NTNU

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Cost benefit analysis of different offshore grid topologies in the North

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PREFACE

This Master Thesis is written by Amaia Larrañaga Arregui, student of the European Wind Energy Master´s programme (EWEM), Electric Power Systems track, 2015-2017 cohort.

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Egunen batean, ikerkuntza munduan ere,

genero-berdintasuna lortuko dugulakoan.

Emakume ikerlari guztientzat…

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ABBREVIATIONS

AC .... Alternating Current

Approx .... Approximate

BE .... Belgium

Cap. .... Capacity

DC .... Direct Current

DE .... Germany

DK .... Denmark

DK-E .... Denmark-East

EMPS .... Multi Area Power Market Simulator

ENTSO-E .... European Network of Transmission System Operators for Electricity

e.g. .... Example given

GB .... Great Britain

FI .... Finland

FR .... France

IE .... Ireland

i.e. .... That is

LP .... Linear Programming

Max .... Maximum

MILP .... Mixed Integer Linear Programming

NI .... Northern Ireland

NL .... Netherlands

NO .... Norway

NSCOGI .... North Seas Countries' Offshore Grid initiative

OPF .... Optimal Power Flow

PowerGAMA .... Power Grid and Market Analysis

PowerGRID .... Power Grid and Investment Model

PV .... Photovoltaic

RES .... Renewable Energy Sources

ROI .... Return on Investment

SE .... Sweden

TSO .... Transmission System Operator

TYNDP .... Ten Year Network Development Plan

UNFCCC .... United Nations Framework Convention on Climate Change

w.r.t. .... With respect to

ABSTRACT

European countries are showing their willingness to reduce their greenhouse gases emissions in the coming years. For example, the Paris agreement within the United Nations Framework Convention on Climate Change (UNFCCC) is one of the most crucial steps that countries have signed recently. The aim is to cause a lower global temperature increase, and thus, to reduce the resulting climate risks.

North Sea countries are working on a greener future in a national level, as well; and these are in fact, the countries which are the most concerned about the climate change globally. Moreover, these are affluent in terms of opportunities for using greener energy sources, due to their climatic and geographic conditions. Clear examples are hydropower plants in the Nordic region or offshore-wind in the North Sea.

Nevertheless, these countries need also of infrastructure to achieve their objectives, such as a Power System which will enable to integrate green generation sources properly and to satisfy the societies' energy needs successfully. Power Systems are in fact, needed key enablers of this energy transition.

The topic of this Master Thesis is transmission expansion planning in the North Sea for the year 2030. PowerGIM and PowerGAMA are used. The objective is to find the socio-economically beneficial grid design which will help achieve these future ambitions that the North Sea countries have and at the same time, which will be robust w.r.t. renewable energy sources' development uncertainty. The main finding of this Master Thesis is that Dogger Bank hub is obtained as part of the most socio-economically beneficial offshore-grid layout for the year 2030, in all implemented scenarios. Each scenario refers to one implemented ENTSO-E Vision (Visions 1-4) with some additional assumptions.

In short, in this Master Thesis, four different offshore-grid layouts are obtained, one per each implemented scenario; and all of them have the same core. The core is Dogger Bank hub's interconnection with Great Britain, Belgium, Germany, Netherlands, Norway and Denmark. Nevertheless, there are some variations which depend on the implemented scenario and on the implemented assumptions. Overall, the obtained Dogger Bank hub could also integrate between 13-32 GW offshore-wind in the North Sea. Then, a reference grid layout is created, as well. This design embraces the previously mentioned four grid layouts in a conservative way, i.e. the repeated lines in all four obtained grid layouts are taken with the lowest capacity value among all four designs.

The grid layout obtained after the implementation of the second scenario is the most robust grid layout w.r.t. different future energy prospects. Its operational cost saving throughout the lifetime of 30 years w.r.t. the reference grid layout is of 20-33 bn €, depending on the implemented future scenario; and the investment cost increase is of 5.5 bn € w.r.t. the reference grid layout.

Index terms: Power System Planning, Power Transmission, Power System Management, Power System Economics, Power System Modelling, Load Flow.

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1. INTRODUCTION

1.1. BACKGROUND AND PROBLEM DEFINITION

North Sea countries are looking into the future and they are taking the necessary steps to build a greener energy scheme which will be the motor of their economies and well-being. Power Systems are part of this, and they also need to be prepared for the future so as to help the mentioned countries to achieve their ambitions. They are in fact, the link between generation and consumption and the ones which will ensure the satisfaction of all parties involved, such as society.

Nevertheless, there is uncertainty. Politics and technological developments could make the future even greener, i.e. more renewable energy sources (RES) could be integrated in the power system; but also, decisions such as having a more integrated power system could make a difference. In addition, the technical developments in the power system's parties, i.e. research in the fields of converters, storage or protection, could also open new opportunities.

Consequently, it is certain that there is a considerable uncertainty regarding the future Power System, since it is a combination of a lot of partners and technical components. Nevertheless, there is one thing which is clear, the transmission expansion investment decisions should be properly done, with the lowest cost possible and with the highest benefits possible.

In addition, the investments require various stages and these mean time; for example, to make investment analysis, to get permits and to actualise them need years. Besides, investments have an average lifecycle between 20 to 60 years. Therefore, it is important to build an infrastructure which would be beneficial for different future scenarios.

ENTSO-E is also looking into the future. For that, every two years, it creates the so called Ten Year Network Development Plan (TYNDP). Its objective is to frame the uncertainty that involves the future of the Power Systems.

To tackle this uncertainty regarding the future, ENTSO-E takes into account the EU council targets for 2020 and 2030, and it also works closely with different decision makers, TSOs and stakeholders of over the whole Europe.

Based on this, ENTSO-E builds four visions. These visions, or scenarios, represent how the future power systems' condition could be like, e.g. generation, demand, fuel costs etc.; and the visions vary depending on the ambitions in terms of the level of market integration between countries and ambitions on renewables.

ENTSO-E's aim is to provide complete and transparent information on what the future transmission needs would be to meet the EU council's targets. Its objective is not to predict the future, it is rather to frame the uncertainty.

1.2. OBJECTIVE OF THIS MASTER THESIS

This Master Thesis looks into the future, year 2030. The goal of this Master Thesis is to consider all different possible opportunities that the North Sea offers for having a socio-economically beneficial grid layout, and to choose the most robust grid layout, i.e. the one which would be the most beneficial in different potential future scenarios.

1.3. LITERATURE SURVEY

In this Master Thesis, different approaches could be followed. Nevertheless, the implemented assumptions and approximations in this study aim to be realistic and at the same time, they aim to cover a gap or need seen in the existing studies. These are found in the literature survey activity done in this Master Thesis and they are shortly explained in the coming pages.

1.3.1. INTRODUCTION

The starting point of this Master Thesis is the Literature Survey. In this stage, different publications are analysed to enrich the authors' background about power systems' planning topic. The subject of analysis in this Master Thesis is the North Sea and the year 2030. The aim is to get a socio-economically beneficial transmission planning design. Therefore, a focus on this topic is done, first. Nevertheless, the steps and analysis of these papers bring the author to find some other gaps of other areas of analysis too.

The objective when doing literature survey is to see what has been already done and to see how research area works. At the same time, the author of this Master Thesis tries to be critical. For that, the method used in each analysis or the gaps in the study are analysed. At the same time, ideas to make the research more innovative are evaluated.

The coming pages aim to give a brief description of the main findings and conclusions obtained in this stage of this Master Thesis. To start with, each publication is mentioned by stating its most important characteristics or gaps. These publications are classified in two groups. First, the publications provided by the partners involved in this Master Thesis are shown, and then, the publications found by the author of this Master Thesis are mentioned. At the end, the overall conclusions of this sub-chart are given.

1.3.2. FOLLOWED STEPS

1.3.2.1. PROVIDED DOCUMENTS

These two reports [1] and [2] are helpful for the author of this Master Thesis for learning some new characteristics of the Power System, and for reviewing some other seen during this Master's programme. The quality of these projects is high, because of the partners involved and the data used on them.

Some comments to add would be the next ones. In the second report, a sensitivity analysis is done. The reference scenario is the so called NSCOGI (North Seas Countries' Offshore Grid initiative), which consists of 55.5 GW of offshore wind in the North Sea. Then, the offshore wind capacity is increased with respect to the reference scenario to 117.4 GW; in order to see if the benefit of meshing would increase by increasing the offshore wind volumes [2].

The cause of this RES+ scenario is the greenest TSO scenario. For this sensitivity analysis, it would be interesting to increase the spectrum of analysis by implementing more scenarios with different wind generation capacities in the North Sea. For instance, another scenario could be of lower offshore wind generation capacities for analysing the carbon based future pattern. It would be of interest to analyse the differences between the obtained results for different scenarios.

The reason for this suggestion is that, the scenario of 2030 still needs a lot of years to come, so analysing another scenario, which is not that green, could give more insight, more information would be available and thus, there will be a stronger base for making decisions.

The next paper [3] suggests that future research is needed especially in the areas of Demand Management and in Non-hydro storage. It also says that governance and regulatory need is high, especially in meshed topologies. These last ones result to be overall, more convenient because they offer higher reliability and flexibility, but at the same time, they require higher investments than radial topologies. Nevertheless, it also adds that meshed technology has shown a marginal advantage than radial in some studies. So, further detailed research is suggested.

Apart from that, it mentions that the timing of the projects will be very important; especially, in the meshed case. The reason is that the projects are expected to develop first nationally, then, bilaterally and then, internationally. Moreover, it says that, even if different actors contribute on policy, there is no clear case for immediate and full cooperation between European players.

Related to this, the research article [4] takes as known and fixed the generation and consumption points of the grid, and it optimizes the grid layout. In other words, the aim is to optimize the investment of the grid for a given generation and consumption scenario. It mentions that usually the demand is taken inelastic.

In this article, it could be interesting to change the share of installed offshore wind generation capacities and to see how the investments and generation costs vary. This also would change some of the needed interconnections. The hypothesis from the author of this Master Thesis is

that more interconnection would be required for getting higher flexibility in the system and thus, to integrate successfully more RES.

Apart from that, it could be of interest to analyse the impact that the elasticity of the demand could cause on the grid investment decision, i.e. to do again a sensitivity analysis which is based on the elasticity of the demand. Its degree may change the optimal grid layout. The hypothesis from the author of this Master Thesis is that lower amount of interconnection would be needed, since the peak demand would be reduced by the provided elasticity by the demand.

The next paper [5] and reports [6]-[7] suggest that there is uncertainty regarding Norwegian hydropower generation plants' generation capacity increase in the future. Paper [5] states that the mentioned generation capacity increase would be technically feasible. Nonetheless, it also says that for Norway, it is politically feasible to provide balancing through the existing generation capacities in the short term.

Apart from that, report [6] by Statnett discusses that there is uncertainty in the mentioned investment plans for the Norwegian hydropower generation units and that the unpredictability is caused by the contingency regarding future prices, costs and potential. It also argues that Statnett do not have the capability to model pumped storage properly, in this analysis [6]. Therefore, they increase just in 2.5 GW the generation capacity values in Norwegian hydropower plants w.r.t. current values, for the implementation of 2030-2040 analysis. Similar conclusions are drawn in [7], as well.

1.3.2.2. CONTINUATION OF THE PROVIDED DOCUMENTS

Then, the author of this Master Thesis Report starts looking for other interesting publications to increase the knowledge of the trends and gaps in the transmission expansion planning research industry.

Another kind of study is [8]. This article analyses the impact that the interconnection between Great Britain and France creates on renewable energy sources' share, as well as, in the conventional technologies. The result says that due to the interconnection, higher renewable energy sources share will be obtained, thus the share of conventional technologies will be lower and consequently, less CO_2 emissions will be released. Apart from that, gas-fired plants' compensating burden for wind and solar will be reduced. These factors will cause a difference when making investment decision. In this study, there is a gap in terms of considering a more active demand side. It would be interesting to consider this factor, as well; and to do the same analysis. In this way, the effect that a more active demand side could cause in the results could be studied.

This paper [9] studies the impact that storage and flexible demand could create in the power system for the 2030 Western Mediterranean case, by making use of PowerGAMA. This last factor, the flexible demand, is not analysed deeper in the previous mentioned analysis. Apart from that, it has not been found (at least so far) any paper analysing this factor (Demand Response or flexibility capacity), that is, doing a sensitivity analysis based on flexible demand.

Even if it is a more short-term focused characteristic, it could make a difference in the longer-term investment decisions as well, because the long-term investments are done for satisfying the everyday short-term needs. Therefore, a focus on this topic is done in the further steps of this Literature Survey.

The project [10] says that in an area predominantly with hydro storage, daily flexibility is abundant, but it also says that there is a need for balancing seasonal fluctuations in hydrology. In an area dominated by wind energy, daily flexibility would be needed.

It also states that it is not known if demand side flexibility can compete with flexible generation, grid investments, or if it would be able to provide the needed flexibility.

This could be an interesting analysis to do. In this way, these uncertainties expressed by the previous statement would be clarified. The topic to answer would be to analyse how powerful flexible demand could be to provide flexibility to the system w.r.t. other means of flexibility providers and which would be its benefits, i.e., the impact on investment costs reduction and on operational costs reduction.

The mentioned project also makes a deep description of each flexible demand type, and a description of each country, i.e. what need each of them have in terms of flexibility. It mentions that Nordic TSO need short-term flexible resources and security and quality of supply, because the frequency in the synchronous Nordic area (Denmark East, Finland, Sweden and Norway) is a regional concern.

It also highlights the importance that the willingness to pay for electricity will have. It mentions some studies' results as well: [10] Norwegian households' potential, taking into account 50% of the Norwegian households with electrical water heaters, the peak load demand could be reduced 4.2%.

Finally, the report says that the flexibility value in the power system is uncertain and it suggests 4 different paths that the future could follow. These scenarios are grouped depending on the degree of flexibility in the power system and the cost of demand flexibility relatively to other flexibility sources. These paths could be included in the previously suggested study.

This document [11] targets the Baltic Sea, and it focuses on analysing which configuration is better, radial or meshed.

A gap in terms of considering a demand-response ability from the load is found here too. Therefore, a search for more useful information on this area is done.

There is a project RESPOND [12], under Intelligent Energy Europe for five countries: Denmark, Germany, the Netherlands, Spain and the United Kingdom. This paper [9] shows that the prices between 2004 and 2010 were close to the usual prices for western Denmark, and consequently, one of the possible drawbacks of the Demand Response which is to have too soaring prices periods, would not happen for this area based on this analysis.

Apart from that, it shows that the existing infrastructures could handle the wind power integration without problems. Nevertheless, it subjects the need of following a path for Demand Response, when higher integration of wind is done, as solution to interconnections. Therefore, the author of this Master Thesis goes into this topic a bit deeper. For that, a focus on existing modelling methods is done, to get an idea. The next interesting documents are found.

Continuing with the same topic, this model [13] is based on an hourly dispatch. It is focused on long-term demand response, days, weeks or even months. It would be interesting to do a short-term demand response analysis, as well. For that, PowerGAMA (Grid and Market Analysis Optimization tool) could be used, since it also gives values in an hourly base, and thus, it has a proper resolution to analyse the impact of wind generation variation, too.

This time frame is not analysed in this document. Therefore, this gap could be filled. The next interesting article [14] is found on its ([13]) reference.

There are two ways stated for doing the Demand Response: Price Based Demand Response (PBDR) and incentive-based demand response (IBDR). This article focuses in the latter one. It would be interesting to do the analysis for the most extreme case, the price based demand response.

Following [15], this article says that usually, all the consumers have a fixed tariff. It adds that it could be interesting to create special retailer contracts which incentivise the consumers to have a more flexible attitude.

In this way, when the prices were above certain value, they could inform the consumer and the consumer could decide to consume or not. This is an example of how important are politics and financial help and how they could make a considerable impact on whether to make become the consumers more active or even prosumers (consumers and producers at the same time).

This article [16] shows that for Denmark, it is recommendable to follow a combined heat and power investment based future path, by integrating them to the local energy systems and by making the current consumers become more prosumers. This is a Danish system based on self-sufficiency rather than on interconnections based future path for managing the fluctuations in wind power. For this, special Danish energy policy is required.

Related to this, the next paper [17] states that 91% of existing Swedish meter readings are monthly based, but they have the capacity to work in an hourly base. In fact, they have the capability to register and store electricity values in the mentioned time range.

Apart from that, two most recent pricing experiments suggest that the demand response can make an average effect of 20% and 50 %, this last value is obtained considering automated solutions in reduction of peak demands.

This paper [18] states that the balancing by the Norwegian pumped hydropower system is possible, and that it has a balancing potential of around 70% of the analysed wind power request.

It could be interesting to see how this balancing potential vary when offshore wind integration is increased or decreased. By reducing the offshore wind integration, which offshore wind generation capacity the 100% of balancing by hydropower generation is obtained for could be seen. In addition, when increasing the offshore wind generation capacity, how much the balancing capability is reduced per each offshore wind generation increase could be seen.

This report [19] says that it would be technically feasible to increase the installed hydro power capacity by 20000MW. For that, new tunnels and generators could be added to the existing reservoirs, increasing the power capacity and thus, reducing the operation time of the hydropower plants without building any additional reservoir. The operation time or energy generation time will depend on highest and lowest water value regulations.

This paper [20] underlines the significant role that Norwegian pumped hydro can play for providing peak generation. The result show that installing new reversible pumping across existing hydro reservoirs for providing peaking power would be more advantageous over new open cycle gas turbines and combined cycle gas turbines, considering additional subsea costs and reinforcements inland.

This review [21] suggests that not enough modelling has been done in terms of wind and solar energy variability. It states that it could be convenient to improve it. It also adds that it is hard to set the real need of balancing or storage in the Power System, therefore, it is hard to predict how the Norwegian power system will develop.

It could be interesting to run simulations with PowerGAMA in high resolution (hourly for instance), increasing the share of PV and wind; and to see what trend follow the power flows and cost of energy. It would be of interest then, to increase the Norwegian hydro power generation capacity in the system and to look on how the cost of energy and power flows change and which is the use of the interconnections.

This review [22] some components and characteristics that future North Sea grid would need to have. It also mentions the challenges of protection. It also refers to, for instance, offshore storage systems. It states that subsea CAES could be already price competitive with hydro storage today, according to a study; and it adds that a Canadian company has already run a prototype outside Toronto. It could be appealing to see the strength that these storage technologies have for balancing, how they could affect the investment costs and the operational cost savings.

1.3.3. CONCLUSIONS

The conclusions could be classified in two different groups: generation (wind, hydro and PV generation technologies) and demand (active demand).

To start with, the conclusions and findings related to generation are the most linked with this Master Thesis. Nevertheless, a wider search has been done for having a clearer idea of the topic and to find some other potential projects for the future.

By this research activity, it could be seen that different sensitivity analysis have been already done for studying the impact that a higher amount of integrated wind energy could produce in the power system, and thus, how the needed grid design would change.

Nevertheless, a gap is found in terms of the deepness of the mentioned studies. The gap would be that a wider range of integrated wind generation capacities should be simulated in the power system, i.e., more scenarios should be analysed.

Most of the studies focus on ENTSO-E's greenest scenario, but there are considerable uncertainties for the future. An analysis for a wider range of wind generation technology integrated in the power system could be interesting, that is, a sensitivity analysis of different wind generation integration levels, and thus, increase the samples of the study.

Secondly, different analysis are done which analyse the strength of Norwegian hydropower plants as balancing providers and thus, as RES integration facilitators. The gap would be the lack of consideration of different future scenarios, i.e. different RES integration levels.

It comes from the fact that Norway has around half of the hydro energy storage capacity of the whole EU. Nevertheless, for the future, some partners do not foresee to build new reservoirs, due to the fact that the PV technology has and will reduce considerably the electricity price during the day, smoothing the prices. Therefore, it is not expected a business case for the installation of new hydro generation technology reservoirs.

The same price reduction would happen if a higher presence of wind generation would be in the Power System, for instance, due to offshore wind generation. Moreover, PV and wind are complimentary, and thus a combination of both technologies would reduce the prices, and make them smoother. Therefore, even if technically would be feasible to install more hydropower generation capacities, it could be found that it would not be of interest from an economic point of view.

Thirdly, based on this literature survey, there is a gap in terms of including the PV, hydropower and wind generation uncertainties in the analysis. As it can be seen, the analysis usually focus on one generation technology's uncertainty, but a combination of them is not very used. They are in fact related, due to the needed flexibility in the Power System.

Consequently, this gap could be fulfilled in this Master Thesis by considering all the uncertainties involving these technologies, such as wind, solar or hydropower. As it is mentioned in the introduction of this report, ENTSO-E frames the uncertainty that these energy sources are related to. Therefore, ENTSO-E scenarios could be used as a reference. Hence, each

implemented scenario in this Master Thesis refers to an ENTSO-E Vision together with some other assumptions.

It is to mention that ENTSO-E assumes an increase in the Norwegian hydropower generation capacity values, in the TYDNP of 2016, which is considerable; up to 17 GW for Vision 4, for instance. This increase is highly related to the fact of seeing Norwegian hydropower generation plants as a balancing providers and RES integration facilitators.

Nevertheless, if other sources are taken into account, such as [6] from Statnett, they do not take into account this high increase in Norwegian hydropower generation capacities, since the prices are low in the existing electricity market and they would be even smoother in the future, they just increase in 2.5GW the existing generation capacities for future scenario analysis, as stated before.

Therefore, it is not clear if the investment for having higher hydropower generation capacities would be economically beneficial. Consequently, in this Master Thesis the hydropower generation units in Norway are kept as they are currently, i.e., the most conservative analysis in this sense is implemented.

1.4. RESEARCH QUESTIONS

The next research question is created for this Master Thesis: **How to find robust solution for grid investment decisions in the North Sea area incorporating European energy scenarios for 2030?**

By the European energy scenarios, the uncertainty related to the future energy prospects is wanted to be addressed.

The previous research question is the core of this Master Thesis. Nevertheless, the mentioned analysis requires the implementation of reliable data as well, such us hydropower generation units' storage or production decision implementation. Therefore, another research question is designed which is: **How to develop and validate an approximate model of a Nordic, UK and Irish power system w.r.t. actual data of 2014, which could be used to study the effects of cross-border trades?**

The objective is to create a model which is validated and thus, it is reliable. Then, some parts of these data-set could be implemented in the future scenario analysis of 2030, as well; and their accuracy would be already validated. Some examples would be, hydropower reservoir's filling and seasonal profiles.

1.5. RESEARCH APPROACH

This Master Thesis is divided in three steps which are related to the research questions. The first step is about the first one which is:

1) How to develop and validate an approximate model of a Nordic, UK and Irish power system w.r.t. actual data of 2014, which could be used to study the effects of cross-border trades?

The second and third steps are related to the second research question which is:

2) How to find robust solution for grid investment decisions in the North Sea area incorporating European energy scenarios for 2030?

- The first stage of this project is to create a model which is able to replicate approximately the real behaviour of the grid by using PowerGAMA. In this way, part of the created data-set could be used in the future scenario analysis, in step 3, e.g. hydropower storage filling and time profiles. A short description of this first step is shown in figure 1.
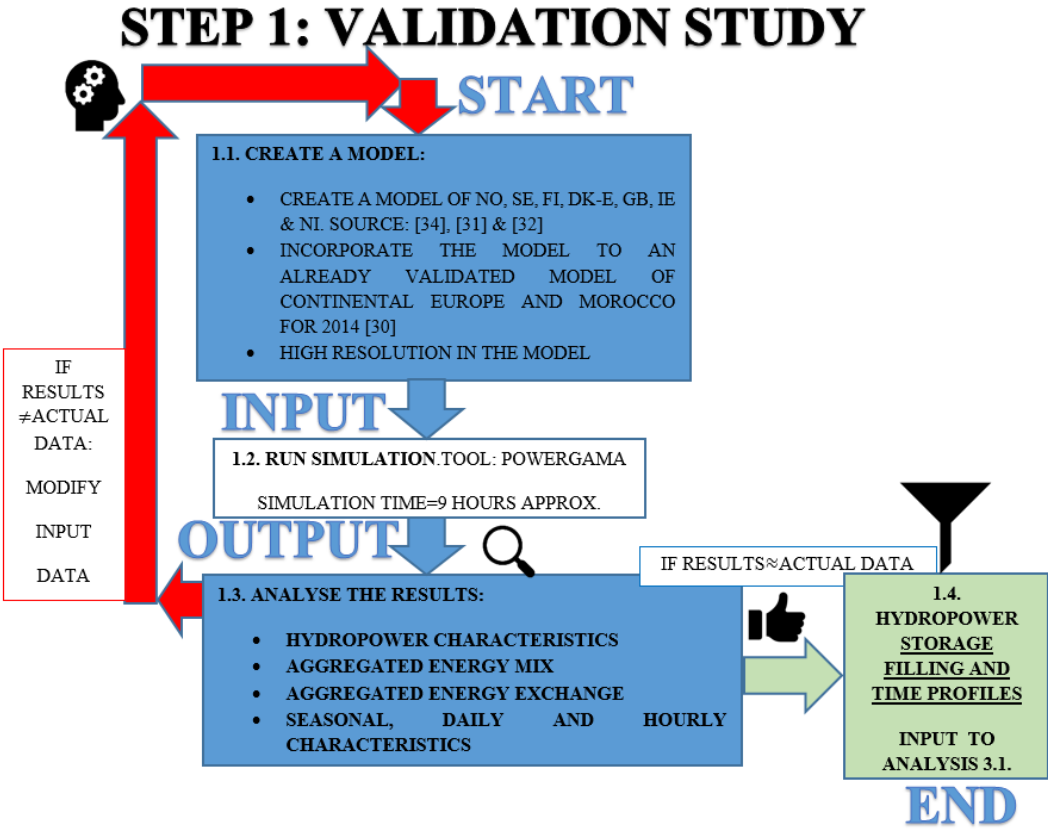
Figure 1. Flow chart of the first step of this Master Thesis.

- The second step of the Master Thesis is to obtain the socio-economically beneficial grid layout for the North Sea for each implemented scenario by using PowerGIM and by considering all possible grid layouts. Each scenario refers to an ENTSO-E Vision from TYNDP of 2016 with some additional assumptions.

Nevertheless, since different approximations could be done in the process, such as, setting the Dogger Bank hub cost, setting the maximum capacity per branch that PowerGIM could choose or setting the maximum amount of parallel lines per branch that PowerGIM could choose; different sensitivity analysis are also implemented so as to see, how these assumptions could affect the obtained results. A short description of the second step of this Master Thesis is given in figure 2.

START

2.0. SENSITIVITY ANALYSIS OF DIFFERENT POSSIBLE ASSUMPTIONS:

- SENSITIVITY ANALYSIS 1: DOGGER BANK HUB COST
- SENSITIVITY ANALYSIS 2: MAXIMUM CAPACITY PER BRANCH
- SENSITIVITY ANALYSIS 3: MAXIMUM AMOUNT OF PARALLEL LINES PER BRANCH

FOR EACH SENSITIVITY ANALYSIS

STEP 2. GETTING OFFSHORE GRID LAYOUTS

2.1. CREATE A MODEL:

- AGGREGATED REPRESENTATION (TIME OF SIMULATION AND ONSHORE POWER SYSTEM) OF NO, GB, BE, NL, DE AND DK.
- SOURCE=ENTSO-E VISIONS (TYNDP 2016) [53] EXCEPT NORWEGIAN HYDRO (= CURRENT VALUES)

INPUT

INPUT MODEL. ONE PER EACH SCENARIO (4 SCENARIOS OF GENERATION AND DEMAND IN TOTAL) AND PER SENSITIVITY ANALYSIS (3 TYPES OF SENSITIVITY ANALYSIS IN TOTAL)

2.2. RUN OPTIMISATION.TOOL: POWERGIM

SIMULATION TIME=10 MINUTES APPROX.

OUTPUT

OUTPUT=GRID LAYOUTS. ONE PER SCENARIO AND PER SENSITIVITY ANALYSIS

2.3. ANALYSE THE RESULTS.

RESULTS= (GRID LAYOUT, INVESTMENT COST AND OPERATIONAL COSTS)

AFTER 3 SENSITIVITY ANALYSIS ARE DONE FOR 4 SCENARIOS

2.4. CHOOSE ASSUMPTIONS AND EACH GRID LAYOUT PER EACH SCENARIO (IMPLEMENTED GENERATION AND DEMAND SCENARIOS, 4 IN TOTAL)

RESULT = 5 OFFSHORE GRID LAYOUTS, INCLUDING INVESTMENT COSTS AND OPERATIONAL COSTS PER LAYOUT.

- 4 GRID LAYOUTS CHOSEN FROM THE OUTPUT OF POWERGIM
- 1 GRID LAYOUT CREATED BY THE AUTHOR OF THIS MASTER THESIS AS REFERENCE GRID LAYOUT

2.5. 5 OFFSHORE GRID LAYOUTS INSERTED AS INPUT IN STEP 3. (ANALYSIS 3.1.)

END

Figure 2. Flow chart of the second step of this Master Thesis.

- The last objective is to analyse the robustness that each grid layout obtained in the previous step 2 have w.r.t. future development uncertainty, i.e. to analyse if each obtained grid layout would be still beneficial for different scenarios, e.g. different generation, demand, load profiles etc. This step is summarised in the next figure 3.

STEP 3:

STUDYING

THE

ROBUSTNESS

OF EACH

GRID

LAYOUT

START

FOR EACH GRID LAYOUT (5 IN TOTAL), CREATE 4 GENERATION-DEMAND MODELS (4 SCENARIOS)

3.1. CREATE A MODEL:

- COLLECT DATA FROM STEP 1 (1.4.) AND STEP 2 (2.5.)
- CREATE GENERATION AND DEMAND MODEL OF NO, DK, DE, NL, BE AND GB (TYNDP 2016, HYDROPOWER IN NO EXCEPTION (=31GW)) [53]. CREATE ONSHORE GRID MODEL BY USING [30], [52],[53], [32] & [46]
- NO AGGREGATION. HIGH RESOLUTION IN TIME AND LOCATION OF NODES.

INPUT

3.2. RUN OPTIMIZATION. TOOL: POWERGAMA

SIMULATION TIME = 7 HOURS APPROX.

OUTPUT

3.3. ANALYSE THE RESULTS.

RESULTS=OPERATIONAL COSTS

AFTER ALL THE SCENARIOS (4) ARE IMPLEMENTED FOR EACH GRID LAYOUT (5)

3.4. CALCULATE:

- THE OPERATIONAL COST SAVING OF EACH IMPLEMENTED SCENARIO w.r.t. REFERENCE GRID LAYOUT'S OPERATIONAL COSTS FOR THE SAME SCENARIO
- THE INVESTMENT COST INCREASE OF EACH IMPLEMENTED GRID LAYOUT w.r.t. REFERENCE GRID LAYOUTS INVESTMENT COSTS.

3.5. CALCULATE:

$$ROI = \frac{OPERATIONAL\ COST\ SAVING - INVESTMENT\ COST\ INCREASE}{INVESTMENT\ COST\ INCREASE}$$

FOR EACH GRID LAYOUT (4) WITH EACH SCENARIO (4)

3.6. CHOOSE THE OFFSHORE GRID LAYOUT WITH THE HIGHEST AVERAGE ROI

END

Figure 3. Flow chart of the third step of this Master Thesis.

1.6. OUTLINE OF THIS MASTER THESIS REPORT

The outline of this Master Thesis report follows the next points:

- 1. Introduction. This is already analysed. It shows the scope, objectives, rationale and approach of this Master Thesis.
- 2. Performed work. This part of the report follows the same structure as the research approach explained in 1.4. Nevertheless, there are two additional chapters which explain the theory behind the used tools in this Master Thesis, and these chapters aim to give a short description of how the modelling is done, how the calculations are done and which results are analysed.
  - o 2.1. Modelling and theory behind PowerGAMA.
  - o 2.2. Validation study of a model in PowerGAMA.
  - o 2.3. Modelling and theory behind PowerGIM.
  - o 2.4. Getting socio-economically beneficial offshore grid-layouts in PowerGIM.
  - o 2.5. Studying the robustness of each grid layout w.r.t. future energy scenarios uncertainty.

For these chapters from 2.1. to 2.5. the implemented data-set and results are given inside each chapter's analysis. In addition, a bit of discussion regarding the results is also included together with the results. The flow chart of this chapter 2 of the report is given in figure 4, in the next page.
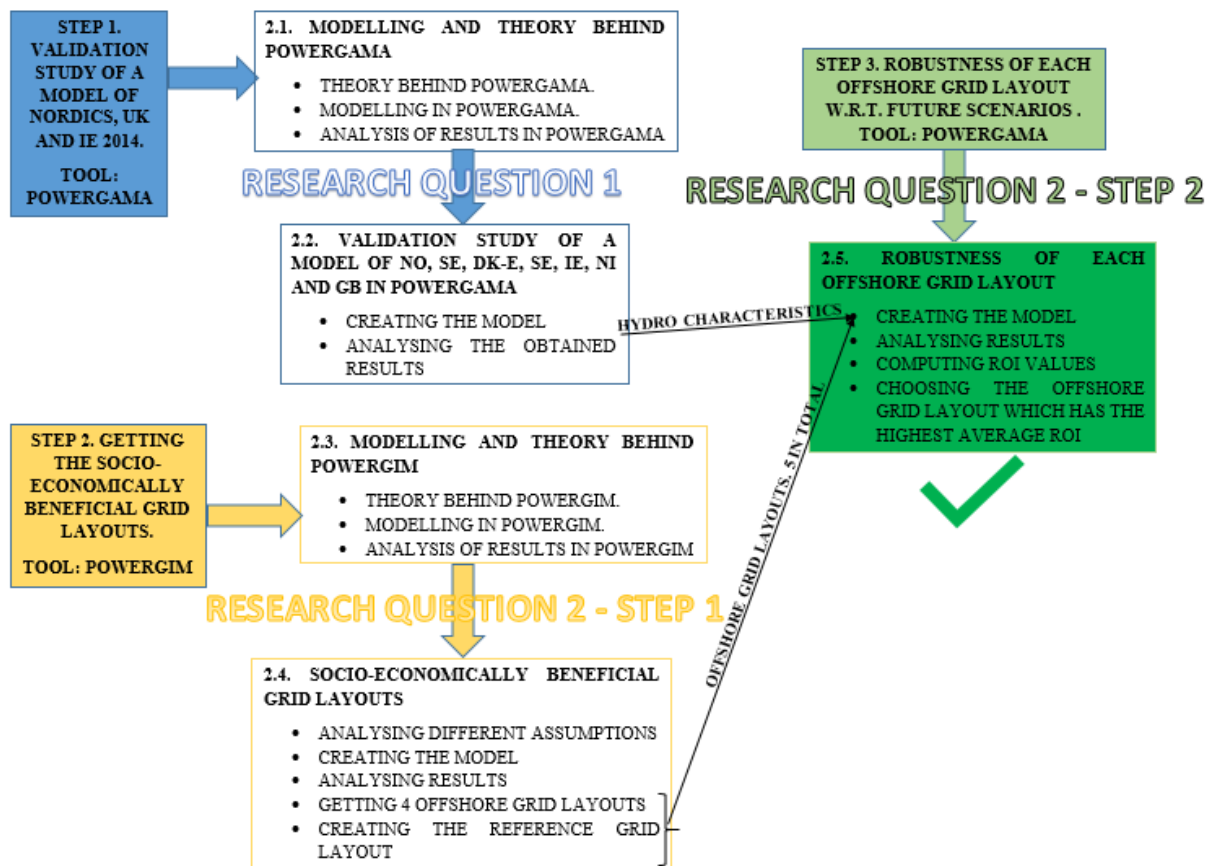
Figure 4. Layout of point 2 (Performed Work) of this Master Thesis Report.

- 3. Conclusions. In this chapter, the conclusions regarding the research questions and the obtained results are given. At the same time, contributions of this Master Thesis and suggestions for further work are stated.

Two python files, which belong to chapter 2.2. and chapter 2.4., are appended at the end of this report. The last appendix is a paper. This is about the Validation Study of a model which can replicate approximately the real behaviour of the Power System by using PowerGAMA. This belongs to research question 1 of this Master Thesis.

1.7. CONTRIBUTIONS OF THIS MASTER THESIS

The first contribution of this Master Thesis is related to its first milestone. It is a model which is able to replicate approximately the real behaviour of the power system of the year 2014. The data-set consists of Ireland, Great Britain and Nordic regional groups. In addition, the interaction of this model with an already validated model which represents Continental Europe and Morocco is also properly implemented and validated.

For mentioning the second contribution of this Master Thesis, it is important to mention as a recap some concepts in short. It is to mention that water values are the economic value of the stored water in the reservoir. By the water values, the decision of the reservoirs to store or discharge water is represented in the power flow studies done for areas with a high share of hydropower generation capacity; for instance, for the Norwegian Power System's analysis.

Water values are commonly obtained by the Multi Area Power Market Simulator (EMPS). This tool has two stages, a strategy part and a simulation part. In the strategy part, the water values are computed on an aggregate local sub areas and on the simulation part, the simulation of the detailed dispatch is done. It can be done for up to 10 years ahead and the time step is of one week.

As mentioned, the water values obtained by the EMPS are commonly used in the power flow studies. Nevertheless, in this Master Thesis, a new way is found to build the water values, i.e. the water values used in this analysis are not fully taken from EMPS, these take partly EMPS values as reference though.

This input data is proven to be able to replicate the reservoirs' filling and seasonal behaviour in the validation study. In short, this Master Thesis founds a partly independent necessary input-data to reproduce reservoirs' discharge and storage decision and it gives proper results.

In the second stage, one of the contribution is related to input data. It is a data-set which follows the ENTSO-E TYNDP 2016 and the exception of the Norwegian hydropower generation capacities, which are kept as their current value of 31 GW. One of the highlights of this data-set is the offshore wind farms' data-set. Aggregated offshore wind farms are created in this Master Thesis which follow the main real trend and which are not too simplified.

Another interesting contribution is to analyse different assumptions that can be done in this second stage of the Master Thesis, which is the acquiring of the socio-economically beneficial grid layout analysis. Different costs assumptions for the Dogger Bank hub, different branches' maximum capacity or maximum parallel lines can be assumed. The contribution is that all these different assumptions are implemented, and the effect that these different assumptions could cause in the conclusive results is studied.

The main contribution of this Master Thesis is to prove that the offshore grid layout which is based on the Dogger Bank hub option is the socio-economically beneficial solution for all implemented scenarios.

The last contribution is to choose the socio-economically beneficial grid design which is at the same time, the most robust w.r.t. RES development uncertainty. As mentioned before, the chosen layout is grid 2 and its characteristics are mentioned above, in the conclusions related to research questions.

2. PERFORMED WORK

2.1. MODELLING AND THEORY BEHIND POWERGAMA

2.1.1. INTRODUCTION

The objective of this chapter is to provide a brief description of the main functionalities of the tool used in this Master Thesis which is called PowerGAMA.

The tool is developed by SINTEF. The author of this report has written this short chapter based on her understanding acquired throughout her Master Thesis and based on [29]- [30].

As mentioned before, the main objective of this Master Thesis is to find different socio economically beneficial investment decisions, i.e. interconnections, for each implemented scenario. After this, the aim is to find the most robust grid layout w.r.t. future energy development uncertainty. Therefore, each implemented scenario refers to one ENTSO-E Vision for the year 2030 with some additional simplifications.

PowerGAMA provides the researcher the ability to analyse the mentioned features, e.g. operational costs, bottlenecks or energy mix. Besides, it has an integrated package which is called PowerGIM (it is explained in chapter 2.3). As it will be shown later, it gives the researcher the competence to find the socio-economically beneficial grid investment layout for the implemented scenario, i.e. optimal interconnections. Consequently, PowerGAMA and PowerGIM are suitable tools for this Master Thesis.

Regarding PowerGAMA, the main functionalities used in this Master Thesis are:

- Generated energy per year for the implemented countries
- Demanded energy per year for the implemented countries
- Power flows per time step (1 hour) and per year for the implemented branches
- Average power exchange between countries per year
- Energy exchange between countries per time step (1 hour)
- Nodal prices calculation per year for all the nodes
- Generated energy per year for some generators
- Demanded energy per year for some loads
- Nodal prices calculation per time step (1 hour) for some nodes
- Generated energy per time step (1 hour) for some generators
- Demanded energy per time step (1 hour) for some loads
- Area prices per time step (1 hour) and per year in the implemented areas
- Storage filling levels per area, per time step (1 hour) and per year for the implemented areas.
- Energy Mix calculation per year for the implemented countries
- Operational costs per country

Most of the analysis above are done for the Nordic, Great Britain, Ireland and North of Continental Europe regional groups. This is better specified in chapters 2.2. and 2.5.

In the next sub-charts of this report a theoretical description of PowerGAMA is given.

2.1.2. MAIN FEATURES OF POWERGAMA

PowerGAMA is an open-source python package and it is developed by SINTEF Energy Research. It is a grid and market analysis tool and it is similar to Power System Simulation Tool (PSST), also developed by SINTEF Energy Research. Per each time step, it minimises the operational costs. For that, it takes into account the grid constraints and the marginal costs of the available generation units. The available generation units with the lowest marginal costs are favoured and the grid limitations are also considered, per each time step decision.

This Direct Current (DC) power flow steady-state based tool can also work with a time step of one hour. This characteristic gives the opportunity to consider hourly dependent features in researchers' studies. Some examples could be wind, hydro or solar inflow profiles or also, load profiles. The mentioned traits are of a significant importance for Renewable Energy Sources (RES) integration analysis or for active demand analysis, for instance. The application could be done in future scenarios' studies, as well.

Another strength of this tool is the ability to consider storage. The problem is solved sequentially and thus, the optimisation takes into account previous step's resulting situation. Solar generation units' storage or hydropower generation units' reservoirs are just some examples of technologies which can be implemented in PowerGAMA. Nevertheless, other storage units, such as compressed air storage units, could be implemented too.

This tool makes use of some simplifications and approximations in order to reduce the computational time and also, to make the input data arrangement easier. It does not take into account the limited ramp-rates, start-up costs or unit commitments, for example. This leads to some overestimation regarding the system's capacity to include RES, i.e. as a result obtaining higher RES energy mix in a country.

In addition, PowerGAMA uses a simplified method for water values calculation, i.e. the economic value in €/MWh of the stored water in the reservoir. In contrast of Multi Are Power Market Simulator (EMPS), which uses a three-dimension variable and implements the exact value; PowerGAMA uses two independent profiles (storage filling level and storage time profiles). This is deeper explained below and also, in chapter 2.2. These simplifications lead to some deviation from actual data, and it is not straight forward to replicate the real behaviour of the hydropower system, i.e. storage filling patterns or nodal prices; especially in countries where the hydropower share is high, such as in Norway.

The system is taken as stable. At the same time, PowerGAMA focuses in nodal pricing and a perfect market is assumed.

2.1.3. OPTIMISATION FORMULATION

Linear Programming (LP) is used for Optimal Power Flow (OPF) optimisation. The Sets, Indices and Parameters used are presented below:

Sets:

G : Set of generators

S : Set of pumps

N : Set of nodes

K : Set of AC and DC branches

Indices:

g : Generator

s : Pump

n, j : Node

k : Branch

Parameters:

C_g^{gen}: Cost of generator g [€/MWh]

C_s^{pump}: Cost of pump s [€/MWh]

C^{shed} : Fixed cost of load shedding [€/MWh]

P_k^{max}: Maximum branch capacity of branch k [MW]

P_g^{min}: Minimum production of generator g [MW]

P_g^{limit}: Limit power of generator g ; available power [MW]

$P_s^{pump,max}$: Maximum pump capacity of pump s [MW]

$G_{n,j}$: Conductance between nodes n and j. [S]

$B_{n,j}$: Susceptance between nodes n and j. [S]

$Y_{n,j}$: Admittance between nodes n and j. [S]

$R_{n,j}$: Resistance between nodes n and j. [Ohm]

$X_{n,j}$: Reactance between nodes n and j. [Ohm]

$G_{n,n}$: Sum of all conductance connected to node n. [S]

$B_{n,n}$: Sum of all susceptance connected to node n. [S]

Variables:

p_g^{gen}: Generation by generator g [MW]

p_s^{pump}: Pump power demand of pump s [MW]

p_n^{shed}: Load shedding, node n [MW]

p_n^{cons}: Consumption at node n [MW]

δ_n: Voltage angle, node n [°]

δ_j: Voltage angle, node j [°]

$p_k^{ac/dc}$: Power flow, AC/DC branch k [MW]

p_n: Active power injection at node n [MW]

q_n: Reactive power injection at node n [MVAr]

V_n: Voltage magnitude at node n [V]

V_j: Voltage magnitude at node j [V]

The objective function is the minimisation of the operational costs per each time step. This can be seen in equation 1. The marginal costs are in €/MWh and the power values are in MWh. n refers to the node.

$$min\ F = min\ Operational\ costs = min(\textstyle\sum_n^N Marginal\ Cost_n \times Powervalues_n)\ (1)$$

In equation 2, a more extended representation of equation 1 can be found. All the costs shown (C) are set in €/MWh and all the power values (p) are set in MW. These power output are taken for the duration of the time step.

$$min\left(\textstyle\sum_{g\in G} C_g^{gen}\ p_g^{gen} - \sum_{s\in S} C_s^{pump}\ p_s^{pump} + \sum_{n\in N} C^{shed} p_n^{shed}\right)\ (2)$$

The implemented constraints can be classified in two groups: constraints limiting the variables and constraints related to power flows.

2.1.3.1. CONSTRAINTS LIMITING THE VARIABLES
The mentioned limitations can be found below, in equations (3) - (5).

$$-P_k^{max} \le p_k \le P_k^{max}\ ,\ k \in K\ (3)$$

This branch limitation (3) sets the maximum and minimum power values that the branch can carry. It is to mention the negative maximum value. This reflects the flexibility the grid should have for representing both possible flow directions, i.e. from A to B and from B to A. The power values (p) and (P) are set in MW.

$$P_g^{min} \le p_g^{gen} \le P_g^{limit}\ ,\ g \in G\ (4)$$

This generator's constraint (4) sets the maximum and minimum generation values of each generation unit. The power values (p) and (P) are set in MW.

$$0 \le p_s^{pump} \le P_s^{pump,max},\ s \in S\ (5)$$

Equation 4-5 are similar. The difference is the technology each of them are referring to. In case of pumps the minimum possible power is zero. The power values (p) and (P) are set in MW.

2.1.3.2. CONSTRAINTS LIMITING THE POWER FLOWS
Before showing the resulting constraint, it is of interest to explain some theory to show how the final restriction is obtained.

As a recap, in equations 6-7, AC power flow's mathematical expressions can be found:

$$p_n = V_n \textstyle\sum_{j=1}^{N} V_j\left(G_{n,j}\cos(\delta_n - \delta_j) + B_{n,j}\sin(\delta_n - \delta_j)\right)\quad (6)$$

$$q_n = V_n \textstyle\sum_{j=1}^{N} V_j\left(G_{n,j}\sin(\delta_n - \delta_j) - B_{n,j}\cos(\delta_n - \delta_j)\right)\quad (7)$$

Equation (6) and (7) are in per unit system. This means that each variable or parameter is normalised w.r.t. its corresponding base value. The exception are the voltage angles(δ_n , δ_j), which are given in degrees.

By making use of Linear Programming the AC power flow equations (6) - (7) are converted into linear power flow equations often known as DC power flow equations (9). As it is better explained below, equation (7) is neglected in DC power flow analysis.

PowerGAMA works in steady-state and the next assumptions are done:

- Voltages are close to the rated values.

  Thus, in per unit (voltage values w.r.t. the base value): $V_n \approx V_j \approx 1$.

- The voltage angle differences between the nodes are small. The following voltage angles are given in degrees.

$$\sin(\delta_n - \delta_j) \approx (\delta_n - \delta_j)$$
$$\cos(\delta_n - \delta_j) \approx 1$$

- Branch reactance is considerably higher than the resistance. Self-admittance can be ignored, since shunt reactance are small. The following resistance ($R_{n,j}$) and reactance ($X_{n,j}$) are given in per unit, each variable or parameter is normalised w.r.t. its corresponding base value.

$$X_{n,j} \gg R_{n,j}$$

As recap, the complex admittance (**Y**) which consists of real part conductance (**G**) and imaginary part susceptance (**B**) is represented in the next way (8). The mentioned parameters are given in per unit, each variable or parameter is normalised w.r.t. its corresponding base value.

$$Y_{n,j} = G_{n,j} + jB_{n,j} \approx jB_{n,j} = \frac{1}{jX_{n,j}} \text{ (8)}$$

Consequently, reactive power is not taken into account and the next linearized power flow constraint (9) is used. The power values (p) are given in MW, voltage angles (δ_n, δ_j) are given in degrees and the susceptances ($B_{n,j}$) are given in siemens.

$$p_n = \sum_{j=1}^{N} B_{n,j}(\delta_n - \delta_j) \text{ (9)}$$

Power injection at each node is given by (10). The power values (p) are given in MW.

$$p_n = \sum_{g \in Gn} p_g^{gen} - \sum_{s \in Sn} p_s^{pump} - p_n^{cons} + p_n^{shed} + \sum_{k \in K_n^{dc}} p_k^{dc} \text{ (10)}$$

2.1.4. WORKING PROCESS

The next figure 5 summarises the workflow that PowerGAMA follows.
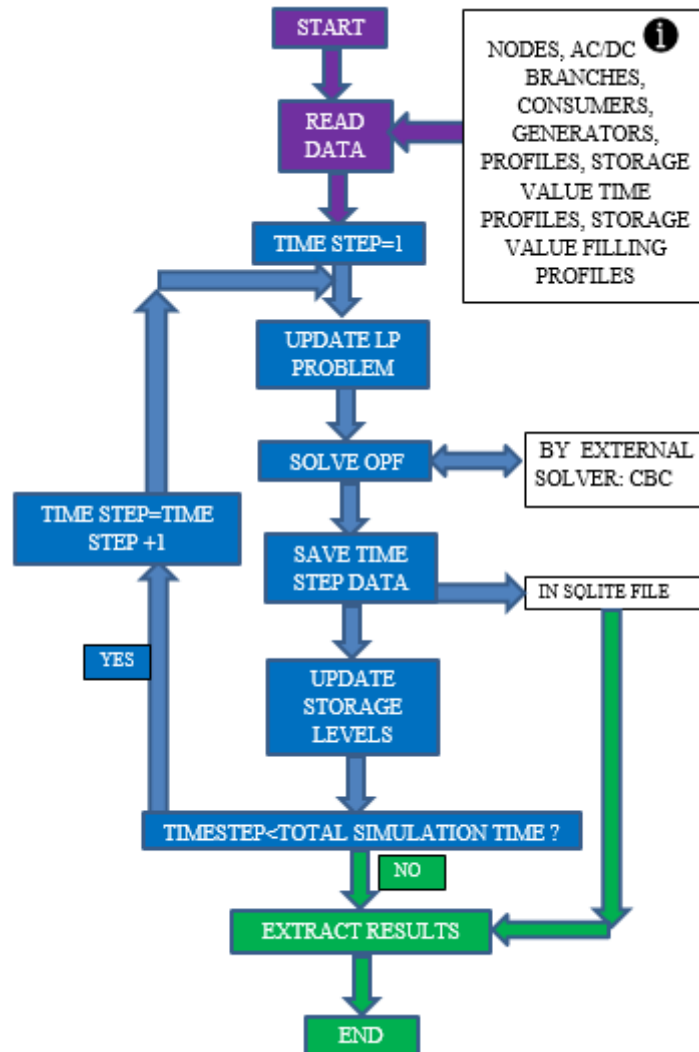
Figure 5. PowerGAMA working process.

ⓘ These input data are explained in 1.5. subsection of this chapter 2.1.

All this figure's working process is implemented in one script, which is the main directory of PowerGAMA. It is named "run_simulation.py" and it is appended at the end of this report. The user does not need to use other scripts unless a deeper understanding of the software wants to be acquired.

In short, PowerGAMA calls the next scripts from the main directory depending on the stage in the process it is. All python files or needed material for using PowerGAMA can be freely downloaded in [29].

- Purple colour in the figure 5. This refers to the starting preparation of the Optimal Power Flow (OPF) analysis, data gathering and initial values settings.
    - o Constants.py: Setting constants such as base values.

- o GridData.py: Saves all input data.
- Blue colour in the figure 5. This step refers to the OPF calculations.
  - o LPproblem.py: Run OPF.
  - o Database.py: Save data obtained in the OPF of the iteration.
- Green colour in the figure 5. It refers to the analysis of results.
  - o Results.py: All possible plots or output data gathering that the user can make use of is stated in this script.
  - o GIS.py: It serves for making graphs in Google Earth.

In short, the main working directory for the user is just "run_simulation.py" where all the functionalities stated above, also shown in the figure 5, are implemented. In case the user wants to analyse different results than the ones already prepared and stated at the end of the "run_simulation.py" file, the researcher needs to add some code by taking a look into the "Results.py" and by calling the output data which is needed to be analysed following "Results.py" file's naming.

This is the case of the author of this report, and thus, some few lines are added at the end of the "run_simulation.py" for getting some additional output data.

2.1.5. INSERTING THE INPUT DATA

The objective of this part of the report is to give an introduction of the input data which can be used in PowerGAMA. This part aims to be theoretical. Nevertheless, in chapter 2.2. more visual information is given.

This report is explained so that the user could make use of the "run_simulation.py" file as the main directory. It is appended at the end of this report.

Therefore, the "run_simulation.py" document is added in python. This is the main working file for the user. At the same time, the input data is inserted in eight different CSV files. These excel files are inserted in a folder which is called "data_h" and it is located in the same location as the main "run_simulation.py" file in the computer.

2.1.5.1. NODES

All branches, generators and consumers belong to a specific node. The mentioned node is defined in the "nodes.csv" file and there, its name, latitude, longitude and its country are specified. The next table I summarises the mentioned characteristics. Nevertheless, the real names used in PowerGAMA are written in bold and between parenthesis.

Table I. Nodes. Input data.

nodes.csv			
Name (**id**)	Area (**area**)	Latitude (**lat**) [°]	Longitude (**lon**) [°]

This input data is useful for creating maps. They will be shown in chapter 2.2. Latitude and longitude are inserted in degrees. Note that it is important to be consistent, and when the nodes

are called for instance in tables II, III, IV and V, these names should match with the names mentioned in table I.

2.1.5.2. AC BRANCHES

In the "branches.csv" file the AC branches are specified. For that, the next characteristics mentioned in table II are used.

Table II. AC Branches. Input data.

branches.csv			
node_from	node_to	reactance [ohm]	capacity [MW]

2.1.5.3. DC BRANCHES

The DC branches are implemented in the "hvdc.csv" file, where the next specifications shown in table III are inserted:

Table III. DC Branches. Input data.

hvdc.csv		
node_from	node_to	capacity [MW]

2.1.5.4. CONSUMERS

The singularities which can be implemented in the case of consumers in PowerGAMA are presented in table IV. There is also an opportunity to implement flexible demand in PowerGAMA. Since it is not used in this Master Thesis, it is not explained. More information about flexible demand's implementation could be found in [29].

Table IV. Consumers. Input data.

consumers.csv		
node	demand_avg [MW]	demand_ref [p.u] (Hourly demand w.r.t. average demand)[*]

[*] It is a string, a time profile. (Length=simulation time)

The node column shows which node the consumer belongs to. The "demand_avg" is a fixed value; it is constant through the whole simulation. It is the average demand value of the corresponding node for the simulated time.

The "demand_ref" is a time profile characteristic and it has an average value of one. Therefore, for each time step the average demand value is taken and it is multiplied by the corresponding profile's value in the corresponding time step. This time profile is defined in the "profiles.csv" file. It will be explained later. Therefore, the name set in the "demand_ref" column should match with the column name set in the "profiles.csv" file.

2.1.5.5. GENERATORS

The input data of the generators also embrace different characteristics; they can be seen in table V. The data is shown using rows instead of columns in contrast to the real "generators.csv" file.

Table V. Generators. Input data.

Generators.csv	desc (**Description**)
	type
	node
	pmax [MW]
	pmin [MW]
	fuelcost [€/MWh]
	inflow_fac [p.u] (total actual generation w.r.t. the ideal full time generation)
	inflow_ref [p.u] (hourly inflow value w.r.t. average inflow value)[*]
	storage_cap [MWh]
	storage_price [€/MWh]
	storage_ini [p.u] (Initial storage filling level w.r.t. 100% of filling level)
	storval_filling [p.u] (Reservoirs' storage filling price w.r.t. 50% of filling price)[**]
	storval_time [p.u] (Reservoirs' hourly filling level w.r.t. 50% of filling level)[*]
	pump_cap [MW]
	pump_efficiency [p.u] (Actual pump's efficiency w.r.t. 100% of efficiency)
	pump_deadband [€/MWh]

[*] It is a string, a time profile. (Length=simulation time)

[**] It is a string, a filling profile. (0%-100%)

"Desc" means description and information about the generator unit is added in this column. This is usually the place to set the name of the generation unit. "Type" means the generation technology type, for instance, gas, wind or hydro. "Node" sets the node which the generation unit belongs to.

"Pmax" is the maximum generation capacity of the generation unit and "pmin" is the minimum generation capacity of the generation unit. "Fuelcost" is the generation cost; it is the marginal cost (€/MWh) of the generation unit. There are two ways to set the "Inflow_factor" and the "Inflow_ref". For each option both characteristics should be consistent.

In the first case, the inflow factor is the availability factor. It is the ratio between the actual generation and the ideal generation in case the energy source would be producing during the total simulated time. In this case the inflow factor would have a maximum value of one. Then, the "inflow_ref" value is set in the "profiles.csv" file, which will be explained later, and it is a time dependent inflow profile. The "inflow_ref" represents for example, wind, solar or water inflow for the wind, solar and hydropower generators. So, when the inflow factor has a maximum value of one, the "inflow_ref" profile will have an average value of one.

The reason is that PowerGAMA calculates the available power of each generator (i) in each iteration (t) by the next equation (11). $Pmax_i$ is given in MW, the $Inflow\_factor_i$ is given in p.u. (total actual generation w.r.t. the ideal full time generation) and the $inflow\_profile_i^t$ is

given in p.u. (hourly inflow value w.r.t. average inflow value), it is a string, a time profile, (length=simulation time). The resulting $pavailable_i^t$ is given in MW.

$$pavailable_i^t = \text{Pmax}_i \times \text{Inflow\_factor}_i \times inflow\_profile_i^t \ (11)$$

The multiplication of the "inflow_factor" and the "inflow_profile" should be between zero and one, since the available power should not exceed the maximum generation capacity and neither should go below the minimum generation capacity. At the same time, it is shown that if the total simulated time is considered and if the inflow profile has an average value of one; for the total simulation, the average available power for the generation unit will be equal to the inflow factor multiplied by the maximum generation capacity; i.e. the availability factor multiplied by the maximum generation capacity.

The second option is to set the "inflow_factor" as one, and to set the inflow profile with an average value equal to the "inflow_factor". The same result would be obtained at the end, using the first or the second option. Note that for the conventional generators such as nuclear or gas the inflow profile is set as one, constant all the time. The time dependency is used mainly for RES.

The "storage_cap", "storage_price", "storage_ini", "storval_filling" and "storval_time" are only used when the generation unit has storage, such as some solar or hydropower generation units. The "storage_cap" gives the amount of storage capacity that the generation plant has in MWh.

The "Storval_filling" and the "Storval_time" columns call the "profiles_storval_filling.csv" and "profiles_storval_time.csv" files, and there, the corresponding profile's value is taken per each step. The "storval_filling" profile shows the dependency that the generation plant has w.r.t the filling level of the reservoir. It is a profile which goes from 0% filling level to 100%. The "storval_time" profile shows the dependency the generation unit's storage has w.r.t. to the time of the year, for example, a daily dependency in case of solar generation technologies or a seasonal dependency in case of hydropower generation plants. This is shown in chapter 2.2.

The mentioned dependency is reflected in an economic way. In case there is no grid constrain the available generation will be the output of the generator (starting with the cheapest generation unit) for the generators which do not have storage. Nevertheless, in case the generator unit has storage, then, the decision between storing or generating energy will depend on the comparison between the nodal price and the storage price. The storage price (€/MWh) for each generation unit (g) with storage per each time step (t) and the corresponding filling level (f) is calculated in the next way, (12). The parameter Storage_price$_g$ is given in €/MWh, $storval\_filling_g^{f(t)}$ is given in p.u., it is the reservoirs' storage filling price w.r.t. 50% of filling price, it is a string, a filling profile (0-100%) and the $storval\_time_g^t$ in p.u., it is the reservoirs' hourly filling level w.r.t. 50% of filling level, it is a string, a time profile (length=simulation time).

$$storage\ price_g^{t,f} = \text{Storage\_price}_g \times storval\_filling_g^{f(t)} \times storval\_time_g^t \ (12)$$

In case the storage price is higher than the nodal price, the generation unit will add water in the reservoir and it will not produce electricity. In the opposite case, when the nodal price is higher than the storage price, the generation unit will produce electricity. With this method, PowerGAMA is able to capture the opportunity cost that for instance, hydropower generation plants have. These characteristics are better shown in chapter 2.2.

"Pump_cap" show the pumping capacity of the generation unit and the "pump_efficiency" show the efficiency of just the pumping process of the mentioned generation plant. The "pump_deadband" is set in order to help the model represented the right pumping behaviour by not allowing the pump to change continuously between generating and pumping.

2.1.5.6.PROFILES

The "profiles.csv" can have as much columns as needed by the user. In each column in the first row, the identification name of each profile is set, for instance in the example of table VI below, seven different profiles are defined.

In this example, solar_ES, wind_DK, o_wind_DE and hydro_NO are inflow profiles. As stated above, all of them are normalised w.r.t. the average inflow values. The inflow profile starting with the "solar" term, means solar irradiance per year per time step of one hour for Spain (ES) in this example. The inflow profiles starting with the "wind" and "o_wind" term, mean available wind per year per time step of one hour for Denmark (DK) and Germany (DE). The inflow profile starting with the "hydro" term, means water inflow per year per time step of one hour for Norway (NO) in this example. Therefore, these names are called from the "generators.csv" file.

Load_GB and load_NL are load profiles for Great Britain and Netherlands, these are also normalised w.r.t. the average load demand value. They represent the time variation of the demand per time step of one hour, in one year; and thus, they are called from the "consumers.csv" file.

Then, when PowerGAMA arrives to the "profiles.csv" it founds the name in the first row, by looking into all the columns, this is shown in table VI. Once the profile is found, the length of the profile should have at least enough data for the whole simulation time. For instance, if the simulated time is one year with a time step of one hour, then, each column presented in table VI will have 8760 rows of data below each name. More visual examples are given in chapter 2.2.

Table VI. Profiles. Example of input data.

profiles.csv						
const	solar_ES	wind_DK	o_wind_DE	hydro_NO	load_GB	load_NL

2.1.5.7.PROFILES_STORVAL_FILLING

The "profiles_storval_filling.csv" is the same as the "profiles.csv" file. The difference is that in this case only the profiles related to the filling pattern of the storages are defined. Therefore,

the length of the columns or in other words, the amount of data for each profile is independent to the simulated time.

The first row after the name of the profile is the value of the filling profile when the storage is completely empty (0% of filling level) and the last row of the profile gives the value of the profile when the storage is completely full (100% of filling level). For example, 100 rows after the name would mean to have data between 0% and %100 filling level with a filling level step of 1%.

2.1.5.8.PROFILES_STORVAL_TIME

The "profiles_storval_time.csv" is also similar to the "profiles.csv" file. The length of the profiles' data should at least match with the simulated time and the needed time step for that. The difference is that for this case the profiles related to the time dependency of the storages are defined. For example, the "profiles_storval_time.csv" for the solar generation unit's storage will have a daily pattern. Overall, during the day the storage will be being filled and in the evening it will be being emptied.

In the case of the "profiles_storval_time.csv" for the hydropower generation plants, the profiles will have a seasonal pattern, and thus, a monthly pattern. It will depend on the countries' characteristics when will be the filling and the emptying periods. This is explained in chapter 2.2. with examples.

2.1.6. ANALYSING THE RESULTS

This section wants to give theoretical information of possible analysis which could be done in PowerGAMA. Nevertheless, a clearer picture is given in chapter 2.2.

The results that PowerGAMA can display are in the "Results.py" [29]. The user can get the wanted results by calling them from the main run file. Some additional script is added in the main run file in order to get some other findings. They can be found at the end of the appended "run_simulation.py" file.

In the "Results.py" file which can be seen in [29], the rows which start with a "def" are the ones which need to be called from the main file. When the "def" is followed by a "get" then, the program will give numbers as output, whereas when the "def" is followed by a "plot" then, the program will give graphs as output.

For example, in row 805 of the "Results.py" the "def getStorageFillingInAreas(…)" is very interesting for getting the storages' filling values throughout the whole simulated time. It is of interest for instance in countries which have considerable storage values, such as Norway's reservoirs.

Another useful function could be found in the row 1747 of the "Results.py" the "def plotEnergyMix(…)". This gives a bar chart as result which shows the total generated capacity for the simulated period of the chosen area (or country) and the bar has different colour levels where different generation technologies' generated amount of energy is shown for the total simulated time. The mentioned figures and more are shown in chapter 2.2.

2.1.7. CONCLUSIONS REGARDING THE SUITABILITY OF THE TOOL

The software is already a ready to use tool. The user needs to focus in the main script, or working directory which is the "Run_simulation.py". For this Master Thesis as well, this main script is used.

Nevertheless, since not all the output data which are wanted to analyse are stated in the "Run_simulation.py" file, some small coding is inserted in this main file for getting the wanted results. For that, the "Results.py" file is analysed to get an idea of the possible analysis that can do the user.

This accessibility to the "Results.py" file is very handy for the researchers, since it gives more freedom to the user to choose the results which want to be analysed. All the mentioned output data analysis is already prepared in the "Results.py" file and thus, the user just need to call them from the main file, "Run_simulation.py".

One of the main volume of the working in this Master Thesis is the understanding of this optimisation tool, since it was unknown for the author of this Master Thesis report. The implementation of the input data also takes time, since a considerable amount of countries are implemented. It is explained in chapter 2.2 and 2.5. At the same time, an important amount of time is expended in the input-data updates, in the Validation study also explained in chapter 2.2., to make the resulting data close to real data.

In this sense, the implementation of the generation units with storage are not easy to replicate, especially in hydropower generation units with reservoirs. For solving this issue, some simplifications and approximations are done, which are stated in chapter 2.2., by using actual data from reliable sources, such as, Nordpool.

PowerGAMA is also updating while doing this Master Thesis and thus, the author of this report has tried to be in close contact with its developer to avoid inconsistencies.

2.2. VALIDATION STUDY OF A MODEL IN POWERGAMA

2.2.1. INTRODUCTION

The objective of this chapter is to show the process followed in this part of the Master Thesis, which is the validation study of a model of Nordics, UK and Ireland regional groups for the year 2014 w.r.t. ENTSO-E statistics 2014 by using PowerGAMA.

A paper is written about this Validation Study for being published, such as, in the 16th Wind Integration Workshop in Berlin. Therefore, some of the points mentioned in this chapter are repeated in the paper. The paper is attached as appendix.

The aim of this chapter is to show that the created model representing Continental Europe, Nordic Region, Ireland and UK is able to replicate approximately the real behaviour of the power system in 2014 by using PowerGAMA.

For that, the created model together with the assumptions done in this validation study are explained. After that, the main results are presented and their meaning is evaluated. At the end of the total report, conclusions and suggestions for further work are given.

The results show that the model has the ability to represent the main characteristics of the stable power system, i.e. hydropower characteristics, energy mix, power flows, generation and demand.

At the same time, this unit of this Master Thesis report is taken as opportunity to give some examples of PowerGAMA's aspects, regarding input data and results, and thus, to clarify some points explained previously in chapter 2.1.

This validation study is done taking as reference ENTSO-E 2014 statistics.

2.2.2. WORKING PROCESS

The key activity of this validation part is the deep understanding of PowerGAMA; apart from other tasks, such as the suitable data gathering. The reason of this statement is that for each simulation, the results are analysed. Then, the analysed results are compared with actual data taken from ENTSO-E statistics of 2014.

When the resulting data from the simulations differ from the actual data, the input data is adjusted. Each adjustment can bring next simulation's results closer to the actual data or farther from the actual data. This process is repeated until satisfying results are obtained, i.e. approximately close results to actual data are obtained.

Therefore, it is very important to understand each component's function in the model. The next chart, figure 6, summarises the working process more visually, which is the same as figure 1 shown previously.
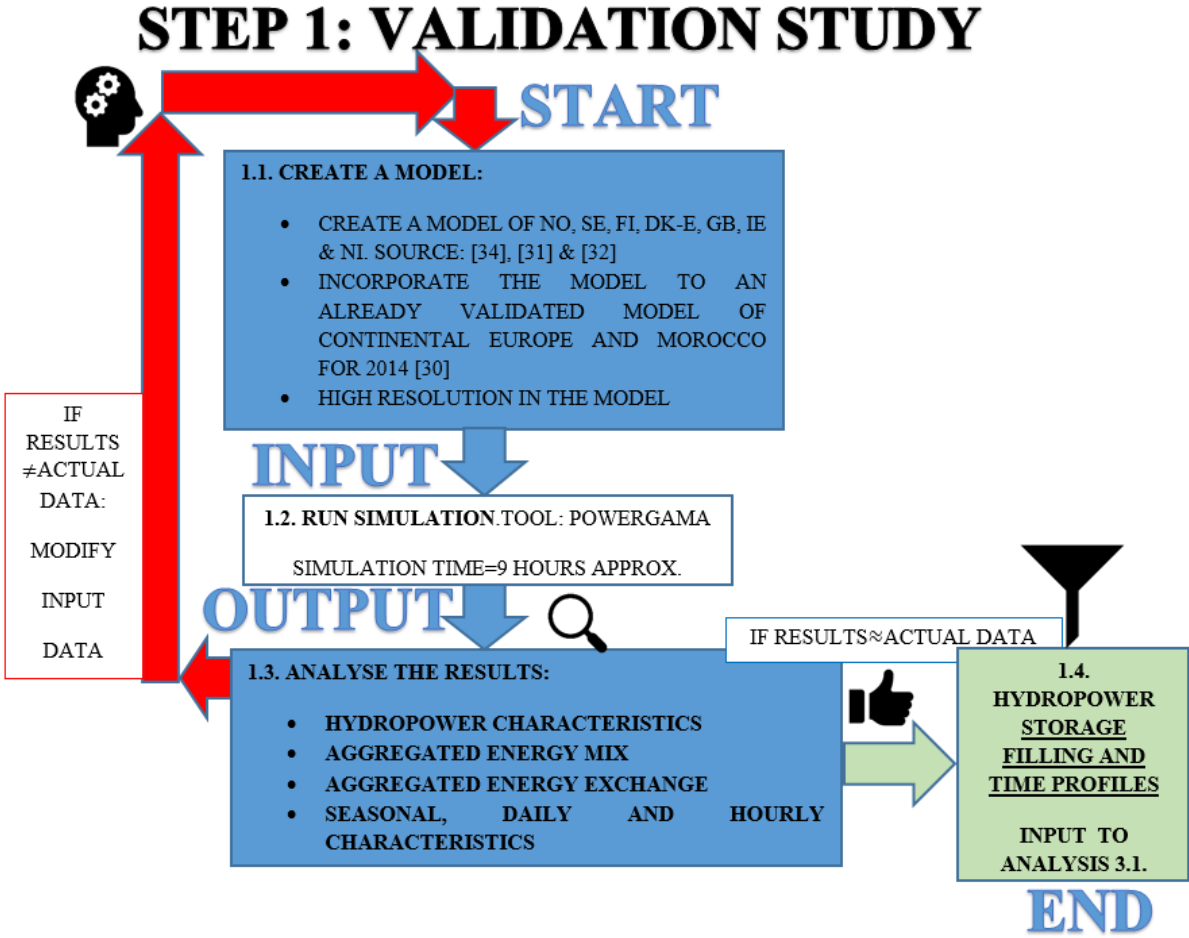
Figure 6. Flow chart of the first step of this Master Thesis.

As it is shown in the "Modify input data", in the red box in Figure 6; in that step, some of the inserted variables are updated so as to help the model replicate the real behaviour of the power system.

The next table VII summarises some variables and parameters which are updated for bringing the results closer to actual data. In addition, it mentions the resulting improvement obtained by

each modification. It is to remark that different variables and areas are fully related to each other in most of the cases and consequently, the modification of several variables at a time is required, sometimes.

Table VII. Implemented updates and the obtained improvements by each modification.

By updating…	Improvement obtained at…
Storage initial value	Hydropower storage filling pattern
Storage reference price	Hydropower storage filling pattern
Marginal costs, generators	Exchange between countries
Inflow factors	Energy mix
Grid limitations	Exchange between countries

All these are better explained in the coming subchapters. Nevertheless, depending on the situation, such as, the country's characteristics; the expected improvement could not be obtained by the mentioned updates, but this table gives a general idea which is applicable in most of the cases.

The condition to finish with this Validation analysis is to obtain approximate results w.r.t. actual data. Certain deviation or error is expected, since approximations and simplifications are done in this analysis compare to actual data, which add certain error to the results. These are explained below.

2.2.3. INSERTING THE INPUT DATA

The data-set could involve a wide range of participants and an endless number of variables to make the model as perfect as possible. Nevertheless, this would be out of the scope of the real objective of this analysis, since it would take an extra time and effort and anyway, it may not be possible to gather all information due to confidentiality issues, for instance. Therefore, the objective is to create an approximate model using publicly available data.

Information is gathered and updated as accurately as possible to 2014 from different open sources. This data is then added to the already validated data-set of 2014 [30]. As mentioned, the final complete data-set is obtained for continental EU [30] and Morocco [30], the Nordic, UK and Ireland regional groups. Therefore, the contribution of the author of this Master Thesis comes mainly by the creation of the model of Nordic Countries, UK and Ireland and the interaction between the already validated part [30] and the newly added part of the system.

Different iterations and adjustments of parameters or variables are done in the input data to make the results be as closest as possible from the actual ENTSO-E 2014 data. Especially, the combination between hydropower storage filling and time profiles is difficult to replicate. Besides, they are key variables due to hydropower's large share in the energy mix of the Nordic countries. The data which give the most approximate results are presented below.

2.2.3.1. SIZE OF THE INPUT DATA

The size of the input data is given in the next table VIII. In fact, each row of this table refers to the CSV files presented in chapter 2.1.

Table VIII. Size of the input data.

	Number of physical units	Defined Parameters/Variables
Nodes	3370	4
Branches	5244	4
Branches DC	14	3
Generators	2811	16
Consumers	2946	9
Profiles	165	(8760 hours, steps of 1 hour)
Storage Time Profiles	8	(8760 hours, steps of 1 hour)
Storage Filling Profiles	6	(100, steps of 1 percent)

The implemented countries can be presented in five different regional groups by following ENTSO-E's regional group division. The next table IX names them.

Table IX. Implemented countries.

Regional Groups	Countries	Source
Continental Europe	Austria, Belgium, Bosnia-Herzegovina, Bulgaria, Czech Republic, Croatia, Denmark (West), France, FYROM, Germany, Greece, Hungary, Italy, Luxemburg, Montenegro, Nederland, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain and Switzerland.	[a]Taken from [30]
Not defined	Morocco[a], Russia[+] and Albania[a]	[a]Taken from [30] [+]Taken from [31]
Nordic	Denmark (East), Finland, Norway and Sweden	Taken from [31]
UK	Great Britain	Taken from [32]
Ireland	Ireland and Great Britain	Taken from [32]

[a]: This is already validated. It is done in [30], and it is a validation study for Continental EU and Morocco.

The next figure 7 taken by Google Earth gives a more visual taste of the size of the implemented system.
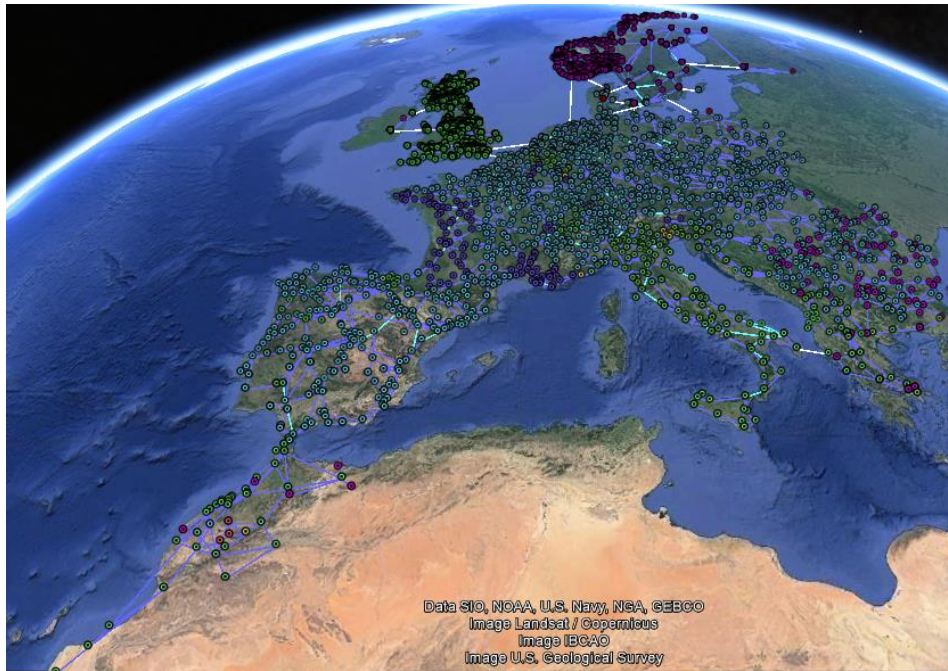
Figure 7. Map of the implemented system in this validation study.

The size of the input data increases considerably the computational time, ending up with around nine hours of simulations in a personal computer.

2.2.3.2. INPUT DATA

The main approximations and assumptions followed in this analysis are also stated in the attached paper, which is about this Validation Study. Nevertheless, some additional information can be found in the next pages of this chapter.

2.2.3.2.1. AREAS AND DATA ARRANGEMENT

Each of the countries make an area of the analysis in this Validation study. Nevertheless, Sweden and Norway are exceptions. For this Validation analysis, Sweden is divided into four areas which are called SE1, SE2, SE3 and SE4. Regarding Norway, it is divided into five parts which are NO1, NO2, NO3, NO4 and NO5.

The implemented area distribution in Norway and Sweden is shown by the next map in figure 8. It is taken from Nordpool, since the implemented area distribution in Norway and Sweden is equal to the bidding area distribution used by Nordpool, i.e. the so-called bidding areas. The implemented area distribution is the one inside the yellow box.
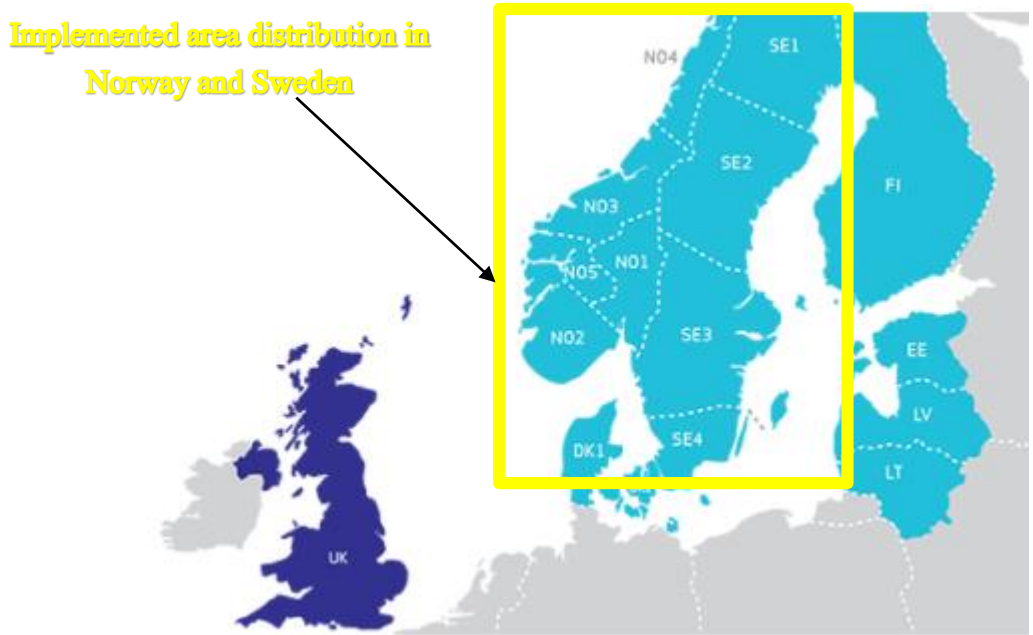
Figure 8. Implemented area distribution in Norway and Sweden.

As it will be explained later, this division is used for implementing different demand and inflow profile patterns and for implementing grid constraints, as well. In short, Sweden and Norway have a higher resolution in terms of input data compared to other countries, where the focus level is per country instead of per country's area.

It is to remark that in Twenties project, even a higher resolution is used. For example, Sweden is divided in six areas, Finland in two areas and Norway in eleven areas. Therefore, from the input data in [31] the next area aggregation is done for this analysis, it is shown in the next table X.

Table X. Implemented area distribution vs. Twenties' area distribution.

Implemented area in this Validation study	In Twenties
NO1	NO_1, NO_3
NO2	NO_2, NO_4, NO_5, NO_6
NO3	NO_8
NO4	NO_9, NO_10, NO_11
NO5	NO_7
SE1	SE_1, SE_2
SE2	SE_3, SE_4
SE3	SE_5
SE4	SE_6

2.2.3.2.2. BRANCHES AND NODES

The branches and nodes are taken from [31] and [32], and they are added in the model of 2014 [30]. At the same time, interconnections between Finland and Sweden, North Wales and Ireland and Scotland and Northern Ireland are added by consulting [33].

36

The internal branches in the UK, Finland and Denmark are set to infinity whereas for Norway and Sweden, they are kept as in [31]. In case of Denmark, grid constrains are added in the north for a better representation of the power flow between Norway-Denmark and Sweden-Denmark.

2.2.3.2.3. DEMAND

Average demands per node are taken from [31] and [32] and they are scaled up to 2014 by [39]. Also, data from [44] is considered for Norway and Sweden.

For obtaining the demand profiles, data from [44] and [39] are taken for the Nordics. In this way, the load profiles resolution is increased since a different load profile is inserted per bidding area in Sweden and Norway. Data are obtained from [39] for Great Britain, Northern Ireland and Ireland. These profiles are normalised w.r.t. the average demand value and thus, they are scaled to have an average value of 1, as mentioned earlier in chapter 2.1. The same is done with the inflow profiles, it is explained below.

2.2.3.2.4. GENERATORS

The data setting for the generators is more complicated, since they embrace more parameters and variables as shown in chapter 2.1. The generation capacities are taken from [31] and [32], and they are scaled to implement the values of [34].

2.2.3.2.4.1. WIND

Additional wind is added to the model by [42]. The location is done approximately and thus, this leads to some congestion problems resulting in high nodal prices in the south of UK, this is shown in figure 9. For avoiding the issue, the transmission capacities are increased to infinity in the mentioned area and more realistic results are obtained.
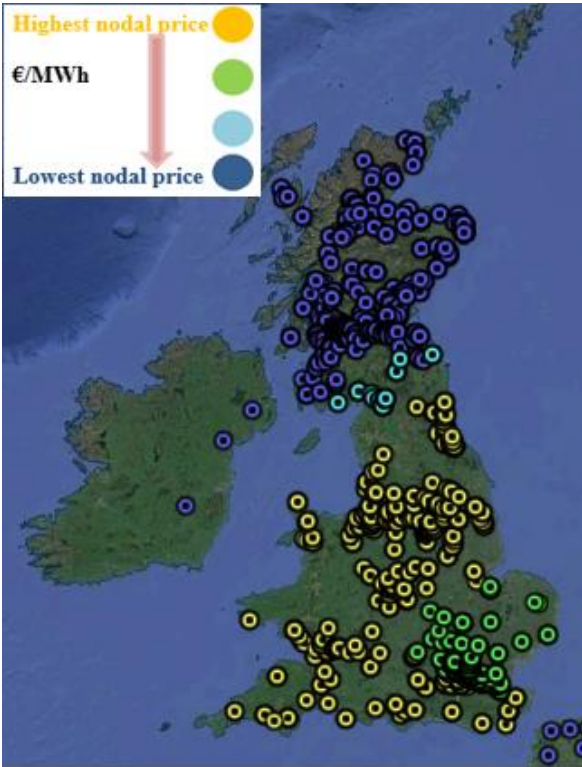
Figure 9. Nodal prices in the UK and Ireland regional groups plotted in Google Earth.

The jump in the price between different countries was too high, around 100 €/MWh, which made the figure to have same price colours in Scotland, France and Ireland. This was giving wrong results in the UK regional area, such as load shedding problems, and a proper picture is captured by setting the UK's internal grid constraints to infinity.

Another solution might be to update the wind generation location properly, but especially, the upgrade would be to update the internal grid constrains in the UK region properly by looking into actual grid data.

2.2.3.2.4.2. RUN OF THE RIVER GENERATION TECHNOLOGY

In [34], hydropower generation is presented as a whole combination between hydro and run of the river generation technology. Nevertheless, part of this total generation capacity comes from the run of the river generation units. So as to implement this, different sources are consulted.

In [31], 33892 MW for hydro and an additional 33892 MW for run of the river in Norway is used, i.e. the run of the river generation units' installed capacity is taken as the same as the hydropower generation plants' in the same node. This implementation in PowerGAMA leads to an overproduction of run of the river technology in Norway. The same applies to Sweden and Finland too.

Therefore, in order to reduce this deviation or error, proper generation capacities are set regarding run of the river generation plants in the mentioned countries.

In Norway, based on [36] the next values are implemented, which are stated in table XI.

Table XI. Implemented hydropower and run of the river generation, generation capacities.

NORWAY	
Installed hydro generation capacity	31080 MW [34]
Hydro	(31080-1521) = 29562MW
Run of the river	1521 MW [36]

No additional changes from the twenties project are applied in hydropower and run of the river generation technologies in Norway. Just a scaling factor of 0.91 for the hydro generation technology.

Then, the nodes with a lower generation capacity than 17 MW are chosen as run of the river generation plants. Apart from that, an additional generation plant of 170 MW is added to the run of the river generation plant. This generation plant (the corresponding node in the TradeWind dataset) has approximately the same longitude and latitude as the station of Akershus and the generation capacity is somehow similar, therefore, it is chosen to represent the run of the river plant of Akershus.

Another possibility would be to go in detail and to check all the run of the river generation plants and their corresponding location in detail. This is out of the scope of this Master Thesis. Therefore, the implemented generation capacities are the same as in XI. Table.

Going into more details, in the next table XII, the share of the implemented hydropower and run of the river generation capacities per bidding areas can be seen.

Table XII. Implemented hydro and run of the river generation capacities in Norway, 2.

NORWAY bidding areas	Hydro [MW]	Run of the river [MW]	Total [MW] = Hydro + Run of the river	Share [%] of each bidding area w.r.t. to Total
NO1	10723.42	454 (29.89%)	11177	35.96%
NO2	9285.49	328 (21.59%)	9613.5	30.93%
NO3	2672.04	228 (15.01%)	2900	9.33%
NO4	4356.90	291 (19.16%)	4647.9	14.95%
NO5	2524.15	218 (14.35%)	2742.2	8.82%

According to [47] the biggest amount of run of the river generation technology is in the east part of Norway and Trondelag and the highest amount of run of the river generation capacity is in fact obtained for the areas stated, the NO1 and a part of NO3.

In Sweden, based on [36] and [34] the next values are implemented, they can be found in the next table XIII. Likewise, it is done in Norway, in this case the hydro generation plants which are below 23 MW are taken as run of the river generation technology.

Table XIII. Implemented hydro and run of the river generation capacities in Sweden.

SWEDEN	
Installed hydro generation capacity	16155 MW
Hydro	(16155-1079) = 15076MW
Run of the river	1079 MW

Based on [36] and [37] the next hydropower and run of the river generation values are implemented in Finland, table XIV.

Table XIV. Implemented hydro and run of the river generation capacities in Finland.

FINLAND	
Installed hydro generation capacity	3234 MW
Hydro	570 MW
Run of the river	(3234-570=) 2664 MW

Therefore, in total, in Norway, Sweden and Finland 1519 MW, 1079 MW and 302 MW are taken as total run of the river generation capacities respectively, from the hydropower generation capacities stated in [34].

2.2.3.2.4.3. MARGINAL COSTS

In [30], the marginal costs of wind, solar, run of the river and hydroelectric generators show the cost of operation and maintenance, and these technologies are set to 0.5 €/MWh. At the same

time, the marginal cost of other renewables, such us biofuel and waste incineration, is set to 50€/MWh and the price of load shedding is taken as 1000€/MWh.

The same pattern is followed for the newly added countries and overall, the marginal costs are taken as uniform, i.e. same marginal costs are implemented for all the countries per generation technology. This is done because the analysis of the marginal costs of each thermal generation technology per node or country is beyond the scope of this project. The next table XV summarises the chosen values for thermal generation technologies.

Table XV. Technology of generation and marginal costs.

Type of generation unit	Marginal costs (€/MWh)
Oil	162
Bio	50
Mixed Fuels	168.32
Gas	70
Coal	60
Nuclear	11

In table XV, a new generation technology called "Mixed Fuels" is added which is not mentioned in [30]. This is decided following [34].

The values from table XV, i.e. the marginal costs, are increased or decreased in some countries for helping the model replicating the cross-border power flows between countries.

2.2.3.2.4.4. INFLOW FACTORS

The inflow factors for renewable energy sources are calculated by taking the data of capacity and energy generation in 2014 from [34]. For offshore wind energy, the inflow factor is taken as 0.4. The theory regarding the meaning of inflow factors is explained in chapter 2.1 of this Master Thesis report.

Regarding the inflow factor for conventional generation, it is assumed the same for all the countries and they can be found in table XVI. Nevertheless, the inflow factors per country for nuclear power are set to the annual average availability in 2014 taken from [35].

Table XVI. Inflow factors per generation unit.

Type of generation unit	Inflow Factors
Oil	1
Bio	0.75
Mixed Fuels	0.9
Gas	0.8
Coal	0.8

As mentioned before, different updates are done in the input data to help the model replicate the real behaviour of the power system. One of the updates, is the update of the marginal costs, as stated before. Another option are the inflow factors. In some countries, the inflow factors of

some generation technologies are increased or decreased for getting the energy mix which is close to the values stated by ENTSO-E [34].

2.2.3.2.4.5. PROFILES

For calculating the inflow profiles for wind and water, data from [41] are used. There, exact inflow profiles for each wind energy generation farm are given. Taking these data into account, the average profiles are calculated for each country's wind energy generation technology by making use of the weighted average method. This is done to have a clearer perspective and a broader margin for tuning the parameters.

Note that the profiles given in [41] have a maximum value of 1, and in [30] the profiles and inflow factors used are designed to have an average value of 1. Therefore, after the mentioned calculations (weighted average profiles), the values obtained from [41] are scaled to have an average value of 1 and to follow the same pattern as the inflow factors likewise it is done in [30].

Nevertheless, for following the real inflow factors of the run of the river generation technology, for this case, the inflow factor is set as one. The inflow profile of the run of the river generation technology has a maximum value of one and the average value of the inflow profiles gives the real inflow factor. This theory has been already deeper explained in chapter 2.1. of this Master Thesis report.

Some of the implemented profiles are shown in the next pages of this chapter.

2.2.3.2.4.5.1. LOAD TIME PROFILES

As it is mentioned in chapter 2.1., one of the PowerGAMA's strength is the ability to account for time variations, such as, hourly load variations. This is used in the validation study and as example, the next figure 10 shows the load profiles implemented in the validation study.
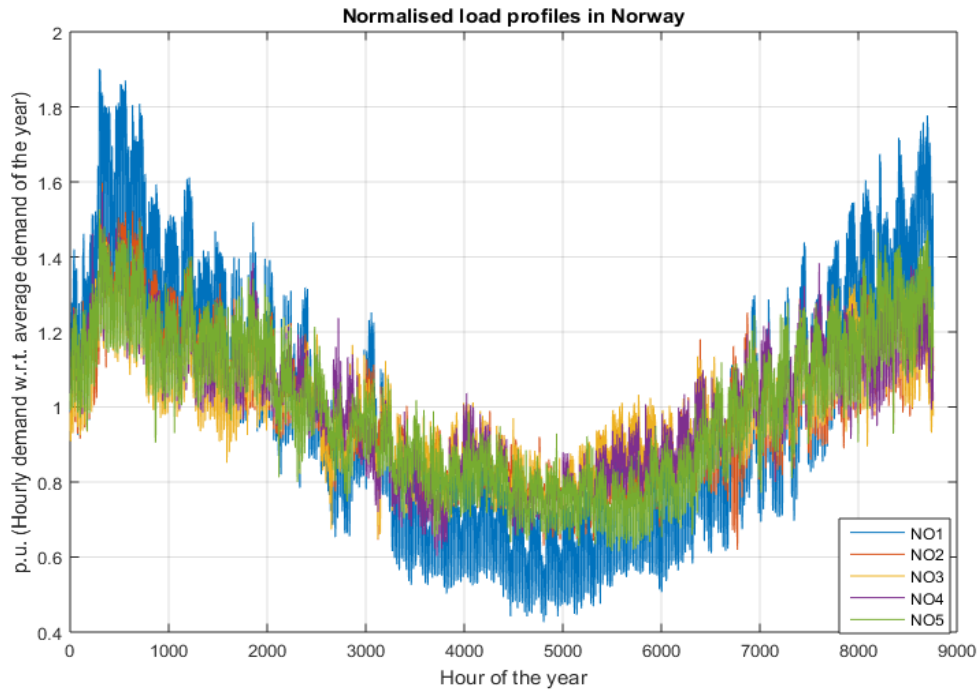
Figure 10. Implemented normalised load profiles in Norway.

Figure 10 shows the implemented profile for representing the load's time variation during the year. As explained in chapter 2.1., the load profile is normalised so as to have an average value of one. This is because the mentioned profile is multiplied with the average load demand value of the year per node in each time step.

In Figure 10, the seasonal variation of the load is represented. In winter, the load reaches higher values than in summer, where the lowest demand values can be seen.

Likewise, the profiles also have a weekly pattern, which has a higher consumption during the week days (from Monday to Friday), and a lower demand during weekends, especially on Sundays. This is shown in figure 11, and it is obtained after zoomed in figure 10.
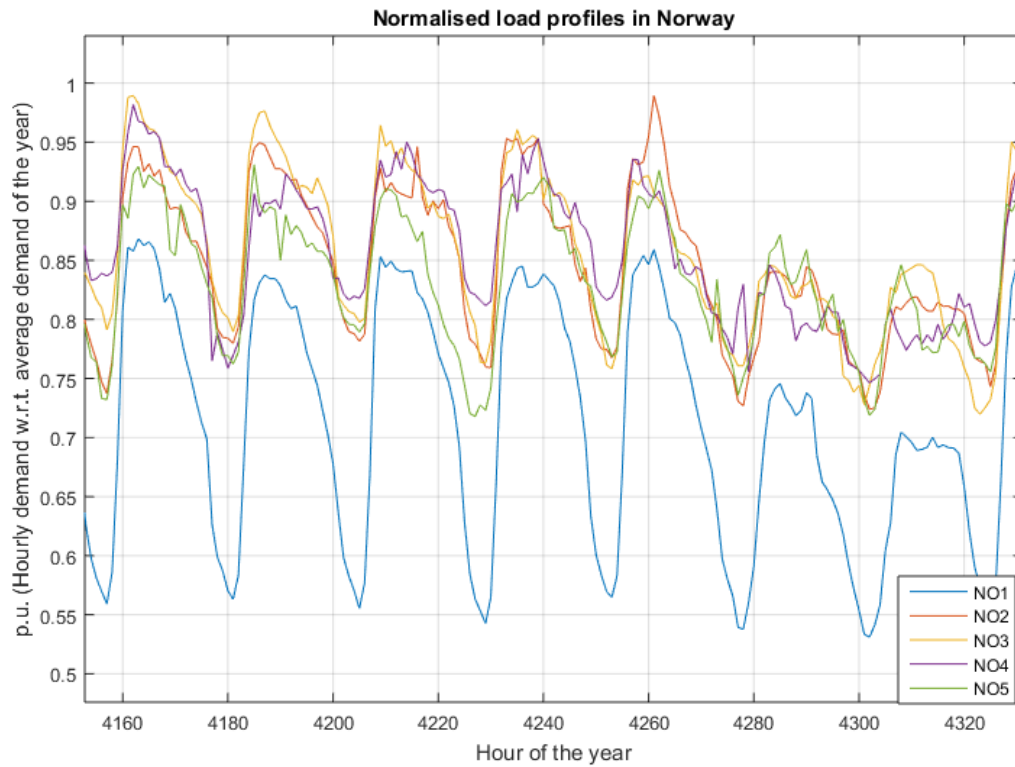
Figure 11. Implemented normalised load profiles in Norway, weekly pattern.

At the same time, the load profiles follow a daily variation, with low consumption values during the night, since low industrial or housing activity is followed; and the opposite is represented during the day. The implemented pattern is shown in figure 12. It is obtained after zoomed in figure 11 more. It shows the load's time variation in NO1-NO5 areas of Norway in a period of 24 hours around end of May 2014.
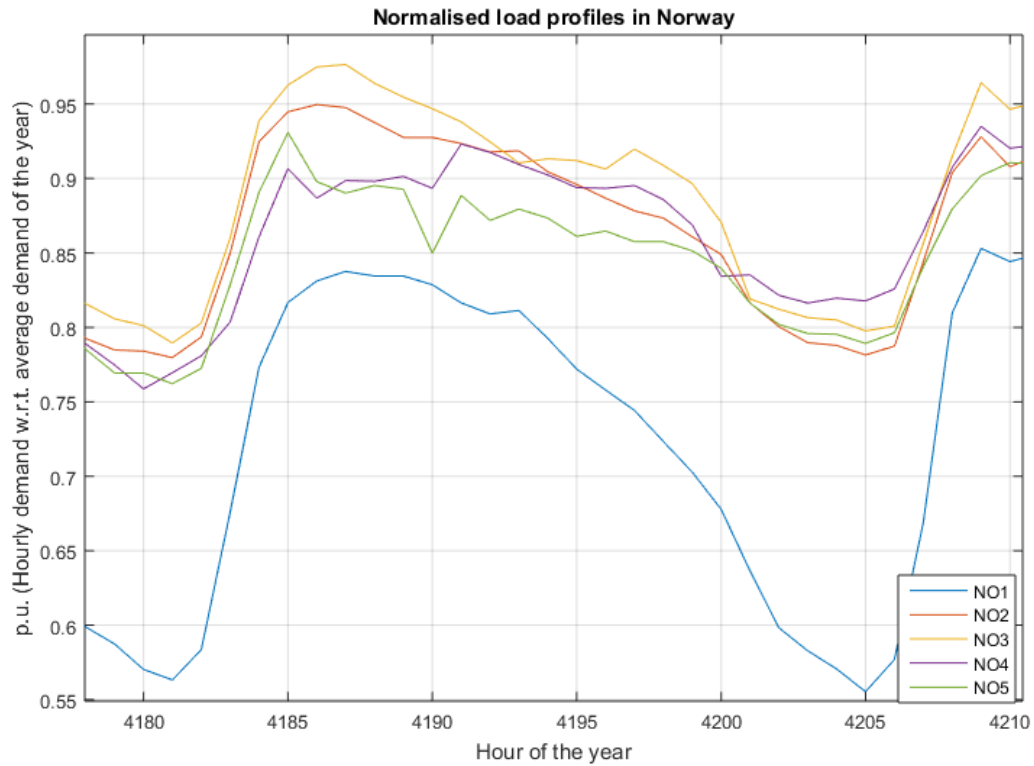
Figure 12. Implemented normalised load profiles in Norway, daily pattern.

2.2.3.2.4.5.2. INFLOW TIME PROFILES

Similarly, inflow profiles of RES are also defined by time profiles of 8760 hours. In the next graph, in figure 13, two examples of solar generation and wind generation's inflow time profiles can be found for south of Germany and for Germany respectively.
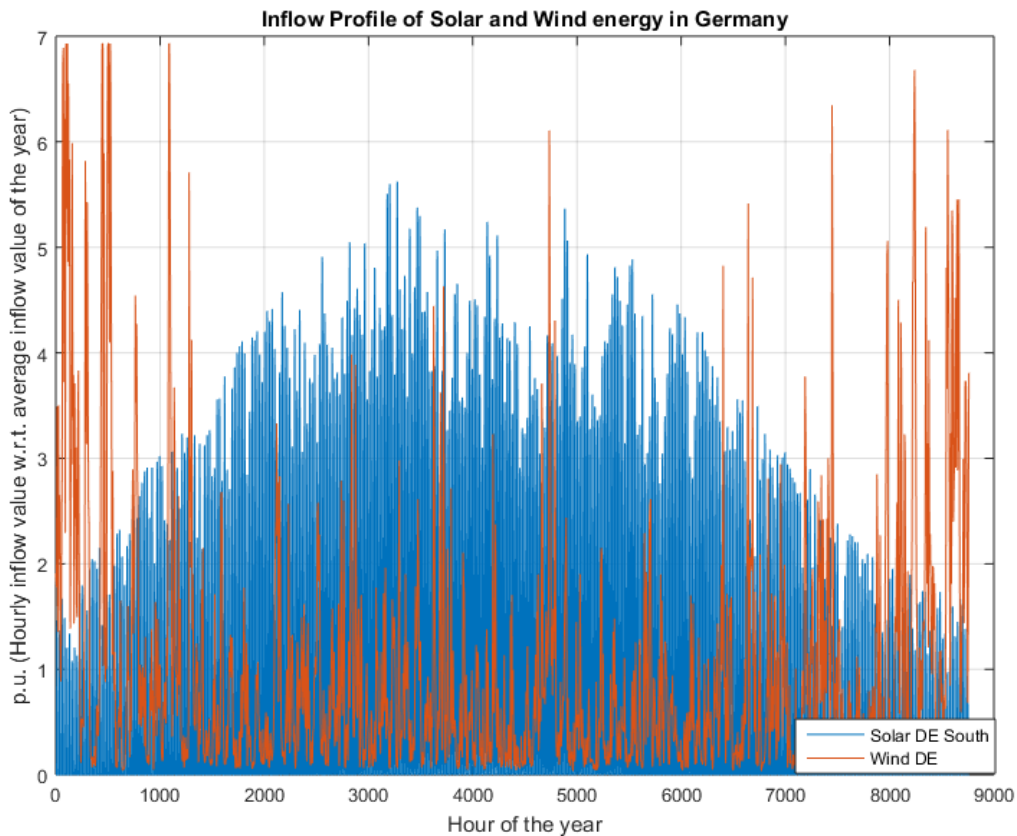
Figure 13. Solar and wind inflow profiles in Germany.

By looking into this graph, the complementarity between the solar and wind input energy to the respective generators can be appreciated. In summer, the amount of solar energy that for instance, PV generation units can take for generating electricity is higher than wind, and the opposite happens in winter, where the available wind is higher than the solar irradiance.

The mentioned characteristic is better seen if the previous profiles are normalised to have a maximum value of one. In the next figure 14, the solar and wind inflow values for winter are shown in the left; and in the right, the values for end of spring are shown.
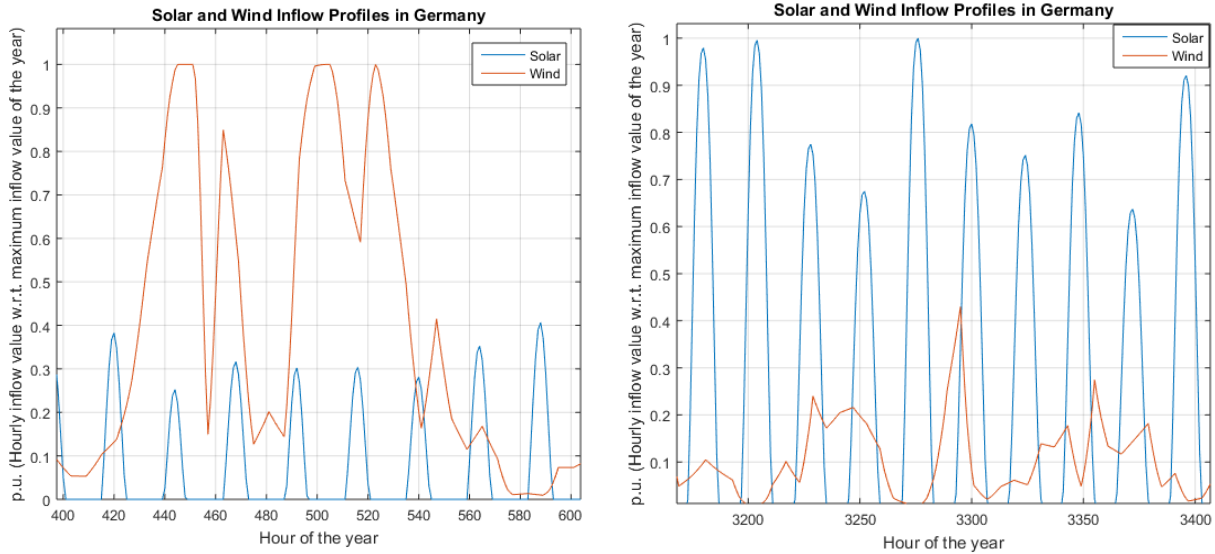
Figure 14. Solar and Wind inflow profiles in summer and winter for Germany.

Another interesting characteristic implemented in the input data is the hydro inflow profile characteristic when the generation unit has storage. This hydro inflow profile has a seasonal pattern, but as stated in chapter 2.1., the mentioned feature can vary clearly from country to country.

For example, in the next figure 15, it is clear how the hydro inflow profile changes depending on the reservoirs' characteristics, which are linked to their corresponding countries' climatic and geographic characteristics. In the mentioned graph, Spanish and Norwegian hydro inflow profiles are represented.
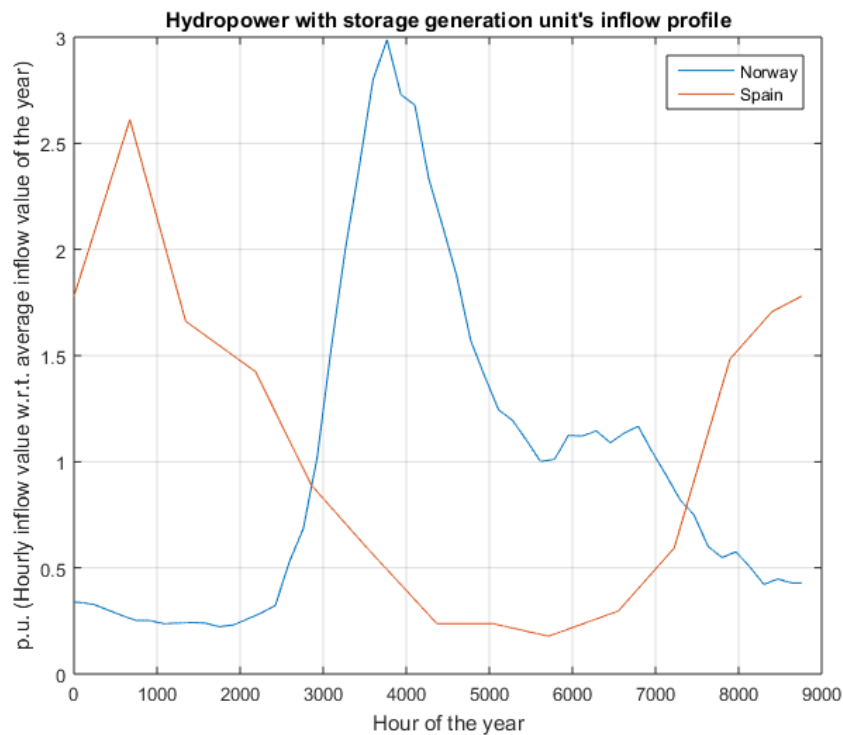
Figure 15. Hydropower with storage's inflow profile in Norway and Spain.

The Norwegian system has the biggest amount of hydropower with storage generation plants in medium or high elevations, starting at around 400 meters and higher. Consequently, the precipitation is given as snow instead of rain in winter. Therefore, the inflow as rain is low in winter time, i.e. starting around November or December. It depends on the year and in the actual elevation and latitude of the generation unit. This lasts until around April or May.

Then, the snow starts to melt, overall, in early spring; and this continues until around end of July in the hydropower generation plants which have the highest elevations. During this period, the inflow is very high, since all the accumulated water plus the rain comes as inflow to the hydropower generation storages.

Going into more details, for representing this period the so called, snow pack principle is followed. More information can be found in [49]. It is also called the spring flood forecasting. This relates the amount of saved water as snow and rain inflow together with the inflow uncertainty.

In short, what it says is that the uncertainty is high in the beginning of the melting season, since still, the accumulated snow is not melted and thus, the biggest amount of inflow comes from rain. At the end of the melting season, or the so-called spring flood, when the highest amount of the inflow comes from the melted snow or from the snow pack, then, the uncertainty is low. After all the snow is melted, then, the inflow comes purely from rain. The concept is explained in the next graph, in figure 16, taken from [49] and with some additional texting.
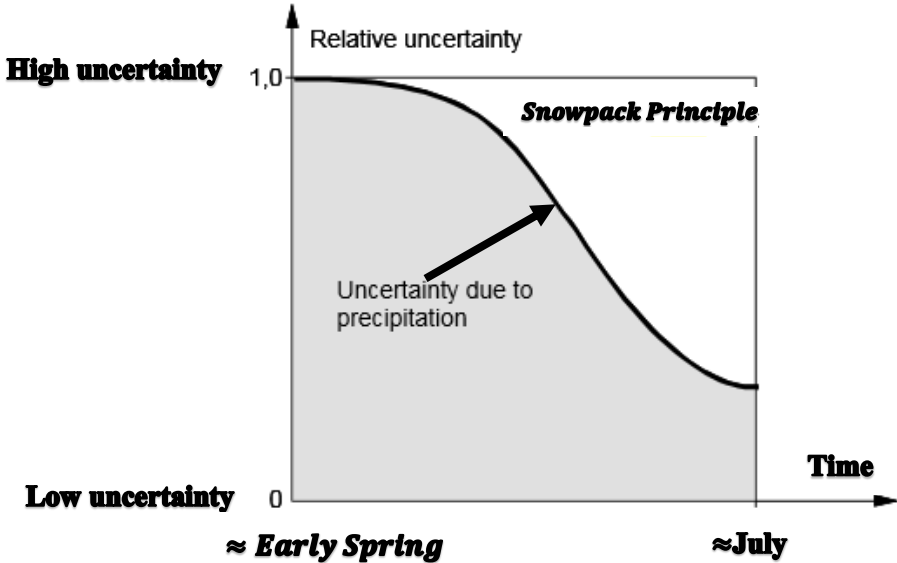
Figure 16. Example to show how the uncertainty is reduced in the spring flood with time.

It is also of interest to show the inflow profiles used for run of the river technology. The hydropower generation units with storage save the water inflow in their reservoirs and they use it, depending on each simulation step's situation, i.e. comparing the reservoirs' economic storage values and nodal prices.

Run of the river technology works as wind though, for example; i.e. it does not save water and the generator unit produces electricity whenever there is water inflow. In Norway, for example, the next inflow profiles for the run of the river generation plants are used. They are shown in figure 17.
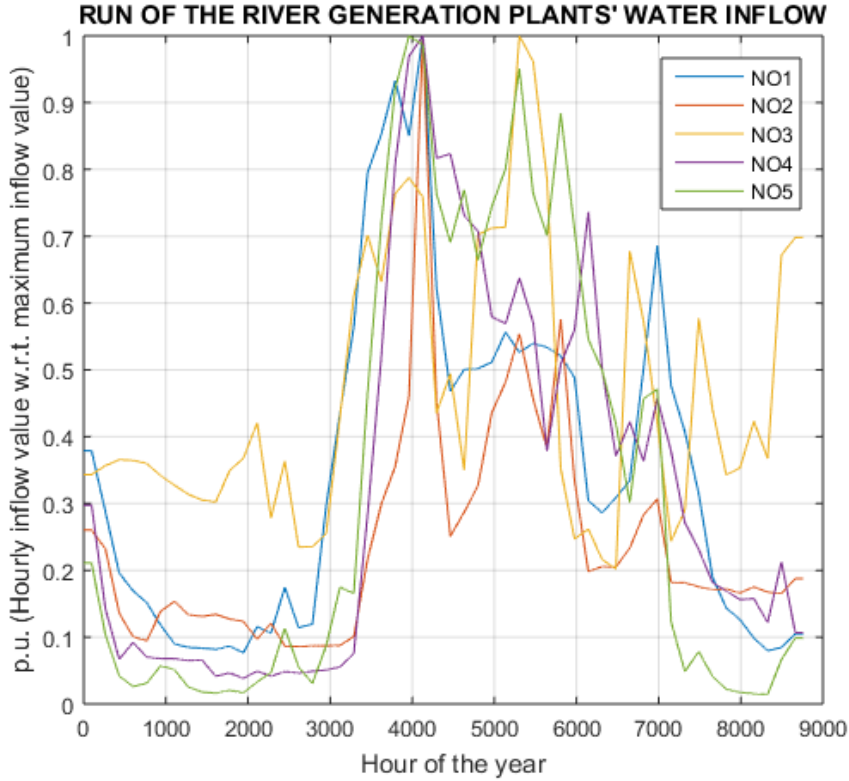
Figure 17. Run of the river generation plants' inflow profiles in Norway.

2.2.3.2.4.6. HYDROPOWER STORAGE CAPACITIES

The total storage capacities per country are taken from [31] and [32], and they are scaled down to each hydroelectric generation plant based on their installed generation capacity, equation 13. This equation is implemented per country. In case of Norway and Sweden, it is implemented per area as well, figure 8 shown previously illustrates the mentioned areas. In the next equation 13, $Pmax_g$ and $\sum_g^G Pmax_g$ are given in MW and the total storage capacity and Storage Capacity$_g$ are given MWh.

$$\text{Storage Capacity}_g = \frac{Pmax_g}{\sum_g^G Pmax_g} \times \text{Total Storage Capacity} \quad (13)$$

Each hydropower generation unit's storage capacity is the product of the ratio of its generation capacity w.r.t. the sum of the total hydropower generation units' generation capacities of its area with the total storage capacity of its area.

For choosing the right storage initial values, simulations are run first, and based on the resulting storage level at the end of the year, the same value is set as initial storage value. This is done iteratively, until the initial and the final filling levels match.

2.2.3.2.4.7. HYDROPOWER STORAGE REFERENCE PRICES

The hydropower storage prices can be found in table XVII.

Table XVII. Hydropower storage reference prices.

Country	Norway	Sweden	Finland
[€/MWh]	15	16	53

This storage prices are set based on the obtained results. Initially, the values were set to the average area prices per country, but based on the obtained results, the storage prices were updated iteratively until relatively realistic results have been obtained regarding storage filling patterns and cross-border flows.

2.2.3.2.4.8. HYDROPOWER STORAGE VALUES OR WATER VALUES

PowerGAMA calculates the economic storage values of the hydropower and solar generation plants by combining the storage filling profile and storage time profile.

For the solar generation technology, the storage filling and time references are taken from [30]. In the case of hydropower generation plants for the Nordics, Ireland and UK the storage filling and time profiles are calculated from [61]. For that, the water values principle is used.

The water values represent the value of adding water inflow to the reservoir in €/MWh, i.e. it is a three-dimension variable which considers the week of the year and the storage filling value of the reservoirs in percentage for giving the economic value of the water stored in the reservoirs.

When the nodal price is higher than the storage value, the hydropower generator will produce electricity. In the opposite case, it will store the water. For example, in figure 18 the water values calculated by EMPS for Norway can be seen [61].
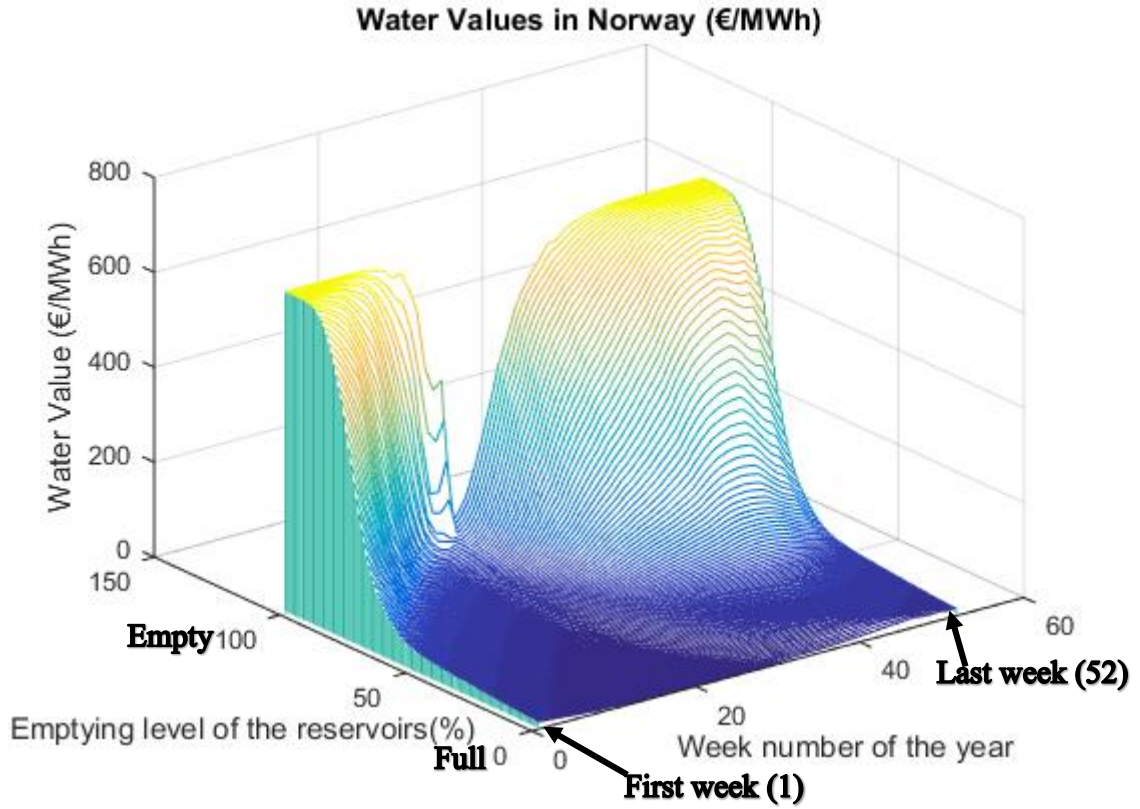
Figure 18. Water values in Norway.

In the x axis, the seasonal pattern of the reservoirs can be seen. In the y axis, the reservoir's filling level behaviour is represented. Around week 18 when the reservoirs are the driest, the hydropower plants should store water due to their high storage's economic value. The opposite happens around week 44.

In chapter 2.1., in equation 12, the equation that PowerGAMA follows for calculating the water values (storage prices) of figure 18 is shown. As a recap, in equation 14 it is shown again, for clarification. The parameter Storage_price$_g$ is given in €/MWh, $storval\_filling_g^{f(t)}$ is given in p.u., it is the reservoirs' storage filling price w.r.t. 50% of filling price, it is a string, a filling profile (0-100%) and the $storval\_time_g^t$ in p.u., it is the reservoirs' hourly filling level w.r.t. 50% of filling level, it is a string, a time profile (length=simulation time).

$$storage\ price_g^{t,f} = \text{Storage}_{\text{price}_g}(fixed) \times storval\_filling_g^{f(t)} \times storval\_time_g^t \ (14)$$

In PowerGAMA, $\text{Storage}_{\text{price}_g}$ is a fixed value and it is the economic reference value in €/MWh that the stored water has when the filling level of the reservoirs is 50%. The $storval\_filling_i^{f(t)}$ value of equation 14 would be the representation of the profile shown in the y axis of the figure 18 and the $storval\_time_i^t$ value of equation 14 would be the representation of the profile shown in the x axis of the figure 18, i.e. hydropower reservoir's seasonal pattern. These two profiles in PowerGAMA are normalised, they do not have any unit. These are multiplied with each other

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in PowerGAMA, and then, with a fixed reference value in €/MWh of the storage price. By the combination of the three, the economic value of the stored water is obtained in each time step of the simulation.

Therefore, from figure 18 obtained in [61] by EMPS, different steps are followed in this Master Thesis for finding a way to represent this figure 18 by following equation 16, for each implemented country.

For obtaining the storage filling profile, a focus in each country is done first, in [61]. Then, all the storage time values are considered and the median value is calculated for each storage filling level. In this way, a 100% filling level profile is obtained where for each reservoir level the median value of all weeks is chosen. Then, the obtained profile is normalized to have a unit value when the storage filling level is 50%.

The same storage filling profiles are used for Sweden and Norway and a slightly different profile is used for UK, in [61]. Nevertheless, in this Master Thesis, some modifications are done based on the obtained results and heuristics, since each countries' behaviour is different as shown in [38] and [43]. The modifications can be seen in figure 19. As it is shown, in this Master Thesis different filling profiles are created for Norway and Sweden, since Swedish reservoirs go drier than Norwegians, based on [38].
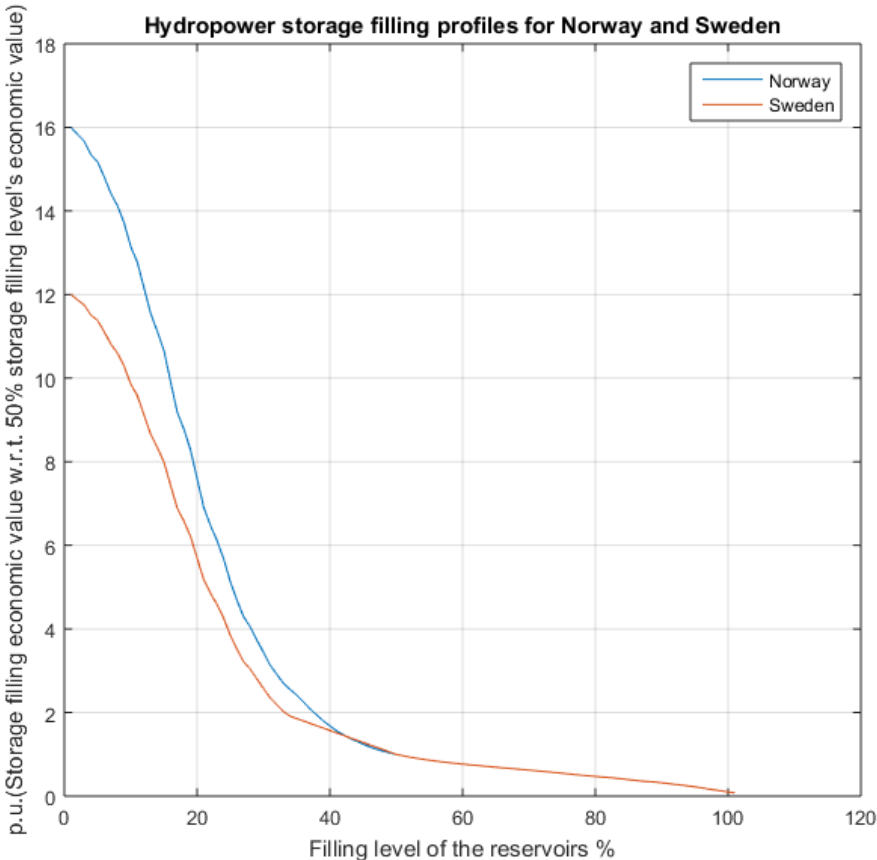
Figure 19. Storage filling profiles for Norway and Sweden.

In [61], same storage time profiles are taken for Finland, Sweden and Norway. Nevertheless, this implementation brings the model to some deviations from real data, too, since these countries' actual reservoir time pattern differ from each other, based on [38].

Therefore, independent time profiles are created for each country based on actual data from the year 2014 obtained from [38], figure 20 shows the normalized values for Norway and Sweden. Nevertheless, average profiles could be used for the analysis of future scenarios. At the same time, the profiles are set to the same level in the beginning and in the end of the year. For the United Kingdom, the time dependency is not considered.
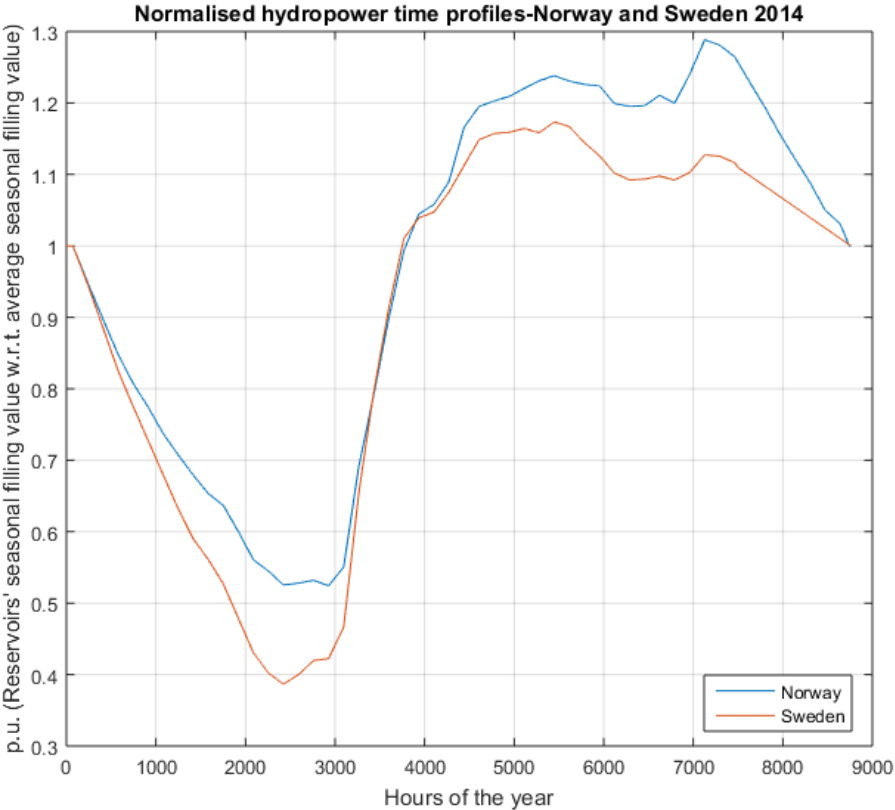
Figure 20. Storage time profiles for Norway and Sweden.

2.2.3.2.4.9. PUMPS
Pumps are neglected for the newly added countries.

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2.2.4. ANALYSING THE RESULTS

Main results are classified in four subgroups: Aggregated energy mix, aggregated cross-border flow, hydropower characteristics and energy balance.

2.2.4.1. AGGREGATED ENERGY MIX

An overview of the obtained aggregated energy mix can be found in the next table XVIII. It shows the deviation or error of the obtained results in percentage with respect to the values given by ENTSO-E in [34], (they are shown in table XVIV), and also, the total generation deviation w.r.t. ENTSO-E [34] in GWh per country.

Table XVIII. Obtained Aggregated Energy Mix values per newly added country.

Country	Nuclear deviation in %	Fossil* deviation in %	Res_Except Hydro+ deviation in %	Hydro deviation in %	Total Generation deviation in %	Total Generation deviation in GWh
DK	-	-10.21	+5.66	+0.44	-2.52	-770.67
FI	-0.2	-1.83	+27.23	-22.62	+2.71	+1733.64
GB	+0.66	-2.72	-17.91	+2.73	-0.77	-2381.49
IE	-	+47.25	-3.803	-4.615	+25.59	+6280.04
NI	-	-59.10	+9.02	+71.82	-43.65	-3490.70
NO	-	-100	+4.55	-0.44	-3.014	-4289.73
SE	-0.29	-0.97	+17.27	+3.11	+2.19	+3311.04

Table XIX. Aggregated Energy Mix values taken from [34]

Fossil*: It embraces Coal, Gas, Oil, Mixed of Fuels and Lignite generation technologies.

Res_Except Hydro+: It covers Biomass, Wind, Offshore Wind, Solar and other RES generation technologies.

As it can be seen, in table XVIII and in the coming figures, the general picture is captured by PowerGAMA. The generation patterns are properly captured. In most of the countries the values are close to actual numbers and the total generation deviation is of +392.13 GWh. For example, the next figure 21 shows the Energy Mix of Norway, Sweden and Great Britain.
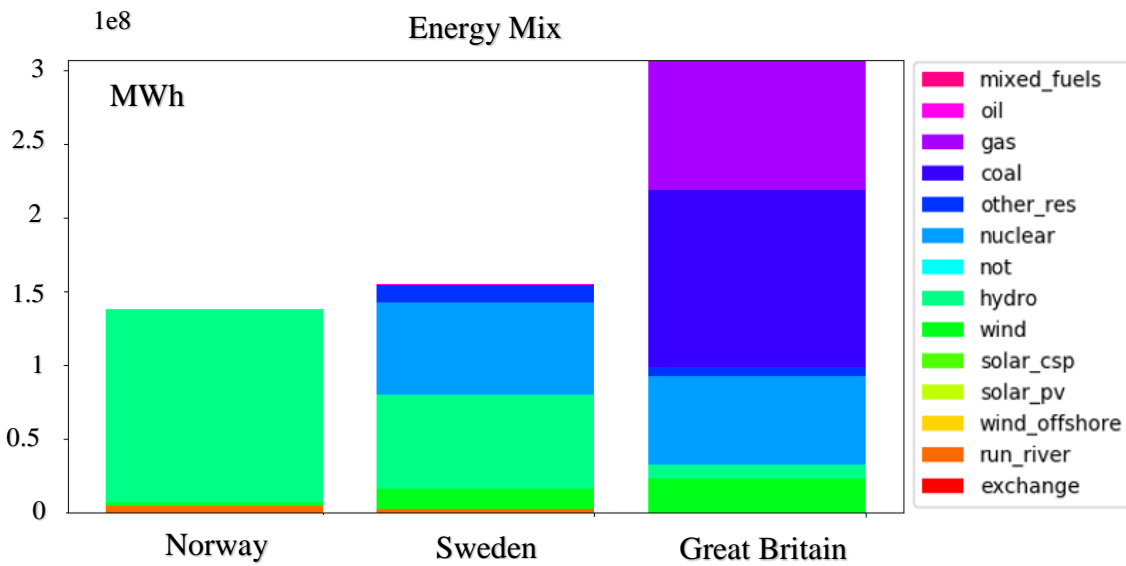
Figure 21. Resulting Energy Mix in MWh, taken from PowerGAMA for the year 2014.

Nevertheless, there is a deviation of the renewable energy sources technologies expect for hydro in Finland. This is partly due to the too high inflow factor inserted as input data for the biomass generation technology. Nevertheless, it is also, probably, related to a deviation when implementing hydropower generation plants, due to the difficulties found for doing so. This high share of the biomass generation technology is shown in the next figure 22.
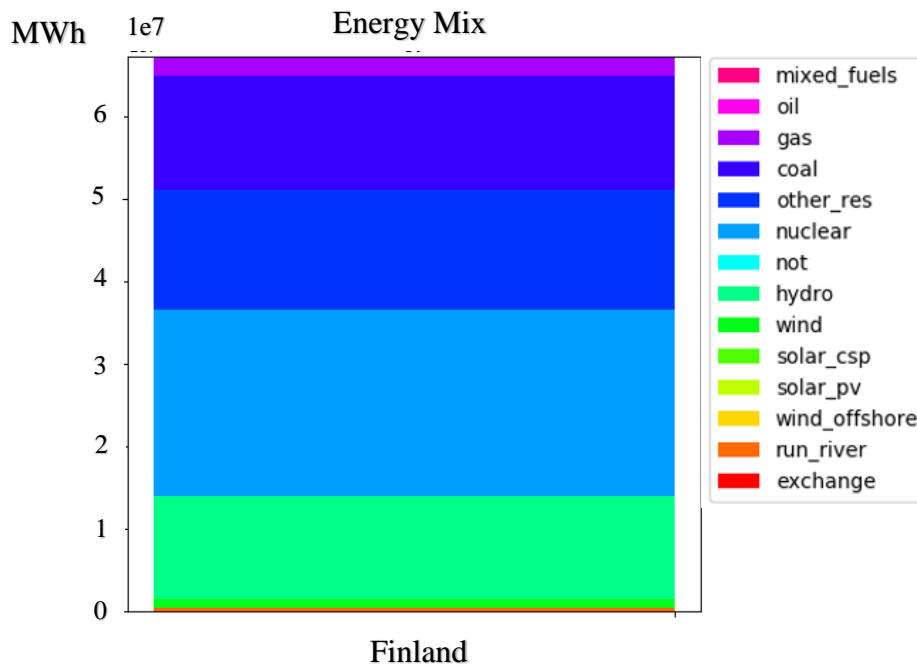
Figure 22. Resulting graph. Finland's Energy Mix for the year 2014.

There are considerable deviations in Northern Ireland and in Ireland in terms of total generation values, this is shown in figure 23. This is related to a wrongly represented cross-border flow in the mentioned countries. The cause of the inconsistency is explained below, in 2.4.2.
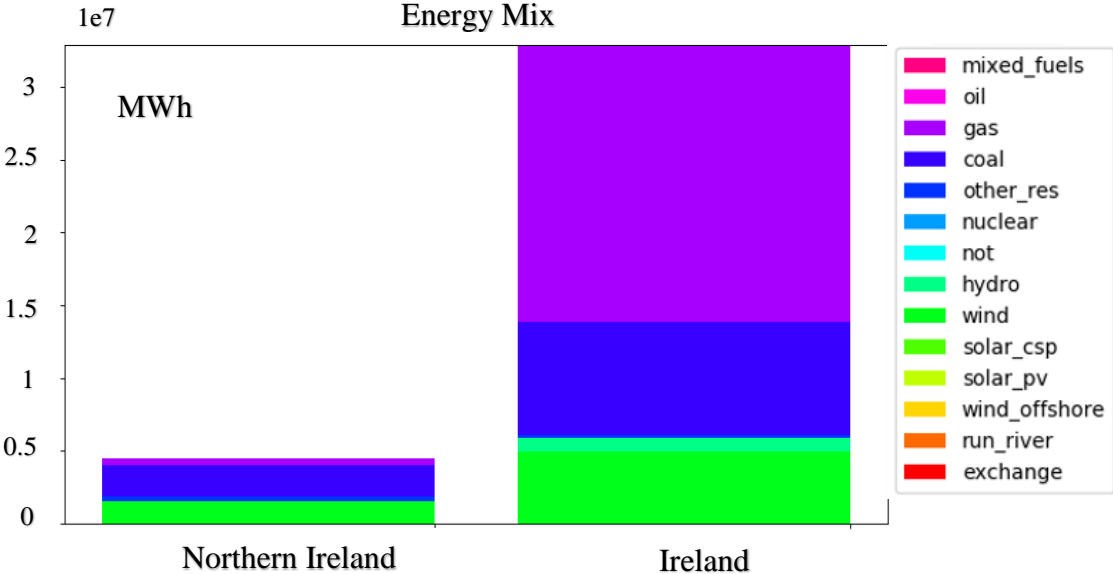
Figure 23. Resulting graph. Energy Mix in NI and IE for the year 2014.

2.2.4.2. AGGREGATED CROSSBORDER FLOW

The results are summed up in the next table XIX. In this case also, the deviation with respect to the results given by ENTSO-E in [34] is shown in percentage. At the same time, it is mentioned if the flow direction is correct or not. In some cases, the deviation is of just few GWh but since the real exchange value is low as well, the deviation percentage is expressed as being big. The total deviation is of 1.916 TWh.

Table XX. Aggregated cross border flow.

From	To	ENTSO-E [34] in GWh	Deviation %	Deviation in GWh	Direction
NO	NL	5355	-2.83	-151.53	Correct
NO	DK	2647	+7.81	+206.57	Correct
NO	SE	6805	-33.46	-2276.62	Correct
FR	GB	15054	-8.61	-1297.11	Correct
NL	GB	7851	+11.58	+908.99	Correct
SE	DK	883	+20.83	+183.93	Correct
SE	DE	1005	-62.21	-625.21	Correct
PL	SE	2984	-22.325	-666.18	Correct
DK	DE	546	-27.705	-151.27	Correct
GB	NI	1046	+6.63	+69.34	Correct
IE	GB	2394	+23.06	+552.05	Opposite
SE	FI	18298	+7.84	+1437.27	Correct
IE	NI	253	+1472.76	+3726.10	Correct

Ireland is producing too much because it is exporting excessive amounts to Northern Ireland and this reduces the need of production in Northern Ireland. Therefore, the total generation in table XVIII is higher than the actual value.

One of the reasons of this inconsistency is that the mentioned countries are represented by just one node each. By this approximation, it is hard for the model to replicate the real behaviour among these countries. At the same time, the reduction of the high hydro deviation in Northern Ireland also, might help to improve the error.

Apart from these results, the exchange between Norwegian and Swedish bidding areas also follow the pattern mentioned in [45], and thus, they are correct. NO1 exports to SE3 and NO4 exports to SE1. At the same time, SE2 exports to NO3 and NO4. The mentioned areas are shown in figure 5.

Going into more details, if a focus in the Norwegian system is done, the model can capture the bottlenecks that happen in the North of Norway around Troms and Finnmark [46]. The mentioned are reflected by higher nodal prices in the stated areas. They are shown by lighter coloured dots. Similarly, the same can be said for Bergen area, as mentioned in [46]. They can be found in the figure 24 below.
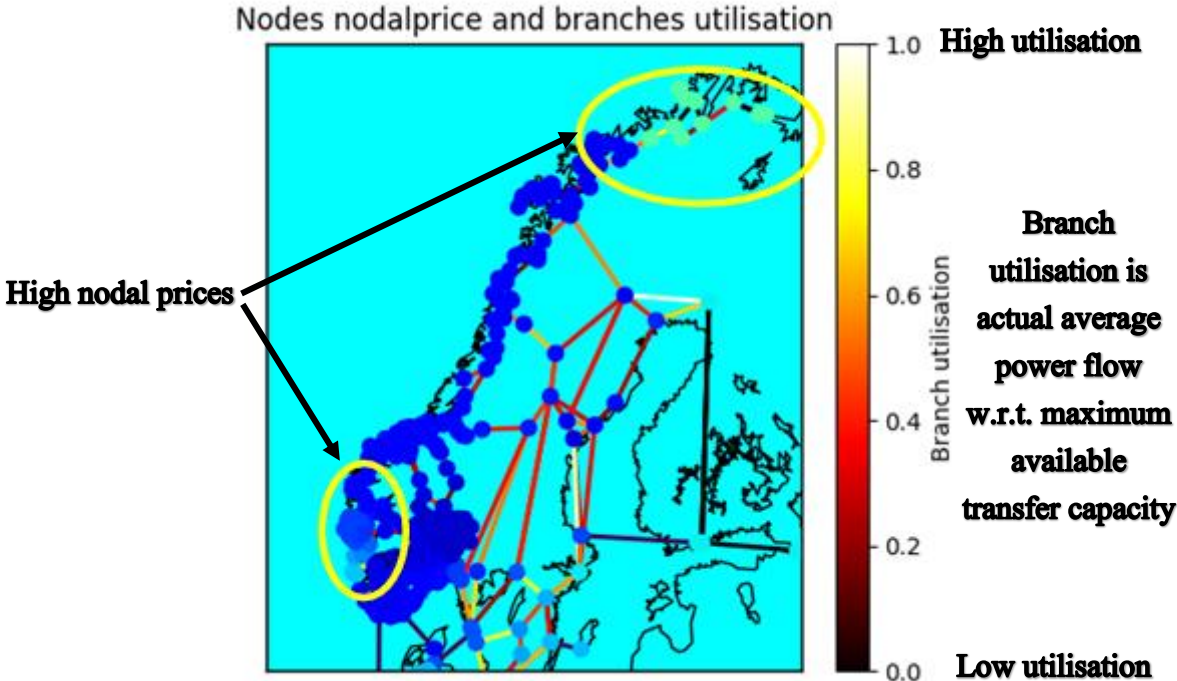
Figure 24. Branch utilisation and nodal prices.

2.2.4.3. HYDROPOWER CHARACTERISTICS

The obtained storage values per area follow a realistic pattern. They can be found in figure 25. The results are normalized for creating the mentioned figure.

The initial and ending points of the reservoir filling level are in the same level, the top and bottom values are also among the actual possible range and the shape of the curve is close to the actual frame [38].

In addition, the generation plants do not produce electricity when they are close to being empty and they produce more when they are close to being full, this is related to the water values explained previously. Moreover, the production is higher in winter and lower in summer due to the demand as well. Besides, it can be seen how the filling level also is linked to the hydro inflow profile, for instance, when the inflow increases, the filling level also rises.
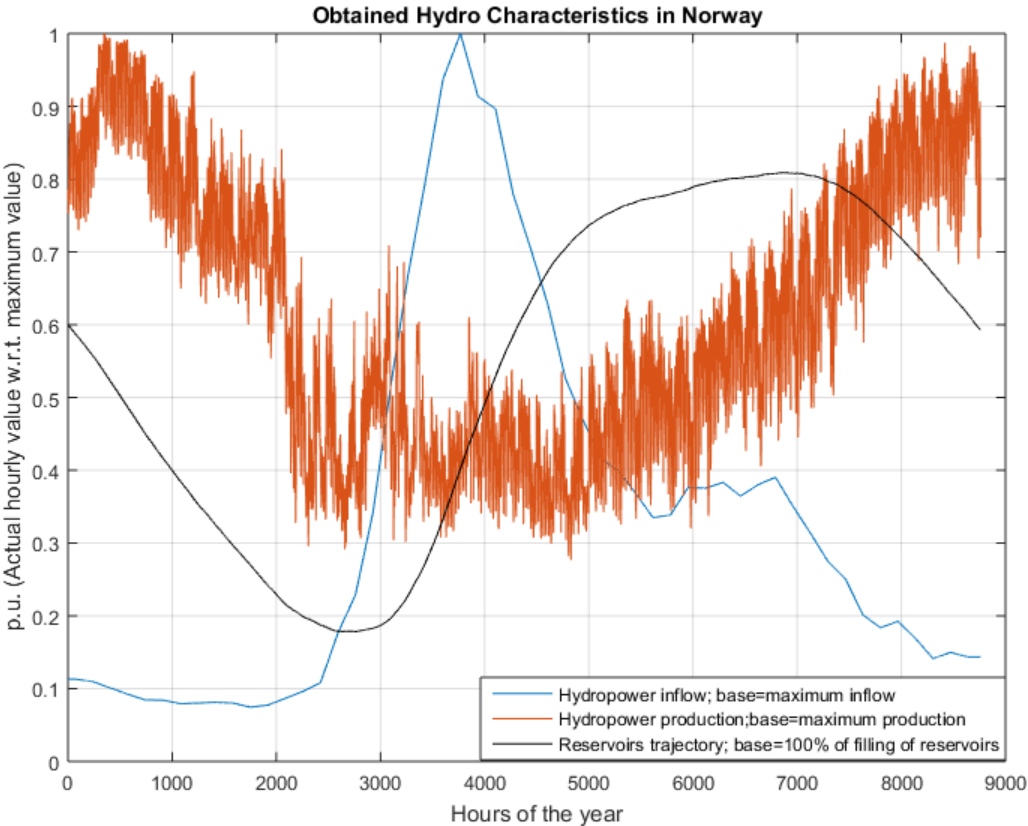
Figure 25. Obtained hydro characteristics in Norway.

2.2.4.4. ENERGY BALANCE CHARACTERISTICS

This hydro generation pattern also affects the exchange between countries. The next figure 26 shows the seasonal pattern that can be found in the exchange between Norway and Netherlands, Norway and Sweden and Norway and Denmark. The positive values mean that Norway is importing and the negative values mean that Norway is exporting. Figures 26, 27 and 28 are linked. And they are explained all together below.
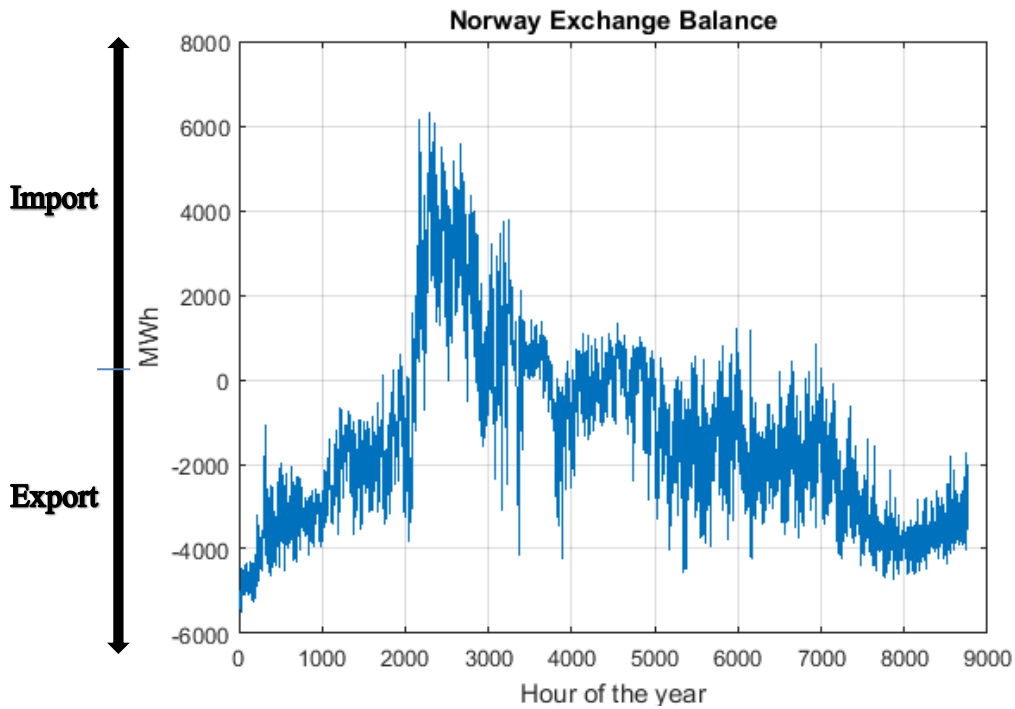
Figure 26. Exchange between Norway and Netherlands, Sweden and Denmark.

The next figure 27 shows the net hourly generation in Norway and also, its total hourly exchange. It can be seen that when the generation exceeds the exchange value, this means that Norway is exporting energy, for example, the purple circles in the left and right corner of the figure 27. The opposite happens when the exchange exceeds the generation, this means that Norway is importing energy. This is shown for example, in the area the yellow circle is referring to. It is to point out that in the next graph the generation by gas or wind generation units is not appreciated. The reason is that the sum of these two generation technologies have a share of 3.99% of the total generation.
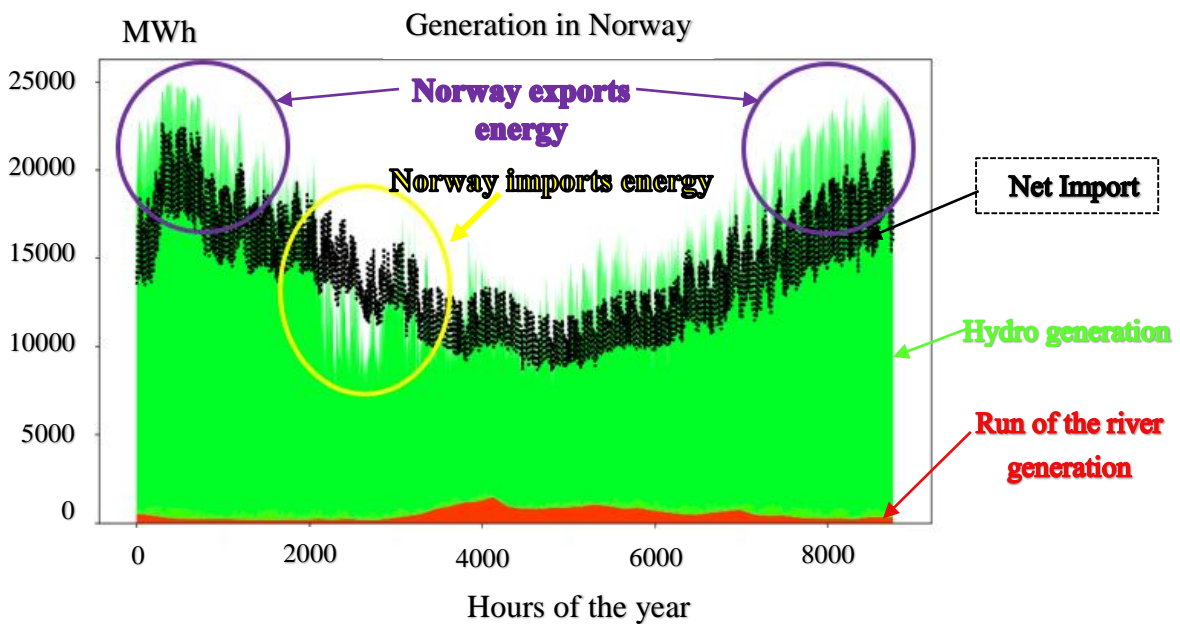
Figure 27. Hourly generation in Norway and, net exchange in Norway.

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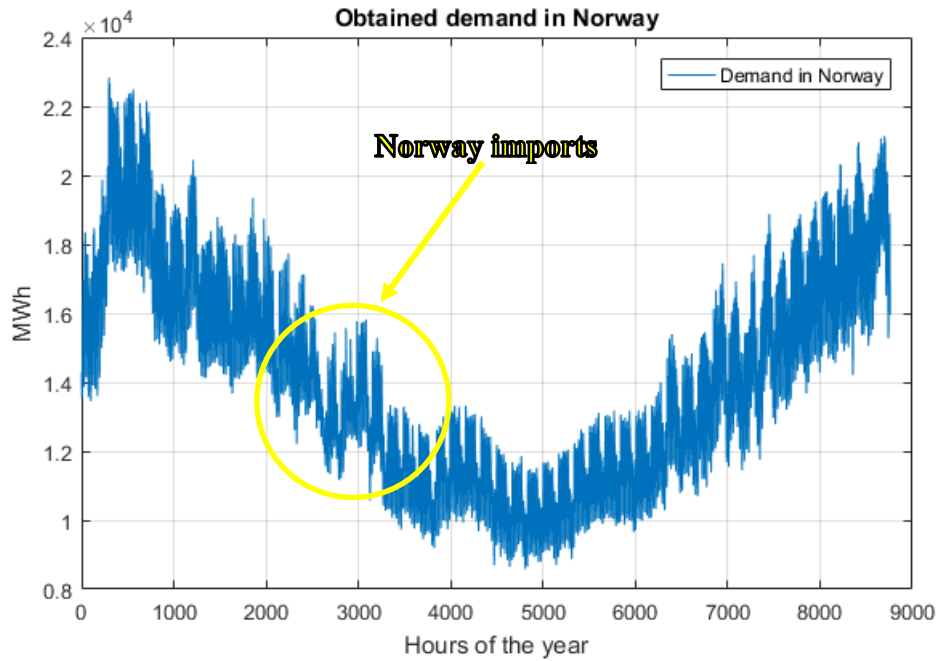
Figure 28. Hourly demand in Norway.

By considering figures 25, 26, 27 and 28; it can be seen how the Norwegian system imports more power when the reservoirs are close to being empty around the hour 2020 due to high water values. This makes hydropower generation plants to not produce electricity and to save water in the reservoirs.

The opposite happens when there is enough water in the reservoirs, and thus, the storage values are low, since the reservoirs are close to being full. In that case, the nodal price is higher than the storage value and the hydropower generation units produce electricity. Norway can produce more energy than the Norwegian demand is asking for, and thus, it can send the surplus to Denmark, Netherlands and Sweden.

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2.3. MODELLING AND THEORY BEHIND POWERGIM

2.3.1. INTRODUCTION

The objective of this chapter is to explain the main possible studies that the tool PowerGIM offers to the user and which data it requires for that.

PowerGIM is developed by SINTEF and NTNU. The author of this report has written this short chapter based on her understanding acquired throughout her Master Thesis and [49] and [51].

In this Master Thesis, the second stage consists on finding the socio-economically beneficial grid layout for the North Sea for the year 2030 per each implemented scenario.

PowerGIM is suitable for doing so. It is a transmission expansion planning model which is incorporated in PowerGAMA. Therefore, it is also a python package. As mentioned before, PowerGAMA is like Power System Simulation Tool (PSST) and PowerGIM is like Network Optimisation (Net-Op). PSST and Net-OP are also developed by Sintef. The main difference is that PowerGAMA and PowerGIM are open-source.

PowerGAMA does LP optimization, whereas PowerGIM does MILP optimization. This helps the program consider binary and integer investment variables. PowerGIM works in two stages. In the first stage the minimisation of the investment decisions is calculated and in the second stage, the minimisation of the operational costs is considered. By considering both characteristics, PowerGIM gives the optimal grid layout.

In addition, one of its strengths is the ability to consider uncertainty, and PowerGIM could be defined as a two-stage stochastic program. Nevertheless, it can also work as a two-stage deterministic program. This last case, two-stage deterministic program, is used in this Master Thesis.

In this Master Thesis, the main functions used from PowerGIM are the next:

- Optimal grid's layout.
- Total operational costs of the system.
- Total investment costs of the system.
- Total needed grid capacity for each grid investment and their location.
- Total needed amount of parallel lines for each grid investment and their location.

In this Master Thesis, the studies described above are mainly done for Norway, Denmark, Germany, Netherlands, Belgium and UK for the year 2030. This is better explained in chapter 2.4.

In the next pages of this report a theoretical description of PowerGIM is given.

2.3.2. OPTIMISATION FORMULATION

As mentioned earlier, PowerGIM can work following a deterministic or a stochastic mathematical formulation. This master thesis uses the deterministic methodology.

First, an overview of the sets, indices, parameters and variables used is presented below:

Sets:

G : Set of generators

N : Set of nodes

B : Set of AC and DC branches

L : Set of loads

T : Set of time steps

S : Set of scenarios

Indices:

i : Generator

n: Node

j : Branch

l : Load

t : Time step

s : Scenarios

Parameters:

r: Interest rate [p.u. (annual fraction relative to the operational costs)]

r^{om}: Maintenance and operations rate [p.u. (fraction relative to the total investment costs)]

n: Economic lifetime (years)

π_s: Probability for scenario s [p.u. (fraction relative to the scenario s' operational costs)]

Voll: Load shedding cost (Value of lost load) [€/MWh]

MC_i: Marginal generation cost of generator i [€/MWh]

CX_i: Additional generation capacity cost of generator i [€/MW]

C_j^{fix} : Fixed cost of the branch j [€]

C_j^{var} : Variable cost of the branch j [€/(kmMW)]

C^{node}: Cost of the node n [€]

B, B_d, $B_{d,p}$: Costs of the branches (fixed, variable w.r.t. distance and variable w.r.t. distance and power rating) [€, €/km and €/(kmMW)]

C^L, C_p^L : Onshore converter costs (fixed and variable w.r.t. power rating) [€ and €/MW]

C^S, C_p^S : Offshore converter costs (fixed and variable w.r.t. power rating) [€ and €/MW]

N^L : Fixed cost of node on land, platform cost [€]

N^S : Fixed cost of node offshore, platform cost [€]

P_i^{min}: Minimum generation capacity, generator i [MW]

P_j^e: Capacity of existing branch j [MW]

$P_j^{n,max}$: Maximum capacity of new branch j [MW]

e_i: Yearly disposable energy for generator i (for example, energy storage) [MWh]

m: Considerable number, very large [-]

Variables:

y_j: Number of new transmission lines, branch j [-]

x_j: Capacity of new transmission lines, branch j [MW]

z_j: Capacity and length of new transmission lines, branch j [(kmMW)]

y_n: New platform at node n, number[-]

x_i: Additional generation capacity of generator i [MW]

$x_{i,t}$: Power generation dispatch of generator i during time step t [MW]

$x_{j,t}$: Power flow in branch j during time step t [MW]

$x_{n,t}$: Load shedding in node n during time step t [MW]

$\delta_{n,t}$: Voltage angle, node n during time step t [°]

d_j: Length of branch j [km]

l_j: Total (fixed and variable w.r.t. distance) transmission losses of branch j [p.u. (total losses w.r.t. no losses in power transmission in branch j)]

P_j^n: Capacity of new branch j [MW]

$P_j^{S/L}$: Power capacity of new node of branch j [MW]

$d_{l,t}$: Demand at load l during time step t [MW]

$P_{i,t}^{max}$: Maximum generation capacity, generator i during time t[MW]

2.3.2.1. DETERMINISTIC ANALYSIS

The objective function is defined in equation 15:

$$min_{x,y} \ (fsc + ssc) \ (15)$$

It is composed by the minimisation of the investment costs (fsc in €) and operational costs (ssc in €).

$$fsc = \sum_{j\in B}\left(C_j^{fix}y_j + C_j^{var}z_j\right) + \sum_{n\in N}\left(C^{node} \times y_n\right) \ (16)$$

In the first half of the equation, the total investment costs of the branches are considered, i.e. fixed and variable costs; and in the second half of the equation, the total investment costs, i.e. fixed costs of the nodes are calculated. C_j^{fix} and C^{node} are given in €, y_j and y_n have no unit, C_j^{var} is given in €/(kmMW) and z_j is given in (kmMW).

These are set clearer in equations 17 and 18. $N^{S/L}$, B and $C^{S/L}$ are given in €, B_d is given in €/km, $B_{d,p}$ is given in €/kmMW, $C_p^{S/L}$ is given in €/MW, d_j is given in km and P_j^n and $P_j^{S/L}$ are given MW.

$$Single \ branch \ cost_j = \left(B + B_d d_j + B_{d,p}d_j P_j^n\right) + \left(C^{S/L} + C_p^{S/L}P_j^{S/L}\right) + \left(C^{S/L} + C_p^{S/L}P_j^{S/L}\right) \ (17)$$

$$Single \ node \ cost_n = \ N^{S/L} \ (18)$$

As mentioned before, the second half of the objective function is about the minimisation of the total operational costs. It can be found in equation 19 below. It is to mention that the operational costs are calculated throughout the lifetime of the investment, after taking as reference the case

of one year and by making use of the interest rate. MC_i, Voll and CX_i are given in €/MWh and $x_{i,t}$, $x_{n,t}$ and x_i are given in MW, and they are taken for the duration of the time step.

$$ssc_s = \sum_{i \in G} \sum_{t \in T} (MC_i) x_{i,t} + \sum_{n \in N} \sum_{t \in T} Voll\, x_{n,t} + \sum_{i \in G} CX_i x_i \ (19)$$

Power losses are also calculated by PowerGIM in a simplified way. For that, it makes use of two components, a constant loss factor (p.u., loss value w.r.t. 100% of loss), for example for converters, and a distance dependent loss factor (p.u., loss value per km w.r.t. 100% of loss per km), such as for cables. Its mathematical representation is shown in equation 20.

$$Loss\ fraction = \text{constant} + \text{slope} \times distance \ (20)$$

Apart from the objective functions and the power losses, PowerGIM also considers some constraints (equation 21-28). They are stated below.

This first constraint presented in equation 21 sets basically the condition of power balance. It is represented between generation and consumption, but also considering loses, load shedding and the contribution from the connected branches to the node. All the variables below are given in MW, the exception is l_j which is given in p.u. (total losses w.r.t. no losses in power transmission in branch j). They are taken for the duration of a time step.

$$\sum_{i \in G_n} x_{i,t} + \sum_{j \in B_n^{in}} x_{j,t}(1 - l_j) - \sum_{j \in B_n^{out}} x_{j,t} + x_{n,t} = \sum_{l \in L_n} d_{l,t} \ (21)$$

In equation 22, the constraint sets that the power flow in branch j during time t should be between the positive and negative sum of the existing branches' capacity and the capacity of the new transmission lines. This negative value shows the ability that the branch should have to represent the flow in both directions, i.e. from A to B and from B to A. All the variables below are given in MW.

$$-\left(P_j^e + x_j\right) \leq x_{j,t} \leq \left(P_j^e + x_j\right) \ (22)$$

Then, the next constraint in equation 23 sets that the total capacity of the new transmission line j should be lower or equal to the multiplication between the maximum capacity of new branch j in node n and the number of the new transmission lines. x_j and $P_j^{n,max}$ are given in MW and y_j has no unit.

$$x_j \leq P_j^{n,max} y_j \ (23)$$

The power generation dispatch of generator i during time step t should be between the maximum and minimum generation capacity of generator i during time step t. This is represented as constraint and it is shown in equation 24. All the variables below are given in MW.

$$P_i^{min} \leq x_{i,t} \leq P_{i,t}^{max} \ (24)$$

In equation 25, the power generation dispatch of generator i during time step t should be equal or lower to the available yearly disposable energy for generator i. $x_{i,t}$ is given in MW and it is taken for the time duration of the time step. e_i is given in MWh.

$$\sum_{t \in T} x_{i,t} \leq e_i \ (25)$$

In Equation 26, the load shedding constraint can be found. It says that the load shedding in node n during time step t should be lower or equal to the demand at load l during time step t. All the variables below are given in MW.

$$x_{n,t} \leq \sum_{l \in L_n} d_{l,t} \ (26)$$

The next constraint in equation 27 says that the number of new transmission lines should be higher than the number of new platforms at node n. All the variables below have no unit.

$$\sum_{j \in B_n} y_j \leq m y_n \ (27)$$

The last constraint in equation 28 sets the condition for the values that the next variables can take to solve the MILP mathematical formulation. $x_j, x_{i,t}, x_{j,t}, x_{n,t}$ are given in MW, $\delta_{n,t}$ in degrees and y_j and y_n have no unit.

$$x_j, x_{i,t}, x_{j,t}, x_{n,t}, \delta_{n,t} \geq 0, y_j \in Z^+, y_n \in \{0,1\} \ (28)$$

2.3.3. WORKING PROCESS

The next figure 29 shows the steps that PowerGIM follows for its calculations.
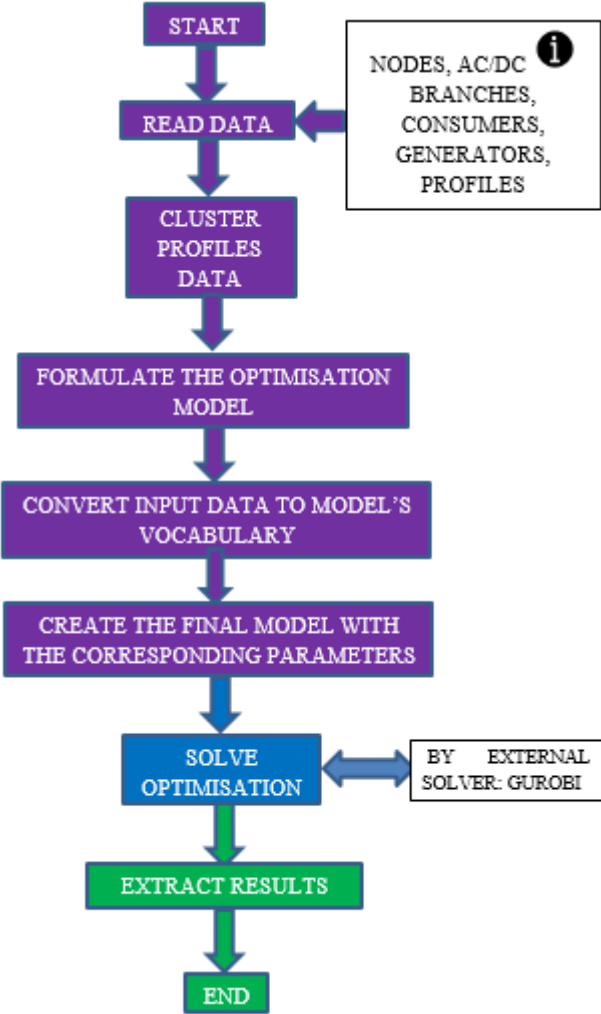
Figure 29. PowerGIM's working process.

ⓘ These input data are shown in 2.3.4. sub-chapter of this chapter.

All these steps shown in figure 29 are implemented in one script, which is the main directory of PowerGIM. The file is named as "RUN_model.py". It is appended at the end of this report. The other python files are only needed to be checked if the user wants to acquire a deeper understanding of the tool. These can be found in [29].

In short, PowerGIM calls the "powergim.py" script from the main directory in the first (purple colour in figure 29), second (blue colour in figure 29) and third steps (green colour in figure 29) of the process. At the same time, for making the map graph of the resulting optimal grid layout, the "Results.py" file shown in chapter 2.1. for PowerGAMA is used.

2.3.4. INSERTING THE INPUT DATA

This part also aims to be theoretical, as chapter 2.1., and in chapter 2.4., more visual information is given by means of examples. Likewise, it is done in chapter 2.1., the necessary input data is

explained based on the needed CSV files and their arrangement, as well as, the main working file (RUN_model.py) of the model. It is appended at the end of this Master Thesis report.

The input data's settlement could be changed by modifying the "powergim.py" file. Nevertheless, this report is explained so that the user could make use of the "RUN_model.py" file as the main directory. It is appended at the end of this report.

The core basis of the input data is the same as in PowerGAMA. The difference is that some additional columns are inserted in the CSV files, since investment costs and potential grid candidates are also implemented. At the same time, all the profiles or strings are set in the same CSV file whereas in PowerGAMA three different CSV files are used. Apart from that, some nomenclature is different compared to PowerGAMA.

2.3.4.1. COST SETTINGS

PowerGIM makes use of a "parameters.xml" file where all the investment costs, CO_2 emission factors per each generation technology, CO_2 emission prices, financial interest rates (%), financial years, operation and maintenance rates and the investment stages are defined.

Some examples could be found in chapter 2.4., in table XXVI. There, the units and values used in the socio-economically beneficial offshore grid layout analysis are shown.

2.3.4.2. NODES

Table XX summarises the characteristics which can be defined in the "nodes.csv" file.

Table XXI. Nodes. Input data.

Nodes.csv								
Id	Area	Lat [°]	Lon [°]	Offshore [1 or 0] (1=offshore node)	Type [AC or DC]	Existing [1 or 0] (1=existing node)	Cost_scaling [p.u.]*	Comment

*Fraction relative to the nodes' investment costs

The difference compared to PowerGAMA are the next. In PowerGIM, the "nodes.csv" file can define if a node is offshore or onshore by setting 1 or 0 respectively in the "Offshore" column. At the same time, the node can be specified as DC or AC in the "Type" column. If the node already exists, then, in the "Existing" column 1 is set and 0 is set in the opposite case.

In case the user wants to do a sensitivity analysis by increasing or decreasing the costs, a factor can be introduced in the "Cost_scaling" column. In case the costs are wanted to be maintained as stated in the "parameters.xml" file, then, the "Cost_scaling" column should be kept as 1. In the "Comment" file any additional information which is helpful for the user can be defined. It does not affect the investment decisions.

2.3.4.3. BRANCHES

In table XXI, the peculiarities of the branches can be found. They are shown as rows, but in reality, they are columns of the "Branches.csv" file.

Table XXII. Branches. Input data.

Branches.csv	Node_from
	Node_to
	Capacity [MW]
	Capacity 2 [MW]
	Expand [1 or 0] (1=expansion possibility in the first stage)
	Expand 2 [1 or 0] (1=expansion possibility in the second stage)
	Max_newCap [MW]
	Distance [km]
	Cost_scaling [p.u. (fraction relative to the branches' investment costs)]
	Reactance [ohm]
	Type [acdirect, dcdirect or dcmeshed]
	Comment

The difference compared to PowerGAMA is that in PowerGIM, there are 2 different columns to set the branches capacities and expansions.

The first column of "Capacity" is used for setting the existing capacity of the branch at time step 1. "Capacity 2" shows the externally added branch capacity at time step 1 plus the stage time delta. The "stage time delta" is defined in the "parameters.xml" file previously explained and it represents the amount of time between the first-time step w.r.t. to the time step t where the investment by the external party is done.

Basically, "Capacity 2" is used if the user wants to consider the construction of additional branches' capacity by other parties in a specific stage. Therefore, in case the user wants to represent the construction in X additional capacity inputs by external parties, then, there will be X plus 1 capacity columns in the branches file.

All these added capacities will not add any cost in the calculations since they are considered done by external parties. If the construction wants to be considered done in one year, then, the stage delta value will be 0 and the stage's value will be set as one in the "parameters.xml" file. In this case, the "Capacity 2" will be left open. This is the analysed case in this Master Thesis and it is better explained in chapter 2.4.

The "Expand" columns refer to the expansion possibility of the branches; for the first stage calculation, i.e. in the investment costs' calculation, "Expand" column is used; and for the second stage calculation, i.e. in the operational costs' calculation, "Expand 2" is used. Therefore, in short, the difference is to which calculation stage each "Expand" value is referring to, i.e. to the first or the second stage.

"Expand" and "Expand 2" columns will be set as 1 if the user wants to give PowerGIM the option to expand the branch capacity; to expand in the first stage (Expand=1), to expand in the second stage (Expand 2=1) or in both stages (Expand=1 and Expand2=1) and the "Max_newCap" column's value will set the maximum value that the branch can get by the expansion.

The "Distance" column sets the length of the branch. Nevertheless, it can be left open (without any value) and PowerGIM will calculate the minimum distance between the two nodes that define the branch ("node_from" and "node_to").

The reactance is the branch's reactance. The type of the branch can be ac, dc direct or dc meshed. The branches' "Cost_scaling" and the "Comment" columns work as the nodes' "Cost_scaling" and the "Comment" columns.

2.3.4.4. GENERATORS

The next information shown in table XXII is used for setting the generators.

Table XXIII. Generators. Input data.

Generators.csv	Desc
	Type
	Node
	Pmax [MW]
	Pmax 2 [MW]
	Pmin [MW]
	Expand [1 or 0] (1=expansion possibility in the first stage)
	Expand 2 [1 or 0] (1=expansion possibility in the second stage)
	P_maxNew [MW]
	Cost_scaling [p.u. (fraction relative to the generator's investment costs)]
	Fuelcost [€/MWh]
	Fuelcost_ref [p.u. (time dependent profile in p.u. relative to the fuelcost][*]
	Pavg [MW]
	Inflow_fac [p.u.](actual generation w.r.t. maximum generation possible through the simulation period)]
	Inflow_ref [p.u.](actual inflow w.r.t. average inflow)[*]
	Storage_cap [MWh]
	Storage_price [€/MWH]
	Storage_ini [p.u.] (Initial storage filling level w.r.t. 100% of filling level)
	Storval_filling_ref [p.u.] (Storage economic value w.r.t. 50% of filling level's economic value)[**]
	Storval_time_ref [p.u.] (Reservoirs' hourly filling level w.r.t. 50% of filling level)[*]
	Pump_cap [MW]
	Pump_efficiency [p.u.] (Actual pump's efficiency w.r.t. 100% of efficiency)
	Pump_deadband [€/MWh]

[*] It is a string, a time profile. (Length=simulation time)

[**] It is a string, a filling profile. (0%-100%)

"Desc" column means description and thus, in this column additional information about the generator unit can be added. In the "type" column, generator's technology can be set, for example, gas, coal, oil or wind.

"Pmax", "Pmax2", "Expand" and "Expand 2" follow the similar concept explained in the branches case, too. In case the user wants to give PowerGIM the chance to decide whether to expand the generation unit's capacity in the first stage, i.e. in the investment cost calculation stage, then, the "Expand" column will be set as 1. 0 will mean no expansion option. Similarly, it will be done for the second stage, in "Expand 2" column.

Likewise, it is mentioned in the branches' case, in the generators' case too, "Pmax2" will be set to a specific number in case the construction of generators by external parties wants to be considered done. In this case too, "Pmax2" will not add any cost to the analysed system, since it is considered done by an external party after a delta stage time w.r.t. time step 1.

The "Cost_scaling" concept is the same as in the "branches.csv" and the "nodes.csv" case. The "Fuelcost" is the marginal cost of the generation unit in €/MWh and the "Fuelcost_ref" is a time profile. In this column, a name could be set and then, this name would be defined in the "profiles.csv" file which is explained below, in this chapter.

"Pavg" and the "Inflow_fac" columns are more or less the same concept. The difference is that "Pavg" reduces the generators' generated amount after the end of the simulation period, and the "Inflow_fac" represents the availability of the generation unit per each time step. "Inflow_ref", "Storage_cap", "Storage_price", "Storage_ini", "Storval_filling_ref", "Storval_time_ref", "Pump_cap", "Pump_efficiency" and "Pump_deadband" are the same concepts explained in chapter 2.1.

2.3.4.5. CONSUMERS
For setting the consumers, the next characteristics mentioned in table XXIII are used.

Table XXIV. Consumers. Input data.

Consumers.csv	Node
	Demand_avg [MW]
	Demand_ref [p.u.] (Hourly demand w.r.t. average demand)[*]

[*] It is a string, a time profile. (Length=simulation time)

These parameters shown in table XXIII are the same as in PowerGAMA. In PowerGIM there is also an opportunity to set some additional characteristics of the consumers. Since they are not used in this Master Thesis, it is not mentioned. It could be found in [49]-[50] though.

2.3.4.6. PROFILES
The "profiles.csv" file follows the same pattern as in PowerGAMA. The difference is that in PowerGIM, all the profiles are defined in the same file. At the same time, since the MILP is heavier than the LP, usually the profiles' length is reduced by means of the clustering techniques.

For example, a profile of 8760 hours is shortened to 586 hours. In this way, the computational time is reduced. This leads to some deviations but it gives approximately realistic results. At the same time, usually, the storage values are not represented since clustering simplifications are done, and usually, only RES inflow time profiles and loads' time profiles are represented in the "profiles.csv" files. This is better explained in chapter 2.4. by examples.

2.3.5. ANALYSING THE RESULTS

The possible results can be analysed by using the "powergim.py" file and the "Results.py" file, this last one is the same file mentioned in chapter 2.1. about PowerGAMA. PowerGIM's results are represented, overall, at the end of the mentioned file [29].

The next calculations are some of the calculations that could be done for the optimal grid investment analysis: Investment costs, operational costs, area prices and area emissions, costs of the branches or the cost of the generator.

The previously mentioned results are for the resulting socio economically beneficial grid investment set up. The grid layout graph can be collected by the "Model.GIS.makekml" function. It is given at the end of "Run_model.py" file.

Nevertheless, all these information is better explained in chapter 2.4. by means of examples and graphs.

2.3.6. CONCLUSIONS REGARDING THE SUITABILITY OF THE TOOL

PowerGIM is capable to choose the socio-economically beneficial grid layout among all the possible choices. For that, it considers the investment costs and the operational costs.

It is a ready to use tool and by the clustering techniques the simulation time is reduced, taking around 10 minutes per simulation. The "RUN_model.py" script is used in this Master Thesis and no additional coding is needed for getting the wanted results.

The drawback of the clustering technique is that some time patterns which are implemented in the profiles CSV file, are lost, such as hydropower's filling patterns.

Nevertheless, it is suitable for this Master Thesis, since the main picture is considered in the studies, such as generation capacities, demand, operational costs, investment costs and the core pattern of the time variations in inflows and demands.

Then, PowerGAMA is used. There, the optimal grid layouts obtained in PowerGIM are implemented. In this way, the operational costs of each scenario are analysed with a higher resolution. This is explained in chapter 2.5.

2.4. SOCIO-ECONOMICALLY BENEFICIAL GRID LAYOUTS

2.4.1. INTRODUCTION

This chapter aims to explain the analysis done for getting the socio-economically beneficial offshore grid layout in the North Sea for the year 2030 per each implemented scenario.

The analysis to find the socio-economically beneficial offshore grid layout in the North Sea is done by implementing the North Sea countries; i.e. the data for Norway, Denmark, Germany, Netherlands and the UK are implemented in PowerGIM, the grid investment model explained in chapter 2.3.

PowerGIM offers a wide range of opportunities for analysis. Therefore, in this chapter, first of all, different possible assumptions are implemented. Then, the results obtained by these approximations are analysed to see the impact that they can cause in the resulting grid layouts by PowerGIM.

After that, the most conservative and realistic assumptions are chosen, and the final grid layout is appointed and analysed for each implemented scenario. Each scenario refers to each vision stated in the TYNDP 2016 of ENTSO-E with some additional modifications which are stated in the coming pages. Therefore, 4 different socio-economically beneficial offshore grid layouts are obtained by PowerGIM. Moreover, based on each scenarios' obtained result, a reference grid layout is created by the author of this Master Thesis which embraces all the obtained grid layouts in a conservative way.

The results show that the Dogger Bank hub project is a very interesting layout for the future. In fact, PowerGIM chooses this option in all the scenarios.

2.4.2. WORKING PROCESS

In this study, three different analysis are done for each implemented scenario, in order to get the socio-economically beneficial grid layout. It can be called as "3x4" analysis, 3 sensitivity analysis for 4 implemented scenarios.

The aim is to see how each assumption could affect the obtained results. The idea is to capture the trend that PowerGIM's decision could follow in each hypothetical scenario. The implemented assumptions, and thus, the sensitivity analysis, are stated below (1.-3.).

1. Dogger Bank Hub's Cost: For ensuring that the hub is implemented correctly in terms of costs, the next sensitivity analysis is done. The objective of this analysis 1 is to see how the different cost setting of Dogger Bank hub would change the investment decision. These are the implemented cases:
   a. Dogger Bank hub is already in the system. To build it does not suppose any cost.
   b. Dogger Bank hub does not exist yet. PowerGIM will decide to build it or not. For that, the cost is set to 406e6€, this is based on the offshore node's cost stated at [55].
   c. Dogger Bank hub does not exist yet. The same as in b, but the investment cost is 1 bn € higher than in b. PowerGIM will decide to build the hub or not. For that, the cost is set to 1.406e9 €.
   d. Dogger Bank hub does not exist yet. The same as in b and c, but the investment cost is 1 bn € higher than in c. PowerGIM will decide to build the hub or not. For that, the cost is set to 2.406e9 €.
   e. Dogger Bank hub does not exist yet. The investment cost is 2 bn € higher than in d. PowerGIM will decide to build the hub or not. For that the cost is set to 4.406e9 €.
   f. Dogger Bank hub does not exist yet. The investment cost is 4 bn € higher than in e. PowerGIM will decide to build the hub or not. For that the cost is set to 8.406e9 €.
   g. Dogger Bank hub does not exist and there is no option to create a dc meshed grid layout.

2. Maximum Capacity of the DC Branches: Different maximum capacity per branch could be set for obtaining the socio-economically beneficial grid layout. To see the impact that this variable could make in the results, the analysis explained below are done.
   a. Maximum capacity per DC branch that PowerGIM can choose= 2000 MW.
   b. Maximum capacity per DC branch that PowerGIM can choose = 2500 MW.
   c. Maximum capacity per DC branch that PowerGIM can choose = 3000 MW.

3. Maximum Number of Parallel Branches: Similarly, different number of maximum parallel branches could be set. The effect that this condition could have in the investment decision is analysed by the next studies:
   a. Maximum number of parallel branches that PowerGIM can choose = 4.
   b. Maximum number of parallel branches that PowerGIM can choose = 5.
   c. Maximum number of parallel branches that PowerGIM can choose = 6.

Analysis 1 to 3 are done for each scenario. The used input data is explained below, in 2.4.3.; and the results are shown in 2.4.4. Based on the results, an offshore grid layout is chosen for each implemented scenario, which are shown in 2.4.4.4.

In the coming pages, the chapter refers to these sensitivity analysis' naming (1, 2 and 3) frequently. The next figure 30 gives a brief description of this step of this Master Thesis. It is the same shown in the beginning of the report, in 1.4. Research approach.
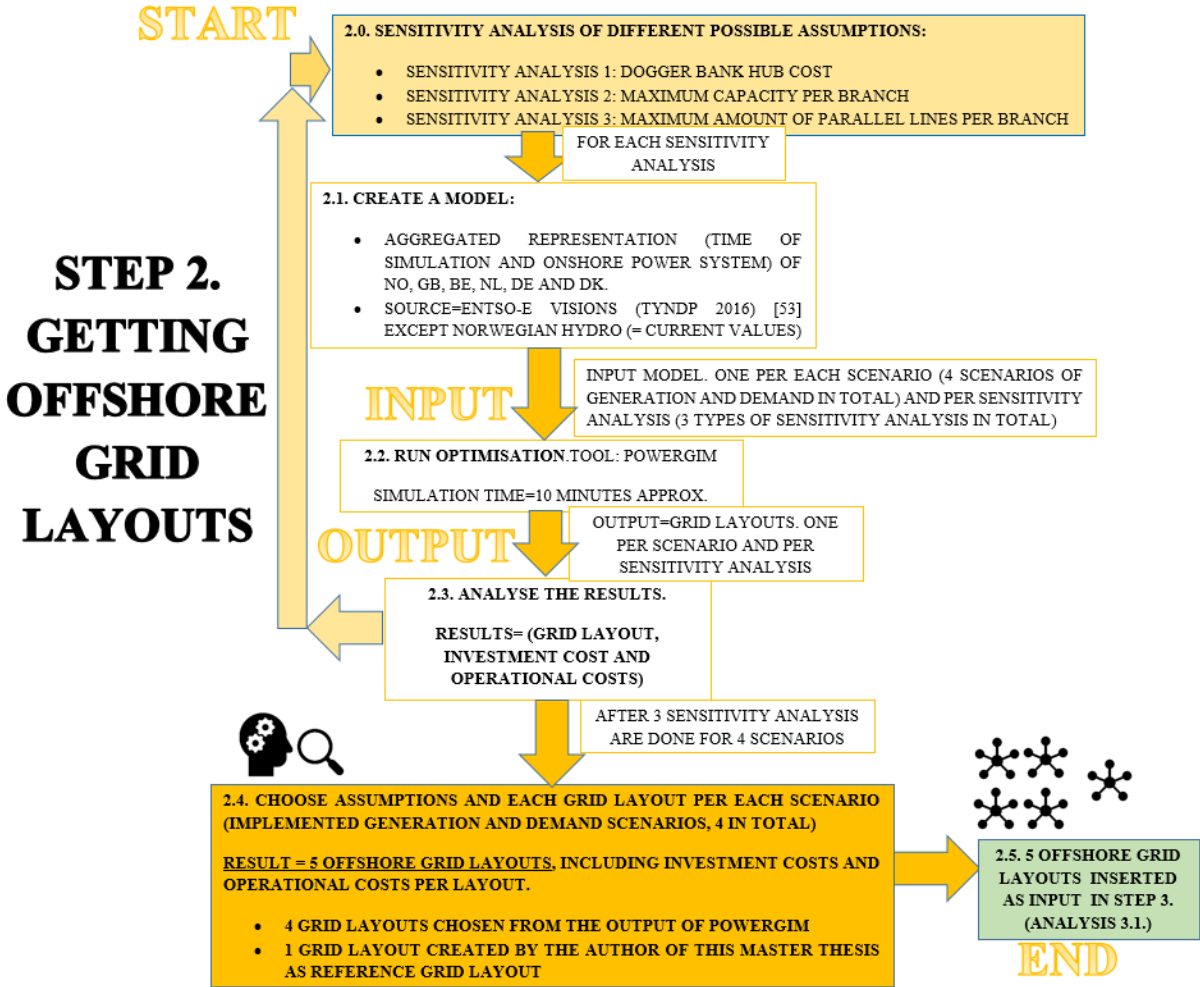
Figure 30. Flow chart of the second step of this Master Thesis.

2.4.3. INSERTING THE INPUT DATA

In the next pages, the data used for the North Sea's offshore-grid design analysis are explained.

For giving an idea of the implemented scenarios, the next table XXIV is created. In short, 4 different scenarios are implemented, in terms of generation and demand. Each of them refer to one ENTSO-E Vision (1-4) of the TYDNP 2016 with some additional modifications.

Table XXV. Implemented scenarios (generation and demand).

Implemented scenarios of generation and demand	Reference for <u>generation, demand and load profiles</u>
Scenario 1	ENTSO-E Vision 1 (Exception=Norwegian hydropower with current generation capacity values, 31GW)
Scenario 2	ENTSO-E Vision 2 (Exception=Norwegian hydropower with current generation capacity values, 31GW)
Scenario 3	ENTSO-E Vision 3 (Exception=Norwegian hydropower with current generation capacity values, 31GW)
Scenario 4	ENTSO-E Vision 4 (Exception=Norwegian hydropower with current generation capacity values, 31GW)

The exception is decided following [5]-[7] as explained in the literature survey, in the beginning of this report. Nevertheless, these data are more deeply analysed in the coming pages.

For each implemented scenario, the socio economically beneficial grid layout is chosen. These are shown in the end of this chapter.

2.4.3.1. SIZE OF THE INPUT DATA

The tool used in this study is PowerGIM. It is deeper analysed in the previous chapter 2.3. As it is explained there, PowerGIM makes use of the Mix Integer Linear Programming. Therefore, the optimisation is heavier than in PowerGAMA which uses Linear Programming; and taking this into account, an aggregated data-base is used in this Master Thesis. It is shown in table XXV.

Table XXVI. Size of the input data.

	Number of physical units	Defined Parameters/Variables
Nodes	77	9
Branches AC/DC	97	12
Generators	99	24
Consumers	6	9
Profiles	25	(8760 hours, steps of 1 hour) *

*These profiles are aggregated for this analysis, resulting in a 400-hour profile. It will be explained below, in 2.4.3.2.6.

The next figure 31 shows the implemented nodes, generators, consumers, profiles and AC/DC branches.
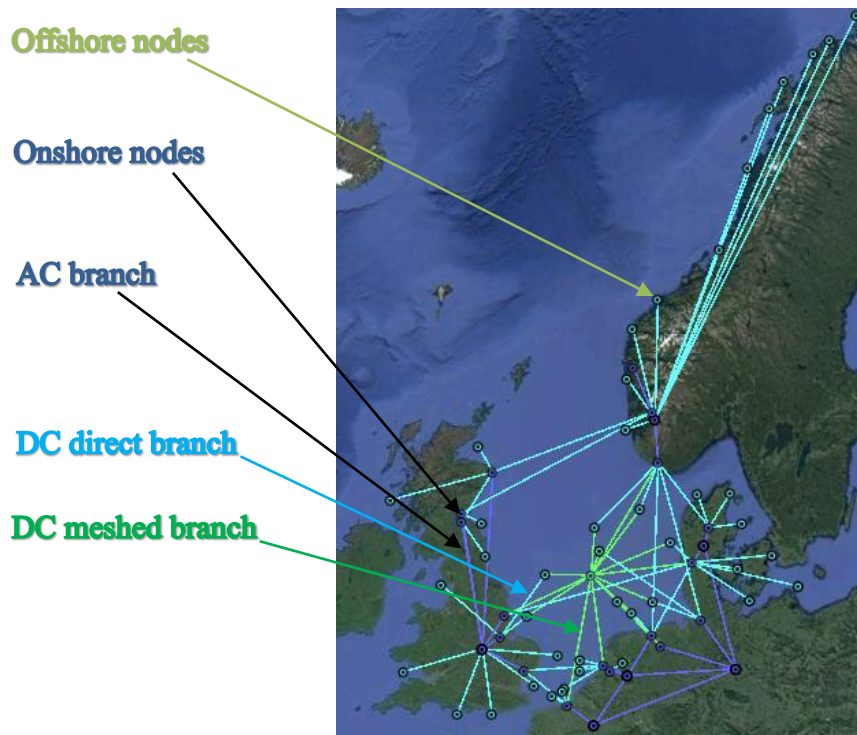
Figure 31. Implemented data-set.

The implemented values and the used sources are mentioned in 2.4.3.2.

2.4.3.2. INPUT DATA

In the next pages the used input-data is explained. Its skeleton follows the same format as in chapter 2.3. For more information regarding the input data, consult chapter 2.3.

In this analysis, ENTSO-E's data regarding the existing and future interconnections [52] and ENTSO-E's Ten Years Network Development Plan from 2016 for the year 2030 [53] are used for generators and consumers' implementation. There is an exception in the Norwegian hydropower generation capacities though. These are kept as the current generation capacities, i.e. 31 GW. The most conservative representation of the system is wanted to be analysed in this Master thesis, i.e. Norwegian reservoir´s balancing strength is not increased for this analysis w.r.t. current values. This is decided following [5]-[7], as stated in the conclusions of the literature survey in 1.3.3.1. of this report.

2.4.3.2.1. AREAS AND DATA ARRANGEMENT

As it can be seen in figure 31, the implemented areas are Norway, Denmark, Germany, Netherlands, Belgium and Great Britain.

The main idea of this decision is that the focus area of this analysis is the North Sea and that the needed computational time should be acceptable. Therefore, the countries surrounding the area of analysis are implemented. Regarding the power exchange that these countries could have with their individual surrounding countries, such as, Belgium-France, is not implemented in this analysis.

2.4.3.2.2. PARAMETERS' FILE

As explained in chapter 2.3, in the parameters' file, the investment costs and factors related to CO_2 emissions and economics are set. The economic factors and investment costs are taken from [55] and [60], and the CO_2 emissions are taken from [56] and [31]. These can be found in the table below, table XXVI. Diverse generation technology's CO_2 emission factor is taken as oil's, as approximation.

Table XXVII. Parameters.xml input file's data.

Component	
Nodes	**Investment costs**
-AC node	50e6 €
-DC node	406e6[*] €
DC-direct branches	**Investment costs**
-Mobilisation cost	312e3 €
-Cost per distance	1236e3 €/km
-Cost per power rating and distance	0.578e3 €/(kmMW)
-Branch's onshore endpoint cost	58209e3 €
-Branch's onshore endpoint cost per power rating	93.2e3 €/MW
-Branch's offshore endpoint cost	453123e3 €
-Branch's offshore endpoint cost per power rating	107.8e3 €/MW
	Losses parameters
-Power loss constant	3.2 %
-Power loss slope (per km)	0.003%
DC-meshed branches	**Investment costs**
-Mobilisation cost	312e3 €
-Cost per distance	1236e3 €/km
-Cost per power rating and distance	0.578e3€/(kmMW)
-Branch's onshore endpoint cost	1562e3 €
-Branch's onshore endpoint cost per power rating	0 €/MW
-Branch's offshore endpoint cost	5437e3 €
-Branch's offshore endpoint cost per power rating	0 €/MW
	Losses parameters
-Power loss constant	0%
-Power loss slope (per km)	0.003%
AC branches	
-Mobilisation cost (Installation cost, vessel)	312e3 €
-Cost per distance (Installation and cable)	1193e3 €/km
-Cost per power rating and distance (cable)	1.416e3€/(kmMW)
-Branch's onshore endpoint cost	1562e3 €
-Branch's onshore endpoint cost per power rating (converter)	0 €/MW
-Branch's offshore endpoint cost	5437e3 €
-Branch's offshore endpoint cost per power rating (converter)	0 €/MW
	Losses parameters
-Power loss constant	0%
-Power loss slope (per km)	0.005%
Converters	
-Branch's onshore endpoint cost	28323e3 €

-Branch's onshore endpoint cost per power rating (converter)	46.6e3 €/MW
-Branch's offshore endpoint cost	20843e3 €
-Branch's offshore endpoint cost per power rating (converter)	53.9e3 €/MW
	Losses parameters
-Power loss constant	1.6%
-Power loss slope (per km)	0%
Parameters	**Values**
-Operation and Maintenance Rate relative to investment costs	2%
-Finance Interest Rate	5%
-Finance Years or Lifetime	30 years
-CO_2 price	-V4=76 €/ton CO_2
	-V3=71€/ton CO_2
	-V2 = 17 €/ton CO_2
	-V1 = 17 €/ton CO_2
-Stage 2 Time Delta	0 years
-Stages	1 stage
CO2 Emission Factors	**Values**
-Applicable for all RES and nuclear	0 ton CO_2/MWh
-Gas	0.4215 ton CO_2/MWh
-Coal	0.99 ton CO_2/MWh
-Oil	0.95 ton CO_2/MWh
-Lignite	0.9 ton CO_2/MWh
-Diverse	0.95 ton CO_2/MWh

*This factor changes in the first sensitivity analysis. It is the variable over which the sensitivity analysis is implemented.

The duration over which to consider the operational costs is taken as 30 years, this is set as the finance years, as mentioned in table XXVI. At the same time, the investment is assumed done in the same year as approximation, i.e. the different stages of the construction are not considered.

2.4.3.2.3. BRANCHES AND NODES
Each country has at least one onshore node implemented which is in the middle of the country. In some countries, there are more than one node, since it helps to implement the possible interconnections and because it helps to implement offshore wind generators.

For instance, in case of Great Britain and Norway, extra nodes are added to replicate the interconnections between Norway and Great Britain, in figure 31. In Norway, more nodes are added to implement the offshore wind generators in the North. All of them are connected to the same central node in this analysis of chapter 2.4.

Nevertheless, these are implemented mainly for the analysis in chapter 2.5, where the analysis of operational costs of each system is done with higher resolution. There, the mentioned generators are connected to their closest onshore nodes. This is better explained in chapter 2.5.

The location of wind generation is taken from [31] and then, some aggregation is done. The resulting nodes are shown in figure 31 and figure 32.

The implementation of the branches is a key step in this analysis. For this, data from ENTSO-E are taken [52]. There, information of existing, under construction and planned branches is given. Apart from that, another project [54] is considered which involves a modular island in the Dogger Bank area as a hub.

Nevertheless, as mentioned before, the different stages of the construction of the modular island are not taken into account in this Master Thesis. All the construction is considered done in one stage.

Based on these information, the next six groups of branches are implemented in PowerGIM for this analysis.

1) Existing DC Direct Branches: These are implemented as fixed values. Their capacity is the one stated by [52], e.g. NorNed.

2) Under Construction DC Direct Branches: Likewise, it is done in 1), these are implemented as fixed capacities, as well; and the values are equal to the stated in [52], for instance, Cobra 1.

3) Under Consideration or Planned DC Direct Branches: In this case, these branches are set as not already existing, and for each of them, an expansion possibility is given to PowerGIM. The maximum expansion that these branches can have is set as equal to the capacity values mentioned in [52].

4) Dogger Bank hub, DC Meshed: Additionally, for each implemented country, the option to connect to the Dogger Bank hub is given for creating a DC meshed grid layout in the North Sea, based on [54]. The central point is set around the middle point of the Dogger Bank sand bank. It can be seen in figure 32.

   At the same time, the offshore wind generators which are the closest to the hub have two options. The input data is set such that the mentioned generators can connect to the hub by a DC meshed grid and/or they can connect to their countries' node by a DC direct grid. In figure 32 the generators which get these opportunities are shown.

5) AC Branches: These are onshore branches, which are considered as already fixed. Their capacity is set such that they follow the same existing grid constraint onshore for the year 2030. For that, the existing maximum grid limitation per country, after the infinity capacity, is implemented in the branches.

6) Offshore Generator's DC Direct Branches: These wind farms branches' capacity are taken as fixed and they are directly connected to the closest onshore node of their corresponding country. These offshore wind generators are far from the Dogger Bank hub. They do not get the opportunity to connect to the hub. A substantial capacity is set for these branches to ensure that all the generated energy is transported properly, and their costs are not taken into account for the investment cost calculation.

All the expansion possibilities are considered only, in the first stage of the optimisation, i.e. in the investment cost calculation. This is referred to the theory explained in chapter 2.3.

2.4.3.2.4. CONSUMERS
The demand is set based on [53] and it is placed in the node located around the centre of the country, because of the aggregation methodology followed in this analysis.

2.4.3.2.5. GENERATORS
2.4.3.2.5.1. GENERATION CAPACITIES
The generation capacities are taken from [53]. An exception is applied for Norway whose hydropower generation capacities are kept as the existing values currently, following [6]-[7]; i.e. the values used in the Validation Study explained in chapter 2.2, thus pumping is neglected in the analysis. For the rest of the countries, the hydropower generation capacities are implemented following [53]. Pumping is neglected in this Master Thesis.

The increase in hydropower's generation capacity and in the pumping would make a difference in the filling level of the reservoirs, making the reservoirs' handling more dynamic. This implementation would be a recommendation for future analysis.

It is to mention that in this aggregated analysis of this chapter, the hydropower reservoirs are not implemented. These are implemented as non-dispatchable energy sources, like solar or wind for this simplified analysis in chapter 2.4.

The reason is that a reduced system is used in this analysis, in terms of time (400 hours are chosen as representation of 8760) and space, few nodes are used for representing the system. Nevertheless, once the grid layouts are obtained in this analysis, then, in chapter 2.5, the obtained grid layouts are deeply analysis by implementing them in PowerGAMA and implementing properly the time and space dependencies. There, the reservoirs are properly represented and hydropower plants with reservoirs are set as dispatchable.

Regarding wind generation units, the next fraction between offshore and onshore wind generation sources are implemented in each country, table XXVII. These are taken from [57] and they are similar to [58]. These ratios are kept constant for all the scenarios.

Table XXVIII. Implemented offshore wind generation ratio.

Country	Offshore Wind (%) from the total wind generation capacity values
Norway	56.14
Denmark	48.34
Germany	20.87
Netherlands	53.13
Belgium	42.69
Great Britain	70

As mentioned earlier, nine offshore wind generation units, which are the closest to the hub, have the chance to whether to connect to the hub creating a dc-meshed grid-layout and/or to connect directly to their countries' onshore node.

In figure 32, the implemented offshore-wind generators in the North Sea can be seen, they are shown as red dots. The Dogger Bank hub is represented as light blue dot. The generation units which have the option to connect to the hub are inside the yellow box, in figure 32.
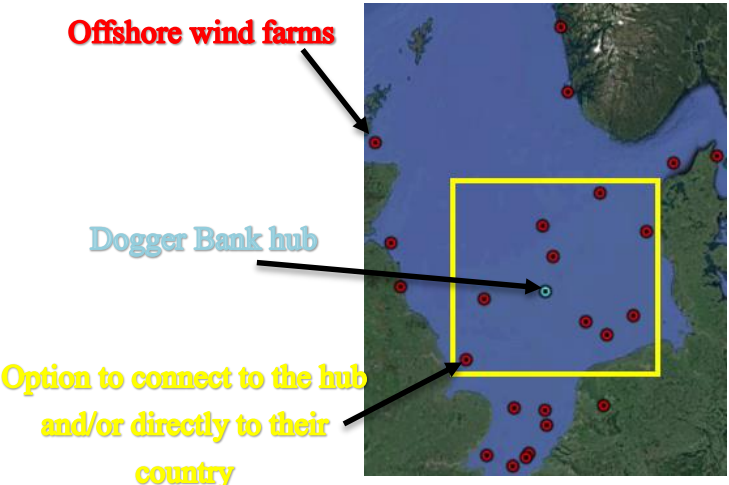
Figure 32. Implemented offshore wind generators and Dogger Bank hub.

By the values of [53] and table XXVII, the next implemented offshore wind generation capacities for each scenario are obtained. They can be found below, in the second column of table XXVIII.

Table XXIX. Implemented offshore wind generation capacities in the North Sea.

Implemented Scenario	North Sea, Offshore Wind Generation Capacity	European Wind Organisation's prospects [58]
Scenario 1	31.746 GW	Low scenario = 32.1 GW
Scenario 2	45.939 GW	Central scenario = 45.1 GW
Scenario 3	56.047 GW	High scenario=61.5 GW
Scenario 4	57.215 GW	High scenario=61.5 GW

It is important to point out how much is the total offshore wind generation amount which gets the option to connect to the Dogger Bank hub in each scenario. Based on [59], the modular island will be able to connect roughly 30 GW. The next values are implemented with the possibility to connect to the hub, table XXIX.

The total implemented maximum possible amount of offshore wind generation capacities connected to the hub goes also beyond the number stated in [59], 30 GW, for the last 2 implemented scenarios, scenario 3 and 4. Nevertheless, the total wind generation connected to the hub is chosen by PowerGIM, due to its choice regarding branches' capacities.

Table XXX. Implemented amount of offshore wind generation - Dogger Bank hub.

Implemented Scenario	Maximum amount of offshore wind generation which can be connected to the Dogger Bank hub
Scenario 1	22.004 GW

Scenario 2	30.534 GW
Scenario 3	36.766 GW
Scenario 4	38.406 GW

The Marginal Costs of the generation technologies are calculated following the next equation 29:

$$mc_i = \frac{Fuel\ Price_i}{Energy\ Efficiency_i} + CO_2 price_i \times CO_2 emission factor_i \quad (29)$$

The marginal costs mc_i are given in $\left(\frac{€}{MWh}\right)$. Fuel Prices are in $\left(\frac{€}{MWh}\right)$ and they are taken from [53], CO_2 prices are in $\left(\frac{€}{ton}\right)$ and they are gathered from [53], the energy efficiencies are in (p.u, the efficiency value w.r.t. 100% of efficiency) and they are collected from [56] and [31] and CO_2 emission factors are in $\left(\frac{ton}{MWh}\right)$ obtained from [56] and [31] and shown in table XXVI, in this chapter.

The implemented energy efficiencies can be found in table XXX below. The efficiency of lignite generation technology is taken the same as coals'. At the same time, the efficiency of diverse generation technology is set the same as oils'.

Table XXXI. Implemented Energy Efficiencies per generation technology.

Generation Technology	Implemented Energy Efficiency Value
Applicable for all RES except Bio	100 %
Bio	29 %
Nuclear	33 %
Gas	48 %
Coal	37 %
Oil	29 %
Lignite	37 %
Diverse	29 %

The resulting implemented Marginal Costs per each scenario are shown in table XXXI.

Table XXXII. Implemented Marginal Costs per Generation Technology.

Generation Technology	Marginal Cost Scenario 1 [€/MWh]	Marginal Cost Scenario 2 [€/MWh]	Marginal Cost Scenario 3 [€/MWh]	Marginal Cost Scenario 4 [€/MWh]
Applicable for all RES except Bio	1	1	1	1
Bio	22.53	22.53	22.53	22.53
Nuclear	5	5	5	5
Gas	78.34	78.34	84.15	86.26
Coal	46.20	46.20	97.61	96.61
Oil	233.66	233.66	233.77	238.53
Lignite	26.03	26.03	74.63	79.13
Diverse	233.66	233.66	233.77	238.53

It is to point out the effect that the CO_2 prices and the fuel costs cause on the final marginal costs. For example, in scenario 1 and 2, gas is more expensive than coal, but in scenario 3 and scenario 4, gas is cheaper than coal. The reason is that coal has a higher CO_2 emission factor and in addition, the CO_2 (ton/MWh) prices are higher in the mentioned scenarios w.r.t. scenario 1 and scenario 2.

The implemented inflow factors are based on [31]. They are shown in table XXXII, and these are the same for all the countries and all scenarios. Hydropower's inflow factor values are taken from the Validation study shown in chapter 2.2.

Table XXXIII. Implemented Inflow Factors.

Generation Technology	Inflow Factor
Wind, Offshore-Wind, Solar and Run of the river	1
Bio	0.7
Nuclear	0.9
Gas	0.86
Coal	0.75
Oil	0.95
Lignite	0.7
Diverse	0.65

The inflow factor is taken as 1 in case of the run of the river, solar, wind and offshore-wind generation technologies, since their inflow profiles have an average value equal to their corresponding availability factor. This comes from the explanations given in chapter 2.1.

2.4.3.2.6. PROFILES

The load profiles are calculated from [53] and wind, solar and run of the river inflow profiles are taken from [31] and from chapter 2.2.

In this study explained in chapter 2.4, two types of aggregation are implemented. As it is mentioned previously, aggregation regarding node's location is one of them. In addition, aggregation regarding time is done.

This means that the analysis is done implementing one year's situation as reference, but the time length is not of 8760 hours. Instead, an aggregated time analysis is followed, i.e. 400 random representative hours are taken from those 8760 hours. This is shown in the next example, figures 33 and 34, where the load profile of Netherlands for scenario 4 of 8760 points is converted into 400 points.

This applies to all the implemented profiles. The chosen 400 hours from those 8760 hours are the same in all implemented scenarios. This decision of implementing 400 is taken based on [4]. In this way, the computational time is reduced.
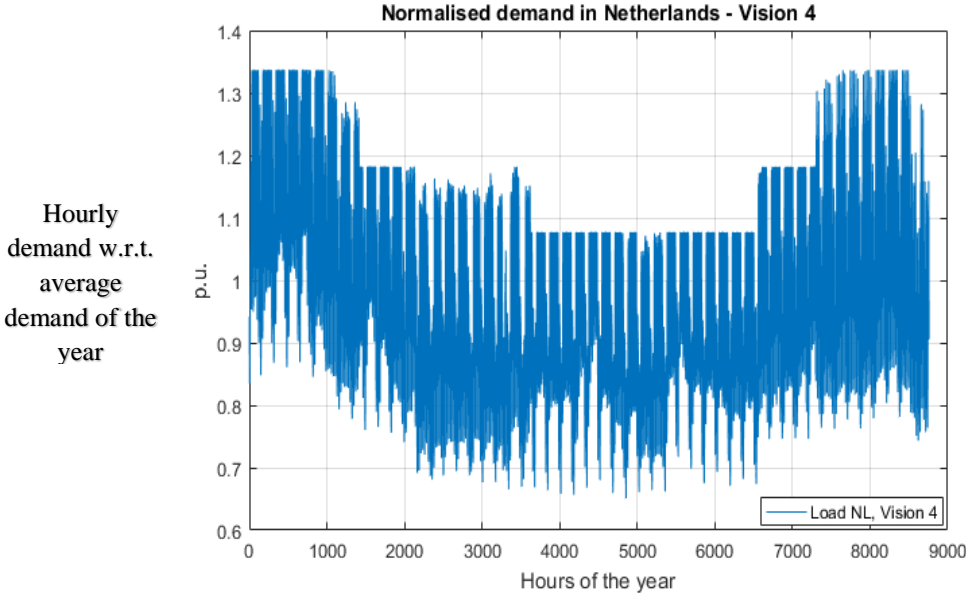
Figure 33. Actual normalised load profiles in Netherlands, scenario 4.
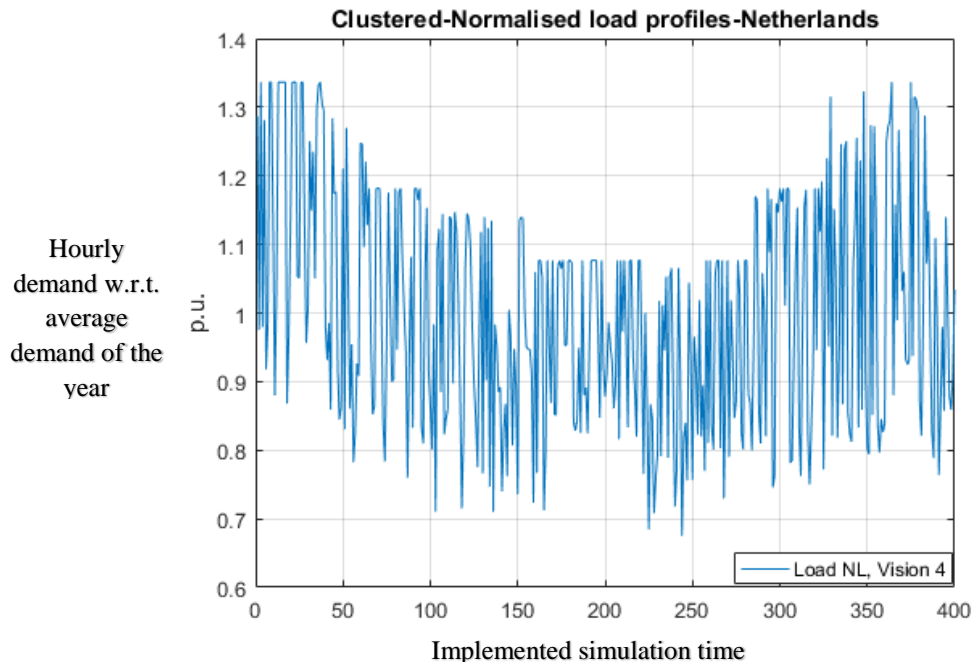
Figure 34. Implemented load profiles in Netherlands, scenario 4.

Due to this aggregation, the hydropower generation units are implemented as non-dispatchable energy sources and the inflow factor is taken from the Validation study. This approximation applies only to this chapter 2.4.'s analysis.

2.4.4. ANALYSING THE RESULTS

The result of each analysis is the socio-economically beneficial grid layout, including the line's capacities. At the same time, the operational costs and the investment costs are calculated. The results are shown following the same points explained in 2.4.2. working process of this chapter.

All the final chosen layouts per each scenario are shown in 2.4.4.4, including capacity of the branches and the amount of branches.

2.4.4.1. DOGGER BANK HUB'S COSTS ANALYSIS

For this analysis, the maximum capacity that PowerGIM can choose per branch is taken as 2 GW and the maximum parallel branches that PowerGIM can choose is set equal to four.

The results show that the Dogger Bank hub's cost does not impact the obtained grid layout if the cost of the hub is up to 8.406e9 €. This is repeated in all the generation and demand scenarios (4 in total).

This is mainly related to the fact that the investment cost is higher if the Dogger Bank hub's DC-meshed layout is chosen, but the operational costs minimisation obtained through 30 years by the hub is such that that the hub is the preferred option by PowerGIM, rather than another option without the hub. This statement comes from the results shown in the next figures 35 and 36. In the graphs below, 1 billion refers to 1e9 €. The following investment costs include the operation and maintenance costs, as well. Each bar column refers to each Dogger Bank hub's cost setting analysis. DB means Dogger Bank hub below.
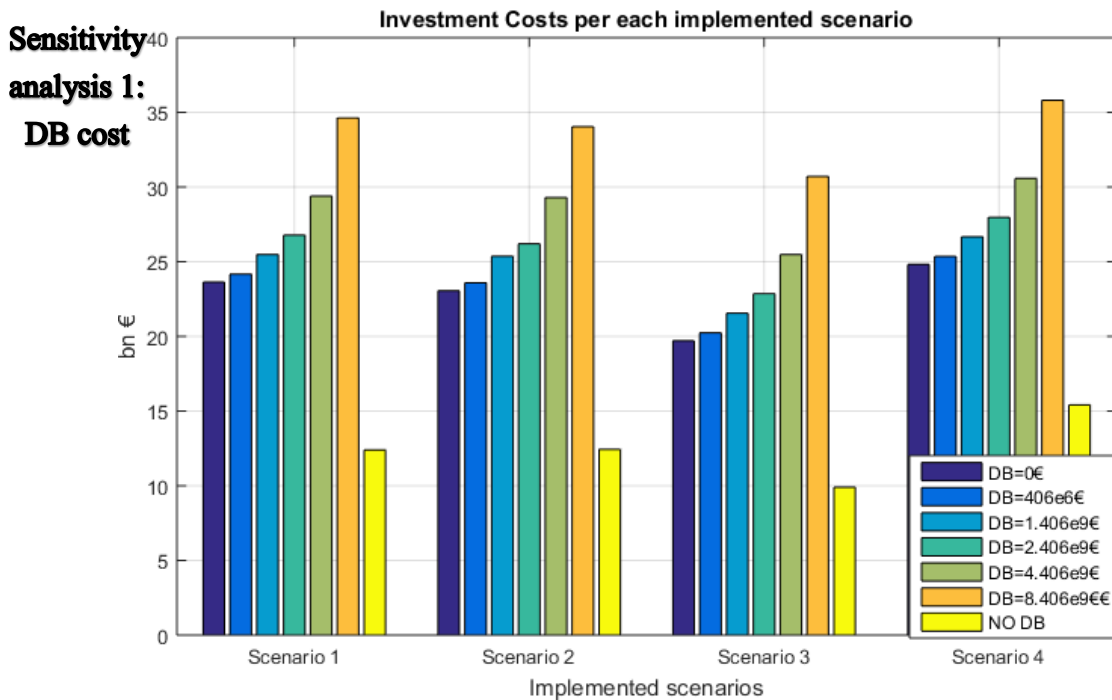
Figure 35. Investment costs results of sensitivity analysis 1. Dogger Bank hub's cost.
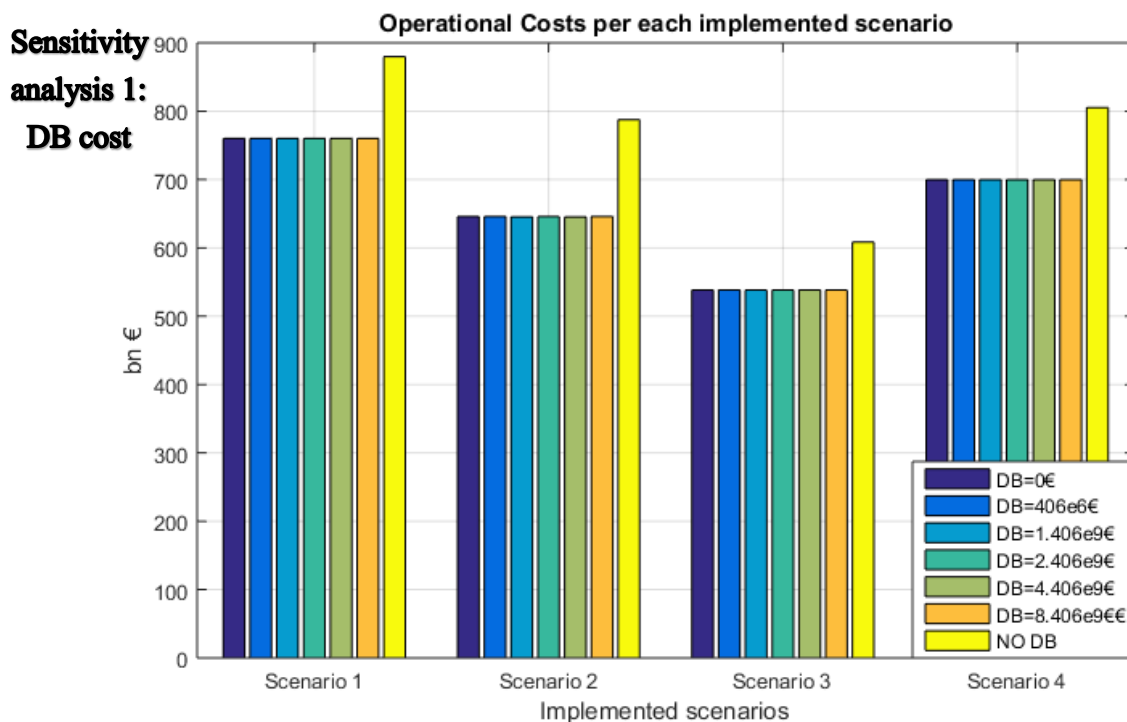
Figure 36. Operational costs results over 30 years, sensitivity analysis 1.

As it can be seen in figure 35, the difference in the investment costs between the highest and the lowest peak is of (35.81e9€ -10.42€) 25.39e9€. The highest cost corresponds to scenario 4's investment cost with implemented Dogger Bank hub's cost as 8.406e9€; whereas the lowest investment cost corresponds to scenario 3 with no Dogger Bank hub option. Therefore, the difference shows the investment saving that could be obtained by not implementing the Dogger Bank hub. The savings are around the same value in all the scenarios.

If we do the same comparison with the operation costs shown in figure 36, around 50-100 billion € would be saved in each scenario by having the opportunity of the Dogger Bank hub connection. Therefore, the Dogger Bank is the option chosen in all the scenarios by PowerGIM.

It is to mention that the operational costs are the lowest in scenario 3, in fact, if the bio, hydro, other_RES, wind and solar generation capacities are summed in the North Sea countries per each scenario, scenario 3 has the biggest amount of RES, thus, probably, the biggest RES share resulting in lower operational costs.

Nevertheless, it does not just depend on the generation capacities, it also depends on other factors, such as the obtained grid layout in each scenario, and how helpful it is for RES integration, i.e. the share of RES in the resulting energy mix.

For example, scenario 4 is assumed to be more integrated, and thus higher use of the interconnections is expected to be done and higher use of the hydropower reservoirs for balancing. It is to point out that a reduction of 17.6 GW is followed in this sense in the implemented data for scenario 4 following [5]-[7] w.r.t. the ENTSO-E's scenario 4 prospects and this creates an impact. The reduction in the rest scenarios is lower than 9.7 GW. This can reduce the opportunity to use RES and at the end, it can turned out in higher operational costs, since the needed flexibility is not taken from hydropower reservoirs, it is taken from other conventional forms which are more costly in this scenario. This applies mainly to the seasonal period when the reservoirs are the driest.

The obtained grid layout is the same per each scenario for 1.-6. analysis; not only the shape, also the capacity values of the branches. Since the Dogger Bank hub option is not given in 7th analysis (1.g), the obtained grid layout is completely different. This is better explained in the Table XXXIII.

DB means "Dogger Bank hub" in the next table. The numbers and letters in the first column of the table XXXIII, refer to the 2.4.2. subchapter of this chapter.

Table XXXIV. Dogger Bank hub's cost analysis and the obtained results.

Sensitivity analysis 1	Scenario 1	Scenario 2	Scenario 3	Scenario 4
1.a. DB=0 €	Same grid layout obtained: -same shape -same grid capacities	Same grid layout obtained: -same shape -same grid capacities	Same grid layout obtained: -same shape -same grid capacities	Same grid layout obtained: -same shape -same grid capacities
1.b. DB=406e6 €				
1.c. DB=1.406e9 €				
1.d. DB=2.406e9 €				
1.e. DB=4.406e9 €				
1.f. DB=8.406e9 €				
1.g. No DB Option	unique grid layout: -shape -capacities	unique grid layout: -shape -capacities	unique grid layout: -shape -capacities	unique grid layout: -shape -capacities

As example, the resulting grid layout obtained for scenario 4 can be seen in figures 37 and 38. Figure 37 shows the grid layout and capacities obtained for 1.a., 1.b., 1.c., 1.d., 1.e. and 1.f. analysis by implementing scenario 4's values. The black lines are fixed lines. The blue lines are the investment decisions. The total picture shows the resulting grid layout. Figure 38 shows the grid layout obtained for 1.g. analysis by implementing scenario 4's values.

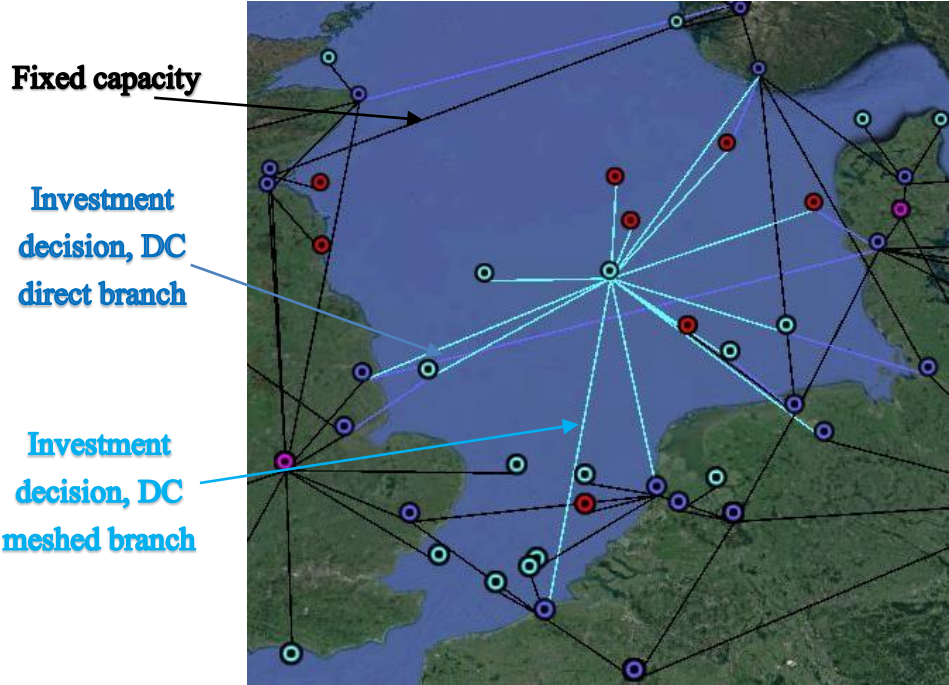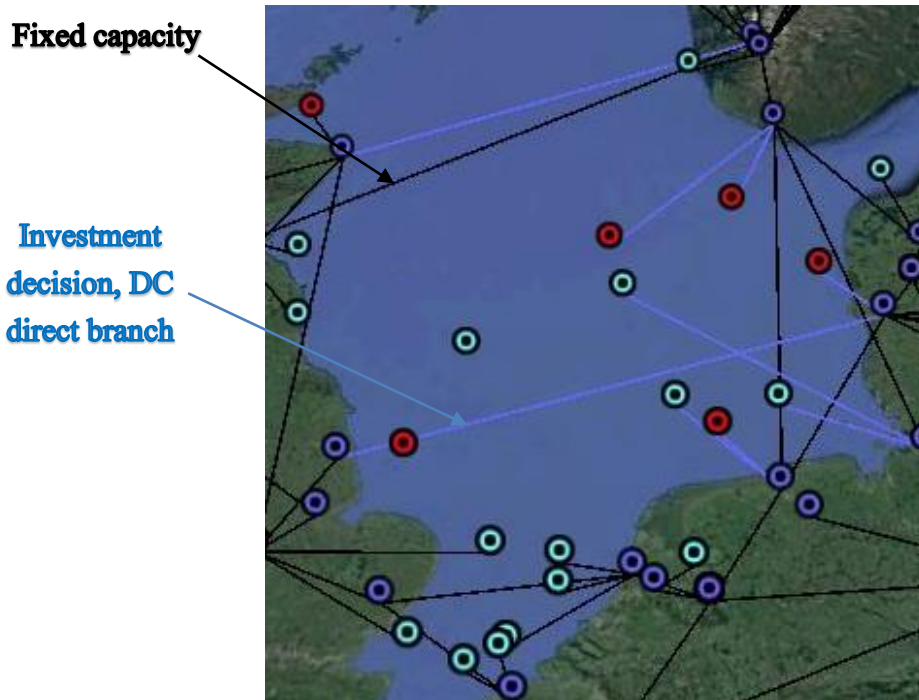**Figure 37. Obtained grid layout for scenario 4. (a, b, c, d and e analysis)**

To get an idea of the process, as a recap, figure 31 can be remembered where all the data set is shown, e.g. existing or under construction branches, branches which are plans or branches which could be interesting (dc-meshed layout by Dogger Bank). PowerGIM choses the layout which gives the lowest investment and operational costs' combination.

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Figure 38. Obtained grid layout for scenario 4, (g analysis).

This example shows clearly one of the reasons of the high operational costs reduction obtained by the Dogger Bank hub compared to not having the Dogger Bank hub option. The reason is that, as stated in figure 32, nine offshore wind generators get the option to connect to the hub or to connect directly to their corresponding countries.

The idea is that if there is no Dogger Bank hub option, the mentioned offshore wind generators, the nine shown in figure 32, follow the same analysis pattern as in a) to f) analysis, i.e. they get the option to connect directly to their corresponding country's onshore node, but in this analysis (1.g), they do not have the option to connect to the hub.

Likewise it is in the previous studies 1. a to 1.f, the maximum possible capacity for doing so is 2 GW, too, in this analysis 1.g. In this way, the consistency between different analysis is ensured, because if these offshore wind farms would be already assumed directly connected to the onshore node, then, the investment costs would not be considered in the optimisation problem, but for the rest of the cases the cost that these connection suppose to the system are taken into account. Equal conditions of analysis are ensured in this way.

The result presented in figure 38 shows that two offshore wind farms are not chosen to be connected onshore. They are left out of the system. This is probably because the operational cost reduction obtained by this choice is not higher than the investment cost needed for the connection. The reason is that the distance onshore is considerable in both cases, and the capacity needed as well, the generation capacities are of 9.341 GW and 7.3 GW thus, the investment cost is considerable. In addition, the corresponding country, i.e. Great Britain might have already enough generation capacity.

Therefore, PowerGIM do not choose these farms to be integrated into the Power System, and it leaves them out of the picture, thus lower RES are integrated in the system. By these two graphs, it is shown that Dogger Bank hub is also a RES integration facilitator.

2.4.4.2. MAXIMUM BRANCHES' CAPACITY ANALYSIS

For this analysis, Dogger Bank hub's investment cost is set as 406e6 € and the maximum parallel lines per branch is set equal to 4. The results are shown in figures 39 and 40.
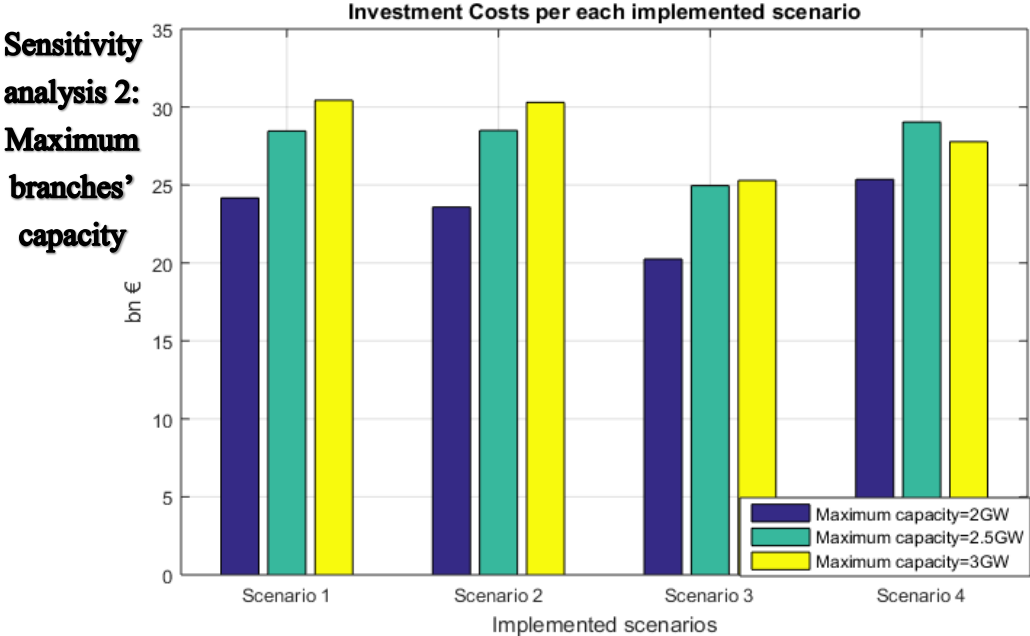

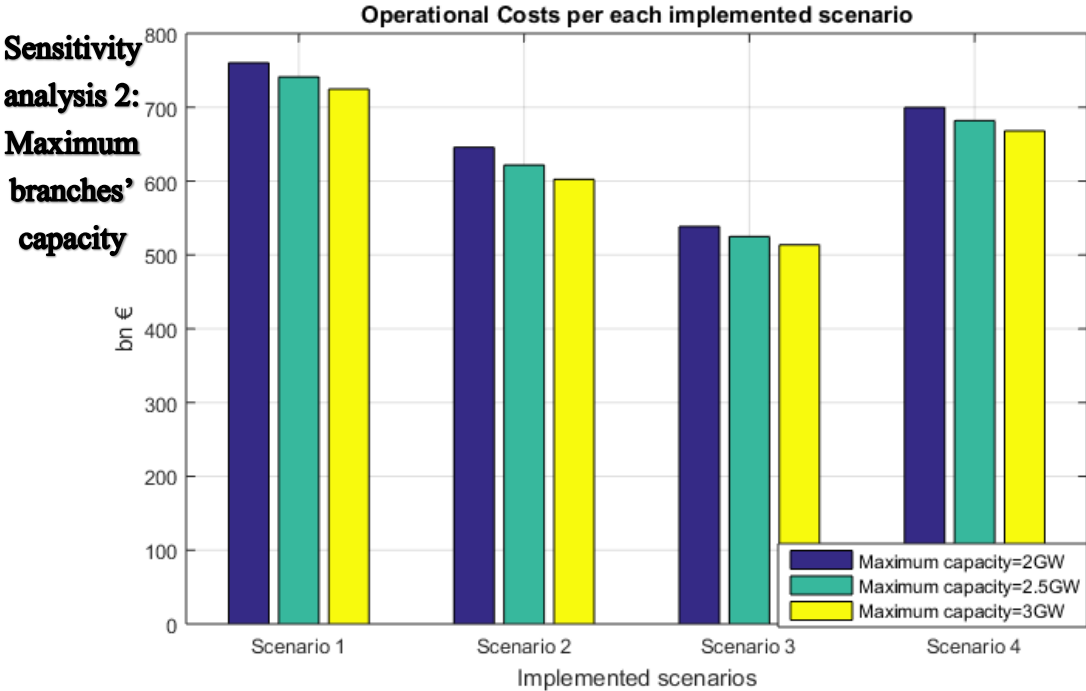**Figure 39. Investment costs results of sensitivity analysis 2.**

Figure 40. Operational costs results over 30 years, sensitivity analysis 2.

Based on figures 39 and 40, the operational costs are reduced when the maximum branches' capacity is increased. The obtained differences regarding grid design and capacities are stated

in the table XXXIV below. The conclusion is that if PowerGIM has the opportunity to choose a higher branch capacity, it does so; since this makes the system's operational cost be reduced.

This is found especially, in the case of the interconnections which are connected directly to the Dogger Bank hub. Nevertheless, even if PowerGIM has the option to increase the amount of parallel branches, and in this way, to increase the transfer capacity, it does not do so. These are shown in table XXXV.

Table XXXV. Obtained results in analysis 2, of chapter 2.4.

Sensitivity analysis 2	Scenario 1	Scenario 2	Scenario 3	Scenario 4
2.a. Maximum Branch Capacity 2 GW	Same grid layout obtained: -same shape -different grid capacities, from case a towards case c, higher grid capacities are selected.	Ringkøbing Fjord Offshore Wind Farm in Denmark prefers DC-Meshed. Below, it prefers, DC direct to DK.	Humber Gateway Offshore Wind Farm in GB, does not chose direct connection to GB. Below, it has.	Same grid layout obtained: -same shape -different grid capacities, from case a towards case c, higher grid capacities are selected.
2.b. Maximum Branch Capacity 2.5 GW		Same grid layout obtained: -same shape -different grid capacities, from case a towards case c, higher grid capacities are selected.	Apart from the differences stated above and below; same grid layout is obtained: -same shape -different grid capacities, from case a towards case c, higher grid capacities are selected.	
2.c. Maximum Branch Capacity 3 GW	Line between DK and hub is not chosen		There is no direct connection in this case for Soerlige Nordsjoe I Wind Farm in Norway. Above, it has.	North-Connect is not chosen as investment option. There is no direct connection in this case for Soerlige Nordsjoe I Wind Farm

Table XXXVI. Chosen amount of cables and capacities in Scenario 2.

fArea	tArea	Type	a. Maximum capacity per branch 2 GW		b. Maximum capacity per branch 2.5 GW		c. Maximum capacity per branch 3 GW	
			NewCables	NewCap. MW	NewCables	NewCap. MW	NewCables	NewCap. MW
BE	DB	DCmeshed	2	2000	2	2000	3	3000
DE	DB	DCmeshed	2	2000	3	2500	3	3000
DK	DB	DCmeshed	1	1000	1	1000	1	1000
GB	DB	DCmeshed	2	2000	3	2500	3	3000
NO	DB	DCmeshed	2	2000	3	2500	3	3000
NL	DB	DCmeshed	2	2000	2	2000	2	2000

In table XXXV, it can be seen, that the chosen capacity is always the maximum for Great Britain, Norway and Germany in this analysis done for scenario 2. Taking into account all scenarios, especially Netherlands and Denmark are more conservative in this sense, and they do not tend to take as much capacity as possible for connecting to the hub in all the cases, for example, Netherlands only takes an interconnection of 1 GW to the hub in scenario 3.

By the following equation 33, the objective is to calculate the efficiency of the investments of having a maximum branches' capacity of 2.5 GW or 3 GW w.r.t. 2 GW. This is calculated for checking the economic difference is obtained in the results when setting the maximum branches' capacity as 2.5 GW w.r.t. 2 GW or when setting the maximum branches' capacity as 3 GW w.r.t. 2.5 GW.

ROI refers to the return on investment. It shows the efficiency of the investment w.r.t. a reference case, which is 2 GW case in this analysis. The higher the ROI value, the higher the efficiency of the investment.

$$ROI = \frac{Operating\ cost\ saving\ (€) - Investment\ cost\ Increase(€)}{Investment\ cost\ Increase(€)} \quad (30)$$

The equation 33 could be reformulated in the next way, equation 31. OC refers to the Operating costs and IC refers to the Investment costs.

$$ROI = \left(\frac{\left(OC_{Sni,referencegrid} - OC_{Sni,gridz}\right) - \left(IC_{Sni,gridz} - IC_{Sni,referencegrid}\right)}{\left(IC_{Sni,gridz} - IC_{Sni,referencegrid}\right)} \right) \quad (31)$$

$$Sni\epsilon\{Scenario1, Scenario2, Scenario3, Scenario4\}$$

$$gridz\epsilon\{Grid1, Grid2, Grid3, Grid4\}$$

The obtained values are the next shown in figure 41.

ROI VALUES
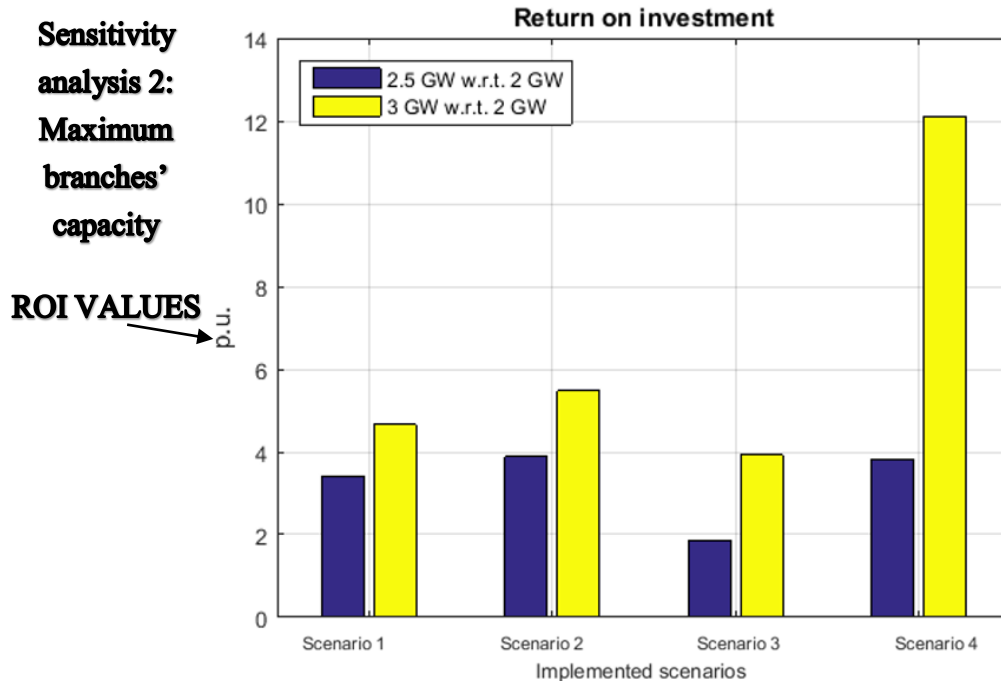
Figure 41. Return on investment values for each scenario.

The biggest difference would be obtained in scenario 4, where the highest investment efficiency values would be reached by increasing the branches' maximum capacity. It can be seen that the increase of branches' capacity of 1 GW makes a difference. Taking into account all the results shown in figure 41, the minimum return on investment would be of around 2.

Going into more details, this positive ROI values are related to the fact that the grid offers higher capability for exchange between countries and for RES integration when the maximum branches capacity is increased. The same happens with the investment costs too. These, overall, increase when the branches' maximum capacity is increased, too; because a higher amount of grid capacity is chosen.

This is shown in the next table XXXVI. The idea is that the transfer capacity between the hub and the offshore wind farms is increased when PowerGIM has the possibility for doing so. This results in a better RES integration to the system. Moreover, this means also a more integrated system since these offshore wind farms are connected to the hub and also to their countries, onshore, in some of the cases.

Table XXXVII. Chosen branches capacities by PowerGIM between wind-hub.

Sensitivity analysis 2	Max. possibility of offshore wind generation capacity connected to the hub	Chosen total branch capacity connected to the hub from offshore wind farms when 2 GW as max. cap. per branch	Chosen total branch capacity connected to the hub from offshore wind farms when 2.5 GW as max. cap. per branch	Chosen total branch capacity connected to the hub from offshore wind farms when 3 GW as max. cap. per branch
Scenario 1	22.004 GW	13.472	24.837	28.646
Scenario 2	30.534 GW	17.428	25.127	29.665
Scenario 3	36.766 GW	15.051	25.550	29.719
Scenario 4	38.406 GW	17.993	28.470	32.579

The idea is that PowerGIM does not decide to invest more in the interconnection to the offshore wind generators from the hub, in case the branches' maximum capacity is of 2 GW. Nonetheless, it does so if the branches capacity is above 2 GW and it even increases the amount of parallel branches to 3.

As it can be seen in table XXXVI, the increase in the offshore wind farms' branches capacity to the hub is almost double from 2 GW case analysis to 2.5 GW analysis. On the other hand, the increase in the branches capacity values from the offshore wind farms to the hub between the analysis of 2.5 GW and 3 GW is small, around 1.15 times higher.

In table XXXVI is also shown how scenario 2 and scenario 4 are expected to be more integrated. The reason is that some of the offshore wind farms are also connected directly to their countries, in addition to the connection to the hub. Therefore, this means these lines are also used for exchange, and not just for RES integration.

The ROI values shown previously are related to this fact. The highest ROI increase belongs to scenario 4 where the highest amount of wind generation capacity is present and thus, a higher increase in the branches' capacity ensures a proper integration of the offshore wind farms and a proper integration of the whole system, as well, by means of the connection between countries and the hub throughout offshore wind farms.

2.4.4.3. MAXIMUM BRANCHES' AMOUNT OF PARALLEL LINES ANALYSIS

For this analysis, the branches' maximum capacity is taken as 2 GW and Dogger Bank hub's investment cost is set as 406e6.

The obtained results say that the choice that PowerGIM does, do not vary if the maximum amount of possible parallel lines that PowerGIM can choose is increased from 4 to 5 and to 6. Per each scenario, always the same grid layout with the same capacities are obtained, and thus,
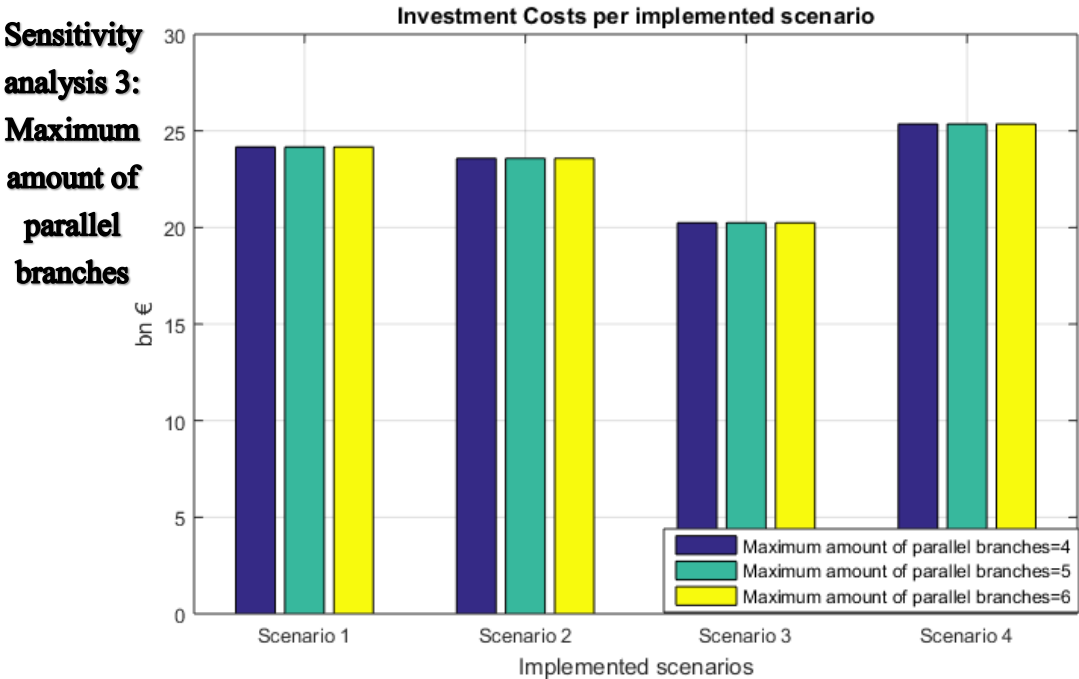
the operational costs and investment costs are also the same. These are equal to the values shown in figures 35 and 36, in the column named as 2.

The maximum number of parallel branches chosen by PowerGIM per each implemented scenario are stated in the table XXXVII below. The operational and investment costs are shown in figures 42 and 43.

Table XXXVIII. Maximum number of parallel branches chosen in each analysis.

Sensitivity analysis 3	Maximum Possible Number of Branches 4	Maximum Possible Number of Branches 5	Maximum Possible Number of Branches 6
Chosen number of parallel lines in scenario 1	2	2	2
Chosen number of parallel lines in scenario 2	2	2	2
Chosen number of parallel lines in scenario 3	2	2	2
Chosen number of parallel lines in scenario 4	2	2	2

Nevertheless, it is to point out that this sensitivity analysis is done for the case when the interconnections have a maximum possible capacity of 2 GW. In case table XXXV is taken into account, it is shown that when the maximum branches' capacity is increased to 2.5 GW or to 3 GW, then, the chosen maximum number of parallel branches goes up to 3.

Sensitivity analysis 3: Maximum amount of parallel branches

Figure 42. Investment costs results of sensitivity analysis 3.

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Sensitivity analysis 3: Maximum amount of parallel branches
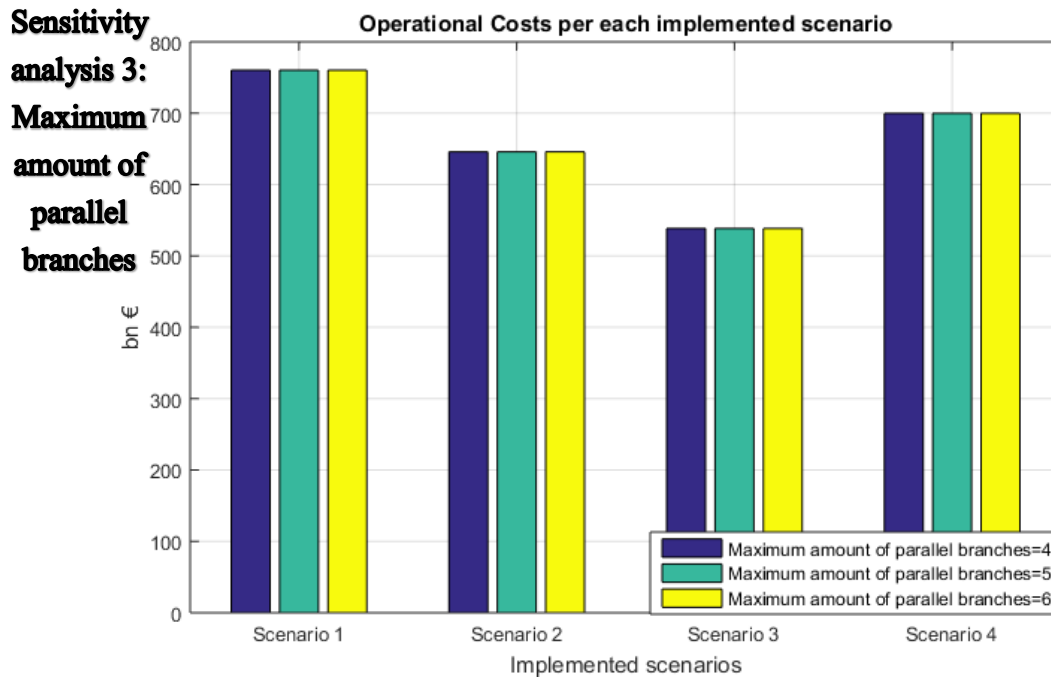
Figure 43. Operational costs result over 30 years, of sensitivity analysis 3.

Taking into account all the analysis done through this chapter, the maximum number of chosen branches is 3, and this corresponds only to the cases where the maximum branches' capacity is set to 2.5 GW or 3 GW. In the mentioned cases, (2.5 GW and 3 GW) there is always at least one branch which makes use of 3 parallel lines. When the branches' capacity is equal to 2 GW no branch makes use of more than 2 parallel lines. The overall pattern is that Norway, Great Britain and Germany make use of the biggest amount of interconnection possible.

These can be seen in the next figure 44, shown as example. It shows the dc-meshed interconnection to the hub directly from an onshore node of each country; for the cases when the maximum branches' capacity is equal to 2 GW, 2.5 GW and 3 GW. It is to mention that the interconnection the countries can have to the hub via an offshore wind farm is not shown in the graphs below, that is the reason why calling it as "**direct** dc-meshed" interconnection.

2.4.4.3.1. SCENARIO 4

Sensitivity analysis 2: Maximum branches' capacity
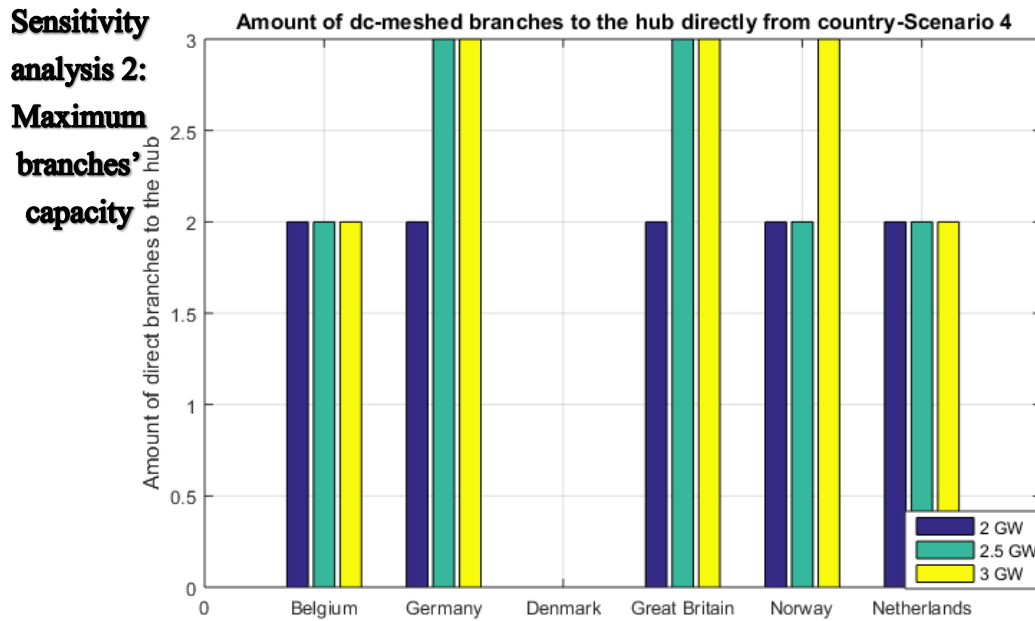
Figure 44. Amount of parallel dc-meshed branches from countries direct to the hub.

2.4.4.4. CHOSEN GRID LAYOUTS

It is to mention that the followed approach for this analysis gives these results, but it can be seen that the assumptions make a difference in some cases.

Based on the results, the Dogger Bank hub's price does not actually create a difference when its cost is between 0-8 bn €. Probably, it can even go far beyond that price, because the obtained operational cost reduction w.r.t. not having a hub option is of at least 60 bn € considering all the scenarios; and the maximum investment cost increase that needs Dogger Bank hub w.r.t. not having a hub option is just around 25 bn €.

At the same time, the results show that the maximum number of parallel branches do not make a difference when the maximum number of possible parallel lines is increased from 4 to 5 and then, to 6, when 2GW are taken as the maximum branches' possible capacity. In each scenario, no difference is obtained by applying the mentioned changes.

Nevertheless, the maximum capacity of the branches does create an impact on the results. Overall, the hub interconnection tends to make use of as much capacity as possible. This applies especially to Great Britain in all the scenarios for all the maximum capacity cases; and the investment is more efficient, especially when the branches' capacity reaches 2.5 GW.

Regarding the dc-meshed interconnections between the countries directly to the hub, the rest of the countries except Netherlands and Denmark take the maximum capacity as possible, when the options of up to 2.5 GW and 3 GW are given. Netherlands and Denmark are more moderate in that sense. This is also probably related to the demand that each of them has and the amount of generation, as well.

PowerGIM would continue deciding to invest on new interconnections until certain threshold is reached, since the investments give proper operational costs reduction. It seems that there is room for that in economic terms. For example, the ROI values are positive at least, up to 3 GW of capacity. Nevertheless, there are technical, environmental and societal limits.

For example, only few interconnections are designed to have 2 GW of capacity based on [52]. It is to consider the under-consideration project, Eastern HVDC Link. Apart from this though, no other lines are above 2 GW of capacity, for the future North Sea.

Besides, a higher number of branches' capacity to the hub means also, a higher area needed in the Dogger Bank sand. It is a Natura 2000 conservation area though, and thus, a higher needed area also would mean a higher social and ethical concern. At the same time, it is not yet very clear how much would cost Dogger Bank hub, but its effect is analysed in this chapter.

Therefore, taking all these into account, the chosen assumptions are the most conservative ones and at the same time, the ones which are closer to current prospects:

- Sensitivity Analysis 1. Result. Dogger Bank hub's investment cost is chosen to be set as 406e6 €. As shown before, this do not make any change until up to 8 bn €, at least. It is a factor to consider in future studies though. Also, the different construction stages that it could have should be considered. For now, the mentioned approximation is followed though.
- Sensitivity Analysis 2. Result. Maximum branches' capacity is chosen to be set as 2 GW.
- Sensitivity Analysis 3. Result. Maximum possible number of parallel branches that PowerGIM can make use of is chosen to be set as 4. As shown before, this do not make any change if previous point 2 is followed, i.e. the maximum chosen number of parallel branches is two in this case.

The corresponding operational costs and investment costs of the grid layouts in the coming figures 45-48 correspond to the values shown in figure 35 and figure 36, in the column named "DB=406e6 €".

2.4.4.4.1. Grid layout 1

The next grid layout 1 is obtained after the implementation of scenario 1. The crosses above the lines in the next figure 45, show the capacity of the line and the boxes show the amount of parallel lines. The values are shown below the figure 41. Black lines are already fixed, they are not part of the investment decision. Light blue and dark blue lines are decisions made by PowerGIM among all the possibilities.
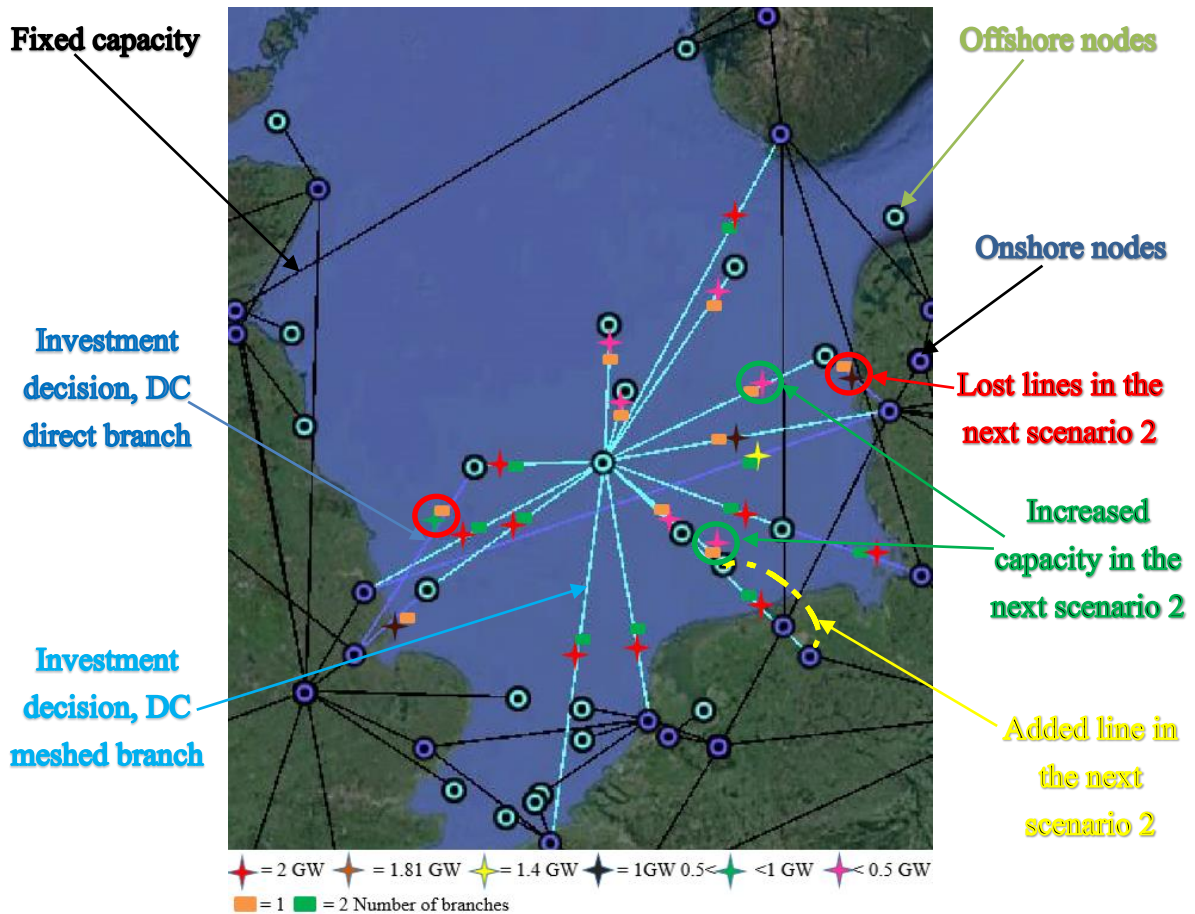
Figure 45. Chosen offshore grid layout for scenario 1.

In the next scenario 2, the lines inside the yellow circles are lost, 1.798 GW lost in total.

In the next scenario 2, the lines inside the green circles have a higher capacity, 4 GW increased in total.

In the next scenario 2, the yellow lines are added, 1 GW in total.

2.4.4.4.2. Grid layout 2

The next grid layout 2 is obtained after the implementation of scenario 2.

Figure 46. Chosen offshore grid layout for scenario 2.

In the next scenario 3, the lines inside the yellow circles are lost, 3 GW lost in total.

In the next scenario 3, the lines inside the green circles have a higher capacity, 0.492 GW increased in total.

In the next scenario 3, the lines inside the orange circles have a lower capacity, 7.936 GW less in total.

In the next scenario 3, the yellow lines are added, 2 GW in total.

2.4.4.4.3. Grid layout 3

The next grid layout 3 is obtained after the implementation of scenario 3.

Figure 47. Chosen offshore grid layout for scenario 3.

In the next scenario 4, the lines inside the green circles have a higher capacity, 4.212 GW increased in total.

In the next scenario 4, the yellow lines are added, 2.431 GW in total.

2.4.4.4.4. Grid layout 4

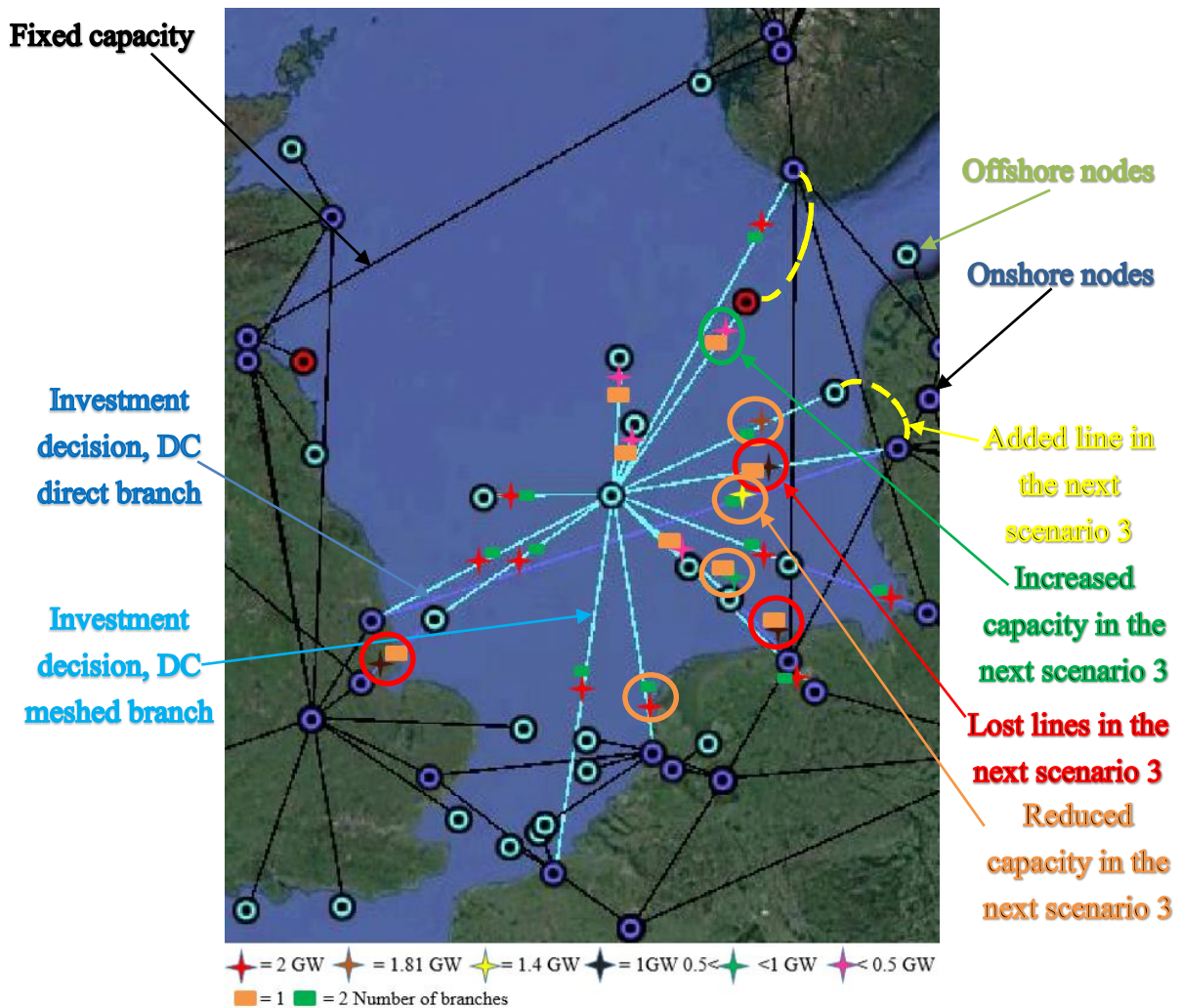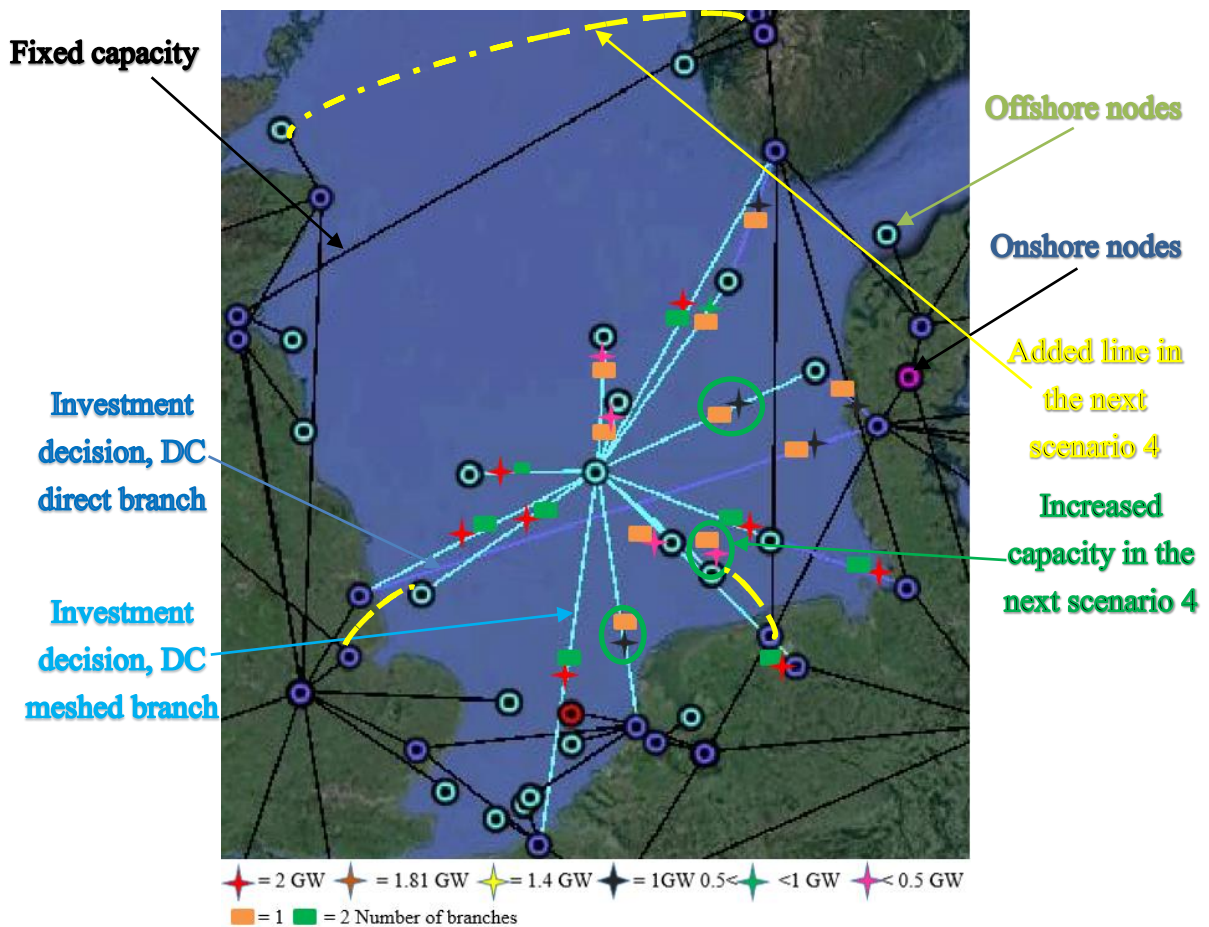The next grid layout 4 is obtained after the implementation of scenario 4.
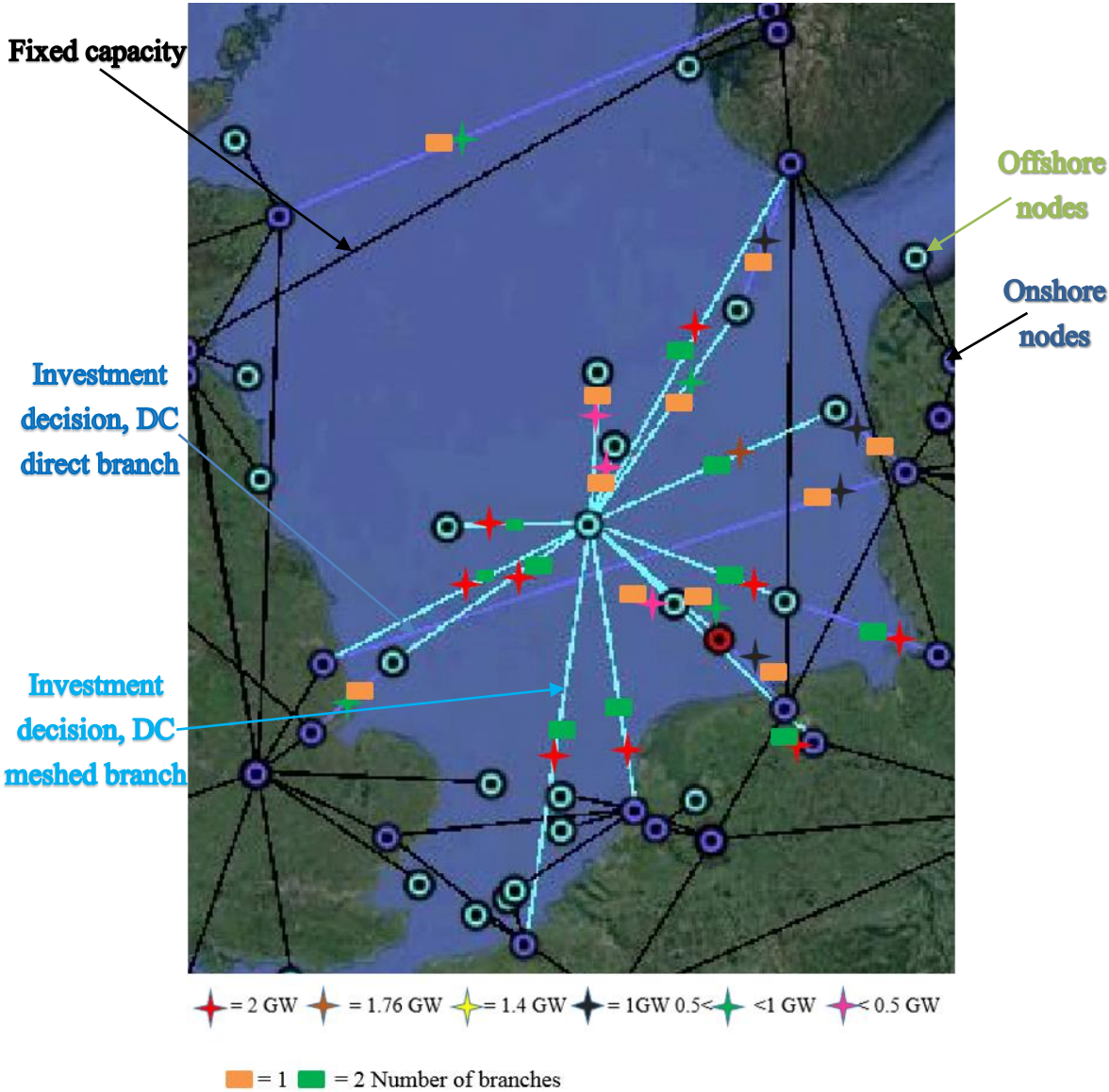

Figure 48. Chosen offshore grid layout for scenario 4.

2.5. ROBUSTNESS OF EACH OFFSHORE GRID LAYOUT

2.5.1. INTRODUCTION

The objective of this chapter is to analyse the robustness that each offshore grid layout obtained in previous chapter 2.4. have. The most robust grid layout is chosen, since it will be beneficial in different future possible scenarios, i.e. even if the future is green or if it gets a slow progress, the grid layout will be still beneficial.

Therefore, in this chapter, the offshore grid designs obtained in chapter 2.4 are deeper analysed, by making use of a higher resolution in the implemented onshore data-set. For this analysis, PowerGAMA is used.

First of all, the input data is explained. It is basically the same as in chapter 2.4., the difference is the resolution of the data: the nodes distribution, the time profiles and the hydropower reservoirs' implementation are done with a higher accuracy. Therefore, in this analysis the time and location aggregations explained in chapter 2.4 are no longer implemented. In this chapter 2.5., a higher resolution is set.

The analysis consists of implementing to each obtained offshore grid layout, each potential future scenario of generation, load and load profiles stated by ENTSO-E with some additional simplifications and a high resolution. For each analysed case, the operational cost saving through the lifetime and the needed investment cost increase are computed and compared w.r.t. the reference grid layout. The offshore grid layout which gives the average highest investment efficiency value taking into account all the potential future scenarios is chosen, i.e. the most robust investment decision is chosen.

The results show that the grid layout obtained by implementing scenario 2 in chapter 2.4 gives the highest ROI values and thus, it would be the most robust grid design.

2.5.2. WORKING PROCESS

In this part of the report, each obtained offshore grid layout in chapter 2.4. per scenario are taken, thus four grid layouts in total are taken. Then, with each offshore grid layout, four analyses are done, which correspond to each ENTSO-E Vision. In total thus, 16 simulations are run. Each analysis, takes 7 hours of computation in a personal computer. The next figure 49 is shown again for showing the steps followed in this chapter 2.5. of the Master Thesis. An additional reference scenario is also created and the same simulations are done for this grid layout as well. It is explained below, how it is formed.
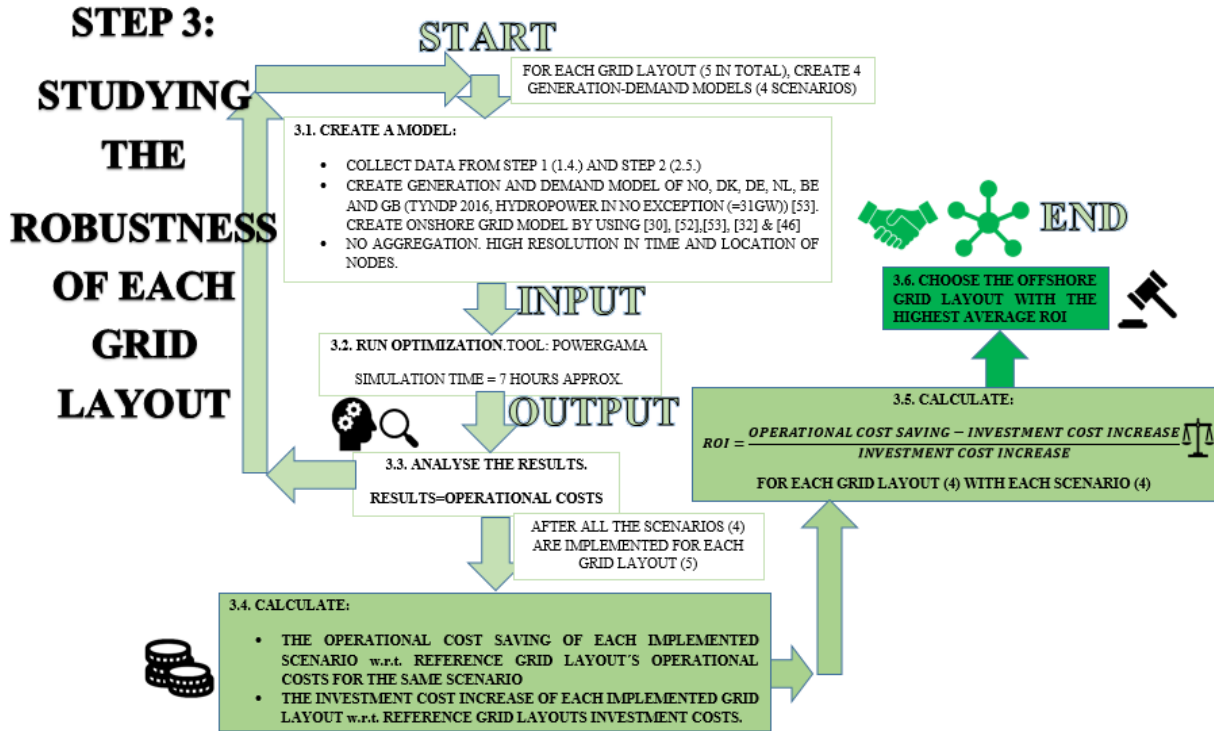
Figure 49. Flow chart of the third step of this Master Thesis.

The next table XXXVIII shows the analysis done in this chapter 2.5. of the Master thesis report.

Table XXXIX. Implemented analysis.

Generation, Consumption and load profiles from [53] Except hydropower in Norway (31GW) [34]	Implemented grid layouts obtained from chapter 2.4. after implementing in PowerGIM…			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Scenario 1	Analysis 1.1.	Analysis 1.2.	Analysis 1.3.	Analysis 1.4.
Scenario 2	Analysis 2.1.	Analysis 2.2.	Analysis 2.3.	Analysis 2.4.
Scenario 3	Analysis 3.1.	Analysis 3.2.	Analysis 3.3.	Analysis 3.4.
Scenario 4	Analysis 4.1.	Analysis 4.2.	Analysis 4.3.	Analysis 4.4.

After these analysis, operational costs of one year are calculated. This year is taken as reference and the operational costs obtained for the entire lifetime are calculated by the next formula 35. It is to point out that PowerGAMA gives the operational cost values of one year, but PowerGIM calculates the operational costs over the lifetime right away (chapter 2.4.).

$$Life\ Time\ Factor = \sum_{n=1}^{30} \frac{1}{(1+r)^n} \quad (32)$$

The Life time factor has no unit. It is given in the next way. n $(years)$ is the lifetime of the investment and it is taken as 30 years in this Master Thesis. r (%) is the interest rate and it is taken as 5%.

After all the calculations are done, regarding equation (32) for all the analysis in table XXXVIII (4x4); each analysis is compared w.r.t. the reference grid layout.

For choosing the reference case different assumptions could be done. Nevertheless, after analysing the obtained results in chapter 2.4., a new grid layout is designed which is formed by the core design of the obtained four grid layouts. The core design means the layout which is repeated in all four obtained grid layouts. Therefore, the 5th grid layout is created as reference, and it embraces the previous four grid layouts obtained in chapter 2.4. in a conservative way.

In other words, in chapter 2.4., four different offshore grid layouts are obtained. Comparing the four of them (figure 45-figure 48) the next is seen:

- There are some branches which are intact, they appear in all four grid layouts.
- There are other branches which appear in all four cases but the capacity varies per scenario.
- There are some branches which are present in some grid layouts, and in some others, they are not.

Based on this, the branches which are intact are chosen. In addition, the interconnections whose capacity varies, their lowest capacity is chosen and for the branches which are present just in some grid layouts, they are not taken for being part of the reference case.

Consequently, the next grid layout is chosen as reference, figure 50, and its investment cost is of 18.20 billion €. Since it has the lowest capacity and amount of branches, the investment cost is the lowest as well, compared to the rest obtained grid layouts. It can be called thus, as the conservative design of all the obtained grid layouts.
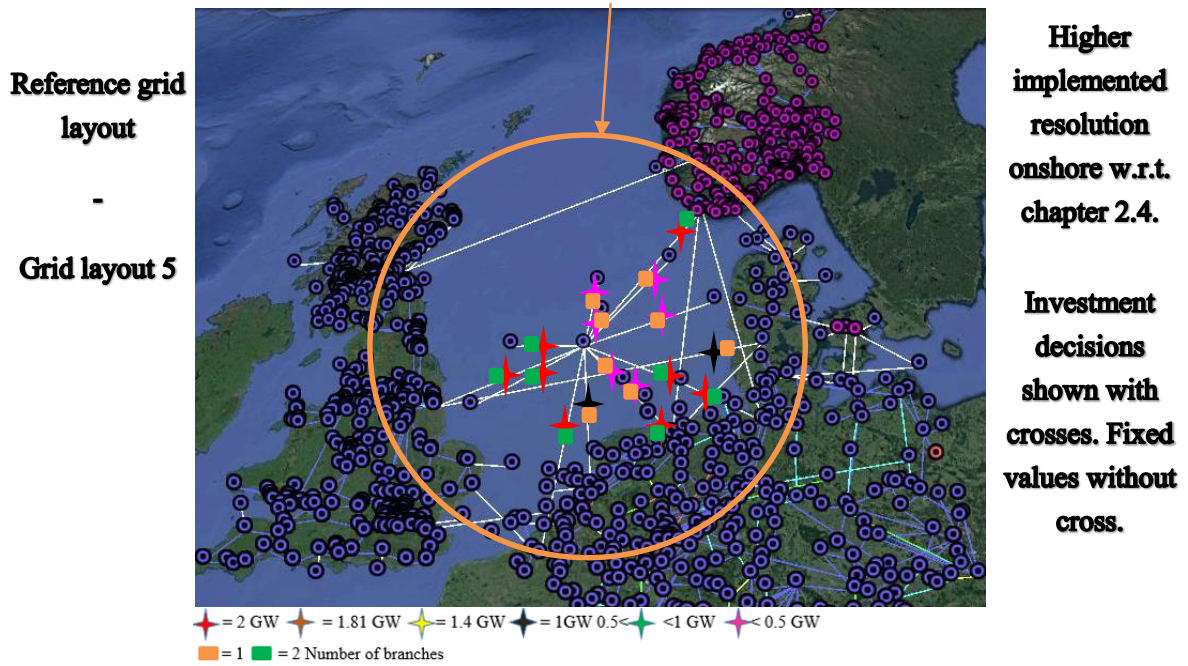
Figure 50: Created reference grid layout.

The same analysis as in table XXXVIII is done for the reference case's grid layout as well.

Table XL. Reference grid layout's implemented analysis.

Generation, Consumption and load profiles from [53] Except hydropower in Norway (31GW) [34]	Reference grid layout
Scenario 1	Analysis 1.R.
Scenario 2	Analysis 2.R.
Scenario 3	Analysis 3.R.
Scenario 4	Analysis 4.R.

Therefore, in total, 4x4 simulations are run based on the grid layouts obtained in chapter 2.4. and then, an extra 1x4 simulations are run for the reference case.

After this, as mentioned before, each 4x4 analysis shown in table XXXVIII is compared with its corresponding reference case in table XXXIX and each 4x4 analysis' ROI is calculated. Subsequently, the grid layout which obtains the highest average ROI by taking all four scenarios into account is chosen as the most robust grid layout.

2.5.3. INSERTING THE INPUT DATA

The implemented input data is the same as in chapter 2.4. The only difference is that the mentioned aggregations followed in chapter 2.4. are not implemented in this chapter 2.5.

As a recap, in chapter 2.4. two types of aggregation are done:

1. Space. The onshore nodes' location is aggregated. Each country is represented by a very simplified system, e.g. just 4 onshore nodes represent the whole country. The onshore nodes resolution is higher in chapter 2.5., figure 50 shows this concept. The offshore nodes are the same in chapter 2.4. and chapter 2.5.
2. Time. The profiles which are of 8760 hours are clustered to have 400 hours in chapter 2.4. Thus, the whole year is represented by 400 hours instead of 8760 hours. In this chapter 2.5., 8760 hours are represented with a time step of 1 hour.

Apart from that, the storage of the hydropower generation plants are not implemented in the previous chapter 2.4., but in this chapter 2.5., reservoirs are implemented and the hydropower generation plants are implemented as dispatchable generation units. Nevertheless, pumping is neglected in this Master Thesis.

2.5.3.1. SIZE OF THE INPUT DATA

As mentioned earlier, the same countries as in chapter 2.4. are implemented in this chapter 2.5., as well. The implemented areas are Norway, Denmark, Germany, Netherlands, Belgium and Great Britain. Nevertheless, as stated previously, the onshore system is represented with higher resolution in chapter 2.5. compared to chapter 2.4.

The size of the input data is much higher than in chapter 2.4., it can be seen in the next table XL.

Table XLI. Size of input data.

	Number of units	Defined Parameters/Variables
Nodes	2243	4
Branches	3299	4
Branches DC	68	3
Generators	1580	16
Consumers	1990	9
Profiles	41	(8760 hours, steps of 1 hour)
Storage Time Profiles	6	(8760 hours, steps of 1 hour)
Storage Filling Profiles	5	(100, steps of 1 percent)

The size of the input data can be visually seen in the next figure 51.

Size and resolution of the input data in chapter 2.5.
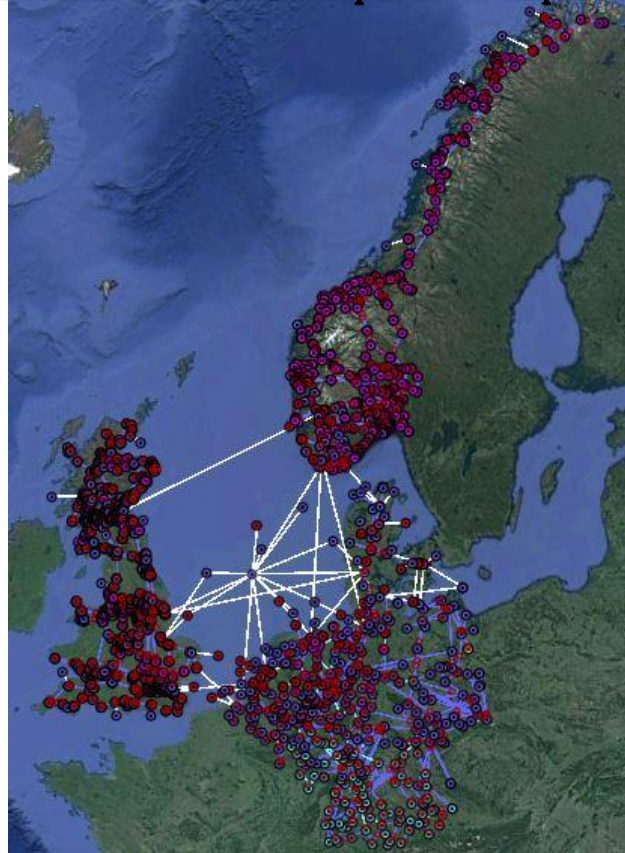
Figure 51. Implemented Power System for grid 1.

2.5.3.2. INPUT DATA

In chapter 2.5., as it is stated, the profiles' resolution is of 8760 hours, no clustering is applied. In addition, the onshore grid and node's locations are taken from chapter 2.2. for Netherlands, Belgium, West of Denmark and Germany. Remember that these countries are set to infinite internal capacity mainly. For the internal grid in Great Britain [32] is used and for Norway [46].

At the same time, the internal grids are updated in some countries such as in Germany and also, interconnections between countries are updated by [52]. Apart from that, as mentioned, the reservoirs are properly implemented in this chapter 2.5., as dispatchable, and their time and filling dependency is represented, no simplification is applied.

2.5.4. ANALYSING THE RESULTS

In the next figures, the operational costs obtained in each implemented scenario of generation and demand with each grid layout are shown, figure 52. These are calculated over 30 years, the lifetime of the investment.
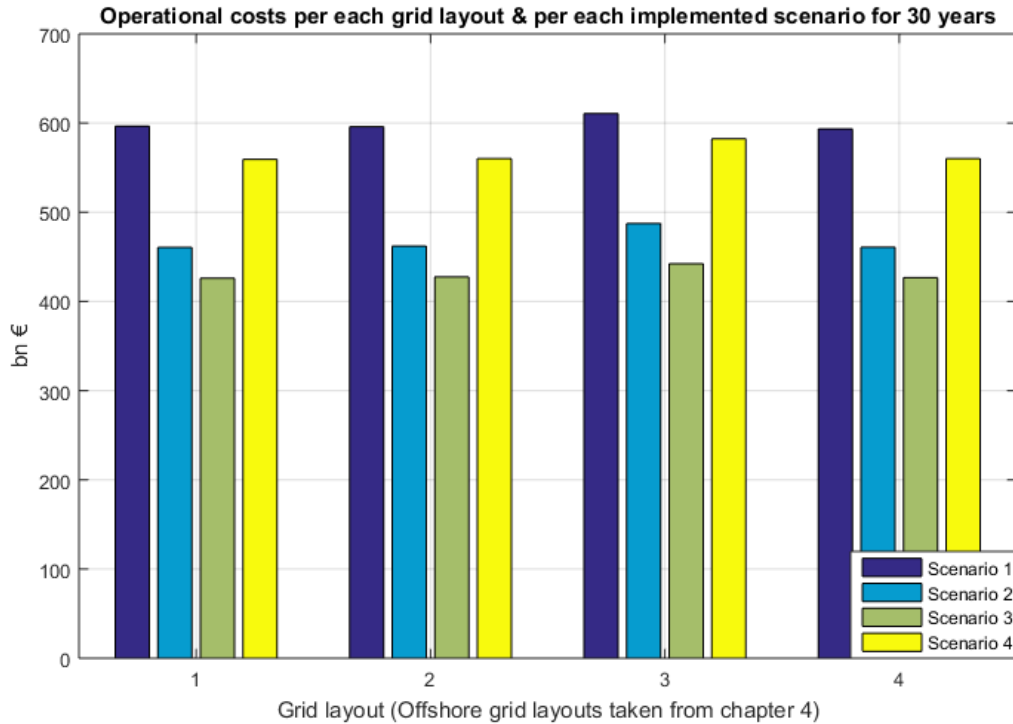
Figure 52. Obtained operational costs per each implemented scenario in each grid layout.

These values are better shown in the table XLI below.

Table XLII. Obtained operational costs per scenario, per each grid layout.

Offshore grid layouts taken from chapter 2.4.	Implemented generation, load and profiles from…			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Grid layout 1	596.51	460.61	426.03	559.34
Grid layout 2	595.92	461.98	427.56	560.07
Grid layout 3	610.59	487.42	442.32	582.27
Grid layout 4	593.35	460.73	426.70	560.05

The reference cases' operational costs per scenario are shown in the table below.

Table XLIII. Obtained operational costs per scenario, reference grid layout.

	Implemented generation, load and profiles from…			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Reference Grid Layout	615.45	493.75	447.56	588.42

The operational costs are very similar for each grid layout. Nevertheless, there is a clear deviation for the grid layout 3. At the same time, there is a deviation in terms of operational costs for the reference grid layout, as well. Moreover, the grid layout 3 and the reference grid layout have similar or close operational costs.

The mentioned grid layouts get higher operational costs. The reason is that they are not as integrated as the rest grid layouts obtained by other scenarios. They have less number of branches and less branches capacity linking different areas of the system. Therefore, they have the lowest investment costs, but the operational cost saving is the lowest. The system is more individual and lower benefits are obtained. This idea can be also seen if the operational costs are analysed per country.

For example, if grid 4 and grid 3 are compared for the case where scenario 4 of generation and demand is implemented; the next can be seen, figure 53 and figure 54.

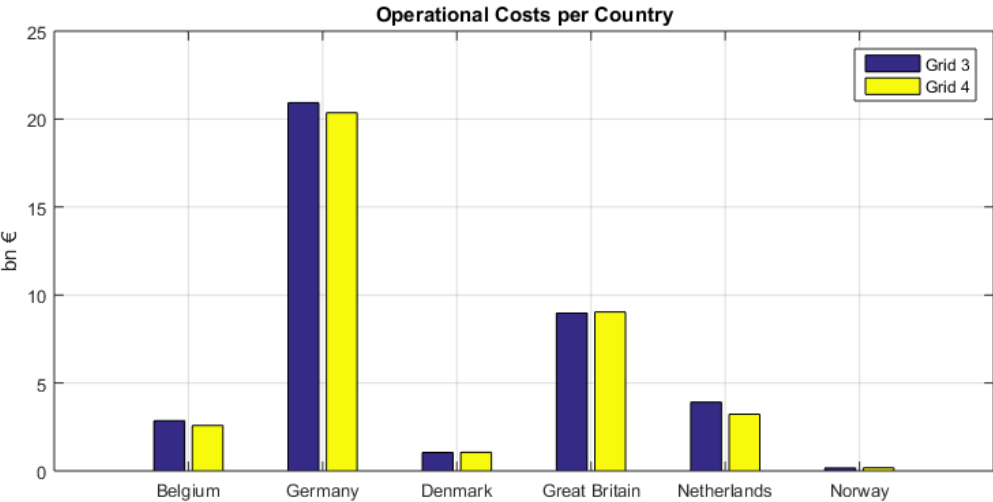**Figure 53. Operational costs per country. Grid 3-4, Sn 4.**
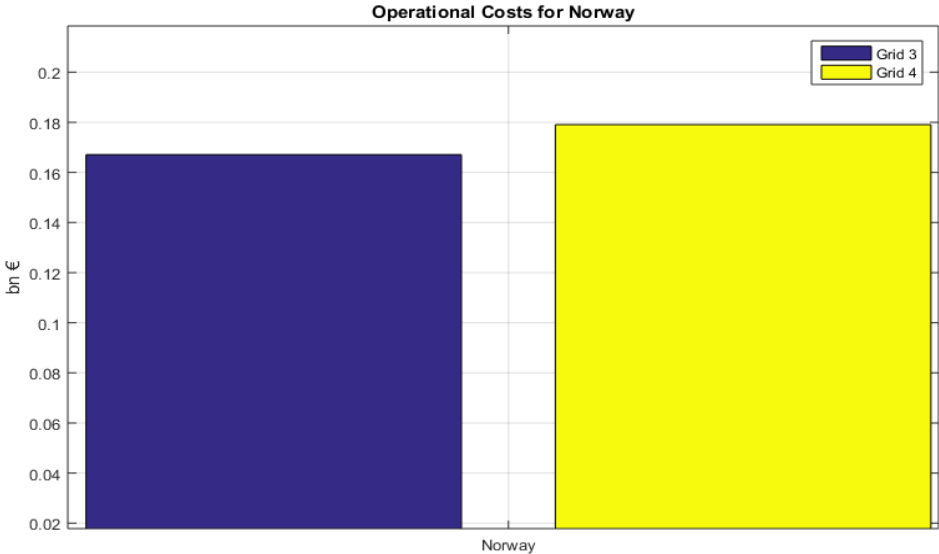

Figure 54. Operational costs in Norway. Grid 3-4, Sn 4.

As it can be seen in figures 53 and 54, for Denmark, Great Britain and Norway, the operational costs rise from grid 3 to grid 4.

This is due to the fact of having a more integrated grid layout in grid 4. The mentioned countries export in both grid layouts, but they export more in case of grid 4. Due to high wind generation surplus in the first two countries, and due to the hydropower generation technologies in Norway. Germany also exports in both grid layouts, but in case of grid 4 it exports less than in case of Grid 3, thus the operational costs are reduced. This is due to its higher internal demand as well, the demand in Germany in scenario 4 is 38.572 TWh higher per year than in scenario 3.

The rest of the countries import energy. Netherlands and Belgium import even more in case of grid 4 and thus, this leads to lower operational costs in case of grid 4. By this integration and exchange, smoother and lower operational costs are obtained taking into account the total operational costs of the system. These concepts are shown in figure 55 below.

Figure 55. Average import-export value per country (Sn 4).

This is related to the obtained Norwegian reservoir's filling characteristics, as well. In the reference grid layout, the system makes less use of the reservoirs. The reason of making use of less reservoirs is a less integrated system and a lower need for balancing. Besides, the bigger the conventional generation's capacity is with low marginal costs, the less balancing and hydropower generation is needed, and the reservoirs do not go that dry.

It can be seen that when the grid is integrated, grid 4 in the figure 56 below, the reservoirs go the driest and it is even dryer if there is more RES in the system and thus, if there is more need for balancing. The dryer the reservoirs go, the higher the operational costs are, since the water values are also higher. Moreover, in that case more conventional generation will be used for balancing and the operational costs will rise.

Besides, in the implemented data-set for scenario 4, Norway has 17.6 GW less of hydropower generation capacity w.r.t. ENTSO-E Vision prospects, and for the rest scenario it has less than 9.9 GW. As mentioned, this is done following [6] by Statnett. This approximation reduces the capability of the system to provide flexibility by means of hydropower reservoirs in scenario 4, and thus, its share is lower resulting in higher operational costs. This applies mainly to winter when the reservoirs go close to being empty and thus, cannot produce electricity. Besides, there

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is no possibility to pump water back into the reservoirs in this Master Thesis, and this also makes a difference, reducing the capability of this storage system to provide flexibility.
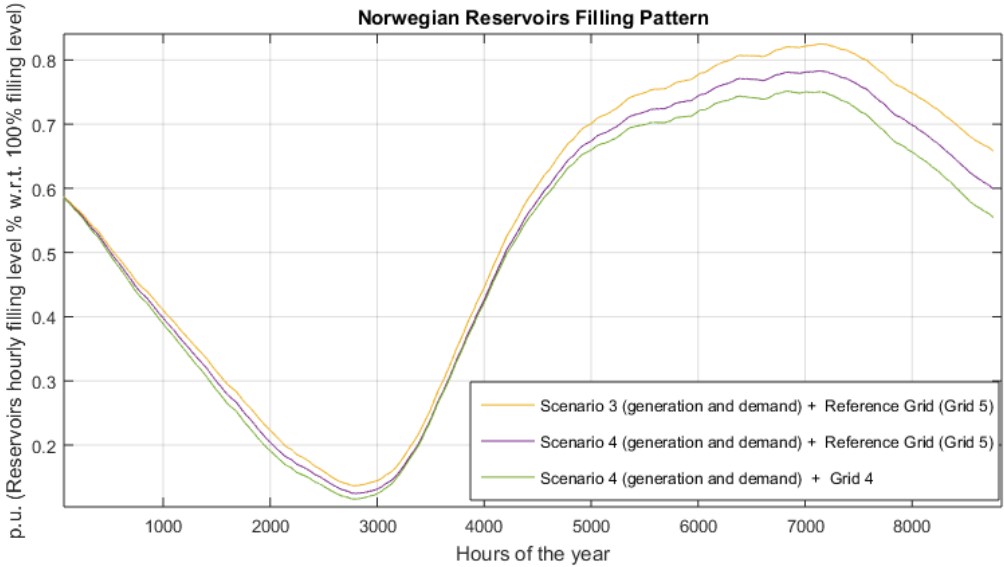
Figure 56. Norwegian reservoirs filling level depending on the grid layout + scenario.

At the same time, the importance of the grid reduction in grid 3 can be seen. For example, in grid 4, Netherlands has 3 GW more of direct connection to the hub w.r.t. grid 3, and the reduction in the operational costs is considerable. This is shown in figure 53 and 55 above.

The next benefits are obtained per each implemented scenario and grid layout w.r.t. reference grid layouts' operational costs, figure 57. In the x axis, each implemented grid layout can be seen. Then, for each implemented grid layout, the benefits obtained for each scenario are shown in dark blue, blue, green and yellow colours.
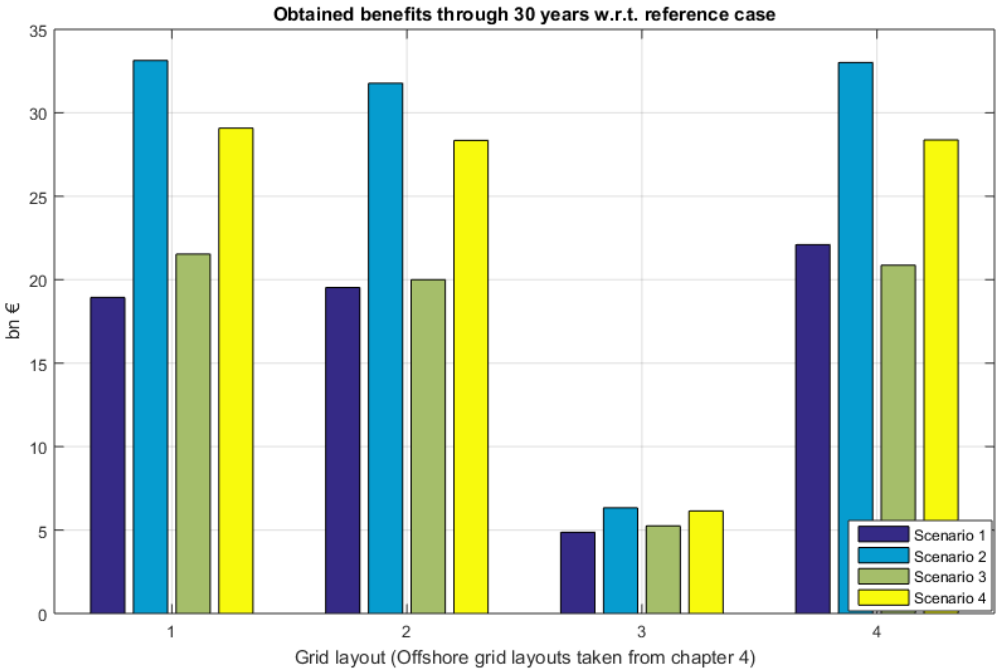
Figure 57. Obtained benefits per each grid layout and per each scenario.

In figure 57, it can be seen that the highest benefits are obtained for grid 4, and the lowest for grid 3. This is related to the idea that grid 4 is more integrated and grid 3 is not. Besides, grid 3 and the reference grid layout are very similar, both are the only grid layouts which have 3 GW less of direct interconnection between Netherlands and Dogger Bank hub. This shows the relevance of the mentioned line as well, i.e. how beneficial it can be, among other factors.

Nevertheless, this is also related to the investment cost, where right the opposite happens. This can be seen in figure 58. In this way, it is clear the compromise it exists between these two characteristics.
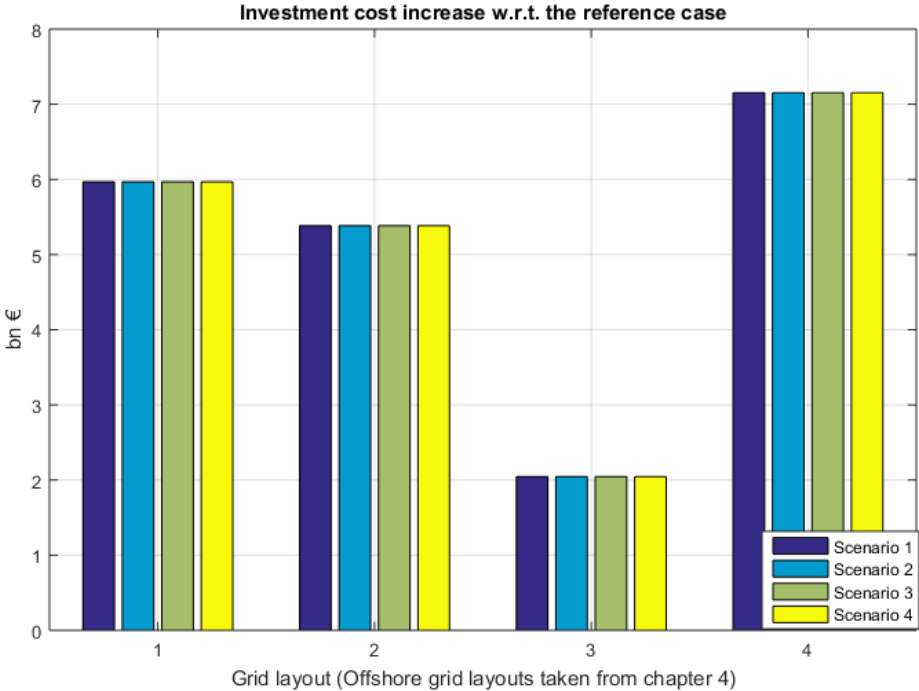
Figure 58. Obtained investment cost increase per each grid layout and per each scenario.

The ROI values are also related to this compromise between the operational cost savings and the investment cost increase. As a results the next ROI values are obtained per each implemented scenario.
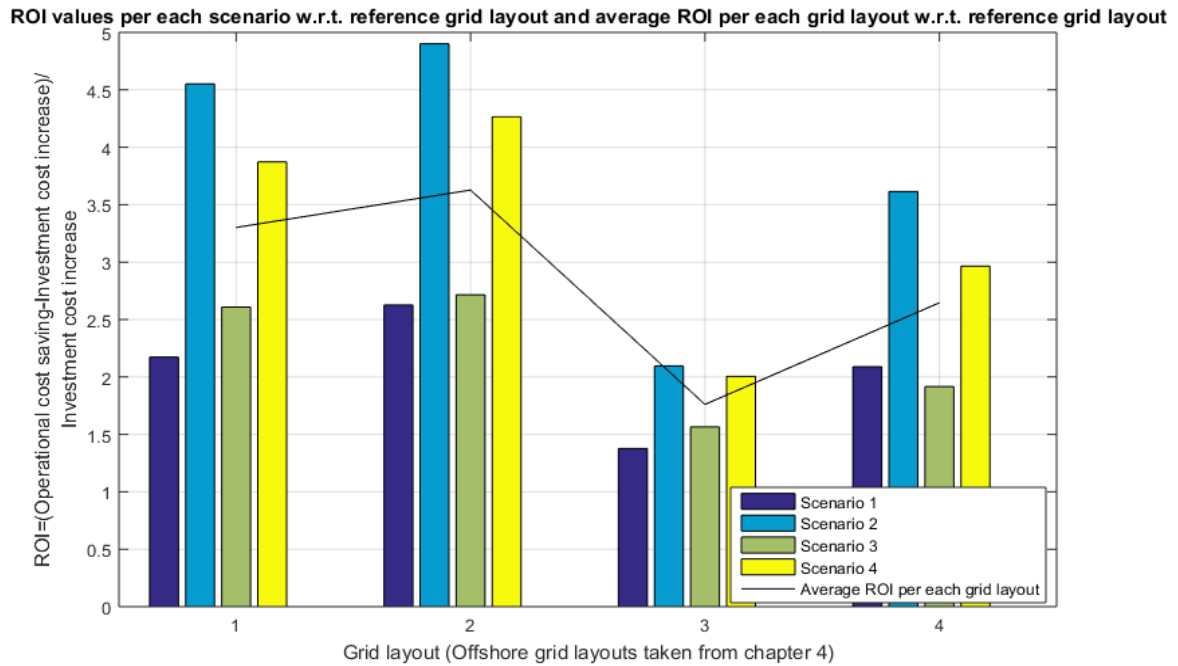
Figure 59. Obtained ROI per each grid layout and per each scenario and average ROI.

The ROI values show how robust each grid design is. As it can be seen in the graph above, grid 3 is not that robust, since it is the lowest integrated. Nevertheless, grid 4 which is the most integrated is not that beneficial if the investment costs are also taken into account. The best relation and balance between the operational cost saving and the investment cost increase is obtained for grid 2.

For this grid layout 2, the Dogger Bank hub has 17.428 GW of connection with offshore wind farms. In addition, some of these offshore wind farms, are connected to their corresponding countries. This applies to Great Britain, Netherlands and Germany.

In total 38.43 GW of branches are connected to the Dogger Bank hub, creating a dc-meshed grid layout. These values are inside the possible range that the hub could get, they are realistic [59].

3. CONCLUSIONS

3.1. INTRODUCTION

The conclusions of this Master Thesis are shown in different categories. First of all, general conclusions are given regarding research questions. After that, more detailed conclusions are explained by means of the main results. At the end, suggestions for further work are given.

3.2. CONCLUSIONS RELATED TO RESEARCH QUESTION 1

The first conclusions are related to the first research question. The model which is able to replicate the main characteristics of the power system in terms of the energy mix, cross-border flows, seasonal and daily patterns of the power system, as well as the characteristics of hydro power generation technology is found.

Overall, the generation and power exchange values are close to the actual values. In fact, in some cases the error is below 5% compared to ENTSO-E statistics. Besides, the energy share of each generation technology is properly represented. Moreover, the data-set proves that it is also able to capture the bottlenecks that were expected to appear in the results, for instance, in the north of Norway.

In addition, the water values are validated. Interesting and realistic results are obtained regarding hydropower generation technologies' behaviour. The hydropower's time and filling dependency is properly captured by this data-set. In this way, the mentioned water values are proved to be accurate enough for using in other studies. Therefore, the validated water values are used in the third step of this Master Thesis.

Different approximations and assumptions are done in the process of selecting the input data, and these leads to some deviations from actual data. As mentioned before, the exchange between Northern Ireland and Ireland is hard to replicate properly, mainly due to the low resolution implemented in the mentioned areas. At the same time, overproduction of bio generation technology is found in Finland, due to a high inflow factor implemented there.

In conclusion, the created data-set offers a capacity to make different analysis, such as hydropower reservoirs' characteristics, capture of bottlenecks, cross-border flows or energy mix analysis.

3.3. CONCLUSIONS RELATED TO RESEARCH QUESTION 2

A robust solution for grid investment decisions in the North Sea area incorporating European energy scenarios for 2030 is found in this Master Thesis.

First of all, different socio-economically beneficial grid layouts are obtained for each European energy scenario for 2030, four in total. Then, a reference grid layout is created, as well. This can be called as a conservative representation of the four grid layouts obtained previously.

The main conclusion is that the option of creating a dc-meshed grid layout by the Dogger Bank hub is a robust decision, since it appears in all the choices that PowerGIM does. The reason is that the presence of a dc-meshed grid layout through the hub reduces the operational costs and

that the reduction is higher than the investment cost increase that this offshore system requires. Besides, it is more beneficial than other investment options, thus PowerGIM chooses it as part of the socio-economically beneficial offshore grid layout in all implemented scenarios.

Nevertheless, some variations happen in the corners of the offshore grid layout, i.e. in the connection between some countries and their offshore wind farms. Therefore, among the 5 grid layouts obtained, the most robust solution is chosen, as it is mentioned in the research question. The most robust means the grid layout which gives the highest benefits w.r.t. the investment cost increase.

The most robust grid layout is the grid layout 2. Its operational cost saving throughout the lifetime of 30 years w.r.t. the reference grid is of 20-33 bn €, depending on the implemented future scenario; and the investment cost increase is of 5.5 bn € w.r.t. the reference grid layout. Its return on investment value (ROI) is of 3.628 w.r.t. the reference grid layout.

For this grid layout 2, the Dogger Bank hub has 17.428 GW of connection with offshore wind farms. In addition, some of these offshore wind farms, are connected to their corresponding countries. This applies to Great Britain, Netherlands and Germany.

In total 38.43 GW of branches are connected to the Dogger Bank hub, creating a dc-meshed grid layout. These values are inside the possible range that the hub could get [54] and [59].

3.4. CONCLUSIONS RELATED TO MAIN RESULTS

Dogger Bank hub project is a robust decision since the obtained layout is repeated for each scenario. There is uncertainty regarding the modular island's cost and the construction timing of the project. Based on the results obtained in this Master Thesis, the hub's costs could have room to reach up to 8 bn €, at least, and the Dogger Bank hub would be chosen anyways. Nevertheless, the timing of the construction etc. are not taken into account in this analysis, and thus, it could be a good point to bear in mind in future studies. It is concluded that the Dogger Bank hub could reach up to 8 bn € and the resulting grid layout by each implemented different cost of the hub would be intact.

The direct interconnections going to the hub tend to have the maximum capacity as possible; especially Great Britain. In addition, Germany and Norway also tend to do similarly; when having the maximum capacity expansion possibility as 2.5 GW this does not happen though, they keep the values as if the maximum capacity for expansion were 2 GW.

If the amount of parallel lines is increased to 5 or to 6, taking as reference 4, the resulting obtained grid layouts are the same. This applies for the case where the branches have a maximum capacity of 2 GW. Nevertheless, if this capacity is increased to 2.5 GW or to 3 GW, then this factor makes a difference. It is to point out though that the maximum amount of parallel lines chosen by PowerGIM is no more than 3, taking into account all the analysis. Since in this Master Thesis, the maximum capacity per branch is chosen as 2GW, then, it is concluded that this factor of having an opportunity to choose more than 4 parallel branches per line do not affect the results.

There are some differences regarding PowerGIM and PowerGAMA. Overall all the operational costs are reduced when the resolution of the analysis is increased. The highest operational costs reduction comparing PowerGIM and PowerGAMA is obtained for grid 4 and the lowest is obtained for grid 3.

In PowerGIM, three especial approximations are implemented in chapter 2.4. The nodes' locations is very aggregated, therefore also the internal grid. At the same time, the hydropower generation plants are taken as non-dispatchable. In addition, the time variations are represented by 400 representative points instead of 8760.

These makes a difference. Especially, the last two points create an impact on the grid layouts obtained in chapter 2.4. for scenario 3 and 4. The reason is that these scenarios have a high amount of RES. Nevertheless, scenario 3 also has the highest generation capacities overall comparing to all the rest scenarios. Besides, its generation is localised, it does not make use of a very integrated system. Consequently, PowerGIM overestimates it. In chapter 2.5. it is proven that the mentioned grid layout is not that beneficial.

The opposite can be said about the grid layout obtained after implementing scenario 4 values in PowerGIM. Scenario 4 does have a lower generation capacity, and besides, it has a higher demand. Moreover, it has a considerable amount of RES and these are not localised, thus it needs balancing. The system is more integrated and more transfer of power is needed. Besides, the internal grid is very simplified. In PowerGIM, as mentioned, the hydropower storage is not represented as storage and thus, PowerGIM underestimates the capability of scenario 4 for having a more integrated power system with a higher share of RES and thus, lower operational costs.

It is to point out that likewise it is seen in chapter 2.4., in chapter 2.5. too, the second highest operational costs are for scenario 4. Therefore, the same trend is followed in PowerGAMA as well.

It is to mention that the marginal costs of conventional generators are much higher in scenarios 3 and 4 since the CO_2 prices rise considerably when going from scenario 1-2 to scenarios 3-4. Nevertheless, the total operational costs seem to have more or less the same values taking into account all scenarios, since more RES is integrated in scenarios 3 and 4 and thus, a higher RES share is in the system. Consequently, the increase in the conventional generation units' marginal costs is kind of balanced by a higher RES share.

Nevertheless, going into details, it is appealing how the operational and investment costs vary among scenarios. Overall, the pattern from scenario 1 to scenario 3 is that the operational and investment costs go reducing, but then, scenario 4 gets the highest operational costs and the second highest investment cost. It is related with the ideas stated below.

When going from scenario 1 to scenario 2, the connection that an English wind farm and a Danish wind farm, which are in the left and right corners of the figures 44 and 45, with their corresponding country's onshore node are disappeared. This is probably because the mentioned

countries have enough generation capacity and it is more beneficial to help to other countries in PowerGIM's view for the operation costs' reduction.

From scenario 2 to scenario 3, the Danish wind farm's connection comes back to the picture, but Great Britain loses an additional connection. When going from scenario 3 to 4, the Danish wind farm keeps connected and one of the English wind farms' connection comes back.

Related to this, it is to mention that scenario 3 has the highest generation per demand ratio. Consequently, in scenario 3, the countries have the strongest potential to answer to its own energy demands, i.e., the demand is covered "locally" or per country. Therefore, as result, the offshore grid layout obtained in scenario 3 has lower amount of capacity of branches.

This is represented, for example, in the fact that the direct interconnection between Netherlands and the hub takes just a value of 1 GW for this case and 4 GW for the rest of the scenarios. Another example is that scenario 3 is the only case where two of the offshore-wind generators in Great Britain, neither of them are connected to Great Britain. This is probably because Great Britain has already enough capacity and it is socio-economically more beneficial to connect them to the hub, and export the generated electricity right away.

Apart from that, another characteristic of scenario 3 is that it has the highest RES w.r.t. conventional generation technologies ratio. This also helps it to have the lowest generation costs.

On the other hand, there is scenario 4, which has the highest demand values and the second highest RES generation capacities. This makes scenario 4 to have a need for balancing. Therefore, PowerGIM chooses a more integrated system and it even choses North-Connect as part of the resulting grid layout.

Related to this, there is a clear pattern in Norway. In scenario 1 and 2 similar layout is obtained for the Norwegian system, but when going from scenario 2 to scenario 3 a new line towards the Dogger Bank hub appears from Norway, and moreover, in scenario 4, the additional North-Connect interconnection is also chosen as part of the socio-economically beneficial grid layout.

These are probably related to the fact that scenario 3 and scenario 4 make use of more RES and thus, higher flexibility is needed in the system. For this, the Norwegian reservoirs are key players, and consequently, PowerGIM increases the interconnection capacity towards Norway. In scenario 4, a more integrated market is aimed, and this is in fact shown in the obtained results, which as mentioned earlier, the North-Connect interconnection is also chosen to be part of the North Sea grid layout.

This is also shown in the Norwegian reservoirs' pattern, where the reservoirs go the driest in scenario 4, due to the needed generation and the provided flexibility.

Besides, the Norwegian hydropower is not increased based on ENTSO-E's values, Norwegian hydropower generation plants are kept as the current values 31 GW, following [6] from Statnett. This makes scenario 4 in need of other conventional sources for balancing, resulting in higher prices. This applies mainly to winter when the reservoirs go close to being empty and thus,

cannot produce electricity, and moreover, the conventional generation units are the most expensive among all the implemented scenarios for scenario 4, due to the high CO_2 prices. All these makes scenario 4 to have higher operational costs.

Another characteristic to mention is that PowerGIM chooses just 1 GW in scenario 3 for connecting directly the hub and Netherlands, and it takes 4 GW in the rest of the cases. Denmark is also similar, since it takes 1 GW of direct interconnection between Denmark and the hub in scenarios 1 and 2, and the mentioned line is lost in scenarios 3 and 4. This is also related to the fact that Denmark is also chosen to be connected directly to Great Britain by an interconnection. On the other hand, Germany, Belgium, Norway and Great Britain take a capacity of 4 GW to the hub, in all the grid layouts, 2 parallel branches of 2 GW each.

The lower interconnection value with Netherlands in scenario 3 could be related to two factors. One would be the demand distribution, for example, in two areas: the first area Netherlands-Belgium and the second area Germany.

Starting with Germany, the expectations are high for a north to south power transfer need in this country. In fact, among the implemented countries Germany has the highest demand. Compared to Netherlands, it has 4.46 times higher demand in scenario 4 and compared to Belgium, it has 6 times higher demand in scenario 4. This ratio is more or less the same in all scenarios. For scenario 1 and 3 the difference is a bit lower, probably due to a less integrated system.

The second idea related to this, is that scenario 3 is more localised than the rest scenarios and the system is stronger to face its demand locally, since it has a higher generation capacity per demand ratio and thus, lower need for interconnection.

PowerGIM thus decides, that the Netherlands-Belgium area is properly covered by the mentioned interconnection of these countries and going beyond that it is not of interest from an economic point of view, for this scenario 3.

3.5. FUTURE SUGGESTIONS

Different future suggestions are mentioned in the coming pages. To start with, there is a suggestion regarding PowerGAMA. For the future, it would be interesting to modify the methodology followed for the implementation of the reservoir's storage or production decision.

It would be interesting to have the option to insert the exact water value in PowerGAMA, i.e. to export the three dimensions matrix from EMPS model and to import it into PowerGAMA. In this way, for every iteration case, the exact water value would be implemented in the tool and the calculation by approximation via a combination between inflow and time profiles would not be needed. Nonetheless, overall, this approximation gives the right picture. If the country mainly depends on hydropower generation technology, such as Norway, this approximation leads to high nodal price variations between seasons and difficulties for getting the right picture, though.

As a result, an efficient implementation of the reservoir's seasonal pattern would be ensured by this update and additional difficulties in this sense would be avoided.

Regarding the implemented scenarios in the second and third step of this Master Thesis, the next suggestions are given. It would be of interest to see how the amount of interconnection to Norway would increase by increasing the Norwegian hydropower generation capacities. Similarly, it could be interesting to see the impact that a higher generation capacity in the Norwegian hydropower plants could cause in the operational cost saving in scenario 4.

The reason is that as stated, in this Master Thesis, similar pattern as [6] from Statnett is followed. Nevertheless, ENTSO-E expects more hydropower generation capacity to be part of the system. Going into details, Vision 1 and Vision 2 from ENTSO-E have 7.8 GW of hydropower more, Vision 3 has 9.7 GW more but Vision 4 has 17.6 GW more of hydropower in Norway w.r.t. the implemented scenarios. This lack is causing higher operational costs in scenario 4. The reason is that the needed flexibility is taken from other conventional generation, which have a higher CO_2 emission factors and are more expensive w.r.t. other scenarios. This applies mainly to winter when the reservoirs go close to being empty and thus, cannot produce electricity.

Moreover, PowerGIM is also similarly choosing less connection between Norway and the rest of the system as part of the investment decision, since it sees this decision as not economically beneficial. The hypothesis is that by implementing a higher hydropower generation capacities with proper pumping capability would increase the system's ability to provide flexibility and this would cause a better reservoirs' handling and thus, lower operational costs. Since it would be beneficial, PowerGIM might choose more interconnection from the system towards Norway, as well.

Therefore, a suggestion is to do the same analysis as in this Master Thesis by increasing the hydropower generation capacities in Norway and thus fully following the ENTSO-E prospects and adding the opportunity for pumping. It would be interesting to see how the needed grid layout would change and how the operational costs are reduced. At the same time, it would be desirable to analyse how much pump it would be used, since there are some uncertainties

regarding the business opportunities of this choice. Apart from that, it would be of interest also, to do the same analysis by implementing other means of storage, such as CAES and to compare the results.

Another suggestion would be related to the implemented assumptions. As mentioned previously, very few interconnections are stated to have 2 GW in the future and consequently, this value is chosen as maximum capacity per branch in this Master Thesis. Nevertheless, it would be interesting to do the same analysis by implementing 2.5 GW as maximum capacity, or setting 3 GW as maximum. This last one would be of interest especially for scenario 4, since it gives a very high ROI value, 12.09.

Besides, when the maximum branches capacity that PowerGIM can choose is set to a higher values than 2 GW, it is seen that Great Britain always takes as much capacity as it can. As a recap, in this Master Thesis each country has just one onshore node with the opportunity to create a dc-meshed connection to the hub, including Great Britain. Therefore, it would desirable to add another onshore node there, for instance, in Scotland, with the opportunity to create a dc-meshed connection to the hub and to see, if PowerGIM chooses an additional dc-meshed connection there.

Higher capacity values might mean higher needed area. But, as mentioned before, ethical and societal concern can raise as well, if a very high area of the Dogger Bank sand is used, since it is Natura 2000 conservation area. In this topic too, a compromise should be done.

Another suggestion is to consider the timing of the construction of the modular island. In this Master Thesis the different construction stages of the hub are not taken into account, and thus, it could be a good point to bear in mind in future studies. This kind of projects are expected to develop first nationally, then, bilaterally and then, internationally. Therefore, the willingness to cooperate with other European players of each country could cause a difference.

In conclusion, a more integrated grid layout based on Dogger Bank hub is certainly a good option for the future North Sea grid layout. Nevertheless, questions arise regarding governance and regulatory need. Different countries would be involved in this project and each of them get different benefits, some even would have higher operational costs, such as Norway.

These means the economic and societal interests of each individual country should be also fulfilled, and thus complex ways are needed to make all the parties satisfied and avoid conflicts among them. Analysis of different policies in this sense would be needed for increasing the willingness of the countries to work together. This is another suggestion for future work.

Dogger Bank hub is certainly the right direction for the future North Sea offshore grid layout. Different political and technical characteristics should be achieved for getting there, first. This analysis done in this Master Thesis could be just a small part of a promising beginning.

SUGGESTION FOR POTENTIAL FUTURE RESEARCH QUESTIONS
In this Master Thesis not all the found gaps could be covered. Hence, another research question is also designed with the aim of covering other needs. The gap is related to the fact of

considering a more active demand in the studies. This would be useful for a future research project.

Radial versus meshed analysis is already done for the North Sea, several analyses have been done about this. The gap seen in these analysis is to not to take into account a more active demand side, for example, the Demand Response.

For instance, [4] says that load is taken as it will not vary too much from the 2012 pattern. It is then, scaled up following ENTSO-E prospects. It would be interesting to analyse the strength that a more active demand has to cause an impact on the transmission investment needs.

The previously stated assumption in [4] could be conservative, especially in the North Sea. There the countries which are pushing sustainable energy technologies and the countries which are most concerned about the global warming issues are present, such as, Denmark, Netherlands or Norway.

These countries' governments are implementing measurements to support electric cars, for example, and much more measurements are expected to come. At the same time, Combined Heat and Power, Tesla walls or also, heat pumps, which are run by electricity, may get more and more common in buildings.

Those technologies will need a considerable amount of electricity consumption, but moreover, they will also play a role as storage, giving the chance to consumers to decide when to consume or not. In short, the power system may have even more prosumers (consumers and producers at the same time), rather than pure consumers or pure producers.

There is a lot of research going on in the field of microgrids and smart grids, as well. The research question to answer would be: **To which extent an active demand side have the capacity to create an effect on the power system by its presence in terms of transmission investment needs, operational costs or energy mix?**

The hypothesis from the author of this Master Thesis is that they might make a difference. The power system may become more active, rather than passive and based on monodirectional flow (especially in distribution level). Market trade and demand response could be key factors on reducing the volatility of renewable energy sources, especially wind.

Demand response may be done more in distribution level, but it may at the same time, produce a decrease in the need of grid investment, and it will also decrease the share of conventional generation technologies, because their support for flexibility will not be that needed. Consequently, it may be a factor to take into account in planning strategies. Nevertheless, for that, the share of capacity of demand should be considerable in the power system.

Although, all these hypotheses may vary with the actual flexibility capacity that demand response offer. Moreover, the technological developments may make the mentioned system even more feasible, and the vision and political aims of the North Sea countries may contribute on that, as well.

This could be an interesting analysis to do. In this way, these uncertainties expressed by the previous statement would be clarified. It would be interesting to analyse also, the comparison of the results of this last research question with other means of flexibility. That is, the whole topic to answer would be to analyse **how powerful flexible demand could be to provide flexibility to the system and which would be its benefits, i.e., the impact on investment costs and on operational costs; and <u>how beneficial are these values w.r.t. the values that other means of flexibility provide</u>?**

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APPENDIX

In the appended python files, the code is written in black colour and the explanations are written in green colour, the explanations start with a % and these are not part of the simulations. They are written just for clarification.

1. run_simulation.py

```
% For clarification, the appended "run_simulation.py" is mainly built by
%PowerGAMA's developer Mr. Harald Svendsen from SINTEF.
% The 3rd part related to analysis of results is developed by the author of
%this Master Thesis by using available information from [27].
% -*- coding: utf-8 -*-
%1. IMPORT DATA
%Import the necessary components which help python to do the required
%calculations and analysis of results.
from __future__ import division
import powergama
import powergama.GIS
import powergama.scenarios
import time
import matplotlib.pyplot as plt
import csv
import powergama.constants
%Set base values.
powergama.constants.baseZ=1
powergama.constants.baseMVA=1
plt.close('all')
% Set simulation time. Timerange=simulation time. range(x,y)=> x=start time.
% y= finish time
timerange=range(0,8760)
% Open the process for reading the data
data = powergama.GridData()
%Set the location where PowerGAMA needs to take information from.
datapath= "data_h/"
resultpath= "results/"
scenarioPrefix = "2030_"
% If instead of running an optimization from the start, an already run file
%wants to be open for analysis, i.e. plots, the next "rerun" is used.
%Rerun=False is set for analysing an already existing file.
rerun = True
%The ".sqlite3" file where the results are wanted to be saved.
sqlfile = "results_db_2030.sqlite3"
%Saving the grid data.
data.readGridData(nodes=datapath + scenarioPrefix + "nodes.csv",
                  ac_branches=datapath +scenarioPrefix + "branches.csv",
                  dc_branches=datapath + scenarioPrefix+ "hvdcH.csv",
                  generators=datapath + scenarioPrefix + "generators.csv",
                  consumers=datapath + scenarioPrefix + "consumers.csv")
%Saving the profiles data.
data.readProfileData(filename=datapath+"profiles.csv",
          storagevalue_filling=datapath +"profiles_storval_filling.csv",
          storagevalue_time=datapath +"profiles_storval_time.csv",
          timerange=timerange,
          timedelta=1.0)
% 2. RUN OPTIMISATION
%If the optimisation wants to be run from the beginning, "if rerun" is
%followed.
if rerun:
    % Run the optimisation.
    lp = powergama.LpProblem(data)
```

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```python
    % Save the results.
    res = powergama.Results(data,resultpath+sqlfile,replace=True)
    start_time = time.time()
    lp.solve(res)
    end_time = time.time()
%At the end of the simulation, give information to the user about the duration
%of the simulation in seconds.
    print("\nExecution time = "+str(end_time - start_time)+"seconds")
%If an already simulated file is wanted to be opened for analysis this "else"
%is followed, for checking its results, for instance, for plotting. The step
%below is followed instead of running the input data again.
else:
    res = powergama.Results(data,resultpath+sqlfile,replace=False)
% 3. ANALYSIS OF RESULTS
%Get average branch flows for each dc branch.
dc=res.getAverageBranchFlows(branchtype='dc')
%Get average branch flows for each interarea branch.
intera=res.getAverageInterareaBranchFlow()
%Get average branch flows for each ac branch.
ac=res.getAverageBranchFlows(branchtype='ac')
%Get average branch exchange value for Denmark
dkav=res.getAverageImportExport(area='DK')
%Plot the Energy Mix in Norway
res.plotEnergyMix(areas=['NO'])
%Get the average price per each node
nod=res.getAverageNodalPrices()
%Plot the implemented system in a map and show the location of each node,
%the location of each branch, the average nodal prices and the utilisation
%of each branch.
res.plotMapGrid(nodetype='nodalprice',branchtype='utilisation')
%Plot the generation values in Norway
res.plotGenerationPerArea('NO')
%Create a ".kml" file which will be able to be opened in Google Earth. The
%file contains the inserted data and the obtained results. For example, the
%nodal price and the flow. The name of the kml file is "output.kml"
powergama.GIS.makekml("output.kml",grid_data=data,res=res,
nodetype="nodalprice",branchtype="flow")
%Plot the obtained area prices in Great Britain
res.plotAreaPrice(areas=['GB'])
stfaSE=res.getStorageFillingInAreas(areas='SE',generator_type='hydro')
% GET HOURLY HYDRO CHARACTERISTICS FOR NORWAY.
import pandas as pd
%Set the area of interest. In this case, Norway.
area = 'NO'
%Set the generation technology of interest. In this case, hydropower.
genType = 'hydro'
%Set the time range of interest. In this case, the simulation time.
timeMaxMin =  [res.timerange[0],res.timerange[-1]+1]
%Set the initial values for the coming production and storage values loop
prodCap = 0
storCap = 0
%Get the generators which fulfil with the setting of area and generation type
%set above.
genTypeIdx = res.grid.getGeneratorsPerAreaAndType()[area][genType]
%Get the generators with pumps which fulfil with the setting of area set
%above.
pumpIdx = res.grid.getGeneratorsWithPumpByArea()[area]
%Get the inflow factor of the first generator obtained above. The assumption
%is that all generators have the same inflow factor.
inflowFactor = res.grid.generator.inflow_fac[genTypeIdx[0]]
```

```python
% Get the inflow profile of the first generator obtained above. The assumption
%is that all these generators have the same inflow profile.
inflowProfile = res.grid.generator.inflow_ref[genTypeIdx[0]]
%Sum the storage capacity and the generation capacity of each generation unit
%for the previously set country.
for gen in genTypeIdx:
    prodCap += res.grid.generator.pmax[gen]
    storCap += res.grid.generator.storage_cap[gen]
%Get the generation production values per each wanted generation plant and
%time.
output = res.db.getResultGeneratorPower(genTypeIdx,timeMaxMin)
import pandas as pd
dem_dfou = pd.DataFrame(output)
%Save the results of the generation production in a ".csv" file
dem_dfou.to_csv(resultpath+"NohydroPowerOutput.csv")
%Calculate the reservoirs' storage filling level per area
reservoirPerc           =           [i*100           for           i           in
res.db.getResultStorageFillingMultiple(genTypeIdx,
                      timeMaxMin,storCap)]
import pandas as pd
dem_dfreper = pd.DataFrame(reservoirPerc)
%Save the reservoirs' storage filling level per area values in a ".csv" file
dem_dfreper.to_csv(resultpath+"NohydroPowerResPer.csv")
%Calculate the hydropower generation plants' inflow values.
inflow = [i*prodCap*inflowFactor for i in res.grid.profiles[inflowProfile]]
import pandas as pd
dem_dfiflow = pd.DataFrame(inflow)
%Save the hydropower generation plants' inflow values in a ".csv" file.
dem_dfiflow.to_csv(resultpath+"NohydroPowerInflow.csv")
% In the next lines the sum of flow on interarea branches between two areas
%are calculated.
%The whole simulation time is taken into account.
%These values are wanted to get for Norway. Thus, 'NO' is written below. At
the same time, in this step, the branch type of analysis is "ac".
br = res.grid.getInterAreaBranches(area_to='NO',acdc='ac')
%For getting the positive AC branches. Norway importing.
br_p = br['branches_pos']
%For getting the negative AC branches. Norway exporting.
br_n = br['branches_neg']
%% Get AC branches's flow, import and export ->NORWAY-SWEDEN CONNECTION
ies=res.db.getBranchesSumFlow(branches_pos=br_p,branches_neg=br_n,timeMaxMin=timeMaxMin,acdc='ac')
% Sum the flows of Norwegian AC interarea branches so as to get the total
%values. Positive if   Norway is importing and negative if it is exporting.
if ies['pos'] and ies['neg']:
    res_ac = [a-b for a,b in zip(ies['pos'],ies['neg'])]
elif ies['pos']:
    res_ac = ies['pos']
elif ies['neg']:
    res_ac = [-a for a in ies['neg']]
else:
    res_ac = [0]*(timeMaxMin[-1]-timeMaxMin[0]+1)
import pandas as pd
dem_dfrac = pd.DataFrame(res_ac)
% For saving the total AC branches's flow ->NORWAY-SWEDEN CONNECTION
dem_dfrac.to_csv(resultpath+"NOres_ac.csv")
% DC branches NORWAY-DENMARK&NETHERLANDS CONNECTION
%set the area of interest. In this case, Norway. The type of branches in this
%case for analysis is  %DC
dcbr = res.grid.getInterAreaBranches(area_to='NO',acdc='dc')
%For getting the positive DC branches. Norway importing.
```

```python
dcbr_p = dcbr['branches_pos']
%For getting the negative DC branches. Norway exporting.
dcbr_n = dcbr['branches_neg']
% Get DC branches's flow, import and export -> NORWAY-DENMARK&NETHERLANDS
%CONNECTION
dcie=res.db.getBranchesSumFlow(branches_pos=dcbr_p,branches_neg=dcbr_n,time
MaxMin=timeMaxMin,acdc='dc')
% Sum the flows of Norwegian DC interarea branches so as to get the total
values. Positive if Norway is importing and negative if it is exporting.
if dcie['pos'] and dcie['neg']:
    res_dc = [a-b for a,b in zip(dcie['pos'],dcie['neg'])]
elif dcie['pos']:
    res_dc = dcie['pos']
elif dcie['neg']:
    res_dc = [-a for a in dcie['neg']]
else:
    res_dc = [0]*(timeMaxMin[-1]-timeMaxMin[0]+1)
import pandas as pd
dem_dfrdc = pd.DataFrame(res_dc)
dem_dfrdc.to_csv(resultpath+"NOres_dc.csv")
%Total flow in Norway, sum of AC + DC branches
NOimporttot = [a+b for a,b in zip(res_ac,res_dc)]
import pandas as pd
dem_dfnoi = pd.DataFrame(NOimporttot)
dem_dfnoi.to_csv(resultpath+"NOimporttot.csv")
```

2. RUN_model.py

```python
% For clarification, the appended "RUN_model.py" is mainly built by
PowerGIM's developer Mr. Martin Kristiansen from NTNU.
%Import the needed tools and components to help python to be ready for the
%wanted MILP optimisation analysis related to the acquisition of the
%socio-economically beneficial grid layout.
import Model
import Model.powergim as pgim
import pyomo.environ as pyo
import pandas as pd
import powergama.GIS
import powergama
import Model.GIS
% Read input data
print("Collecting grid input data")
grid_data = Model.GridData()
grid_data.readSipData(nodes = "data_input2/nodes.csv",
                      branches = "data_input2/branches.csv",
                      generators = "data_input2/generators_S4.csv",
                      consumers = "data_input2/consumers_S4.csv")
grid_data.readProfileData(filename = "data_input2/profiles.csv",
                              timerange = range(8760),
                              timedelta = 1.0)
% Reduce the size of the time series ("sampling" or "clustering")
print("Sample new time steps...")
samplesize = 400
timerange = pd.np.random.choice(8760, size=samplesize, replace=False)
pd.np.random.seed(2017)
grid_data.readProfileData(filename="data_input2/profiles.csv",
                              timerange = timerange,
                              timedelta = 1.0)
% Formulate the optimization model
print("Formulating model...")
sip = pgim.SipModel()
% Convert the data input to an input format that the model understands
dict_data = sip.createModelData(grid_data,
                                datafile='data_input2/parameters.xml',
                                maxNewBranchNum=4,
                                maxNewBranchCap=10000)
% Formulate the final model with parameters
cmodel = sip.createConcreteModel(dict_data)
% Solve the resulting optimization problem with a "solver". Use "gurobi"
print("Solving optimization model")
opt = pyo.SolverFactory('gurobi')
results = opt.solve(cmodel, tee=True, %stream the solver output
                        keepfiles=True, %print the LP file for examination
                        symbolic_solver_labels=True) % use human readable
names

print("Finished!")
% The optimization problem is solved. Now; collect and present the results,
% for example like %this:
%Extract results.
```

```
%Save the results in an already existing .xlsx file. It is called:
%Results/Results_NorthSea_2030.xlsx
sip.saveDeterministicResults(model=cmodel,excel_file='Results/Results_North
Sea_2030.xlsx')
%Save the results in the so called "pg_res" variable.
grid_res =
sip.extractResultingGridData(grid_data,model=cmodel,newData=True)
pg_res = powergama.Results(grid_res, databasefile='res.sqlite3', sip=True)
%Create 2 different .kml files for analysing the results in Google Earth.
%The "Input_grid.kml" file shows the inserted data.
Model.GIS.makekml("Input_grid.kml",grid_data=grid_data,
                  nodetype='powergim_type',branchtype='powergim_type',
                  res=None,title='North Sea 2030 input')
%The "Results_grid.kml" file shows the investment decision that powerGIM
does.
Model.GIS.makekml("Results_grid.kml",grid_data=grid_res,
                  nodetype='powergim_type',branchtype='powergim_type',
                  res=None,title='North Sea 2030 result')
```

Validation study of an open-source power-flow model of Nordic, UK and Ireland regional systems for 2014 Using PowerGAMA

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Abstract— **This paper presents a validation study of an open-source power-flow model of Nordic, UK and Ireland regional systems for 2014 using PowerGAMA. It expands an already validated model of continental EU in the year 2014 by adding the Nordic countries, UK and Ireland. The validation is done by comparing the obtained results, such as, energy mix of each country and cross-border power flows, with actual data from ENTSO-E. The implemented dataset is based on publicly available data and updated to 2014. The results show that the model can capture the seasonal as well as daily pattern of the power system in terms of energy generation, demand and power exchange.**

Index Terms-- **Power system economics, power system management, power system planning, power transmission, wind energy integration.**

I. INTRODUCTION

The future for the energy markets and the power systems is uncertain. Political decisions and technological development will make those fields to follow one path or another and different challenges could appear. For instance, having a more integrated power system and likewise, a more integrated power market could increase the flexibility of the system. At the same time, a higher share of renewable energies in the market also could rise different challenges to maintain a balance between production and consumption.

Consequently, there is a need to do analysis regarding grid expansion planning. By these studies, different scenarios could be depicted and/or compared. Hence, technical, economic and societal conclusions could be obtained and decisions for forthcoming steps regarding future grid designs could be taken with a solid basis.

The North Sea offers huge opportunities but also challenges for planning the optimum Power System, for instance. The fact of having well-established tools could help researchers to find untapped opportunities in that area.

Specially, regarding interconnections and offshore grid layouts, this model could be a valuable tool.

The contribution of this study is to create a model which gives the next characteristics. First of all, the Nordic hydropower plants' storage or production decisions are reasonably captured. Their relevance is high due to the flexibility they provide to the system. At the same time, the model is able to replicate the generation mix and the exchange between countries including the Nordic, UK and Ireland regional systems. Moreover, it is able to capture the expected bottlenecks in detailed Norwegian power system model.

This paper gives an overview of PowerGAMA tool. It also explains the inserted data together with the assumptions done in the process. After that, the results are presented and their important characteristics are discussed. At the end, suggestions for further work are given.

II. POWERGAMA

A. Introduction

PowerGAMA is an open source python package created by SINTEF Energy Research. It investigates a grid and market analysis and optimizes the generation dispatch using the marginal costs of each generation technology and the grid limitations.

Storage values can be implemented in PowerGAMA and the calculations in every iteration are done by considering the results of previous iteration.

PowerGAMA is based on multiple simplifications, e.g. it does not consider the start-up costs, limited ramp rates or unit commitments. At the same time, it assumes a perfect market focused on nodal pricing.

B. Optimization

This optimization tool considers two main factors: the objective function of minimizing the operational costs and the existing grid constraints. It is a DC-OPF tool. For that, two different type of constrains are implemented which help the optimization tool to bear in mind grid limitations in each optimal choice that it does. In this way, both variables i.e. grid availability and economic availability are considered.

The objective function is to minimize the operational cost of the system (1). For that, generators with the lowest marginal cost are favoured and in this way, the overall cost of generation is always minimized.

The sets, indices, parameters and variables used for each time step are the followings.

Sets:

G : Set of generators
S : Set of pumps
N : Set of nodes
K : Set of AC and DC branches

Indices:

g : Generator
s : Pump
n, j : Node
k : Branch

Parameters:

C_g^{gen}: Cost of generator g [€/MWh]
C_s^{pump}: Cost of pump s [€/MWh]
C^{shed} : Fixed cost of load shedding [€/MWh]
P_k^{max}: Maximum branch capacity of branch k [MW]
P_g^{min}: Minimum production of generator g [MW]
P_g^{limit}: Available power of generator g [MW]
$P_s^{pump,max}$: Maximum pump capacity, pump s [MW]
$B_{n,j}$: Susceptance between nodes n and j. [S]
$Y_{n,j}$: Admittance between nodes n and j. [S]
$X_{n,j}$: Reactance between nodes n and j. [Ohm]
$B_{n,n}$: All susceptances connected to node n. [S]

Variables:

p_g^{gen}: Generation by generator g [MW]
p_s^{pump}: Pump power demand of pump s [MW]
p_n^{shed}: Load shedding, node n [MW]
p_n^{cons}: Consumption at node n [MW]
δ_n: Voltage angle, node n [°]
δ_j: Voltage angle, node j [°]
$p_k^{ac/dc}$: Power flow, AC/DC branch k [MW]
p_n: Active power injection at node n [MW]
V_n: Voltage magnitude at node n [V]
V_j: Voltage magnitude at node j [V]

$$min\left(\sum_{g\in G} C_g^{gen} p_g^{gen} - \sum_{s\in S} C_s^{pump} p_s^{pump} + \sum_{n\in N} C^{shed} p_n^{shed}\right) \quad (1)$$

The constraints delimiting the variables are the next (2-4)

$$-P_k^{max} \leq p_k \leq P_k^{max} , \ k \in K \quad (2)$$
$$P_g^{min} \leq p_g^{gen} \leq P_g^{limit} , \ g \in G \quad (3)$$
$$0 \leq p_s^{pump} \leq P_s^{pump,max} , \ s \in S \quad (4)$$

The constraints related to power flows are shown in (5). By making use of approximations, the AC power flow equations are converted to linear power flow equations often known as DC power flow equations (5).

$$p_n = \sum_{j=1}^{N} B_{n,j}\left(\delta_n - \delta_j\right) \quad (5)$$

Power injection at each node is given by (6).

$$p_n = \sum_{g\in Gn} p_g^{gen} - \sum_{s\in Sn} p_s^{pump} - p_n^{cons} + p_n^{shed} + \sum_{k\in K_n^{dc}} p_k^{dc} \quad (6)$$

III. INPUT DATA

The data set could involve a wide range of participants and an endless number of variables to make the model as perfect as possible. This would be out of the scope of the objective of the paper, since it may not be possible to gather all information due to confidentiality issues. Therefore, the objective is to create an approximate model using publicly available data.

Information is gathered from different open sources and it is updated as accurately as possible to 2014 values. This data is then added to the already validated model of 2014 [2]. As mentioned, the final model is obtained for continental EU [2], the Nordic, UK and Ireland.

Different iterations and adjustments of parameters or variables are done in the input data to replicate the actual ENTSO-E 2014 data. Especially, the combination of hydropower storage filling and time profiles is difficult to replicate. Besides, they are key variables due to hydropower's large share in the energy mix of the Nordic countries. This terminologies are explained below and more information can be found in [18]. The followed approach is given in figure 1, below.
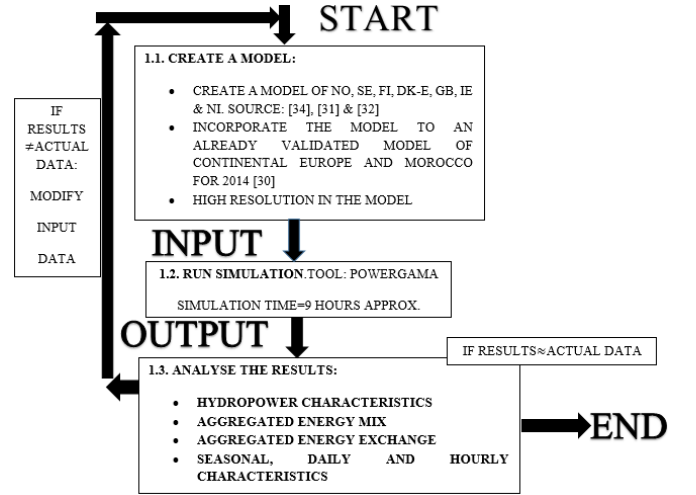

Fig. 1. Followed approach in this validation study

The data, which give the most accurate results among all the implemented data, are presented below.

A. Nodes and Branches

The branches and nodes are taken from [1] and [3], and they are added in the model of 2014 [2].

At the same time, interconnections between Finland and Sweden, North Wales and Ireland and Scotland and Northern Ireland are added by consulting [4].

The internal branches in the UK, Finland and Denmark are set to infinity whereas for Norway and Sweden, they are kept as in [1]. In case of Denmark, grid constrains are added in the north for a better representation of the power flow between Norway- Denmark and Sweden-Denmark.

B. Generation

The data setting for the generators embraces more parameters and variables. The generation capacities are taken from [1] and [3], and they are scaled to implement the values of [5].

Additional wind is added to the model using [13]. The location is done approximately. For implementing the run of the river technology, [7] and [8] are used. The nodes with a lower generation capacity than 17 MW are chosen as run of the river generation plants in Norway. The same is done in Sweden with less than 23 MW. Apart from that, an additional generation plant of 170 MW is added to the run of the river generation plant in Norway. This generation plant (the corresponding node in the TradeWind dataset) has approximately the same longitude and latitude as the station of Akershus and the generation capacity is somehow similar, therefore, it is chosen to represent the run of the river plant of Akershus.

Therefore, in total, in Norway, Sweden and Finland 1519 MW, 1079 MW and 302 MW are taken as run of the river generation plants respectively, from the hydropower generation capacities stated in [5].

- In [2], the marginal costs of all wind, all solar, run of the river and hydroelectric generators show the cost of operation and maintenance, and these technologies are set to 0.5 €/MWh. At the same time, the marginal cost of other renewables, such us biofuel and waste incineration, is set to 50€/MWh and the price of load shedding is taken as 1000€/MWh.

The same pattern is followed for the newly added countries and overall, the marginal costs are taken as uniform for all of them, since, the analysis of the marginal costs of each thermal generation technology is beyond the scope of this project. The next Table I. summarizes the chosen values for thermal generation technologies:

TABLE I. MARGINAL COSTS

Type	Oil	Bio	Mixed Fuels	Gas	Coal	Nuclear
Marginal costs [€/MWh]	162	50	168.32	70	60	11

In table I, a new generation technology called "Mixed Fuels" is added which is not mentioned in [2].

The values from table I are increased or decreased in some countries for helping the model replicating the cross-border power flows between countries. For example, the marginal cost of the generation technology which is setting the price in a country is reduced if this country needs to export more energy, the opposite is done in case it needs to import energy.

- The inflow factors, or availability factors, for renewable energy sources are calculated by taking the data of capacity and actual generation in 2014 from [5]. It is the division between the actual generated energy during the year and the ideal generated energy if the generator produces energy during the whole year. For offshore wind energy, the inflow factor is taken as 0.4.

Regarding the inflow factor for conventional power, it is assumed the same for all the countries and they can be found in Table II. Nevertheless, the inflow factors per country for nuclear power are set to the annual average availability in 2014 taken from [6].

TABLE II. INFLOW FACTORS

Type	Gas	Oil	Mixed Fuels	Coal	Bio
Inflow Factor	0.8	1	0.9	0.8	0.75

In some countries, the inflow factors of some generation technologies are increased or decreased for getting the energy mix stated by ENTSO-E [5].

- For calculating the inflow profiles for wind and water, data from [12] are used. There, exact inflow profiles for each wind energy generation farm are given. Taking these data into account, the average profiles are calculated for each country's wind energy generation technology by making use of the weighted mean method.

- The total storage capacities per country are taken from [1] and [3], and they are scaled down to each hydroelectric generation plant based on their installed generation capacity.

For choosing the right storage initial values, simulations are run first, and based on the resulting storage level at the end of the year, the same value is set as storage initial value. This is done iteratively until the initial reservoirs' level and the level at the end of the year are approximately the same.

The hydropower storage prices can be found in table III.

TABLE III. HYDROPOWER STORAGE PRICES

Country	NO	SE	FI
Storage reference price [€/MWh]	15	16	53

This storage prices are set based on the results obtained. Initially the values were set to the average price values per country, but based on the results obtained the storage prices were updated iteratively until relatively realistic results are obtained regarding energy mix and cross-border flows.

- PowerGAMA calculates the storage values of the hydropower and solar generation plants by multiplying the storage filling profile and storage time profile (both normalised) together with the previously mentioned storage prices in table III, in €/MWh.

For the solar generation technology, the storage filling and time references are taken from [2]. In the case of

hydropower generation plants for the Nordic, Ireland and UK the storage filling and time profiles are calculated from [19].

The water values represent the value of adding water inflow to the reservoir in €/MWh, i.e. it is a three-dimension variable, which considers the week of the year and the storage filling value in percentage for giving the economic value of the water stored in the reservoir, in €/MWh.

When the nodal price is higher than the storage value, the hydropower generator will produce electricity. In the opposite case, it will store the water. For example, in figure 2, the water values calculated by EMPS for Norway can be seen [19].

In the x axis, the seasonal pattern of the reservoirs can be seen. In the y axis, the reservoir's filling level behaviour is represented. Around week 18 when the reservoirs are the driest, the hydropower plants should store water due to their high storage value. The opposite happens around week 44.
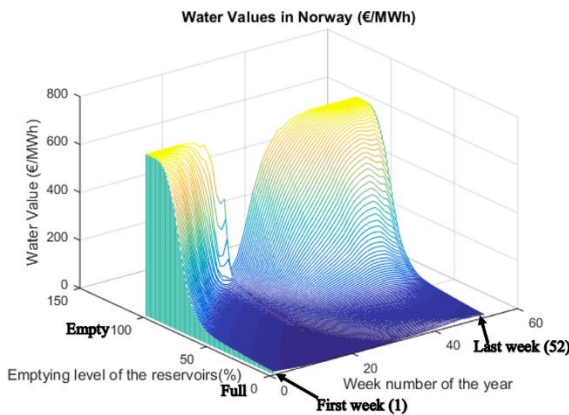

Fig. 2. Water Values in Norway €/MWh [19]

For obtaining the storage filling profile, a focus in each country is done first. Then, all the storage time values are considered and the median value is calculated for each storage filling level. In this way, a 100% filling level profile is obtained where for each reservoir level the median value of all weeks is chosen. Then, the obtained profile is normalized to have a unit value when the storage filling level is 50%.

The same storage filling profiles are used for Sweden and Norway and a slightly different profile is used for UK, in [19]. For creating this new model, different profiles are built for each country, this is done based on the obtained results, since each countries' behaviour is different [9] and [14]. They can be seen in figure 3.
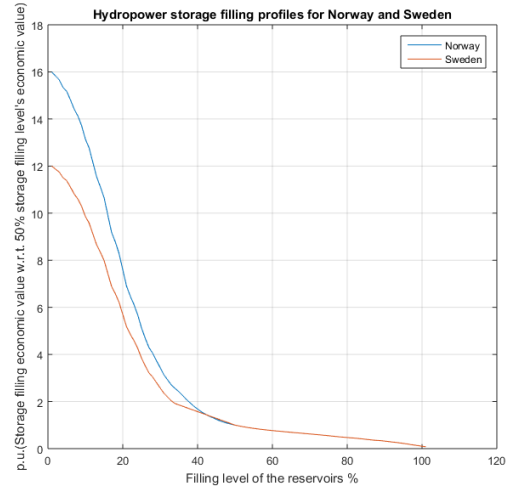

Fig. 3. Created Storage Filling Profiles

In [19], same storage time profiles are taken for Finland, Sweden and Norway. Nevertheless, in this case this implementation brings the model to some deviations from real data, since these countries' actual reservoir time pattern differ from each other, [9].

Therefore, in this study, independent time profiles are created for each country based on actual data from the year 2014 obtained from [9], figure 4. Nevertheless, average profiles could be used for the analysis of future scenarios. For the United Kingdom, the time dependency is not considered.
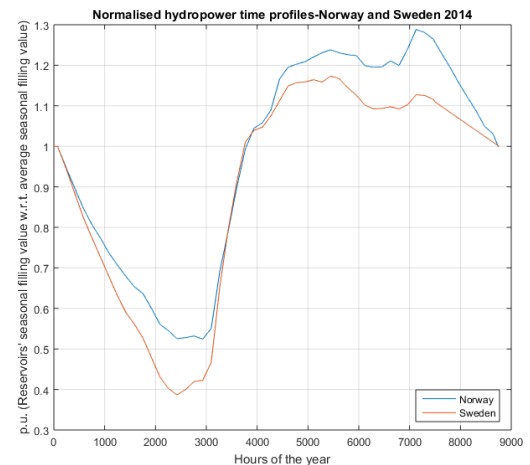

Fig. 4. Created Storage Time Profiles 2014

At the same time, the profiles are set to the same level in the beginning and in the end of the year.

- Pumps are neglected for the newly added countries.

C. Demand

Average demand per node is taken from [1] and [3] and they are scaled up to 2014 by [10]. Also, data from [15] is considered for Norway and Sweden.

For obtaining the demand profiles, data from [15] and [10] are taken for the Nordics. In this way, the load profiles resolution is increased since a different load profile is inserted

per bidding area in the mentioned countries. Data are obtained from [10] for Great Britain, Northern Ireland and Ireland. These profiles are also scaled to have an average value of 1, as mentioned earlier for the inflow profiles.

IV. RESULTS

Main results are classified in three subgroups: Aggregated energy mix, aggregated cross-border flow and seasonal hydro characteristic.

A. Aggregated Energy Mix

An overview of the aggregated energy mix can be found in the table below in Table IV. It shows the deviation of the obtained results in percentage with respect to the values given by ENTSO-E in [5]:

TABLE IV. AGGREGATED ENERGY MIX

Country	Nuclear %	Fossil %	Res_Except Hydro %	Hydro %	Total Generation deviation GWh
DK	-	-10.21	+5.66	+0.44	-770.67
FI	-0.20	-1.83	+27.23	-22.62	+1733.64
GB	+0.66	-2.72	-17.91	+2.73	-2381.49
IE	-	+47.247	-3.803	-4.615	+6280.04
NI	-	-59.10	+9.02	+71.82	-3490.70
NO	-	-100	+4.55	-0.44	-4289.73
SE	-0.29	-0.97	+17.27	+3.11	+3311.04

As it can be seen, the general picture is captured. The total generation deviation is of +392.13 GWh. Nevertheless, there is a deviation of the renewable energy sources technologies expect for hydro in Finland. This is due to the too high inflow factor inserted as input data for the biomass generation technology.

There are considerable deviations in Northern Ireland and Ireland too, in terms of total generation values. This is a consequence of a wrongly represented cross-border flow in the mentioned countries. The cause of the inconsistency is explained below.

B. Aggregated Cross-Border Flows

The results are summed up in the next table V. In this case also, the deviation with respect to the results given by ENTSO-E in [5] is shown in percentage. At the same time, it is mentioned if the flow direction is correct or not. In some cases, the deviation is of just few GWh but since the real exchange value is low as well, the deviation percentage is expressed as being big. The total deviation is of 1.916 TWh.

TABLE V. AGGREGATED CROSS-BORDER FLOW

From	To	ENTSO-E [34] in GWh	Deviation %	Deviation in GWh	Direction
NO	NL	5355	-2.83	-151.53	Correct
NO	DK	2647	+7.81	+206.57	Correct
NO	SE	6805	-33.46	-2276.62	Correct
FR	GB	15054	-8.61	-1297.11	Correct
NL	GB	7851	+11.58	+908.99	Correct
SE	DK	883	+20.83	+183.93	Correct
SE	DE	1005	-62.21	-625.21	Correct
PL	SE	2984	-22.325	-666.18	Correct
DK	DE	546	-27.705	-151.27	Correct
GB	NI	1046	+6.63	+69.34	Correct
IE	GB	2394	+23.06	+552.05	Opposite
SE	FI	18298	+7.84	+1437.27	Correct
IE	NI	253	+1472.76	+3726.10	Correct

Ireland is producing too much, because it is exporting too much to Northern Ireland, and this reduces the need of production in Northern Ireland. Therefore, the total generation in table IV. is higher than the actual value.

One of the reasons of this inconsistency is that the mentioned countries are represented by just one node each. By this approximation, it is hard for the model to replicate the real behaviour among these countries.

Apart from these results, the exchange between Norwegian and Swedish bidding areas also follow the pattern mentioned in [16]; NO1 exports to SE3 and NO4 exports to SE1. At the same time, SE2 exports to NO3 and NO4.

Going into more details, the model can capture the bottlenecks that happen in the North of Norway around Troms and Finnmark [17]. The mentioned are reflected by higher nodal prices in the stated areas. They are shown by lighter coloured dots. Similarly, the same for Bergen [17] area. They can be found in the figure 5 below. This effect is also shown in the Statnett grid development plant [17].
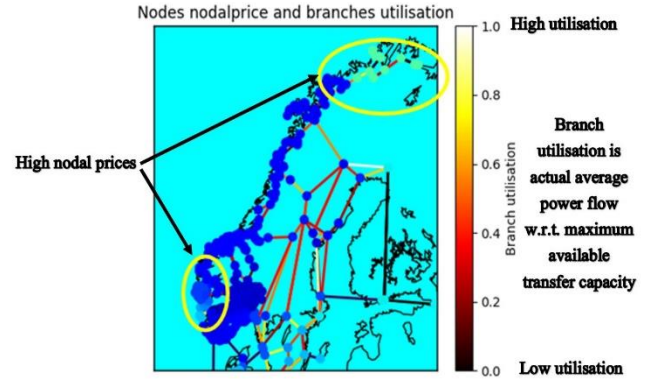

Fig. 5. Nodal prices and Branch utilisation

C. Seasonal Hydropower characteristic

The obtained storage values per area follow a realistic pattern. They can be found in figure 6. The results are normalized w.r.t. their corresponding maximum values.

The initial and ending points of the reservoir filling level are in the same level, the top and bottom values are also among the actual possible range and the shape of the curve is close to the actual frame [9].

In addition, the generation plants do not produce electricity when they are close to being empty and they produce more when they are close to being full, this is related to the water values explained previously. Moreover, the production is higher in winter and lower in summer due to the demand as well. Besides, it can be seen how the filling level is also linked to the hydro inflow profile.
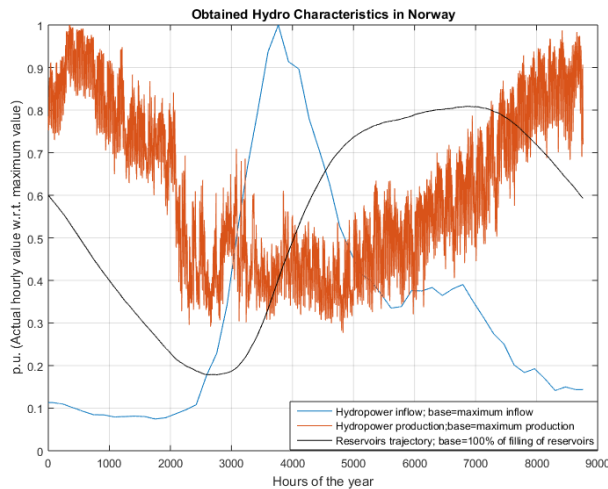
Fig. 6. Hydropower characteristics

This hydro generation pattern also affects the exchange between countries and creates the seasonal pattern that can be found in the exchange between Norway and Netherlands, Sweden and Denmark.
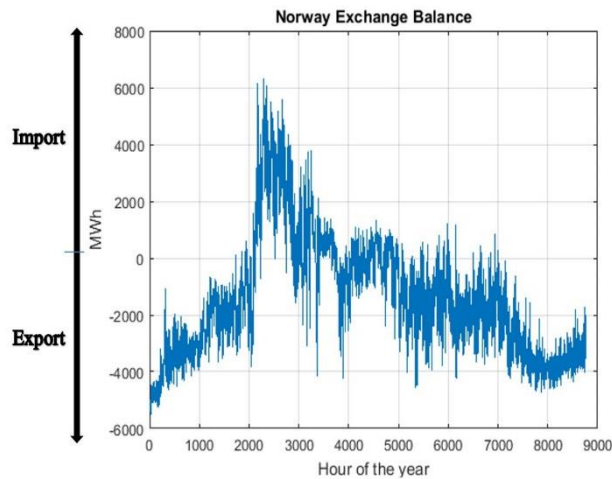

Fig. 7. Exchange of Norway with Denmark, Netherlands and Sweden

By considering figure 6 and 7, it can be seen how the Norwegian system imports more power when the reservoirs are close to being empty around the hour 2020 due to high water values. This makes hydropower generation plants not to produce electricity and to save water in the reservoirs.

V. CONCLUSIONS

The model can reproduce the main characteristics of the power system in terms of energy mix, cross-border flows, seasonal and daily patterns of the power system as well as the characteristics of hydro power generation technology.

Different approximations and assumptions are done in the process of selecting the input data, such as, aggregated nodes' representation (especially in Ireland and Northern Ireland), some areas branches' unlimited transfer capacities implementation (UK and Finland, for example) or simplified water values calculations, and these lead to some deviations from actual data.

For future improvements, it would be interesting to have the option to insert the exact water value in every iteration case, rather than calculating it by approximation via a combination between filling and time profiles.

Overall, this approximation leads to high nodal price variations between seasons.

In conclusion, the tool offers a powerful enough capacity to make different analysis, such as future interconnections or offshore grid layouts.

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