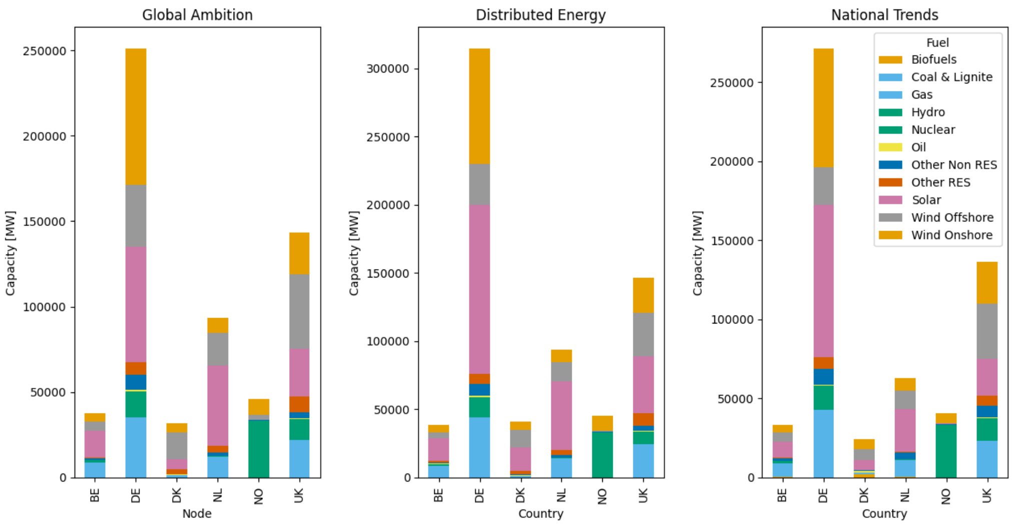

Figure 4.4: Installed capacity for all generation types in 2030

The generator input file incorporates the installed capacities while also allowing for curtailment. The curtailment feature enables generation reduction if a cheaper option is available, thereby optimizing the generation dispatch. The selection of the specific generation type is determined based on two crucial parameters: the marginal cost and the CO_2 price, which are further discussed in Section 4.4.6. To ensure a more realistic representation of intermittent energy sources like wind and hydro, an inflow reference series was constructed. This reference series captures the variations in wind and hydro resource availability, providing a more accurate generation profile. The construction of time series is described in detail in Section 4.4.5.

Even though PowerGIM is a model designed for both generation and transmission expansion, generation expansion is outside the scope of this research. All generators were set to non-expandable, meaning their capacities were fixed and not subject to modification or expansion.

4.4.4 Branches

The input data for the model include both existing and potential branches between the nodes, with binary variables indicating whether these branches are expandable or non-expandable. Existing branches cover those currently in operation, as well as planned projects scheduled for completion by 2030 [53]. On the other hand, potential branches represent those planned to be built after 2030.

The case study incorporates four different types of branches: AC, DC-Direct, DC-Mesh, and DC-Mesh-Conv. The onshore nodes are interconnected using AC cables, each with a max capacity of 400 MW per cable. As the focus of this thesis is the expansion of the offshore grid, the branches connecting each county's main node are considered non-expandable. Consequently, congestion arises between the countries in the onshore connections. To ensure adequate power flow to the main nodes, the branches from the coast to the main nodes are expandable. This expansion is allowed to avoid bottlenecks in the onshore power system.

The interconnectors between countries are represented in the model using DC-Direct cables. For the branches connecting the coast nodes to the wind nodes and PLI nodes, the DC-Mesh-Conv technology is utilized. The connections between the PLI nodes are modeled as DC-Mesh branches. The included costs for each branch type are presented in Table 4.3, and detailed costs can be found in Appendix 0.10. This approach ensures the nodes are connected with the appropriate high-voltage technology, resulting in realistic and accurate outcomes. All the DC branches in the model are expandable, as they are the branches of interest for the research.

Table 4.3: Costs included in the different branch types

Type	Costs included
AC	Cable
DC-Mesh	Cable, two breakers
DC-Direct	Cable, two converters
DC-Mesh-Conv	Cable, one converter, one breaker

The max capacity per DC cable is set at 2000 MW to ensure reliability and compliance with the N-1 criterion, which guarantees that the system remains operational even if one component fails [54]. The maximum number of cables per branch is limited to ten to obtain a feasible and realistic solution. It is important to note that the presence of ten branches in parallel does not reflect the actual transmission system. The nodes in the model represent a consolidation of multiple nodes that are geographically dispersed in reality.

In the initial state of the model, the wind nodes are not connected to the transmission grid. The branches between the wind nodes and other nodes in the system need to be expanded to accommodate the installed capacity of offshore wind generation. This variable expansion makes it evident if offshore wind penetration is economically feasible in the different scenarios. The existing branches are presented in Figure 4.5, and specific capacities can be found in Appendix 9.

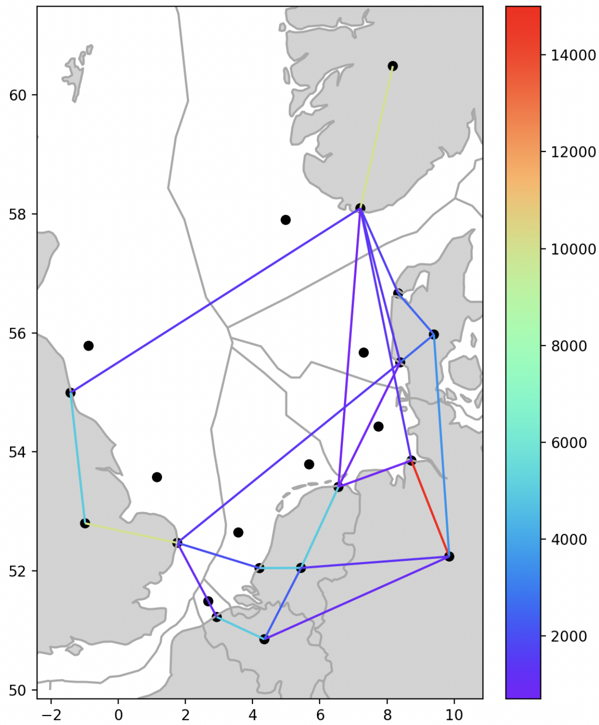

Figure 4.5: Initial grid topology

4.4.5 Time series

The time series used in the simulations were derived from the demand data for all countries [48], as mentioned earlier. The data consisted of demand for all 8760 hours of the year 2009. To streamline the computational process and save time, the time series data was reduced from 8760 to 365 timesteps. This reduction was accomplished using the K-Mean clustering technique [55]. Through this clustering algorithm, the 8760 observations were grouped into 365 new clusters. Each cluster represents a certain number of original observations, and the mean value of these observations was assigned to the respective cluster [29].

Inflow profiles for wind were obtained from relevant sources [56][57]. To maintain consistency in the data, these profiles represent the expected wind inflow for the year 2009. In order to preserve the correlation between generation and demand, the 8760 values of the wind inflow time series were selected at the same time instances as the demand time series.

For hydropower generation, a common time series was adopted for all countries, utilizing the production series for Norway in 2009 as a representative sample [58]. Although this assumption may introduce minor discrepancies in each country's generation profile, it is considered reasonable given the relatively small contribution of hydropower to the overall generation mix. By employing a common time series for hydropower generation, the model captures the general characteristics and variations without the need for country-specific data. The resulting time series for hydropower is plotted in Figure 4.6.

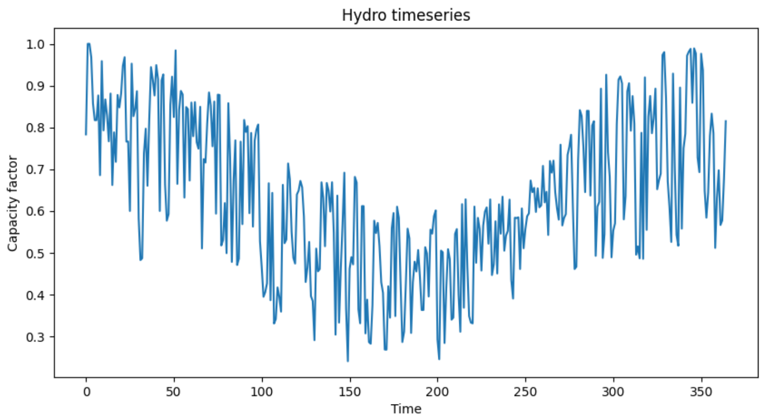

Figure 4.6: Hydro time series for 2009 [58]

4.4.6 Cost parameters

Fuel prices are a fundamental input for PowerGIM as they directly impact the cost of generation. Emission factors are another important parameter as they determine the amount of greenhouse gas emissions associated with each unit of energy generated. Costs associated with various aspects of the energy system, such as infrastructure investments, operation and maintenance, transmission, and RES deployment, also need to be considered. These costs influence the overall economic viability and feasibility of different energy generation options.

The fuel prices used in the simulation were obtained from TYNDP2022. However, since the unit for commodity prices was given in $€/GJ$, a conversion was performed to convert the prices into the marginal cost of energy production with the unit €/MWh. The conversion involved dividing the fuel price by the efficiency of the corresponding generation technology. The efficiency of conventional generators was assumed to be between 30-40% [59]. Note that the price for biofuel, hydro, and other NON-RES was not included in the dataset, hence obtained from a similar study [8]. All marginal costs are presented in Table 4.4.

Table 4.4: Fuel prices used in the simulations for GA, DE, and NT.

Fuel	**NT [€/MWh]**	**DE/GA [€/MWh]**
Biofuel*	50.00	50.00
Coal	25.51	20.26
Gas	64.51	41.35
Lignite	18.51	18.51
Nuclear	4.83	4.83
Light Oil	130.55	95.59
Other NON-RES*	100.00	100.00
Hydro*	30.00	20.00
Solar	0	0
Wind Offshore	0	0
Wind Onshore	0	0
Other RES	0	0

It is important to distinguish marginal cost from the Levelized Cost of Energy (LCOE) as they are metrics that capture different aspects of electricity generation. LCOE takes into account many factors, such as the fixed cost of the power plant, lifetime, and other variable costs, while the marginal cost is the cost to produce an additional unit of electricity [60].

The CO_2 price was set to 78 €/tonne [50], and the emission factors for each generation type were obtained from [17], and can be found in Appendix 0.10. However, since CO_2 emissions were not a part of the scope in this thesis, there was no emission cap constraint implemented in PowerGIM.

5 Case study: North Sea Offshore Grid

The North Sea region holds immense potential for offshore wind production, and its proximity to the surrounding countries makes it an attractive area for energy development. However, the expansion of interconnected grids in this region comes with numerous challenges due to the involvement of multiple countries and their respective energy systems. In order to ensure a successful and efficient transition to a low-carbon future, detailed studies, and proof-of-concept analyses are crucial. The case studies conducted in this investigation specifically focus on the implementation of PLIs. This study will undertake three distinct case studies with a focus on assessing the required installations in 2030 and comparing the outcomes across the three storylines from TYNDP.

5.1 Case 1 - Integration of PLI in 2030

Case 1 investigates the impact of gradually integrating a PLI into NSOG. With the construction of a PLI entailing a substantial investment, the objective is to analyze the variations in the total system cost as the PLI is incorporated. This case study aims to lay a foundation for further development of the PLI concept by simulating its immediate benefits. The PLI will have a maximum transmission capacity of 30 GW, chosen as a realistic sizing according to the literature [8].

Scenario A

Scenario A acts as the base scenario where no PLI integration is considered. This implies the inclusion of main, coast, and wind nodes exclusively. The model expands the necessary branches to satisfy the projected demand for 2030 with the given installed generation.

Scenario B

Building upon the foundations set in Scenario A, Scenario B incorporates the integration of a PLI into the system, only available to connect with coastal nodes. The selected location for the PLI is the Doggerbank area, which has been identified as an ideal site for PLI installation based on prior research [8].

Scenario C

Scenario C further builds upon the advancements in Scenario B, but now the PLI has the option to connect directly to the wind nodes as well as to the coasts. The wind farms are assumed to be flexible nodes that can be used to import and export power from the coast to the PLI. This expanded connectivity enhances the integration of OWP and multinational transmission.

5.2 Case 2 - PLI capacity

Case 2 further examines the optimal topology from Case 1 by conducting a sensitivity analysis of the PLI transmission capacity. The PLI capacity is a crucial decision as it directly affects power flow, branch connections, the cost of power electronics, as well as the security and reliability of the system. By examining different PLI capacities, this study aims to understand how capacity influences these parameters within the given model.

The chosen capacities for the sensitivity analysis are 10 GW, 20 GW, and 50 GW. While a 30 GW PLI represents a realistic capacity with state-of-the-art technology [8], investigating higher capacities allows for an assessment of the potential grid improvements and the associated risks and benefits. This analysis provides insights into the feasibility of developing new technologies and frameworks to accommodate higher PLI capacities.

5.3 Case 3 - Multiple PLI

Case 3 explores the concept of multiple PLIs in the North Sea, expanding upon the setup from scenario D. Three different scenarios are examined, each involving a varying number of PLIs. By introducing multiple PLIs, the study aims to evaluate the potential improvements in power grid performance and determine whether the additional cost associated with constructing multiple artificial islands is justified by the system savings. Multiple PLIs are also more realistic in the near future as it demands simplified cooperation, technology development, and investment costs as the capacity can be reduced. 10 GW PLIs will be utilized throughout this case.

An in-depth analysis of the PLI locations was conducted prior to this case study. The results of the study showed that with the configuration of the model, the PLI location had minimal impact on the total costs. The focus was on identifying locations that represent key geographical areas in the North Sea. The number given to each PLI, along with the country they are closest to, are presented in Table 5.1, offering insights into the geographical distribution of nodes.

Table 5.1: Scenario overview for Case 3

Scenario	Name	Location
D	2	Germany
E	3	Belgium
F	4	Norway

5.4 Presentation of results

To provide a holistic understanding of the system dynamics and the impact of PLIs, this study focuses on presenting five key results. The selected results will form the foundation for the discussion and will be presented and analyzed in detail in Section 6.

5.4.1 Transmission capacity expansions

The transmission expansion is a crucial output of the model, providing insights into the changes in the grid topology resulting from the addition of new branches and increased capacities. These results will be visually represented through plots, highlighting the branch capacities and their spatial distribution. The plots for all three storylines will be presented side by side, facilitating easy comparison. Note that only the additional branches and capacities are plotted and do not include the existing branches depicted in Figure 4.5. This makes it easy to identify prominent branch choices.

5.4.2 Total project costs

The total costs of the expansions considered in this study encompass both the investment and operational costs over a project lifetime of 30 years. The investment costs include the expenses related to the construction of new nodes, new cables, and their associated high-voltage equipment (as discussed in Section 4.4.4). The investment cost provides a comprehensive representation of the significant investments required for the considered expansions.

5.4.3 Allocation of investment costs

The cost allocation for interconnecting two areas in this study follows the operating methodology recommended by ENTSO-E, which suggests a 50/50 distribution of costs between the respective areas. This approach ensures an equal sharing of the investment costs and congestion revenues associated with the interconnection projects, promoting cooperation and equitable burden-sharing among the involved regions [61].

The allocation of the investment cost of the PLIs is not considered part of the analysis. Allocating the cost of the PLIs is a complex task that requires careful consideration of various factors and stakeholders. Due to the scope of this thesis, which focuses on the expansion of the offshore grid, the specific cost allocation for the PLIs is not addressed.

5.4.4 Power flow in PLI

The analysis of power flow in PLIs provides a deeper understanding of each country's utilization of these branches. With the introduction of PLIs into the system, the flow patterns undergo significant changes. By assessing the power flow through the nodes, valuable insights can be gained, which can inform the design and optimization of the PLIs. To facilitate this analysis, average power imports and exports for each PLI are presented in horizontal bar plots. The left side of the plot represents the flow into the node, while the right side represents the flow out of the node. Additionally, the capacity of each branch is plotted to provide a visual representation of line utilization. It is important to note that the average power flow depicted in these plots does not capture the actual fluctuations in power flow throughout the year.

5.4.5 Average area prices

To evaluate the impact of TEP, one can examine the area prices as they directly influence the operational costs, which the objective of TEP aims to minimize. Considering that prices are of utmost significance to various stakeholders, examining the impact of transmission expansion on these prices is vital. The findings will be presented in a diagram to provide a comprehensive understanding, showcasing the implications of different scenarios and cases.

Due to limitations with MILP problems within the Gurobi solver, it was not possible to extract the area prices by finding the dual value of the power balance constraint (6) from the optimization problems. This is because dual variables are not well defined for MILPs, as they derive from convex analysis, and MILPs are non-convex due to the presence of integer variables [62]. Thus, there were made assumptions to find the area price.

The operational cost from Equation 3 was utilized to approximate the cost of electricity. The required data for estimating the power price was obtained from PowerGIM, which consists of three key components. Firstly, the generation dispatch for a year of operation was extracted from the results. The marginal price of the highest-cost operational generator in each area was recorded, along with its corresponding CO_2 cost. These values over time formed a series from which the mean value was calculated to determine the average cost of power production per country. Lastly, the VOLL was derived from the load-shedding capacity for each country. It is important to note that the area prices reflect the marginal cost of the generator, which gives an approximate area price with some deviations.

6 Results

6.1 Case 1 - Integration of PLI in 2030

6.1.1 Scenario A - No PLI

Transmission capacity expansion

Figure 6.1 illustrates the capacity expansion in 2030 for scenario A across all storylines. Each country builds branches connecting to their offshore wind nodes, with the branch capacity primarily determined by the installed OWP in 2030. The capacity expansion reflects the characteristics of each storyline. DE, with its high production rate and moderate load demand, exhibits the lowest overall expansion as most countries can meet their demand with their own production. In contrast, GA, with its low production rate and high demand, shows significant capacity expansion in each branch, highlighting its reliance on transmission expansion to avoid load shedding and cover the demand. NT, with its moderate production rate and low demand, differs from the other scenarios due to production and CO_2 costs, leading to an incentive to expand branches and reduce operational costs.

In all storylines, most countries expand the branches between the coastal and main nodes to reduce the bottlenecks in the onshore grid. Expansions can be observed in four interconnectors, (NO-UK),(DK-UK), (BE-UK), and (NL-UK), connected to the UK. Additionally, there are expansions between (NO-DE), (NO-NL), and (DK-NL) in most of the storylines as well.

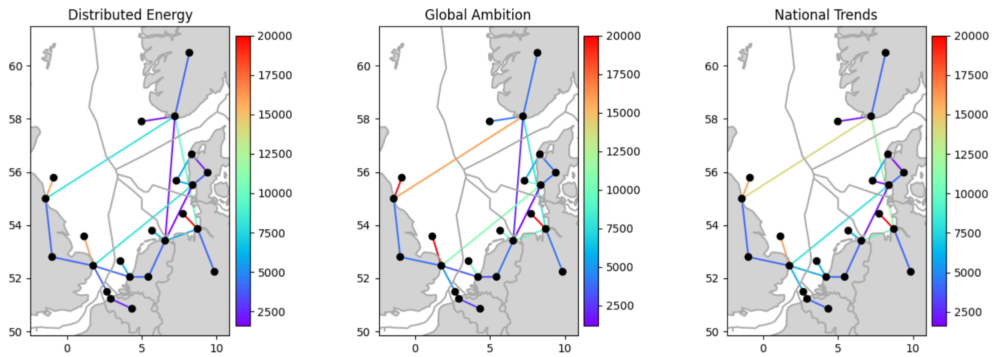

Figure 6.1: Optimal branch expansion for Scenario A

Total project costs

Table 6.1 displays the investment and operational costs for the three storylines. NT emerges as the most cost-effective solution considering the entire analysis lifespan, while GA incurs the highest expenses. DE exhibits the lowest investment cost among all storylines. These costs align with the previous results, where DE had the lowest capacity investments, and GA had the highest. The operational costs reflect the total operating costs throughout the project's lifetime, and one can observe that these costs correspond to the demand level in each storyline. The varying demand levels contribute to significant differences in operational costs.

Table 6.1: Investment, operational, and total costs for Scenario A

	DE [Bn €]	GA [Bn €]	NT [Bn €]
Investment cost	16.13	21.04	20.58
Operational cost	1037.92	1395.37	807.42
Total cost	1054.06	1416.41	828.01

Allocation of investment costs

Table 6.2 displays the allocated investment costs for the transmission expansion in scenario A. The UK, Germany, and Norway consistently have the highest investment costs due to the long-distance interconnectors and high-capacity branches connecting the wind nodes. Other countries derive their costs primarily from the branch connecting to the wind node and their interconnector to the UK. Belgium stands out with relatively low investment costs, which can be attributed to the shorter distances to the UK and the wind nodes compared to other countries.

Table 6.2: Allocation of transmission investments for Scenario A and percent of total transmission cost

Country	DE [Bn €]	GA [Bn €]	NT [Bn €]
NO	3.289 (20.38)	4.391 (20.87)	4.220 (20.50)
DK	1.878 (11.64)	2.433 (11.56)	1.825 (8.87)
DE	3.042 (18.86)	3.288 (15.63)	3.973 (19.30)
UK	4.630 (28.70)	6.678 (31.74)	6.220 (30.22)
NL	2.540 (15.75)	3.253 (15.46)	3.210 (15.59)
BE	0.754 (4.68)	0.997 (4.74)	1.136 (5.52)

Average area prices

Figure 6.2 showcases the average area prices in scenario A. Despite higher fuel prices in the input data for NT compared to DE and GA, the area prices exhibit remarkable similarities. This can be attributed to variations in production and demand levels, resulting in distinct dispatch and unit commitments across the storylines. Additionally, shedding incidents in GA and DE contribute to an increase in price. The average prices for DE, GA, and NT are 57.78 €/MWh, 57.40 €/MWh, and 54.58 €/MWh, respectively.

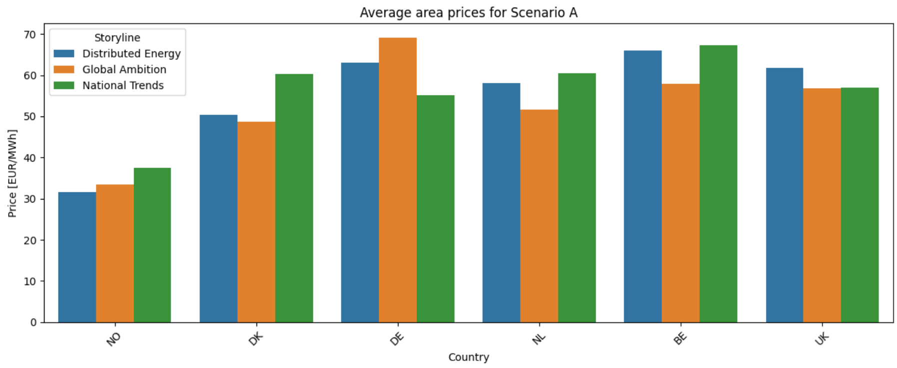

Figure 6.2: Average area prices for scenario A

6.1.2 Scenario B - PLI to coastal nodes

Transmission capacity expansion

In scenario B, a single PLI node with a capacity of 30 GW is introduced, allowing branches to be built exclusively to coastal nodes. Each country constructs the same branches connecting to their offshore nodes as in scenario A. However, unlike scenario A, the model not only establishes direct interconnectors between countries but also utilizes the PLI to interconnect all countries. Figure 6.3 illustrates that Germany and the UK make extensive use of the PLI's capacity. The UK constructs two branches from its coast nodes to the PLI, while Germany builds one high-capacity branch to the PLI. Although Germany and the UK are connected to the PLI, they still rely on the interconnectors (NO-UK), (DK-UK), and (NO-DE) in most storylines.

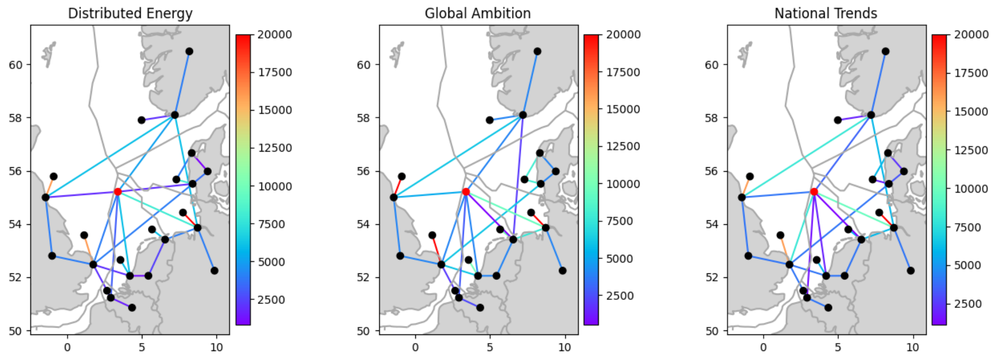

Figure 6.3: Optimal branch expansion for Scenario B

Total project costs

Table 6.3 presents a comparison of costs in scenario B and the PLI integration results in cost reductions across all aspects. DE maintains the lowest investment cost, while NT incurs the highest investment cost among the storylines. Furthermore, both investment and operational costs in scenario B are lower compared to scenario A. Specifically, DE, GA, and NT experience cost reductions of 1.52 %, 1.75 %, and 1.38 %, respectively, in total costs.

Table 6.3: Investment, operational, and total costs for Scenario B

	DE [Bn €]	GA [Bn €]	NT [Bn €]
Investment cost	12.42	14.92	15.03
Operational cost	1025.62	1376.65	801.51
Total cost	1038.04	1391.56	816.54

Allocation of investment costs

The allocated investment costs for the transmission expansion in scenario B are represented in Table 6.4. Generally, all countries have reduced their costs compared to scenario A, and the UK stands out with the most significant cost reduction. These costs are reduced due to fewer interconnectors and reduced cable length, shown in Figure 6.3.

Table 6.4: Allocation of transmission investments for Scenario B and percent of total transmission cost

Country	DE [Bn €]	GA [Bn €]	NT [Bn €]
NO	2.140 (20.46)	1.500 (11.58)	2.416 (18.49)
DK	0.996 (9.52)	1.400 (10.81)	0.878 (6.72)
DE	2.257 (21.58)	1.934 (14.93)	2.621 (20.06)
UK	3.161 (30.22)	4.383 (33.84)	4.252 (32.54)
NL	1.394 (13.33)	3.171 (24.48)	2.040 (15.61)
BE	0.513 (4.90)	0.566 (4.37)	0.860 (6.58)

Power flow in PLI

The PLI is exclusively connected to the coastal nodes of each country to facilitate the efficient transfer of electricity. The average power flow in and out of the PLI is illustrated in Figure 6.4. Upon observation, it is evident that Germany and Norway primarily utilize the PLI for exporting power, whereas the UK relies on it for importing power. Other countries generally exhibit a more balanced utilization, engaging in both power import and export. Furthermore, one may notice the significantly low-capacity branch to the Netherlands in both GA and NT.

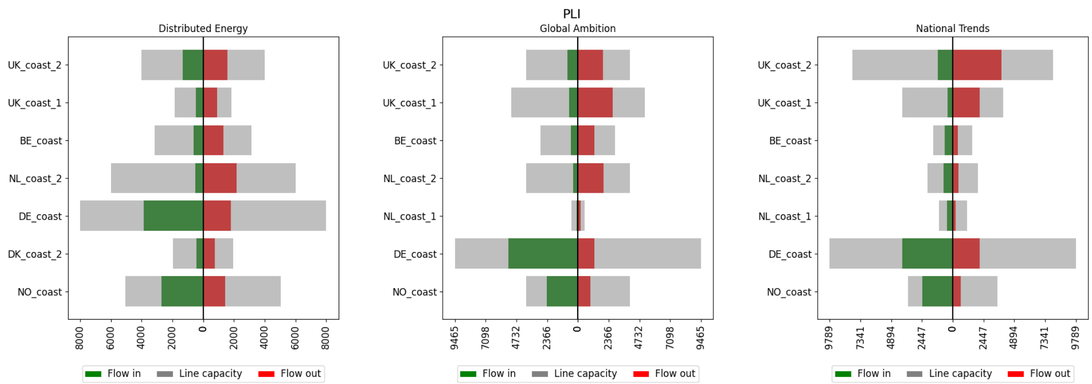

Figure 6.4: Power flow in MW for all branches connected to the PLI

Average area prices

Figure 6.5 depicts the average area prices for the storylines in scenario B. While overall prices remain relatively stable, there are notable changes compared to scenario A. In the DE storyline, Denmark experiences a decrease in average price from 50.36 €/MWh to 44.78 €/MWh. In the GA storyline, Belgium, the Netherlands, and Norway observe a slight increase in price, while other countries see a reduction. The NT storyline shows a price decrease for Germany, Belgium, and the UK, with the Netherlands being the only country experiencing an increase. The average prices for DE, GA, and NT are reduced to 56.77 €/MWh, 57.09 €/MWh, and 52.49 €/MWh, respectively.

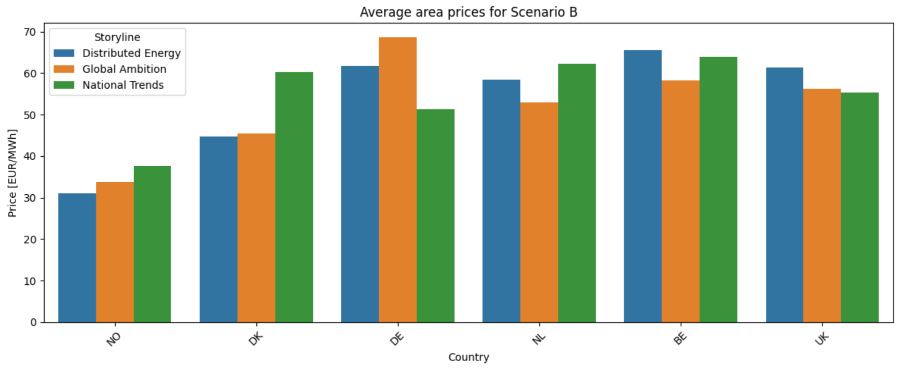

Figure 6.5: Average area prices for scenario B

6.1.3 Scenario C - PLI to coastal and offshore nodes

Transmission capacity expansion

The final scenario in case 1, scenario C, involves a fully developed topology with the option to construct branches from both the coast nodes and the wind nodes to the PLI, which has a capacity of 30 GW. Similar to scenarios A and B, the branches between the wind and coast nodes are expanded. However, unlike scenario B, the wind nodes in scenario C have the flexibility to import and export power through the node. This leads to shorter branches and less installation between countries and the PLI.

The resulting topology is approximately similar across all storylines when the grid is fully integrated. However, the capacities of the branches vary and depend on the production and demand levels specific to each scenario. Figure 6.6 provides an illustration of the topology in scenario C. It can be observed that Germany and the UK are still reliant on direct interconnectors with Norway, in addition to utilizing the PLI. Moreover, Norway and the UK are the only countries with two branches connecting to the PLI. In the case of Norway, the branches extend from both the wind node and the coast node, while for other countries, the branch only originates from their wind node.

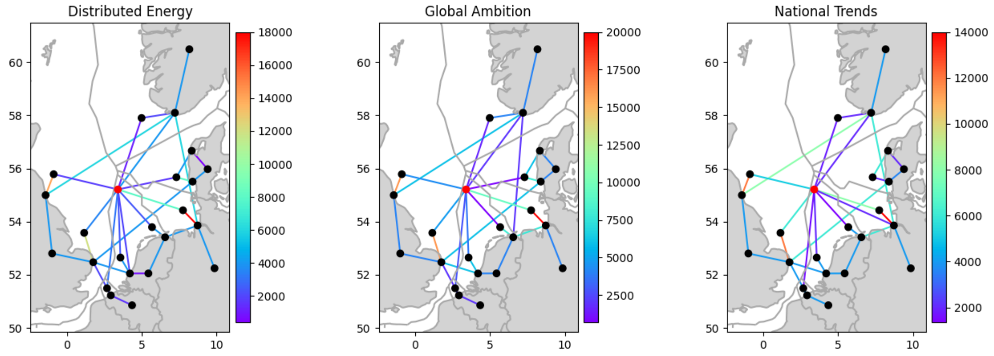

Figure 6.6: Optimal branch expansion for scenario C

Total project costs

Table 6.5 presents a comparison of costs for the storylines in scenario C. The full integration of the PLI into the NSOG results in a reduction in total costs. DE maintains the lowest investment cost. However, the cost is slightly higher than scenario B, but it results in a lower operational cost which is more beneficial in the long run. NT still incurs the highest investment cost among the storylines but the lowest operational cost. Furthermore, the total costs in scenario C are lower compared to scenarios A and B. Specifically, DE, GA, and NT experience cost reductions of 1.64 %, 1.88 %, and 1.49 %, respectively, compared to scenario A.

Table 6.5: Investment, operational, and total costs for Scenario C

	DE [Bn €]	GA [Bn €]	NT [Bn €]
Investment cost	12.44	14.08	14.80
Operational cost	1024.35	1375.64	800.84
Total cost	1036.79	1389.72	815.65

Allocation of investment costs

The allocation for the transmission expansion costs in scenario C is presented in Table 6.6. Compared to scenario B, the investment costs are slightly lower, resulting in a similar allocation of transmission investments. However, there are some variations among the countries depending on the storyline, with some gaining and others losing from the full integration of the grid.

One notable change is an increase in investment costs for the UK. This can be attributed to the reduced number of direct interconnectors with other countries, which translates into a higher capacity expansion to the PLI. Consequently, the UK bears the cost of the

Table 6.6: Allocation of transmission investments for Scenario C and percent of total transmission cost

Country	DE [Bn €]	GA [Bn €]	NT [Bn €]
NO	2.109 (20.13)	1.469 (12.13)	2.386 (18.58)
DK	0.965 (9.21)	1.369 (11.30)	1.198 (9.33)
DE	2.091 (19.95)	1.792 (14.80)	2.367 (18.43)
UK	3.257 (31.09)	4.068 (33.58)	4.213 (32.81)
NL	1.605 (15.31)	2.960 (24.44)	1.891 (14.73)
BE	0.451 (4.31)	0.456 (3.76)	0.785 (6.12)

branch to the PLI on its own.

Power flow in PLI

The reconfigured offshore grid topology has had an impact on both the branches and the power flow within the PLI. Figure 6.6 and 6.7 provide insights into these changes. There are more branches connected to the PLI compared to scenario B, although with reduced capacity due to the max capacity constraint for the PLI. The power flow through the PLI exhibits similarities to that observed in scenario B. However, in the GA storyline, a branch is constructed between the Norwegian coast and the PLI, demonstrating a high flow toward the PLI. This suggests that the power exported from Norway, originating from cost-effective hydropower generated on the mainland, is transferred to the PLI and distributed to other countries. Furthermore, one may observe a couple of branches with significantly low capacity in storyline GA and NT.

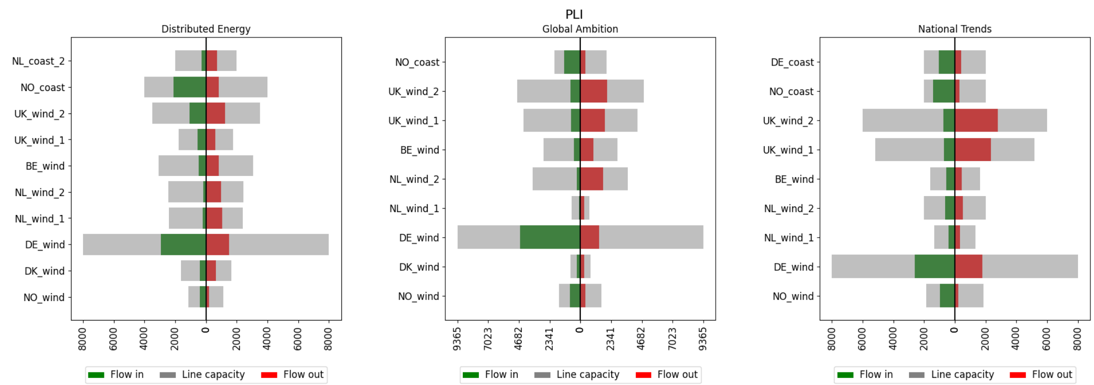

Figure 6.7: Power flow in MW for all branches connected to the PLI

Average area prices

Table 6.8 showcases the average prices for the different storylines in scenario C. The overall average price for GA and NT has decreased to 56.32 €/MWh and 50.74 €/MWh, respectively. However, in the DE storyline, the price has slightly increased by 0.10 €/MWh to 56.87 €/MWh compared to scenario B.

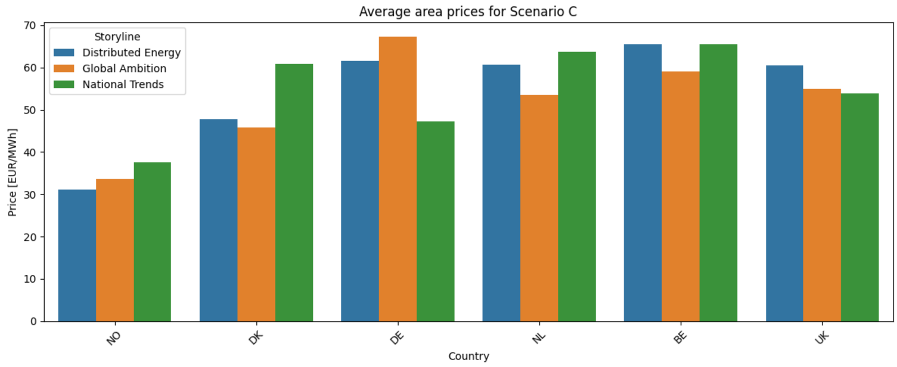

Figure 6.8: Average area prices for scenario C

6.2 Case 2 - Capacity of PLI

6.2.1 Scenario D - 10 GW

Transmission capacity expansion

With a 10 GW PLI, the transmission capacity expansion results in a topology consisting of direct interconnectors between countries, as well as a few branches connected to the PLI through their offshore node. Additionally, each country constructs a branch between the wind and coast nodes, with transmission capacity corresponding to the installed wind capacity. In Figure 6.9, it is evident that interconnectors (NO-UK), (NO-NL), (NO-DE), and (DK-UK) are constructed in each storyline, similar to scenario A. This highlights the UK's reliance on power from Norway and Denmark.

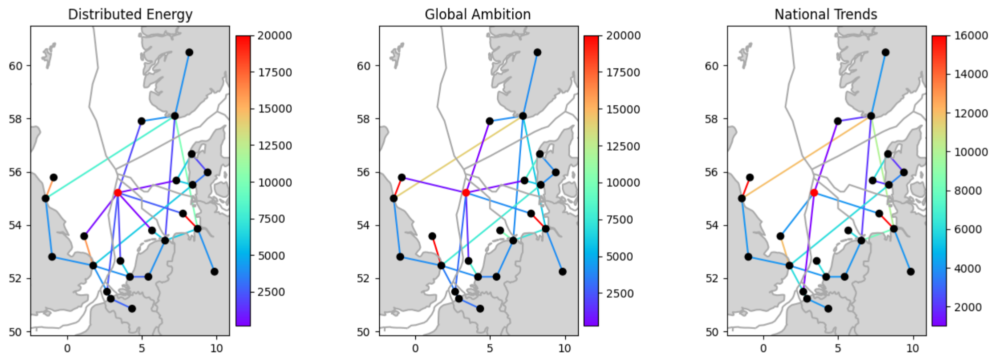

Figure 6.9: Optimal branch expansion for Scenario D

Total project costs

Table 6.7 presents the comparison of the transmission expansion costs for the storylines. It is evident that NT offers the most cost effective solution when considering the entire lifespan of the analysis, while GA incurs the highest overall expenses.

Despite the comparable investment costs to scenario A, the inclusion of a 10 GW PLI in this scenario results in a significant decrease in operational costs. This leads to lower total costs across all storylines. However, it is important to note that this scenario still has higher investment and operational costs compared to scenarios B and C with the 30 GW PLI. The total costs for DE, GA, and NT have been reduced by 0.60 %, 0.69 %, and 0.46 %, respectively, compared to scenario A.

Table 6.7: Investment, operational, and total costs for Scenario D

	DE [Bn €]	GA [Bn €]	NT [Bn €]
Investment cost	17.06	19.66	19.35
Operational cost	1030.65	1386.90	804.87
Total cost	1047.71	1406.56	824.23

Table 6.8: Allocation of transmission investments for Scenario D and percent of total transmission cost

Country	DE [Bn €]	GA [Bn €]	NT [Bn €]
NO	3.346 (22.16)	3.986 (22.52)	3.942 (22.67)
DK	1.294 (8.57)	1.654 (9.35)	1.198 (6.89)
DE	3.068 (20.32)	2.663 (15.05)	3.301 (18.98)
UK	4.323 (28.63)	5.691 (32.16)	5.208 (29.95)
NL	2.285 (15.13)	2.967 (16.76)	2.592 (14.91)
BE	0.785 (5.20)	0.737 (4.17)	1.149 (6.61)

Allocation of investment costs

The allocated investment costs for the transmission expansion in scenario D are presented in Table 6.8. The UK continues to have the highest investment costs due to the capacity and number of offshore branches connecting them to other countries and the PLI. However, when comparing the results with scenario A, it is noticeable that Denmark, Norway, and the UK have experienced a slight decrease in costs, while the other countries have seen a small increase. Furthermore, the costs are generally higher than scenarios B and C. This is primarily due to the limited capacity of the PLI, which necessitates the construction of additional interconnectors and branches to ensure an adequate power flow throughout the grid.

Power flow in PLI

With the PLI's capacity limited to 10 GW, the power flow is reduced, resulting in fewer branches connected to the PLI compared to scenario C. Despite the lower capacity of the PLI, the overall trend in power flow remains consistent across the storylines. Figure 6.10 illustrates the power flow in and out of the PLIs. In the DE storyline, power primarily flows from Germany and Norway to Belgium and the Netherlands. In the GA scenario, Germany has a significant surplus capacity and serves as the primary power supplier, while the other countries predominantly consume power. The same pattern holds true for the NT scenario. Furthermore, one may observe a couple of branches with significantly low capacity in storyline DE and GA.

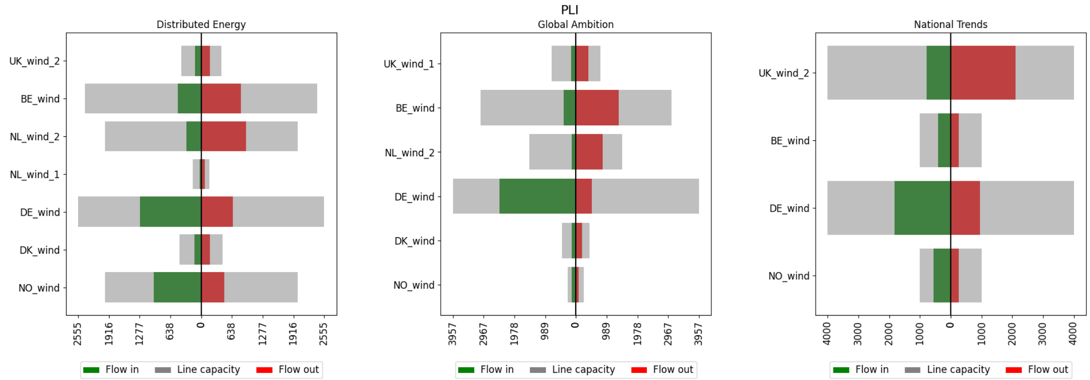

Figure 6.10: Power flow in MW for all branches connected to the PLI

Average area prices

Table 6.11 displays the average prices for the different storylines in scenario D. Overall, compared to scenario A, there is a decrease in prices across all storylines. The average price for DE is 56.76 €/MWh, GA is 56.67 €/MWh, and NT is 52.65 €/MWh.

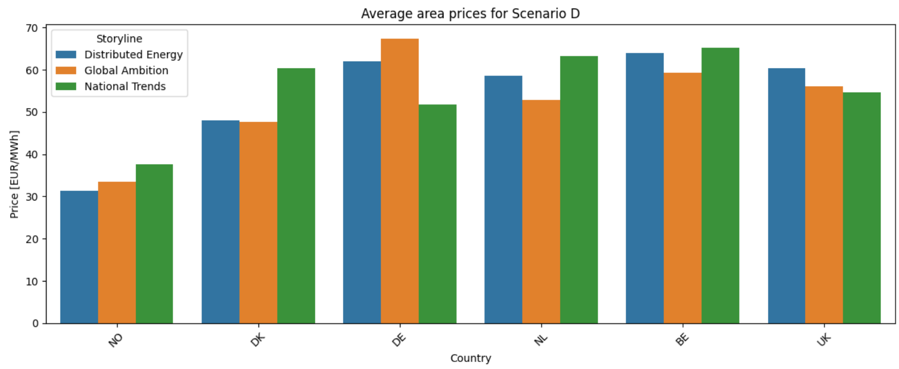

Figure 6.11: Average area prices for scenario D

6.2.2 Scenario E - 20 GW

Transmission capacity expansion

The second scenario involves testing a 20 GW PLI. The topology of this scenario is a combination of the topologies from scenarios C and D. All the storylines continue to expand direct interconnectors in addition to the PLI for power transmission. However, the capacities of the branches vary depending on the production and demand levels specific to each storyline.

The topologies for the expansion are represented in Figure 6.12. In the DE storyline, there is relatively minimal capacity expansion, with more emphasis on expanding branches connected to the PLI. In the GA storyline, there is a moderate expansion of interconnectors and a moderate number of branches connected to the PLI. On the other hand, the NT storyline experiences the most significant expansion in transmission capacity for interconnectors, with fewer branches connected to the PLI.

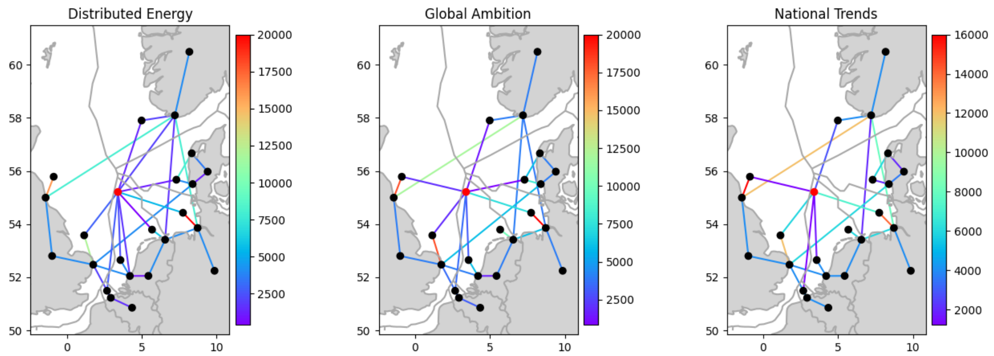

Figure 6.12: Optimal branch expansion for scenario E

Total project costs

Table 6.9 compares the costs for the storylines in scenario E. It is evident that there is a decrease in both investment and operational costs compared to scenario A with the 10 GW PLI for all storylines. GA continues to have the highest total costs, while NT has the lowest costs among the storylines. The cost reductions for DE, GA, and NT in scenario E are 1.16 %, 1.32 %, and 1.00 %, respectively, compared to scenario D.

Table 6.9: Investment, operational, and total costs for Scenario E

	DE [Bn €]	GA [Bn €]	NT [Bn €]
Investment cost	14.34	17.18	17.47
Operational cost	1027.47	1380.46	802.20
Total cost	1041.81	1397.64	819.67

Allocation of investment costs

The allocated investment costs for the transmission expansion in scenario E are displayed in Table 6.10. The UK continues to have the highest investment costs, but when comparing the results with scenario D, it is evident that the expenses for all countries have decreased. However, the costs in scenario E remain significantly higher compared to scenarios B and C.

Table 6.10: Allocation of transmission investments for Scenario E and percent of total transmission cost

Country	DE [Bn €]	GA [Bn €]	NT [Bn €]
NO	2.987 (24.14)	3.317 (21.80)	3.679 (23.73)
DK	0.969 (7.83)	1.369 (9.00)	1.198 (7.73)
DE	2.441 (19.73)	2.115 (13.90)	2.643 (17.05)
UK	3.608 (29.16)	5.001 (32.86)	4.914 (31.70)
NL	1.917 (15.49)	2.679 (17.60)	2.242 (14.46)
BE	0.451 (3.65)	0.737 (4.84)	0.829 (5.35)

Power flow in PLI

The power flow through the 20 GW PLI in scenario E is naturally twice as much as in scenario D, resulting in increased flow and more branches connected to the PLI. However, as mentioned earlier, the trend of branches connected to the PLI depends on the storyline and the expansion of interconnectors. In the DE storyline, there are more branches connected to the PLI with lower capacity. In contrast, GA and NT have fewer branches but with higher capacity. Figure 6.13 illustrates that Germany and Norway are notable exporters of power, with their exports surpassing their imports. In the DE storyline, there is a more balanced import and export ratio for all countries. However, in GA and NT, it is evident that Belgium, the Netherlands, and the UK face a deficit in production and rely more on imports from Germany and Norway through the PLI. Furthermore, one may observe a couple of branches with significantly low capacity in all the storylines.

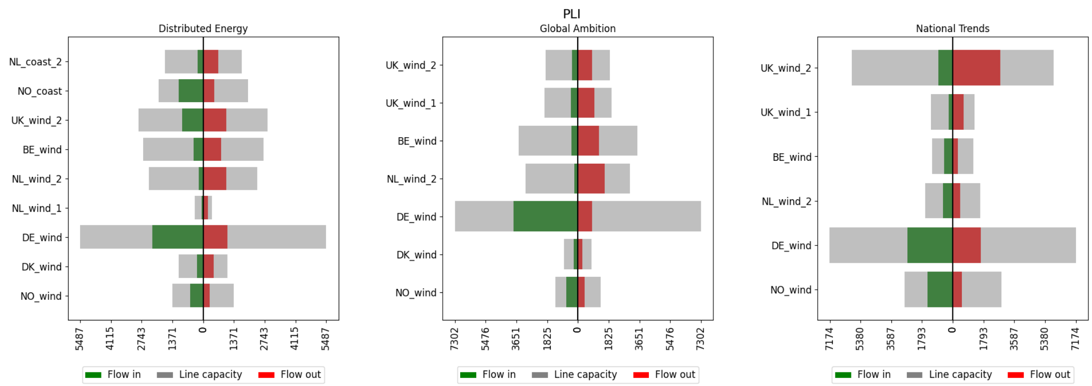

Figure 6.13: Power flow in MW for all branches connected to the PLI

Average area prices

Table 6.14 displays the average prices for the different storylines in scenario E. In comparison to scenario A, there is a noticeable decrease in prices for all storylines. The average price for DE has decreased and is now 56.59 €/MWh, GA is 56.37 €/MWh, and NT is 51.08 €/MWh.

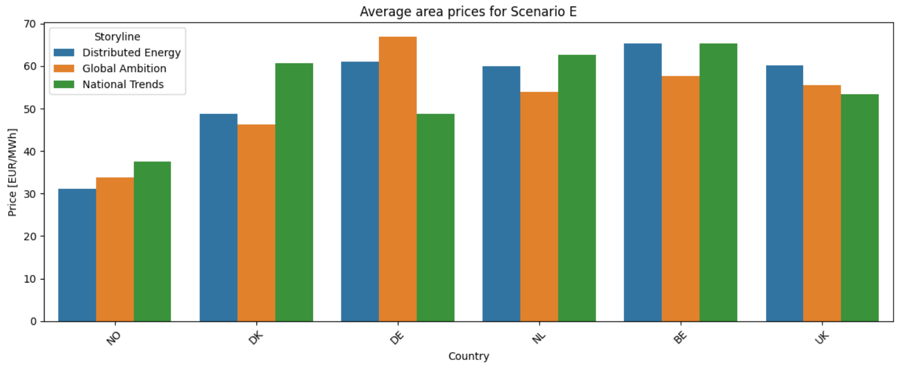

Figure 6.14: Average area prices for scenario E

6.2.3 Scenario F - 50 GW

Transmission capacity expansion

In the final scenario of case 2, a 50 GW PLI is tested. While there are still expanded interconnectors, their capacities have been significantly reduced compared to previous scenarios. With such a high capacity in the PLI, it is expected that a larger portion of power will flow through the node rather than the direct interconnectors between countries. Figure 6.15 provides a visual representation of the transmission expansion in response to the increased capacity of the PLI. Notably, there is a substantial increase in Germany's expansion, with more capacity connected to the PLI. Norway and the UK also show significant expansions compared to previous scenarios.

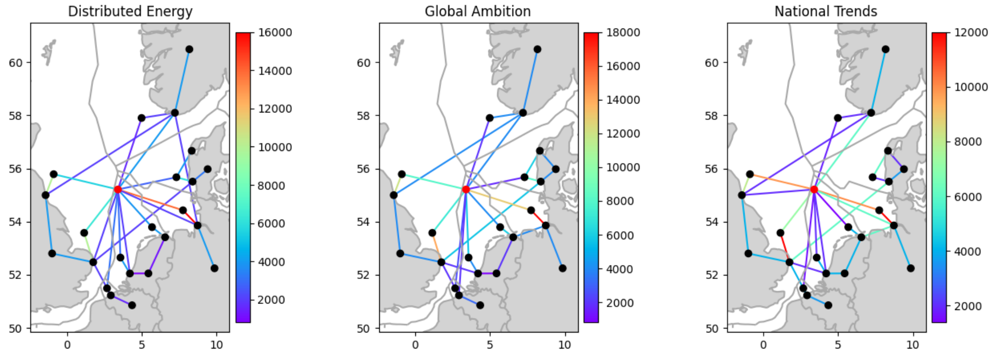

Figure 6.15: Optimal branch expansion for Scenario F

Total project costs

The introduction of the 50 GW PLI has resulted in significant cost reductions for all storylines. Despite the increased investment in more branches, the overall costs have decreased, as shown in Table 6.11. This is because the high-capacity branches are now connected to the PLI. Thus less capacity is invested in the costly long-distance interconnectors. In terms of cost comparison among the storylines, the DE storyline still maintains the lowest costs, while GA remains the most expensive. The total cost reductions in scenario F, compared to scenario A, are 2.44 % for DE, 2.72 % for GA, and 2.34 % for NT.

Table 6.11: Investment, operational, and total costs for Scenario F

	DE [Bn €]	GA [Bn €]	NT [Bn €]
Investment cost	6.61	10.08	10.50
Operational cost	1021.75	1367.80	798.12
Total cost	1028.35	1377.88	808.61

Allocation of investment costs

The allocated investment costs for the transmission expansion in scenario F are displayed in Table 6.12. As anticipated, the reduction in total costs is reflected in the allocated costs as well. Germany, Norway, and the UK exhibit the highest reduction in costs across all storylines. The reduction can be attributed to a shift in investment focus from long interconnectors to shorter branches connected to the PLI. This reallocation contributes to the overall cost savings achieved.

Table 6.12: Allocation of transmission investments for Scenario F and percent of total transmission cost

Country	DE [Bn €]	GA [Bn €]	NT [Bn €]
NO	0.829 (17.85)	0.873 (10.75)	0.553 (6.48)
DK	0.601 (12.93)	1.328 (16.35)	1.198 (14.03)
DE	0.849 (18.29)	1.169 (14.40)	1.464 (17.14)
UK	1.622 (34.91)	2.961 (36.47)	2.928 (34.29)
NL	0.293 (6.31)	1.275 (15.70)	1.615 (18.91)
BE	0.451 (9.72)	0.513 (6.32)	0.781 (9.15)

Power flow in PLI

Similar to the previous scenarios, the DE storyline exhibits the highest number of branches connected to the PLI, followed by GA and NT with progressively fewer branches. The power flow patterns observed in the previous scenarios are also observed in scenario F but distributed across other branches. This can be seen in the DE storyline, where Germany, Norway, the Netherlands, and the UK have two separate branches connected to the PLI. Moreover, Figure 6.16 illustrates that the branches connected to the PLI are designed to accommodate high fluctuations in power flows. This can be observed by comparing the installed capacity with the average flow. Lastly, this is the only scenario with sufficient capacity in all PLI branches due to the 50 GW PLI.

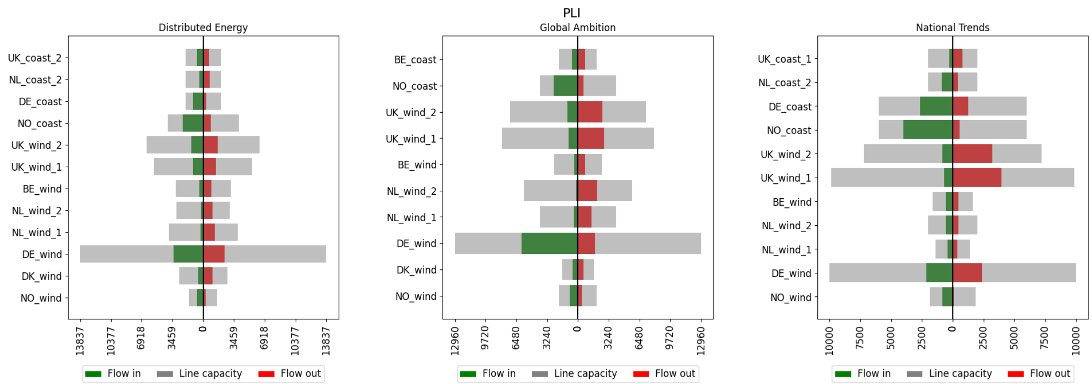

Figure 6.16: Power flow in MW for all branches connected to the PLI

Average area prices

Table 6.17 displays the average prices for the different storylines in scenario F. Overall, compared to scenario A, there is a decrease in prices across all storylines. The average price for DE has decreased and is 57.75 €/MWh, GA is 56.49 €/MWh, and NT is 50.30 €/MWh.

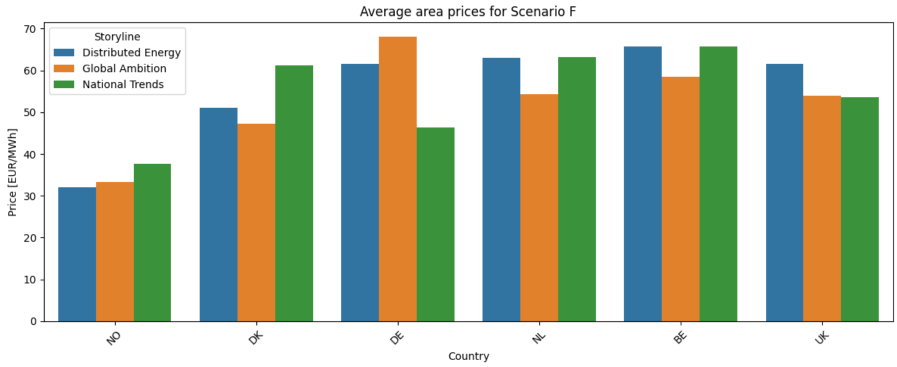

Figure 6.17: Average area prices for scenario F

6.3 Case 3 - Multiple PLIs

6.3.1 Scenario G - Two PLIs

Transmission capacity expansion

The expansion of transmission capacity with two 10 GW PLIs in scenario G yields a topology that is similar to scenario D. The interconnectors (NO-UK), (NO-DE), (NO-NL), and (DK-UK) continue to play a crucial role in all storylines. Figure 6.18 provides a visual representation of the scenario, where it can be observed that the two PLIs do not connect to each other in any of the storylines. Additionally, most countries expand connections to both PLIs, with the exception of Denmark, which switches to the closest PLI, from PLI_1 to PLI_2.

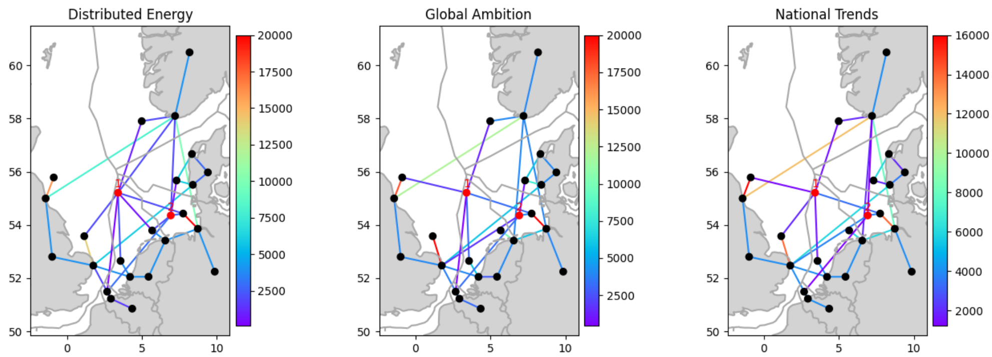

Figure 6.18: Optimal branch expansion for Scenario G in 2030

Total project costs

Table 6.13 provides a comparison of the transmission expansion costs for the different storylines in scenario G. The NT storyline offers the most cost effective solution when considering the entire analysis lifespan, while the GA storyline incurs the highest overall expenses. The DE storyline requires the least investment cost. It is worth noting that the investment costs for the storylines in scenario G are very similar to those in scenario D, which involved a single 10 GW PLI. However, in scenario G, the investment is distributed across two PLIs, resulting in reduced cable costs but similar overall investment costs due to the additional PLI. The operational costs have slightly decreased with the integration of two PLIs compared to one. When comparing the total costs to scenario D, the DE storyline has seen a reduction of 0.37 %, the GA storyline a reduction of 0.49 %, and the NT storyline a reduction of 0.30 %.

Table 6.13: Investment, operational, and total costs for Scenario G

	DE [Bn €]	GA [Bn €]	NT [Bn €]
Investment cost	17.07	19.32	19.52
Operational cost	1026.78	1380.39	802.22
Total cost	1043.85	1399.71	821.74

Table 6.14: Allocation of transmission investments for Scenario G and percent of total transmission cost

Country	DE [Bn €]	GA [Bn €]	NT [Bn €]
NO	3.069 (23.34)	3.338 (21.68)	3.666 (23.50)
DK	1.298 (9.87)	1.369 (8.89)	1.198 (7.68)
DE	2.761 (21.00)	2.127 (13.81)	2.643 (16.95)
UK	3.959 (30.11)	5.104 (33.14)	5.020 (32.18)
NL	1.597 (12.14)	2.692 (17.48)	2.242 (14.37)
BE	0.464 (3.53)	0.769 (4.99)	0.829 (5.32)

Allocation of investment costs

The allocation of investment costs for the transmission expansion in scenario G is provided in Table 6.14. It can be observed that the allocated costs have slightly decreased compared to the results from scenario D. Notably, Belgium, Germany, the Netherlands, and the UK experienced the most significant reduction in costs, while Norway and Denmark had relatively similar costs compared to scenario D.

Power flow in PLIs

The power flow through PLI_1 and PLI_2 is presented in Appendix 9. In general, a more balanced import and export of power can be observed at both PLIs for all the storylines. However, in the DE storyline, power mainly flows from Germany and Norway to Belgium and the Netherlands. In the GA scenario, Germany has a significant surplus capacity and acts as the primary power supplier, while the other countries primarily consume power. The NT scenario follows a similar pattern, with Germany as the primary power supplier. Furthermore, one may observe the branch from Belgium to PLI_1 and from Denmark to PLI_2 is significantly low capacity in storyline DE and GA.

Average area prices

Figure 6.19 displays the average prices for the different storylines in scenario G. Overall, compared to scenario D, there is a decrease in prices across all storylines. The average price for DE has decreased and is 56.38 €/MWh, GA is 56.63 €/MWh, and NT is 51.67 €/MWh.

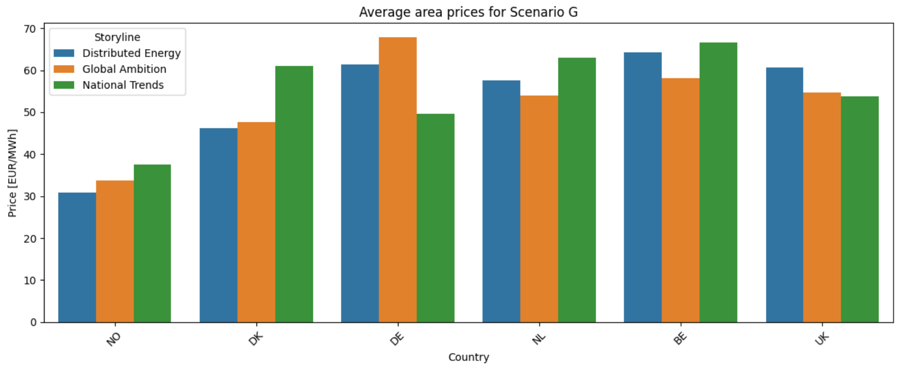

Figure 6.19: Average area prices for scenario G

6.3.2 Scenario H - Three PLIs

Transmission capacity expansion

The transmission capacity expansion with three 10 GW PLIs in scenario H results in a topology that shares similarities with scenarios D and G. The interconnectors (NO-UK), (NO-SE), (NO-NL), and (DK-UK) are still expanded in all the storylines. However, Figure 6.20 indicates a decrease in the capacity of these interconnectors when the third PLI is integrated into the NSOG. Additionally, none of the three PLIs are directly connected to each other in this scenario.

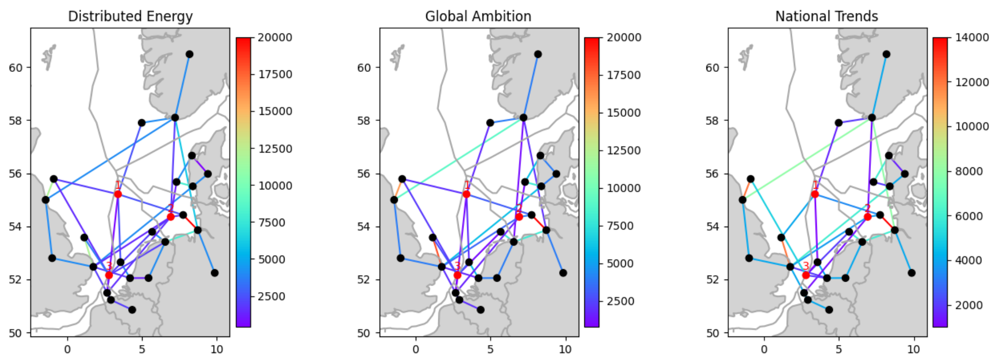

Figure 6.20: Optimal branch expansion for Scenario H

Total project costs

Table 6.15 presents a comparison of the transmission expansion costs for the different storylines in scenario H. It is notable that the investment and operational costs have decreased compared to the scenarios with one single 10 GW PLI. When comparing the total costs to scenario D, the DE storyline has seen a reduction of 0.58 %, the GA storyline has a reduction of 0.84 %, and the NT storyline has a reduction of 0.51 %.

Table 6.15: Investment, operational, and total costs for Scenario H

	DE [Bn €]	GA [Bn €]	NT [Bn €]
Investment cost	16.44	18.29	18.90
Operational cost	1025.19	1376.51	801.12
Total cost	1041.63	1394.79	820.02

Allocation of investment costs

Table 6.16 displays the allocation of investment costs for the transmission expansion in scenario H. Notably, a comparison with scenario G reveals a noticeable decrease in allocated costs for Norway and the UK. On the other hand, the Netherlands has experienced a slight increase in expenses.

Table 6.16: Allocation of transmission investments for Scenario H and percent of total transmission cost

Country	DE [Bn €]	GA [Bn €]	NT [Bn €]
NO	1.802 (17.07)	2.158 (17.40)	2.706 (20.79)
DK	0.965 (9.14)	1.369 (11.04)	1.198 (9.20)
DE	2.761 (26.16)	2.134 (17.21)	2.643 (20.31)
UK	2.630 (24.92)	4.042 (32.59)	3.967 (30.48)
NL	1.929 (18.27)	2.230 (17.98)	1.671 (12.84)
BE	0.469 (4.44)	0.469 (3.78)	0.829 (6.37)

Power flow

The power flow through PLI_1, PLI_2, and PLI_3 is illustrated in the Appendix 9. The integration of three PLIs leads to a more balanced power flow across all storylines, ensuring efficient energy exchange. In the DE storyline, power primarily flows from Germany and Norway to Belgium, the Netherlands, and the UK, aligning with previous scenarios. In the GA scenario, Germany demonstrates a significant surplus capacity and acts as the primary power supplier, while other countries primarily consume electricity. Similarly, in the NT scenario, Germany serves as the primary power supplier, but the Netherlands also contributes with power production to the third PLI. Lastly, the branch from Belgium to PLI_1 is significantly low capacity in storyline DE.

Average area prices

Table 6.21 displays the average prices for the different storylines in scenario H. Overall, compared to scenario D, there is a decrease in prices across all storylines. The average price for DE has decreased and is 56.67 €/MWh, GA is 56.56 €/MWh, and NT is 51.34 €/MWh.

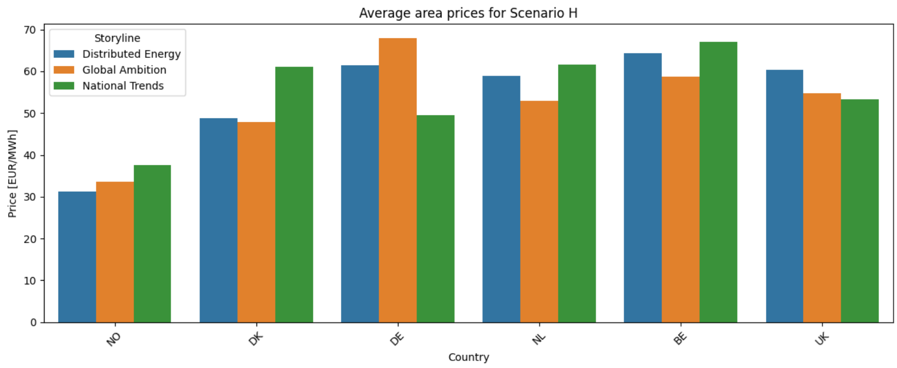

Figure 6.21: Average area prices for scenario H

6.3.3 Scenario I - Four PLIs

Transmission capacity expansion

In the final scenario, the NSOG integrates four 10 GW PLIs, as illustrated in Figure 6.22. The topology closely resembles scenario H, with only a few changes related to the fourth PLI near the Norwegian coast. Notably, only Germany and the UK make use of the fourth PLI across all three storylines. In the NT storyline, the Norwegian wind node is connected to the fourth PLI. There are still no branches expanded between the PLIs.

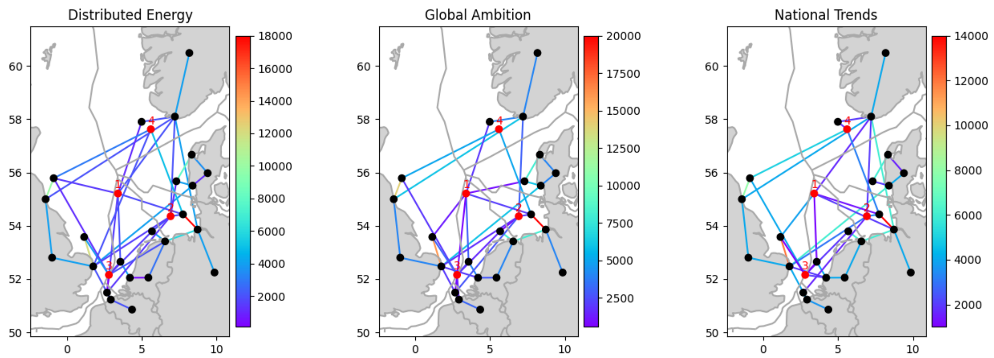

Figure 6.22: Optimal branch expansion for Scenario I in 2030

Total project costs

Table 6.17 provides a comparison of the transmission expansion costs across the different storylines in scenario I. It is worth noting that the investment and operational costs have decreased compared to all scenarios featuring 10 GW PLIs. When comparing the total costs of scenario I to scenario D, the DE storyline shows a reduction of 0.83 %, the GA storyline experiences a reduction of 1.19 %, and the NT storyline observes a reduction of 0.73 %.

Table 6.17: Investment, operational, and total costs for Scenario I

	DE [Bn €]	GA [Bn €]	NT [Bn €]
Investment cost	15.82	18.22	18.94
Operational cost	1023.24	1371.54	799.24
Total cost	1039.06	1389.76	818.18

Allocation of investment costs

Table 6.18 displays the allocation of investment costs for the transmission expansion in scenario I. Notably, a comparison with scenarios G and H reveals a noticeable decrease in allocated costs for Germany, Norway, and the UK. On the other hand, the Netherlands has experienced a slight increase in expenses.

Table 6.18: Allocation of transmission investments for Scenario I and percent of total transmission cost

Country	DE [Bn €]	GA [Bn €]	NT [Bn €]
NO	1.149 (14.41)	1.193 (11.50)	1.789 (16.12)
DK	0.969 (12.16)	1.369 (13.20)	1.198 (10.79)
DE	2.104 (26.38)	1.840 (17.74)	2.380 (21.44)
UK	2.016 (25.29)	3.441 (33.17)	3.279 (29.54)
NL	1.267 (15.88)	2.004 (19.32)	1.671 (15.06)
BE	0.469 (5.88)	0.526 (5.07)	0.781 (7.04)

Power flow

The power flow through PLI_1, PLI_2, PLI_3, and PLI_4 is depicted in Appendix 9. The power flow patterns align with the findings from previous scenarios. However, it is worth noting that only Germany and the UK fully utilize the capacity of the fourth PLI, which allows for greater availability of capacity in the other PLIs. In the DE storyline, the power flow is relatively balanced across countries, with the exception of the Netherlands, which primarily imports power, and Norway, which predominantly exports power. In the GA storyline, the UK and the Netherlands emerge as the major consumers of power from the PLIs, while Germany and Norway serve as the primary power producers. This pattern holds true for the NT storyline as well. Lastly, the branch between Belgium and PLI_3 has a significantly low capacity in storyline DE.

Average area prices

Table 6.23 displays the average prices for the different storylines in scenario I. Overall, compared to scenario D, there is a decrease in prices across all storylines. The average price for DE has decreased and is 56.66 €/MWh, GA is 56.49 €/MWh, and NT is 52.24 €/MWh.

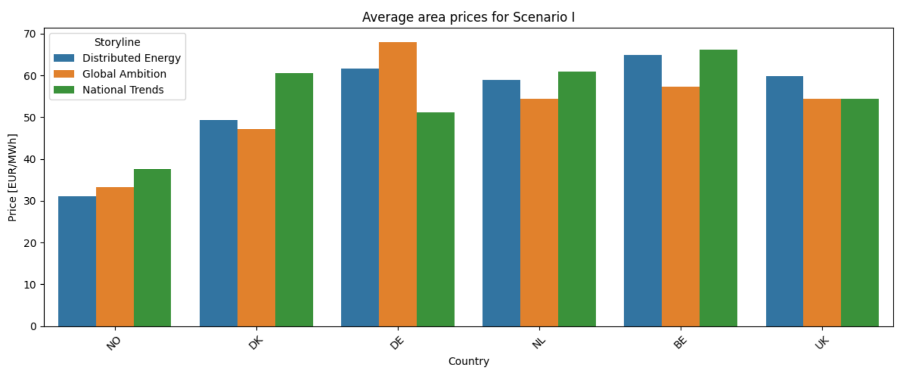

Figure 6.23: Average area prices for scenario I

6.4 Key results from the cases

This section provides a closer look at the critical results derived from the case studies' total costs and area prices. The aim is to present a detailed, comparative overview of the different scenarios by tabulating the data with all scenarios included. By structuring the data this way, similarities and differences among scenarios are highlighted.

6.4.1 Distributed Energy

Total project costs

Table 6.19 presents the total costs for all the scenarios in DE. An analysis of these scenarios reveals a clear trend: as the level of PLI integration increases, both in terms of capacity and quantity, the total costs tend to decrease.

The most significant cost variation is observed between scenarios A and F. There's a noticeable reduction of 25.71 Bn €between the two scenarios, translating to a 2.4 % decrease. This highlights the potential economic efficiency that can be achieved through the integration of high-capacity PLIs.

Table 6.19: Total costs for Distributed Energy

Scenario	Total Cost [Bn €]	Difference from Scenario A
Scenario A	1054.06	0.00
Scenario B	1038.04	-16.02
Scenario C	1036.79	-17.27
Scenario D	1047.71	-6.35
Scenario E	1041.81	-12.25
Scenario F	1028.35	-25.70
Scenario G	1043.85	-10.21
Scenario H	1041.63	-12.42
Scenario I	1039.06	-15.00

Area prices

Table 6.20 provides a detailed breakdown of the average area prices for all scenarios under the DE storyline. Across all scenarios, the average prices are highest in Belgium, ranging from 63.96 to 65.96 €/MWh. In contrast, the area prices in Norway are consistently the lowest across all scenarios, oscillating between 30.78 to 32.12 €/MWh. This suggests Norway has the most affordable power generation cost, reasoned with cheap hydro generation.

There is significant variability in prices within Denmark, with prices varying from 44.78 €/MWh in Scenario B to 51.06 €/MWh in Scenario F. This indicates that the Danish energy market is more sensitive to changes to the scenario guidelines. The prices for the remaining countries change minimally, which indicates that the scenario guideline's impact on area prices is minor.

Table 6.20: Area prices [EUR/Mwh] for Distributed Energy

Scenario	NO	DK	DE	NL	BE	UK	Average
Scenario A	31.59	50.36	62.98	58.12	65.96	61.86	57.78
Scenario B	31.06	44.78	61.75	58.34	65.59	61.28	56.77
Scenario C	31.04	47.81	61.50	60.63	65.50	60.43	56.87
Scenario D	31.32	48.00	61.98	58.51	63.96	60.35	56.76
Scenario E	31.04	48.74	61.02	60.02	65.38	60.19	56.59
Scenario F	32.12	51.06	61.48	63.03	65.69	61.62	57.75
Scenario G	30.78	46.23	61.43	57.61	64.31	60.68	56.38
Scenario H	31.32	48.69	61.49	58.85	64.38	60.41	56.67
Scenario I	31.05	49.33	61.67	58.99	64.89	59.91	56.66

6.4.2 Global Ambition

Total project costs

The total costs for all scenarios in the GA storyline are presented in Table 6.21. It is worth noting that the differences in costs between the scenarios are relatively small, with a variation of only 38.53 Bn €(2.80 %) between the most expensive scenario (scenario A) and the least expensive scenario (scenario F).

Table 6.21: Total costs for Global Ambition

Scenario	Total Cost [Bn €]	Difference from Scenario A
Scenario A	1416.41	0.00
Scenario B	1391.56	-24.84
Scenario C	1389.72	-26.69
Scenario D	1406.56	-9.85
Scenario E	1397.64	-18.76
Scenario F	1377.88	-38.53
Scenario G	1399.71	-16.70
Scenario H	1394.79	-21.62
Scenario I	1389.76	-26.65

Area prices

Table 6.22 presents the average area prices for GA. It is evident that scenario A exhibits the highest average prices, particularly in Germany. For the other countries, the prices remain relatively constant, showing little variation among the different scenarios.

Table 6.22: Area prices [EUR/Mwh] for Global Ambition

Scenario	NO	DK	DE	NL	BE	UK	Average
Scenario A	33.51	48.62	69.10	51.68	57.94	56.73	57.40
Scenario B	33.78	45.40	68.63	52.93	58.23	56.27	57.09
Scenario C	33.54	45.71	67.26	53.45	59.01	54.89	56.32
Scenario D	33.51	47.66	67.34	52.75	59.32	56.01	56.67
Scenario E	33.77	46.20	66.90	53.90	57.58	55.48	56.37
Scenario F	33.27	47.28	68.06	54.32	58.50	53.95	56.49
Scenario G	33.77	47.72	67.84	53.93	58.07	54.64	56.63
Scenario H	33.51	47.88	67.91	52.99	58.77	54.67	56.56
Scenario I	33.23	47.21	67.94	54.35	57.21	54.36	56.49

6.4.3 National Trends

Total project costs

Table 6.23 presents the total costs for the NT storyline. The costs vary across the different scenarios, with scenario F having the lowest total cost of 808.61 Bn €, while scenario A has the highest total cost of 828.01 Bn €. The remaining scenarios fall within this range, showing relatively small variations in total costs.

The NT storyline supports the observation that the overall costs tend to decrease with the higher integration of PLIs, increased PLI capacity, and multiple PLIs. This suggests that the integration and expansion of PLIs can lead to cost savings and improved economic efficiency.

Table 6.23: Total costs for National Trends

Scenario	Total Cost [Bn €]	Difference from Scenario A
Scenario A	828.01	0.00
Scenario B	816.54	-11.47
Scenario C	815.65	-12.36
Scenario D	824.23	-3.78
Scenario E	819.67	-8.34
Scenario F	808.61	-19.39
Scenario G	821.74	-6.27
Scenario H	820.02	-7.99
Scenario I	818.18	-9.82

Area prices

The results in Table 6.24 showcase variations in power prices across different scenarios, highlighting the impact of PLI integration on price levels. scenario A stands out with the highest average prices, particularly in the Netherlands and Belgium. It is also worth noting that the prices in Norway remain constant across all scenarios, indicating the stability of the Norwegian energy market.

Table 6.24: Area prices [EUR/Mwh] for National Trends

Scenario	NO	DK	DE	NL	BE	UK	Average
Scenario A	37.57	60.25	55.09	60.50	67.31	57.01	54.58
Scenario B	37.58	60.30	51.24	62.32	63.99	55.25	52.49
Scenario C	37.58	60.75	47.28	63.62	65.51	53.90	50.74
Scenario D	37.58	60.43	51.69	63.17	65.24	54.60	52.65
Scenario E	37.58	60.61	48.75	62.60	65.36	53.34	51.08
Scenario F	37.58	61.16	46.38	63.27	65.67	53.56	50.30
Scenario G	37.58	61.01	49.62	62.90	66.63	53.83	51.67
Scenario H	37.58	61.10	49.40	61.53	67.01	53.33	51.34
Scenario I	37.58	60.46	51.19	60.82	66.09	54.38	52.24

7 Discussion

The discussion will begin by analyzing the simulation findings, focusing on the five result categories. This will provide a deeper understanding of the observed trends in the scenarios and their implications. Additionally, the main similarities and differences between the storylines will be discussed, offering valuable insights into the potential impacts of different energy policy directions in the future. Finally, the limitations and possibilities of the model used in the study will be addressed to provide a comprehensive assessment of its strengths and weaknesses.

7.1 Transmission capacity expansion

The PLI was fully exploited with maximum connection capacity; however, there was still a need for the expansion of direct interconnectors between countries. This showcases the substantial need for interconnectivity in Europe to accommodate the rising share of RES.

The sensitivity analysis suggested that the integration of a low-capacity PLI had a minor impact on the required expansion of interconnections. Most of the direct interconnectors were expanded but with a small reduction in capacity. With the 50 GW PLI, certain existing direct interconnectors did not experience any expansion, confirming the benefits of PLI integration. It is also worth noting that expanding existing branches is a costly and infrequent undertaking, and a more common approach would be to build new interconnections, which the model did not allow.

One intriguing finding in the incorporation of multiple PLIs is the absence of direct connections between the PLIs. Direct connections to the wind nodes are prioritized instead. This transmission topology can be attributed to the fact that there is no wind generation on the PLIs, resulting in the islands functioning as distribution hubs rather than generation sources. As the wind nodes have a transmission capacity of 1000 GW, the flow is not constrained, allowing sufficient power flow. It is improbable that these high-capacity branches connecting the wind nodes would be constructed as the main purpose of the PLI is to facilitate high-capacity power flow.

The analysis in this research provides valuable insights by presenting the optimal branch extensions for all three storylines. This allows stakeholders and investors to identify common branches across scenarios. This simplifies the decision-making process and provides a clearer understanding of the infrastructure requirements for integrating the PLI.

7.2 Total costs

The analysis of total project costs across different scenarios provides valuable insights into the economic implications of integrating and expanding PLIs. There is a clear trend that increased integration of PLI reduces investment and operational costs. A 50 GW PLI comes forward as the cheapest option as it allows a large number of high-capacity branches to connect. However, the construction and maintenance costs of a high-capacity PLI might be considerable, and it is essential to assess whether the benefits and cost savings outweigh these expenses. Developing technologies capable of handling such high capacities will also incur additional costs, which could diminish the overall cost benefits. A careful evaluation of the feasibility, cost-effectiveness, and technical considerations is necessary before proceeding with the construction of a high-capacity PLI.

The increase in the number of PLIs results in a modest reduction in investment cost, despite the significant investment required for each island. The investment in PLIs appears to be justified due to the associated reduction in transmission expansion costs. The operational cost gradually decreases with more PLIs due to increased flexibility and utilization of cost-effective energy sources. These findings raise interest in exploring the implications of multiple PLIs in future analysis.

An interesting finding is the relationship between capacity and the number of PLIs. The cost analysis reveals that implementing three PLIs with a capacity of 10 GW results in a higher investment cost compared to one single 30 GW PLI. The finding can be attributed to the insignificance of PLI location and the absence of cost variation in the model. As a result, having one PLI incurs lower investment costs, leading to a more cost-effective solution compared to multiple PLIs with the same combined capacity. The operational cost shows little variation between the two scenarios. This highlights the importance of accounting for cost variations based on the location and capacity of the PLI.

7.3 Allocation of investment costs

The analysis of allocated investment costs provides insights into the distribution of costs among countries in different scenarios. The results show that Norway and Germany contribute to the majority of the transmission investments. As both these countries are exporters of power, their lines are predominantly built to help other countries reduce their operational costs. Norway and the Netherlands experienced a significant reduction in allocated cost with the high-capacity PLI as they were no longer dependent on the expansion of the interconnectors. This finding serves as a motivation for Norway to build a PLI in order to reduce investment costs in the offshore grid.

The allocation of PLI costs raises important considerations for multinational projects.

The economic incentives and cost implications of such projects can influence countries' decisions to participate. Achieving a fair and transparent cost allocation framework is crucial to encourage cooperation and facilitate the expansion and integration of OWP in the NSOG. Allocation frameworks have been investigated in the following papers [18] [19], which is reviewed in Section 2.

7.4 Power flow in PLI

The power flow patterns illustrate the utilization and benefits of PLI integration in facilitating efficient power exchange. The PLIs lead to increased transmission capacity, ensuring robustness and stability in the system. By integrating PLIs, countries can tap into the renewable energy potential of neighboring regions to increase their share of RES.

One of the main advantages of the PLI in terms of power flow is the increased flexibility. As intermittent RES gradually becomes a larger part of the energy mix, flexibility in the power system becomes more important. Direct interconnectors between countries are restricted by two connection points. The PLI makes it possible to configure power flow in a much more efficient way by allowing power to flow where it is needed the most. As seen in the power flow plots, all branches are utilized for import and export, and the distribution of power flows can be optimized to meet demand and supply requirements.

An interesting observation is the presence of low-capacity branches connected to the PLIs, with a substantial number having capacity levels below 500 MW. These branches are primarily utilized for the import of OWP from specific countries, raising concerns about the feasibility of constructing such low-capacity infrastructure. It would be more strategic to invest in the development of higher-capacity branches, allowing them to serve as both importers and exporters.

The average power flow through the PLI may appear marginal based on the displayed results. While the average power flow may show low utilization, this is caused by fluctuations in the power flow, which depends on the specific conditions and storylines. Therefore, careful consideration of interconnector capacities is crucial before making significant investment decisions.

7.5 Average area prices

It is evident that the average area prices vary among countries but remain relatively stable within each scenario. Belgium consistently exhibits the highest average prices, reflecting the expensive generation cost in the country. Denmark shows significant variability in prices, indicating a higher sensitivity to changes in the offshore grid and the reliance on OWP.

On the other hand, the Norwegian area prices are the lowest and the most stable. This can be explained due to Norway's low-cost energy mix, mostly comprising wind power and hydropower. Hydropower has a fixed price of 30 €/MWh in the model. It is important to acknowledge that the hydro price is subject to volatility and often correlates with the electricity price [17]. Considering the indirect influence of gas prices in Europe on electricity prices in Norway, it becomes evident that a historical time series profile for Norwegian power prices would provide a more accurate reflection. Additionally, as the volume of power exports from Norway continues to rise, the impact on domestic electricity prices could become more substantial. This has already been observed as a prevailing trend for the past few years [63].

Due to the difficulties in extracting the dual values from the MILP problem, it was not possible to obtain the precise electricity price for each area. Hence, the area prices reflect the average marginal cost of the generator. This gives an approximate area price but has some deviations since the marginal generator in one area may cover the load in other areas. The price-duration curve was originally planned to be used to analyze and evaluate the impact of the transmission expansion. Due to the irregularity in the electricity prices, this analysis was not conducted as the results would have been misleading.

This price deviation is observed in the GA, which turned out to have the highest operational cost of the storylines. The area prices for all the countries were significantly low, except for Germany, which experienced the highest area prices. This occurrence can be attributed to Germany's role as the primary supplier to other countries. Consequently, the operational cost is heavily influenced by the price of the marginal generator in Germany. Since the other countries rely on German exports, they do not utilize their expensive generators, and their area prices appear to be low.

7.6 Comparison of storylines

Despite the similarities observed in transmission expansion across the different storylines, the NT storyline stood out with the highest investment costs in most scenarios. This can be attributed to the extensive expansion of interconnectors, indicating a strong focus on cross-border integration. While the NT storyline had fewer connection points to the PLIs, the capacity of these connections was generally higher compared to DE and GA.

The NT storyline also exhibited the lowest average area prices, suggesting a cost-effective solution in terms of sufficient generation dispatch and transmission distribution. However, it is important to note that the NT storyline falls short of meeting the emission targets outlined in the Paris Agreement. This misalignment raises concerns about the feasibility of such a development path, considering the commitment of European countries to transition towards cleaner and more sustainable energy systems.

In the DE storyline, the results showed a minimal capacity expansion on existing branches, with emphasis placed on expanding more branches connected to the PLI. The investment costs for this storyline were lower compared to the other two storylines in all scenarios. The GA storyline, characterized by a moderate expansion of interconnectors and a considerable number of branches connected to the PLI, exhibited the highest total costs among the three storylines. GA incurred the highest operational costs, attributed to the high demand and relatively low amount of installed capacity. This ratio between demand and installed capacity led GA to be the storyline with the most load shedding resulting in high operational costs.

As observed in the results, the total costs greatly depend on operational costs, which are heavily reliant on the storyline's demand level and generation costs. These findings indicate that the direction of the European energy system in terms of RES capacity and demand has a considerable influence on the overall costs, surpassing the impact of the scenarios and degree of PLI integration. In light of these findings, it becomes increasingly important to prioritize the expansion of low-cost RES in order to meet the increasing demand due to electrification. Actively reducing peak demands, and embracing sustainable practices through the development of energy-efficient technologies will pave the way for a sustainable future.

7.7 Model possibilities and limitations

The modeling of power systems is a complex task, necessitating the formulation of numerous assumptions and simplifications to replicate the real-world system. These assumptions play a role in shaping the simulation and influencing the outcomes. However, it is important to recognize and acknowledge the deviations arising from these assumptions and identify the limitations in the model in order to improve further research.

Clustering and time series

One potential limitation in the methodology is the clustering of demand data using k-means and the subsequent use of wind and hydro series for the same time instances. While clustering is necessary to reduce the computation time, the sampling technique utilized in this study may overlook temporal dependencies and fluctuations in demand. This approach might lead to inaccuracies in the results, as it does not fully capture the dynamic nature of renewable generation and its correlation with actual demand patterns.

Inelastic load

In the model, the load is assumed to be constant and unaffected by price fluctuations or other external factors. The inelastic load assumption limits the model's ability to capture the responsiveness of demand to changes in electricity prices or other influencing factors. As technology and smart systems are evolving, consumers have more flexibility to decide whether to use energy or wait until the prices are lower [64]. Incorporating more realistic and dynamic demand models that consider consumer behavior and response to price signals, would enhance the model.

Inelastic costs

The fuel prices used in the model are constant throughout the year and multiplied by 30 years, which makes the simulation static. Although the annuity factor considers the net present value of the operational costs, the fuel costs do not reflect the normal fluctuations and dynamics in the energy market. In recent years, the energy market has undergone rapid transformations, particularly with the increasing reliance on RES that are heavily influenced by weather conditions. Additionally, Europe has witnessed a notable rise in CO_2 prices, leading Germany to phase out coal plants by 2038 [65]. Furthermore, following Russia's invasion of Ukraine in February 2022, the EU has imposed several sanctions on Russia, resulting in restrictions on the import of raw materials like oil, gas, and coal to the EU [66]. These examples highlight the market's inherent fluctuations and dynamics, which must be taken into account when analyzing the energy landscape.

Onshore grid

Although the onshore branches in the model are an approximation to the real-life AC grid, it can provide a lot of information. The simulations of the model resulted in an expansion in all AC branches on the mainland. This indicates that there are bottlenecks in the grid, which prevent optimal power flow in the offshore grid. In this thesis, the focus has mainly been on the offshore grid. However, it was evident by observing the results that the onshore grid plays a crucial role in the expansion of the offshore grid. There were no constraints in the onshore grid in order to ensure that the offshore grid was fully utilized. This implies that one of the fundamental assumptions for the offshore grid to be advantageous is the capability of the onshore grid to facilitate the import and export of power flows.

One of the topics discussed at the Annual WindEurope 2023 conference in Copenhagen was the consideration of offshore transmission expansion with respect to the onshore grid [67]. Given the huge ambition regarding the NSOG, it was emphasized that it is a substantial risk of over-dimensioning the offshore grid due to the bottlenecks in the onshore grid. In order to secure an efficient expansion in the NSOG, the onshore grid must be taken carefully into consideration. The bottlenecks must either be expanded or be considered as constraints in the offshore expansion. The latter is conducted and can be read in [34].

Safety & reliability

The safety aspect of connecting multiple branches at a single joint (PLI) is a consideration that needs to be carefully evaluated in terms of security. The electricity infrastructure is classified as critical. [68]. Therefore, in the event of unforeseen electrical faults and acts of sabotage, a PLI becomes a vulnerable element for the entire European electricity system.

The high capacity of the PLI presents challenges in terms of technological feasibility and safety considerations. Building a high-capacity PLI necessitates advanced engineering, robust materials, and efficient cooling systems to handle the elevated power levels [69]. The alternative approach is to install multiple PLIs with lower capacities, to achieve the desired capacity. The proposed approach was proven to have the same benefits in terms of operational costs but with a slightly higher investment cost. When considering the pay-off between costs and reliability, it may be convinient to invest in multiple PLIs.

Technology standardization

While individual countries may develop their own technologies and standards based on their specific needs and resources, the successful connection of multiple countries to a PLI requires a common set of standards and interoperability. Standardization ensures seamless integration, efficient operation, and optimal utilization of the PLI infrastructure. A notable challenge lies in connecting existing wind farms to future PLIs, as these wind farms may not have been designed with the necessary infrastructure for integration. This highlights the urgent need for rapid technology standardization to address compatibility issues and ensure a smooth transition toward a unified and interconnected power system.

8 Conclusion

This thesis has provided a comprehensive analysis of the effects of integrating PLIs into the NSOG. Through a series of case studies, the research has explored the impact of different scenarios on the transmission grid expansion, system costs, power flows, and average area prices. The case studies included a gradual integration of PLI, sensitivity analysis of PLI transmission capacity, and integration of multiple PLIs.

The results displayed a clear economic advantage of investing in the PLI. The scenario that introduced a 50 GW PLI showcased the most significant cost reduction, with investment costs reduced to less than half compared to the base case scenario without a PLI, across all storylines. The sensitivity analysis revealed the influence of the PLI's transmission capacity on the expansion and costs of the countries. Specifically, higher PLI capacity resulted in lower total cost, and it was observed that the PLI was fully utilized across all capacity ranges. This concludes the extensive potential for a PLI in the North Sea.

The implementation of multiple PLIs resulted in higher investment costs compared to installing a single PLI with the same capacity as all the PLIs combined. However, the operational costs remained the same for both scenarios. Therefore, building high-capacity PLIs in the North Sea emerges as the most cost-effective option given the model configuration.

The allocation of investment costs emphasizes the significant contributions of Norway and Germany, which have implications for multinational projects. In terms of average area prices, Belgium consistently exhibited the highest prices, while Norway demonstrated low and stable prices due to increased interconnections. These findings underscore the importance of establishing a fair and transparent cost allocation framework to encourage cooperation across nations.

The case studies were simulated with three different sets of input data (storylines) obtained from the most recent report from ENTSO-E, TYNDP2022. The storylines represent different directions the European energy market can develop in the coming years. National Trends stands out with high investment costs, indicating a strong focus on cross-border integration but falling short of meeting emission targets. Distributed Energy exhibits lower investment costs, while Global Ambition incurs higher total costs due to high demand and load shedding. The operational costs for the three storylines differ significantly, indicating the impact of generation costs and demand on the total project cost. This highlights the need for extensive RES expansion and energy-saving initiatives in the future.

9 Further works

Implementing stochastic programming with different weighting would provide a more realistic and comprehensive solution considering the importance of unity in multinational transmission expansion. Using stochastic theory, one could obtain the estimated value of perfect information, which may be interesting and valuable for predicting future scenarios.

Interesting studies would be sensitivity analysis of various cost parameters and their impact on transmission expansion. As technology progresses in the coming years, it is difficult to determine specific prices of converter-, transmission-, and breaker technology. The investment cost of the PLI itself is also an uncertain parameter, as it requires technology that is potentially undeveloped. This analysis would shed light on the economic viability of an interconnected North Sea grid.

Interesting studies would be the implementation of a realistic range of energy storage, such as batteries, power-to-X technology, or pumped hydro storage. Energy storage can potentially mitigate the consequences of the variability of RES and facilitate the accelerated integration of large-scale offshore wind power.

Applying game theory to accommodate cooperation and offer incentives can potentially increase offshore wind generation expansion, which is necessary for the coming years.

Further research could explore the inclusion of wind power costs in the optimization model, specifically examining the optimal generation capacity. Additionally, investigations could consider different wind generation technologies, such as floating wind.

Introducing additional constraints to the optimization problem, such as generation ramping and the N-1 Criterion, would add complexity and realism to the model. Furthermore, governance constraints like max investment costs may be considerable to evaluate in the optimization.

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Appendices

Github repository

Original PowerGIM repository

Description: The original PowerGIM GitHub repository developed by Harald Svendsen for Sintef Energy Research.
URL: https://github.com/powergama/powergim

PowerGIM repository for this research

Description: The PowerGIM GitHub repository developed for this research, with input files and functions for reading results.
URL: https://github.com/tobiassjoli99/tdg_powergim/tree/tdg

Branch capacities

Table 0.1: Transmission capacities in 2030

Node from	Node to	Existing capacity [MW]
NO_m	NO_c	10000
NO_c	DK_c_1	1700
NO_c	DK_c_2	1400
NO_c	DE_c	1400
NO_c	UK_c_1	1400
NO_c	NL_c_1	700
DK_m	DK_c_1	2500
DK_m	DK_ct_2	2500
DK_c_2	UK_c_2	1400
DK_c_2	NL_c_1	700
DE_m	DE_c	15000
DE_c	NL_c_1	700
NL_m	NL_c_1	5000
NL_m	NL_c_2	5000
NL_c_2	UK_c_2	2000
BE_m	BE_c	5000
BE_c	UK_c_2	1000
UK_m	UK_c_1	5000
UK_m	UK_c_2	10000
DK_m	DE_m	3500
DE_m	BE_m	1000
NL_m	BE_m	2400
NL_m	DE_m	1300

Power flow

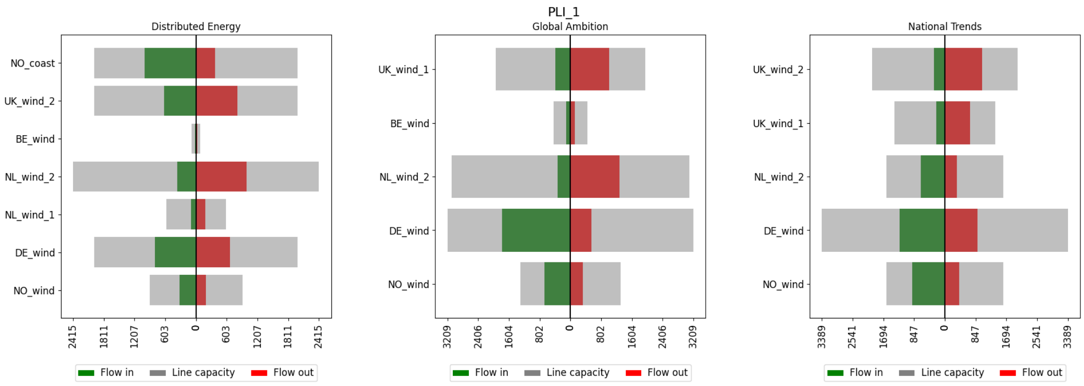

Figure 0.1: Power flow in MW for all branches connected to PLI_1 in scenario G

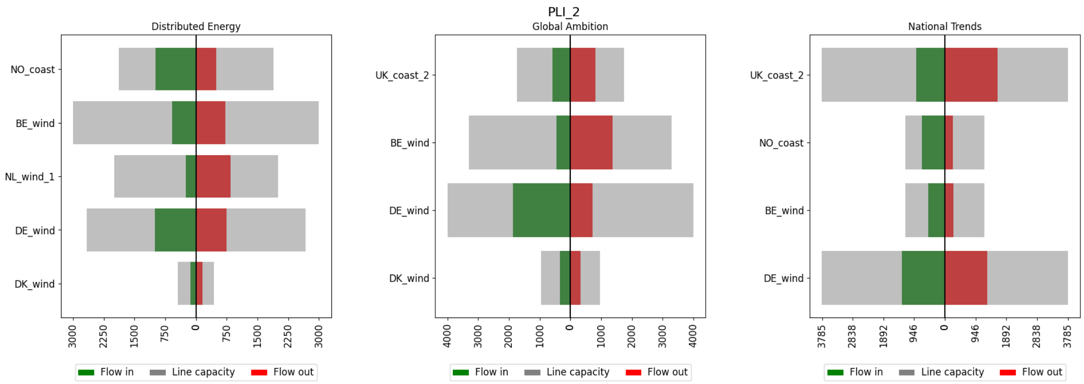

Figure 0.2: Power flow in MW for all branches connected to PLI_2 in scenario G

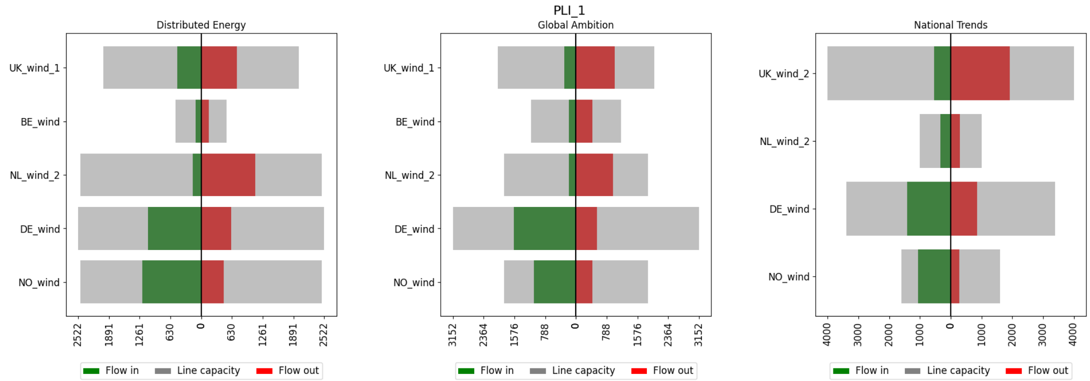

Figure 0.3: Power flow in MW connected to PLI_1 in scenario H

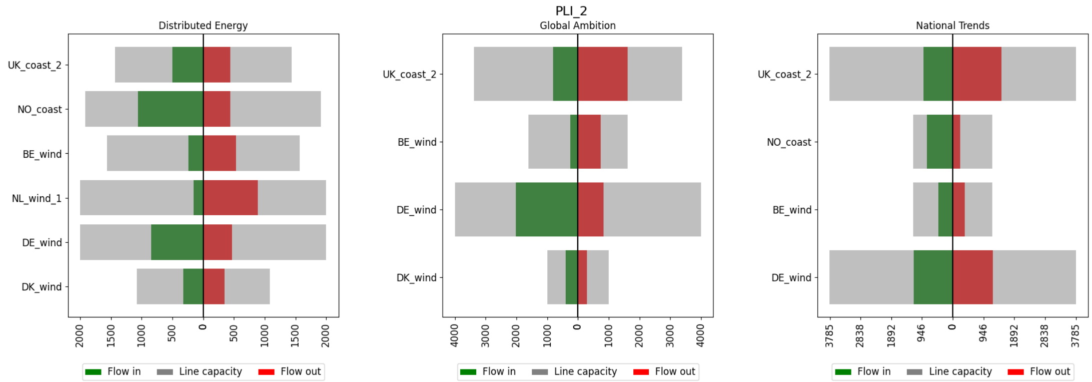

Figure 0.4: Power flow in MW for all branches connected to PLI_2 in scenario H

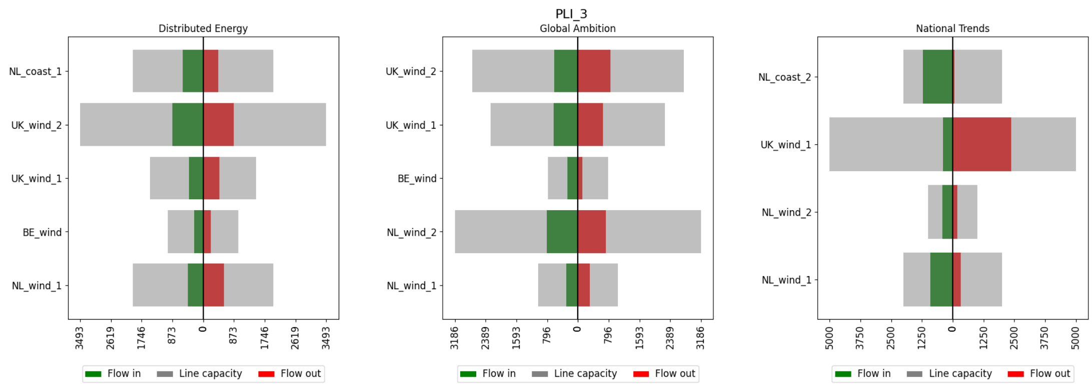

Figure 0.5: Power flow in MW for all branches connected to PLI_3 in scenario H

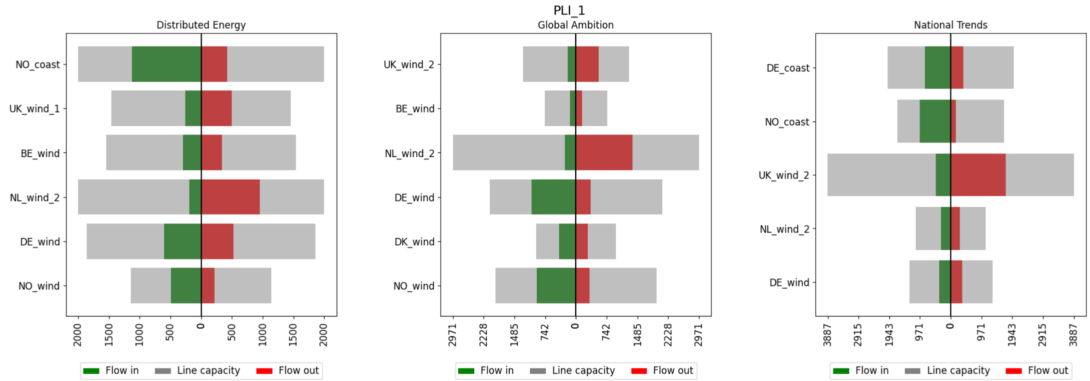

Figure 0.6: Power flow in MW for all branches connected to PLI_1 in scenario I

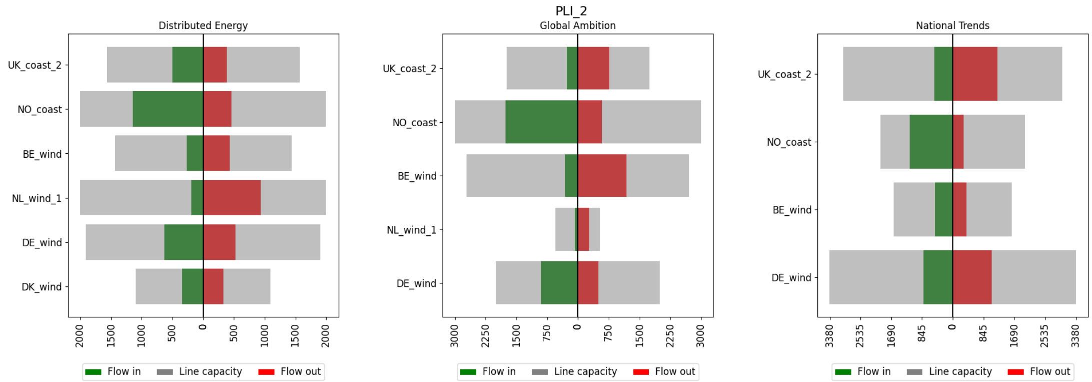

Figure 0.7: Power flow in MW for all branches connected to PLI_2 in scenario I

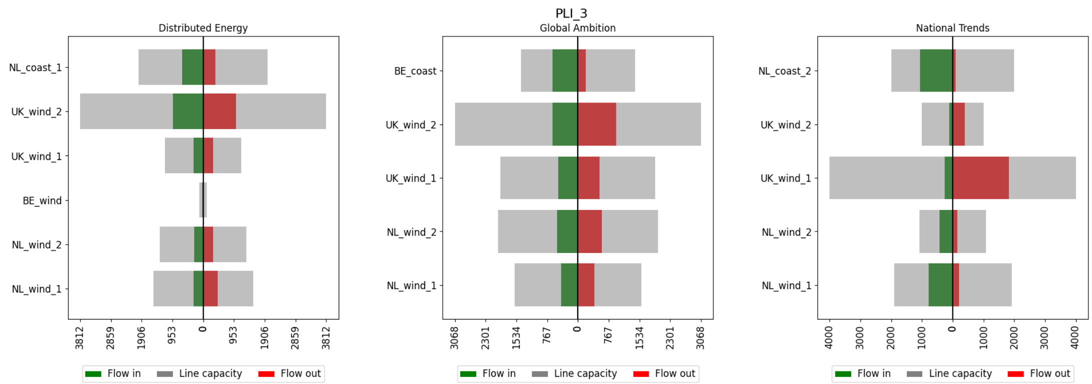

Figure 0.8: Power flow in MW for all branches connected to PLI_3 in scenario I

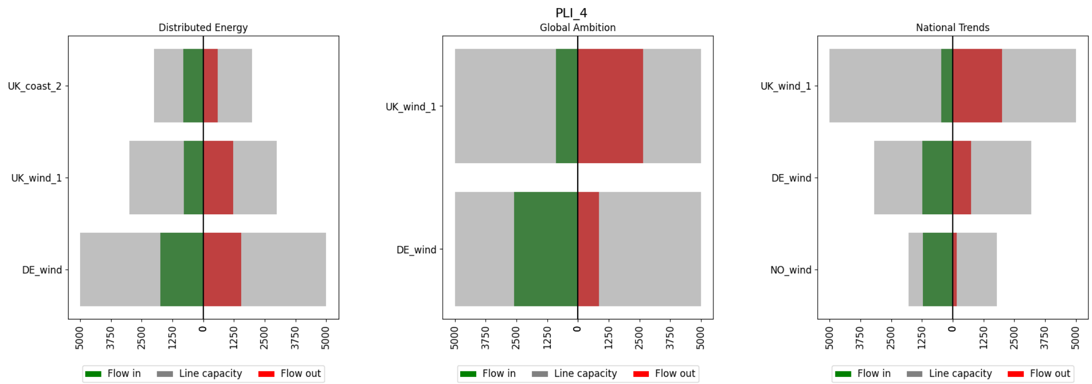

Figure 0.9: Power flow in MW for all branches connected to PLI_4 in scenario I

Parameters

```
nodetype:
   ac: {'L': 1, 'S': '50e6', 'Lp': 0, 'Sp': 0}
   hvdc: {'L': 1, 'S': '406e6', 'Lp': 0, 'Sp': 0}
   pli: {'L': 1, 'S': '150e7', 'Lp': 0, 'Sp': 0}
branchtype:
   ac: {'B': '312e3', 'Bdp': '1.416e3', 'Bd': '1193e3', 'CL': '1562e3',
   'CLp': 0, 'CS': '4813e3', 'CSp': 0, 'max_cap': 400, 'loss_fix': 0,
   'loss_slope': '5e-5'}
   dcmesh: {'B': '312e3', 'Bdp': '0.578e3', 'Bd': '1236e3', 'CL': 1562,
   'CLp': 0, 'CS': '4813e3', 'CSp': 0, 'max_cap': 2000, 'loss_fix': 0,
   'loss_slope': '3e-5'}
   dcmesh_conv: {'B': '312e3', 'Bdp': '0.578e3', 'Bd': '1236e3', 'CL':
   '28323e3', 'CLp': 0, 'CS': '4813e3', 'CSp': 0, 'max_cap': 2000,
   'loss_fix': 0, 'loss_slope': '3e-5'}
   dcdirect: {'B': '312e3', 'Bdp': '0.578e3', 'Bd': '1236e3', 'CL':
   '58209e3', 'CLp': '93.2e3', 'CS': '452499e3', 'CSp': '107.8e3',
   'max_cap': 2000, 'loss_fix': 0.032, 'loss_slope': '3e-5'}
   conv: {'B': 0, 'Bdp': 0, 'Bd': 0, 'CL': '28323e3', 'CLp': '46.6e3',
   'CS': '20843e3', 'CSp': '53.9e3', 'max_cap': 2000, 'loss_fix': 0.016,
   'loss_slope': 0}
   ac_ohl: {'B': 0, 'Bdp': '0.394e3', 'Bd': '1187e3', 'CL': '1562e3',
   'CLp': 0, 'CS': 0, 'CSp': 0, 'max_cap': 4000, 'loss_fix': 0,
   'loss_slope': '3e-5'}
gentype:
   bio: {'CX': 124150, 'CO2': 0}
   gas: {'CX': 35025, 'CO2': 0.4215}
   hard_coal: {'CX': 93401, 'CO2': 0.8605}
   hydro: {'CX': 109250, 'CO2': 0}
   lignite: {'CX': 110000, 'CO2': 0.9}
   nuclear: {'CX': 233503, 'CO2': 0}
   oil: {'CX': 53200, 'CO2': 0.7167}
   solar: {'CX': 76983, 'CO2': 0}
   onshore_wind: {'CX': 84205, 'CO2': 0}
   wind: {'CX': 156000, 'CO2': 0}
   other_res: {'CX': 85000, 'CO2': 0}
   other_non_res: {'CX': 85000, 'CO2': 0.2}
parameters:
   investment_years: [2030]
   finance_interest_rate: 0.05
   finance_years: 30
   operation_maintenance_rate: 0.02
   CO2_price: 78
   load_shed_penalty: 10000
   profiles_period_suffix: False
```

Figure 0.10: Parameters used in the simulations

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