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Norwegian Energy Scenarios

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Abstract

The penetration of renewable energy sources is increasing in the European power system. Their interaction with the power market is fundamentally different from that of traditional thermal power production. This thesis aims to highlight the consequences this development has for the Nordic power system. The consequences studied are mainly related to power flows, power prices and storage handling.

To fulfil the research objective, a new EMPS[1] dataset has been created. The dataset uses the overall data and consistency from ENTSO-E TYNDP Vision 4 2016, but applies a different areal resolution than that of TYNDP Visions. The dataset uses the same areas as used in the current power trade of Nord Pool Spot, for Norway, Denmark, Sweden and Finland. This way, the dataset can better answer questions regarding consequences for the Nordic power system.

Two datasets have been simulated with the EMPS model[1]. One using data from Vision 4 2016, V4-16, and one where the installed capacity of solar and wind power has been doubled, DoubleRES.

The share of production from RES is 39 % in V4-16, a number which increases to 69 % in DoubleRES. The consequence of this increase includes a 49 % reduction in total net load, while the peak net load is reduced with 3 %. Where net load is defined as demand minus production solar, wind and run-of-the-river hydro power. An estimate for an upper limit for feasible battery storage capacity has been found to be 0.5 GWh/TWh/year. This would reduce the peak net load with 20 % in V4-16 and 30 % in DoubleRES.

Norway has an average power deficit of 22 TWh in V4-16, hence the Nordic average prices are no longer among the lowest in Europe.

The storage from summer to winter is on average reduced by 11 TWh in the Nordic areas from V4-16 to DoubleRES. A result of the increased use of Nordic reservoirs for year to year storage. Mostly to withstand year to year variations of neighbouring areas. This leads to larger seasonal average power price difference in the Nordics in DoubleRES than V4-16, increasing the economic benefit of reservoirs and storage units.

The Nordic areas have been found to push low summer prices to its neighbouring areas, driven by the risk of spillage and coherent low water values. The Nordic areas does however absorb

daily price differences from its neighbours. So much so that the lowest average price of the day is at noon, and the highest average price of the day is in the evening, even in the Nordics.

Sammendrag

Mengden installert effekt av solkraft og vindkraft øker i det europeiske kraftsystemet. Deres interaksjon med kraftmarkedet er fundamentalt forskjellig fra hvordan tradisjonell termisk kraft interagerer med kraftmarkedet. Denne masteroppgaven søker å framheve konsekvensene av denne utviklingen for det nordiske kraftsystemet. Konsekvensene som er studert relaterer seg først og fremst til kraftflyt, kraftpriser og magasinhåndtering.

Det har blitt laget et nytt EMPS[1] datasett som et ledd i denne oppgaven. Datasettet bruker overordnede data og den overordnede sammenhengen mellom data fra ENTSO-E TYNDP Vision 4 2016. Den geografiske oppdelingen er derimot forskjellig fra hva som er brukt i TYNDP Visions. Denne oppgaven bruker den samme geografiske oppdelingen av Norge, Sverige, Danmark og Finland som blir brukt i kraft handel på Nord Pool Spot. På denne måten er datasettet bedre skikket til å svare på spørsmål relevant for det Nordiske kraftsystemet.

To datasett har blitt simulert med EMPS modellen[1] (Samkjøringsmodellen). Ett datasett basert på Vision 4 2016 kalt V4-16. I tillegg et datasett kalt DoubleRES blitt simulert for å sjekke sensitiviteten til økt fornybar produksjon. DoubleRES er også basert på Vision 4 2016, men installert effekt av solkraft og vindkraft er doblet.

Andelen av kraftproduksjon som kommer fra fornybare kilder (ekskludert regulert vannkraft) er 39 % i V4-16, et tall som øker til 69 % i DoubleRES. Konsekvensen av det er at total netto last reduseres med 49 %, samtidig reduseres maksimum netto last bare med 3 %. Hvor netto last er definert som forbruk minus produksjon fra solkraft, vindkraft og uregulert vannkraft. I denne oppgaven har det blitt funnet et estimat på den øvre grensen for hva som er sannsynlig mengde batterier installert i systemet. Denne grensen er 0,5 GWh/TWh/year. En slik lagringsmengde vil kunne redusere maksimum netto last med 20 % i V4-16 og 30 % i DoubleRES.

Det har kommet fram av denne oppgaven at Norge ikke lenger har et kraftoverskudd i V4-16. Norge har isteden et kraftunderskudd på 22 TWh, noe som gjør at de nordiske prisene ikke lenger er blant de laveste i Europa.

Lagring av energi i nordiske vannmagasiner fra sommer til vinter reduseres med 11 TWh i gjennomsnitt fra V4-16 til DoubleRES. Dette er på grunn av det økende behoved for

flerårslagring. Behovet for flerårslagring øker noe på grunn av økt mengde vindkraft og solkraft i det nordiske systemet, men mest på grunn av økt mengde vindkraft og solkraft i omkringliggende områder. Dette fører til større forskjeller mellom gjennomsnittlig vinter og sommer priser i Norden i DoubleRES enn i V4-16. Med andre ord vil verdien av lagring bli større jo mer fornybar energi som blir installert. En viktig sammenheng for de som planlegger nye eller rehabilitering av gamle dammer.

I denne oppgaven har vi funnet at de nordiske områdene presser lave sommer priser over på sine naboer. Dette er drevet av faren for overløp om sommeren, og dertil hørende lave vannverdier. På den annen side absorberer de nordiske områdene prisforskjeller gjennom døgnet. Dette fører til at også Norden opplever å ha lavest priser rundt kl 12, når solkraftproduksjonen er på topp.

Acknowledgments

This master thesis concludes my master's degree within Energy and Environmental Engineering at NTNU, and marks the ending of a chapter in my life.

I would like to thank everyone that I have had the pleasure to share my five university years with. A special thanks to Hossein Farahmand and Stefan Jaehnert for continued guidance and support during the work of this master thesis and the preceding specialization project. My thanks also go to all my colleagues at "the Office" for contributing to a warm and welcoming working environment, and procrastinating opportunities to intriguing to miss.

My sincere thanks also go to family and friends, for all the shared moments, pleasant days, and happy nights that have been thus far.

I am especially grateful to Jens Austerheim, for taking the time to read this document, helping me writing this thesis in a consistent and grammatically correct language.

Trondheim, June 2017

Audun Tysnes

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Abbreviations and concepts

Business cycle	Business cycle is a concept used in economic theory to describe the fluctuations of economic activity. This is closely related to the concepts of expansion and recession.
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CenSES	Centre for Sustainable Energy Studies
Depletion season	The part of the year where the inflow to a reservoir is less than the discharge.
DSR	Demand Side Response
ENTSO-E	European Network of Transmission System Operators – Electricity
Equivalent full-load hours	The amount of hours it would take to produce one years' worth of production at maximum capacity.
EU ETS	EU emission trading system is a cap and trade system implemented in EU. Trading within EU ETS gives the CO_2 price in Europe.
Filling season	The part of the year where the inflow to a reservoir is greater than the discharge.
Firm power	Firm power includes all energy loads that are not flexible.
FME centre	Centre for Environment-friendly Energy Research
IAM	Integrated assessment modeling.
IAV	Impacts, adaptation, and vulnerability.
IEA	International Energy Agency
IIASA	International Institute for Applied Systems Analysis
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
LinkS	Linking Global and Regional Energy Strategies
Minimum release of water	Some hydro power systems have requirements that the amount of water flowing in a related river, cannot be below a certain level.
MSR	Market Stability Reserve is a market measure proposed by EU to reform EU ETS.

Net load	Demand minus power production with a marginal cost of 0. In this study that means demand minus power production from solar, wind, offshore wind and run-of-the-river hydro.
Occasional power	Occasional power includes all energy loads that are flexible. This could be large industrial actors that are willing to pause production during a period of high prices, or boilers that have several options regarding energy source.
OCGT	Open Cycle Gas Turbine
RCP	Representative Concentration Pathways
RES	Renewable Energy Sources
Relative damping	Unused volume of a reservoir divided by its annual inflow.
Soft-linking	Combining models by using the output data of the global model as input data of the local model.
SSP	Shared Socio-economic Pathways
TSO	Transmission System Operator
Water value	A water value is the expected marginal value of a water in a given reservoir. The water value will in other words imply at which price the water should be used.
Water value matrix	A water value matrix is a matrix describing all possible water values in the dimensions of time and reservoir level
WEO	World Energy Outlook

1 Introduction

The connection between CO_2 and climate change is widely recognized, and has a firm support in the work done by the IPCC. The Fifth Assessment Report, their latest main report, states that; *carbon dioxide concentrations have increased by 40 % since pre-industrial times, primarily from fossil fuel emissions.[2]* Energy, as a main contributor to CO_2 emissions, plays a key role within the issue of climate change. Especially, electricity and heat generation.

Up until today, the world has relied on several energy carriers, including gas, petrol and electricity. Even though electricity is not an energy source, it has the benefit of being able to transport energy cheaply, efficiently, at an instance, in large quantities and free of CO_2 emissions. These properties combined with the political will to reduce CO_2 emissions are the basis for electrification – the tendency for electricity to supersede other energy carriers. The most prevalent being electrification of transportation and heating. This will lead electricity to play, an even more, important role in the future energy system.

In recent years, a fast cost reduction of solar and wind power has been observed [3]. This has lead solar and wind power from being a very expensive way of producing energy, to be imaginable, as successors of coal and gas, as electricity generators.

The cost-reduction of solar and wind power, implies an impact on the power generation mix. This creates uncertainty caused by a fundamental difference between solar and wind power and fossil power. Whereas fossil power has a marginal price based on the price of the fuel, and will produce at full power if the price is high enough, solar and wind power has a marginal price of almost zero. Solar and wind power will therefore produce at maximum at all times (disregarding the phenomena of generation shedding), a maximum that is ever changing. One dimension of uncertainty, concerning the future power market, revolves around long-term prices. In a fuel based power system, the fuel prices, and the future development of the future fuel prices is essential to understand the future electricity price. The future fuel price is, hence very important when doing investment decisions or operational decisions of storage facilities.

Both electrification, cost-reduction of solar and wind power and the uncertainties they represent, creates a changing power market. Within the area of a changing power market, there are two main issues regarding the research of the future energy market. There is an uncertainty issue, and a computer power issue.

1.1 Project thesis description and project goals

Within the FME CenSES (http://www.ntnu.edu/censes) a set of Energy scenarios will be developed, based on Norwegian energy and climate targets for 2030 and ambitions for 2050. The scenarios shall both contribute to further quantification of the targets/ambitions, as well as help give recommendations related to how the targets and ambitions can be achieved.

Among others, the main objective of the Energy scenario development is to provide scenario-based knowledge to policy- and decision makers at a "high-level" to contribute to sustainable energy strategies and targets for Norway in the time perspective 2030 to 2050. The CenSES scenarios will mainly be based on Norwegian energy and climate policies and take EU policies into consideration. They will be based on the cross-disciplinary knowledge in CenSES and include both quantitative and qualitative aspects.

The objective of the student work is to contribute to the quantification of the CenSES energy scenarios and to conduct dedicated scenario studies. The quantification and the studies will be done with the SINTEF's power market simulator EMPS.

Following specific research questions shall be addressed:

· Develop selected consistent Energy scenarios for the European power system for the horizons of 2030 and 2050 based on the qualitative description of these CenSES energy scenarios

· Assess the energy scenarios with regard to:

- *emission reduction*
- *value creation*
- *sustainability*

Important goals, for the master projects, are:

- Develop a scenario which better suits the Nordic viewpoint of the research
- Familiarize and use manual calibration of the EMPS model.
- Analyse the results from a Nordic viewpoint.

1.2 Scenarios

The future is by nature unpredictable, this creates a natural sense of uncertainty in the market. There are several ways in which to deal with this issue. One approach is to make a forecast, a projection of the most likely future. Another approach is to make scenarios, several plausible projections, which together maps out a room of possibilities. This way, scenarios act as guidelines to understand what is to come. Scenarios can also be a useful way to quantify and analyze the detailed outcome of today's concerns, i.e. assess what the result of a feared development actually will be. In addition, scenarios can act as decision support, both within companies and among politicians.

The scenario building process starts with a narrative. First some qualitative characteristics of each scenario is found. These characteristics are then quantified into input data for the most comprehensive model. Models are then used to quantitatively describe each scenario in more detail.

1.3 Market models

Within the area of energy market models, the issue is not to create a model which can both describes all energy systems with a high detailed level both in time and area, and is capable of finding market equilibrium across all energy and adjacent markets. The issue is obtaining both a high resolution across all energy, and adjacent, markets with an acceptable computation time. In other words, a computer power issue.

This predicament is partly solved by splitting the problem into smaller, more manageable problems, and partly by simplifying the problem. When analyzing the result, one should be aware that splitting the problem into smaller problems, creates heuristics in the solving process, i.e. one cannot be sure to have found the best solution. Simplification implies that the problem solved is not exactly equal to the real-world problem.

In practice, the problem is split into smaller problems by using several market models, and later linking them. The work done within CenSES splits the problem into three. One model for all energy and adjacent market with a global scope, but with low resolution, the second model for the European power market with medium resolution, and a third model for European power market operation with high resolution. This research described in this report deals with the third model.

1.4 CenSES

CenSES (Centre for Sustainable Energy Studies) is a national FME centre (Centre for Environment-friendly Energy Research), established in 2011. The FME centres is managed by the Norwegian Energy Council. The objective behind this way of allocating resources to research is to conduct time-limited, concentrated, focused and long-term research on a high international level, to solve specific challenges within the energy field.

CenSES' main research objective is stated in their annual report as follows.

> *CenSES' main research objective is to conduct research that supports public and private decision makers in strategic decisions and policies that will promote environment-friendly energy technologies and lead to a sustainable energy system. The research will result in new policy recommendations, tools and models, strategies and scenarios supporting the transition to a sustainable energy system.[4]*

To answer the research objective, 5 research areas have been defined.

- Research Area 1: Policy making and transition strategies
- Research Area 2: Energy systems and markets
- Research Area 3: Economic analysis
- Research Area 4: Innovation, commercialization and public engagement
- Research Area 5: Scenario development

The research described in this report is a part of CenSES' Research Area 5 (RA 5).

1.4.1 Research Area 5 Scenario Development

> *The main objective of RA 5 is to provide scenario driven knowledge and analyses to policy- and decision makers to aid in the development and evaluation of sustainable energy strategies.[4]*

1.5 Scope

The research presented in this thesis will focus on Nordic, future, energy scenarios, with 2030 as a time horizon, and the modelling of these scenarios with the EMPS model. The main research objectives are:

- Construct a complete dataset for the EMPS model of Europe based on ENTSO-E Vision 4, with a more suitable areal partition for research with a Nordic/Norwegian viewpoint. A dataset that can be utilized by future research.
- Create variations of the dataset with different degrees of RES penetration.
- Simulate these datasets with the EMPS model by using manual calibration.

- Analyse the results with the following as focus:
  - In terms of energy, which areas are producing more than they consume, and which consume more than they produce.
  - Does the areas import/export because they can, or because they need to?
  - How will a higher implementation of RES change the dynamics of the net load, and how is this visible in the power price.
- Discuss the consequences for the development of the Nordic power sector.

1.6 Relation to specialization project

Several chapters of this master thesis are partly or completely based on chapters in the specialization project.[5]

Chapter 1 Introduction used chapter 1 Introduction from the specialization project as a basis, and adjustments were made were the substance of the content was no longer viable. As a result, subchapter 1.1, 1.2, 1.3 and 1.4 are from the specialization project with minor adjustments.

Chapter 2 Theory is equal, with some small changes, to 2 Theory in the specialization project, except for subchapter 2.4.1.4, which have been written purposely for the master thesis.

Chapter 3 Method of Research is rewritten for the master thesis, but chapter 3 Method of Research of the specialization project was used as a basis, meaning some phrases may be similar in the two chapters.

In the project thesis, the following was written about the further work that should be implemented in the master thesis:

> *As this project thesis aims to be a basis of a master thesis, the further work described in this section refers to the further work that should be done in the master thesis.*
>
> *In the master thesis, the work of analyzing different future energy scenarios will be continued. One main pursuit in this work is to analyze, and compare several energy scenarios. The energy data in which these analyses will be based, will be decided in collaboration with SINTEF Energy Research, to make the collaboration between scenario development process within the CenSES research project and the master thesis fruit-bearing.*

To lay the foundation for a more comprehensive analysis of the Nordic region, it desirable to use a more detailed description of the hydropower in the Nordic region, as well as representing the Nordics with more than one node per country. The TYNDP Visions already differentiates between eastern and western Denmark in their dataset. A disaggregation of Norway and Sweden can use a sufficiently detailed dataset describing the present situation as a guideline, if the output data from EMPIRE within CenSES isn't available.

To reduce the amount of data created as results, and to make it easier to present the larger picture in the periphery of the Nordic power system, a coarser areal partition is desirable in especially south-eastern Europe. In addition, the master thesis should consider how get a more realistic modeling of gas power.

A dataset of the present situation would be desirable, both to as a reference point in the discussion and analysis of the future scenarios, and as a basis to develop a more detailed description of amongst other gas power.

The master thesis should also include an analysis of the combination of RES and consumption, and how they vary over time. Investigating covariation, within and between countries. In addition, achieved price for wind and solar should be computed and compared to the average market price.

As a part of the work of the master thesis, time should be spent on understanding and tweaking the calibration factors of the EMPS model. The master thesis should aspire utilize automatic computation of the calibration factors.[5]

Of the elements described in project thesis, most of them have been included in the master thesis. The work described in this report uses a several nodes per country in the Nordic area, it uses a coarser areal partition in parts of Europe distant from the Nordics, it includes an analysis of the input demand and RES data, and considerable time have been used calibrating the EMPS model.

Some of the suggestions proposed have, on the other hand, not been implemented. This includes a detailed description of the hydropower in Norway, and a dataset representing the present situation. It should however bee noted that the hydropower description in the master thesis is better than that of the project thesis, as it split between 5 price areas, but it still uses one reservoir per price area. Creating a dataset representing the present would be very beneficial for comparative purposes, but was abandoned in accordance with supervision when the labour heavy nature of this work was clear.

1.7 Contribution

- This thesis aspires to highlight some of the trends of the future power market, to lower uncertainty for involved parties. The uncertainties regarding power prices, power flows and reservoir handling have been the focus.
- To achieve this, a new EMPS dataset has been created based of TYNDP Vision 4 2016, with an aerial resolution suited for Nordic research. This thesis has created a dataset using TWENTIES to divide data from TYNDP Vision 4 2016 into a finer areal resolution in the Nordic area. This way, 5 areas represents Norway, 4 represents Sweden and 2 represents Denmark without the consistency of the TYNDP Vision 4 2016 dataset being lost. The Nordic areas are consistent with the price areas used in current power trade at Nord Pool Spot. This dataset is created with future research at NTNU in mind, serving as a basis for other research, including research not directly linked to the research question of this thesis.
- A second dataset have been created to show the sensitivity of installing more RES in the Vision 4 2016 system. This dataset uses the double amount of RES as Vision 4 2016.
- In the process of creating a broad platform for discussion, the input data used to the EMPS model have been studied and validated, this includes demand series and RES production series.
- The two scenarios created have been simulated and manually calibrated in the EMPS model, and the results have been studied and analysed based on the research questions.
- Visualization is an important part of result presentation in this report as the results includes large amount of data. To display the power situation in all areas in the same figure, a map has been created. This map is excel based and can import data from any EMPS simulation using the same areal resolution as this study. The map displays a

snapshot of the power situation of Europe for an average the user's choice of price periods. The excel sheets needed for the map is made available for further work and research at Department of Electrical Power Engineering, NTNU.

2 Theory

This chapter describes theory in the field. It comprises a description of scenarios, how they are built within the CenSES research program. In addition, this chapter describes different studies already conducted, and it contains a description of the EMPS model. The power market model used in this study.

2.1 Theory of scenarios

A scenario is defined by the Oxford English Dictionary as...

> *A postulated or projected situation or sequence of potential future events; (also) a hypothetical course of events in the past, intended to account for an existing situation, set of facts, etc. Also more generally: a set of circumstances; a pattern of events. [6]*

This definition does not say anything about the need for a scenario to be realistic or probable. There is in other words a difference between a forecast and a scenario. Where a forecast is predicting the future, describing the most likely outcome, possibly with a stated uncertainty, a scenario is describing a possible future or set of events without considering how likely they are to become real.

Even though a scenario doesn't predict the most likely outcome of the future - as a forecast, there are things scenarios can illuminate that forecasts cannot. Firstly, a scenario usually does not exist alone. It is normal that several scenarios are presented together. In this way, the scenarios are mapping an area of possible futures. Secondly, scenarios can make stakeholders prepared for the future events. By mapping an area of possible futures, they can get to know the applicable consequences within a variety of different futures. Thirdly, scenarios have an advantage over forecasts when presented to policy makers, as they get to influence the future. Policy makers can thereby explore the consequences of different decisions.

One dividing line between different types of scenarios, is whether they are dynamic or static. Take the power market as an example. In a static scenario, energy markets are typically cleared for one future characteristic year. In dynamic scenario, on the other hand, several following years are considered, and the development from one year to the next is important. Usually dynamic scenarios describe the development starting with today's situation. In other words, the dynamic scenario must predict when new technology is implemented, and when old technology is phased out. Thus, the system does not need to be in equilibrium. This is especially relevant in the power market because of some characteristics of power stations. A power station has very high up-front investment cost compared to the day-to-day running cost, a characteristic that is even more true for renewable energy sources. In addition, a power station last for a long time, usually several decades, and have a long building time, usually several years. These characteristics give positive conditions for a business cycle to develop. Thus, one would expect there to rarely be an equilibrium between installed capacity and consumption in the power market.

2.2 About the scenario building process

In this subchapter, you will find a description of the scenario building process. Note that this process can differ slightly from publication to publication. The scenario building process described here, is therefore closely linked to the work done within CenSES.

2.2.1 Qualitatively

The first step of creating a scenario is to create a storyline. This is usually a set of qualitatively described attributes. This storyline could, for example, include if the economic growth is high or low, if technological development is high or low, if global trade will increase much or not etc. The storyline should say something about the large uncertain trends, and connect the different trends in a plausible way. It would for example be more plausible if both technological development and economic growth are high instead of one of them being high and the other low.

Often, more than one scenario are developed. When several qualitatively described scenarios are developed, the process of quantification begins.

2.2.2 Quantitatively

When quantifying a scenario, there are two properties of the data one wants to achieve, consistency of data, and satisfactory resolution.

Consistency of data means that all the data satisfy the rules of the system. In a power market scenario, this means that the data is based on market equilibriums in all relevant markets. This includes day-to-day power markets, fuel markets, CO_2 market, and investment in power generation etc. For example, the percentage of renewable energy sources in a system, influences the amount of fossil fuels that are burnt to make power, this will in EU influence the CO_2 price of the EU ETS, which again influences the percentage of renewable energy sources in the system. To have a market equilibrium in all relevant markets, these data needs to be consistent. Note that a dynamic scenario doesn't need to be in market equilibrium to have consistent data, but it needs the equilibrium to be the reference for where the market is going. One way to achieve consistency of data is to get all data from the same model.

The other desirable property of the data is satisfactory resolution. Resolution includes both time and area. Aggregating Europe into one node is too coarse if an analysis of power flows between European countries is performed. In the same way, a time step of one week is too coarse if daily power price variations are to be assessed.

In order to quantify scenarios, models are used. Making a model that models the energy markets with both satisfactory resolution and consistency of data is not all too difficult, but it would use unacceptable computing time to find a result. One way to solve this is to link global and regional models. A global model typically calculates fuel prices, installed capacities etc. with a coarse resolution (Europe is typically treated as one node), whereas a regional model typically models the power market in one specific region, with assumptions about the rest of the world. Christian Skar refers to global and regional models as top-down and bottom-up models respectively in his PhD [7].

It is possible to use results from the top-down model as input to the bottom-up model. Consequently, the bottom-up model creates higher resolution, both in terms of time and area, to the results from the top-down model. This way of linking regional and global models is called soft-linking.

2.3 Former and ongoing research

This subchapter comprises an overview of research related to this study, and research this study is based upon. After relevant studies are listed and described, a comparison of scenarios within these studies is displayed in tabulated form.

2.3.1 SSP and RCP

RCP (Representative Concentration Pathways) are developed as a collaboration between the international scientific community and the IPCC (Intergovernmental Panel of Climate Change). The RCP's are used in the IPCC Fifth Assessment Report. The underlying data of the RCPs can be found in the RCP database hosted by IIASA (International Institute for Applied Systems Analysis).

The RCPs are scenarios describing the development into futures with different overshoots in the energy balance. There are four RCPs: RCP3, RCP4.5, RCP6 and RCP8.5. They represent overshoots in the energy balance in 2100 of 3, 4,5, 6, and 8,5 W/m^2 respectively. The RCPs uses this energy unbalance as a starting point, and makes predictions of the emissions of short lived as well as long lived greenhouse gasses, land-use change etc.[8]

One of the RCPs major drawbacks is the lack of connection between greenhouse gas emissions and socioeconomic development. Consequently, impact, adaptation, and vulnerability (IAV) research lacks important information if based on the RCPs. To respond to this challenge, the international scientific community has been asked to develop SSPs (Shared Socioeconomic Pathways). SSPs are meant to be used in combination with RCP, with RCPs on one axis and SSPs on the other, to map out a matrix of possible futures. [9-11]

As with the RCP, IIASA is creating a SSP database with detailed background data for each SSP. This is however a work in progress.

2.3.2 IEA WEO

IEA (International Energy Agency) is a member state based organization within OECD (Organization for Economic Co-operation and Development). One of IEAs objectives is to *improve transparency of international markets through collection and analysis of energy data. [12]* To meet this objective, the IEA makes the WEO (World Energy Outlook). The WEO is one of IEA's most important reports, and is updated every year, and includes extensive statistics regarding the current energy situation, projections about the future energy situation as well as analysis and advice.

To make projections of the future energy situation, the report uses scenarios. These scenarios include detailed information about energy demand, installed capacities and investment divided into regions and energy sources.

2.3.3 IRENA

The International Renewable Energy Agency (IRENA) is an international organization created to support countries in their transition to a future with sustainable energy. IRENA has 149 member states as of October 2016, not including Canada and Brazil. One way in which IRENA exerts its objective, is through publishing extensive energy statistics. IRENA does not make extensive scenario based projections of the world's energy markets, like what is found in IEA's

WEO, but they make some predictions about the future. Examples of this is presented in the report “The Power to Change: Solar and wind cost reduction potential to 2025”.

2.3.4 ENTSO-E 2030 Visions

ENTSO-E (European Network of Transmission System Operators – Electricity) is an organization with the TSOs of 35 European countries as members. ENTSO-E has an objective to create a European energy market with free trade, in addition to support the climate goals of the EU. ENTSO-E has a legal mandate from the European Union.

As a part of their role to support the climate goals, ENTSO-E develops a Ten-Year Network Development Plan (TYNDP), which intend to predict the network development needed in Europe. To develop the TYNDP, ENTSO-E uses scenarios referred to as “2030 Visions”. In the 2030 Visions ENTSO-E describes installed capacities for every energy source for every country as well as the average demand. These data are freely available. ENTSO-E uses the market models BID, ANTARES and PowerSym.

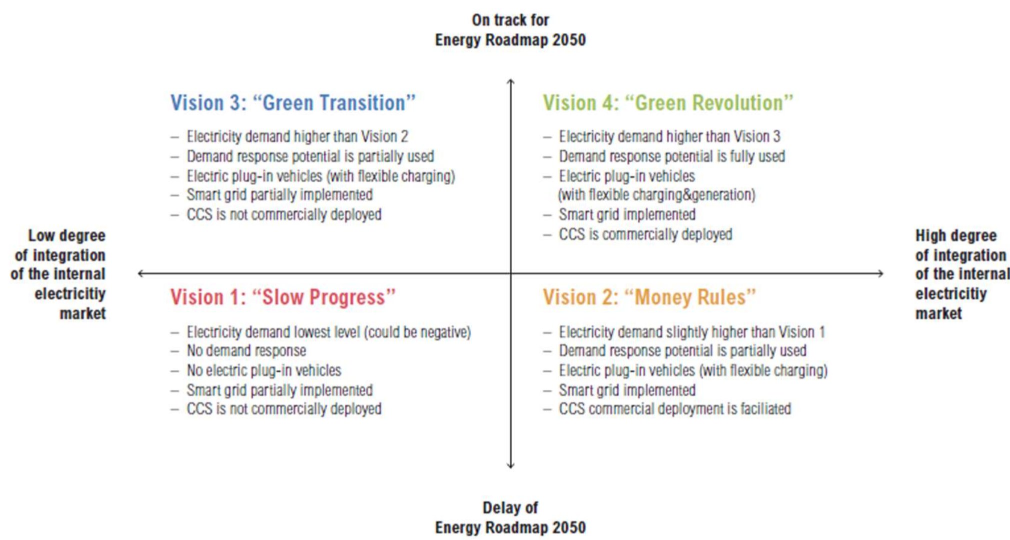

Figure 1: Scenario map – TYNDP Visions. [13]

Figure 1 shows the how along what axes the 2030 Visions maps an area of possible futures. It also describes the main generation and demand characteristics of each scenario.

Table 1: Data collection within TYNDP.[13] is an overview of how the Visions are quantified, and the approach used.

Table 1: Data collection within TYNDP.[13]

Data	Source	Comment

Scenarios major characteristics (electric vehicles volumes, DSR potential, storage, etc.)	Stakeholders' survey	Guidance from the survey + implementation by ENTSO-E expert team
Peak load, load curves (V1, V3)	ENTSO-E members (basic inputs) + ENTSO-E expert team (for EV charging, heat pumps, …)	Consistency checks and tuning by ENTSO-E expert team
Peak load, load curves (V2, V4)	V1, V3 data evolved by ENTSO-E expert team	According to the consulted methodology
Generation means (V1, V3)	ENTSO-E members, complying with common standard guidelines	V3 RES assumptions derived from NREAPs (or other national goals)
Generation means (V2, V4)	V1, V3 data evolved by ENTSO-E expert team	According to the consulted methodology
Fuel and CO_2 costs	IEA WEO 2011	
Grid models 2030	ENTSO-E members, complying with common standard guidelines	
Projects technical details	Project promoters (if pre-existing), ENTSO-E experts (if new)	

2.3.5 Nordic Energy Technology Perspectives

In addition to the WEO, IEA (International Energy Agency) makes an annual report called Energy Technology Perspectives (ETP) which identifies *technology and policy opportunities available for accelerating the transition to sustainable urban energy systems. [14]*

In cooperation with Nordic Energy Research (Norden) a Nordic version of the ETP is made, the "Nordic Energy Technology Perspectives". The analysis uses both back-casting and forecasting to develop quantified scenarios. The Nordic ETP integrates the TIMES model with the global model to get more detailed results for the Nordic region.[12]

Figures and data are freely available.

2.3.6 NORSTRAT

NORSTRAT was a research project conducted by SINTEF Energy Research, DTU (Technical University of Denmark) and SEI (Stockholm Environment Institute) through Nordic Energy Research (Norden), and was finished in 2015. This research project used scenarios and had a Nordic focus. In part D3.1 of this research project, an analysis of the energy market with the EMPS model was conducted. Identifying the need for transmission capacity was one of the key research questions for the energy market analysis.

2.3.7 Statnett

Statnett is the TSO of Norway, and makes long-term power market assessment as a part of their objective. Their latest, Long-term Power Market Assessment – The Nordic and Europe 2016-2040 [15] uses the BID and Samlast/Samnett model, where Samnett is and extension module to the EMPS model, with a more realistic and detailed grid model. BID is a power market model made by Pöyry. Statnett uses the BID model to assess the European power market. Samnett is then used to model the Nordic market with the results from BID as boundary conditions. This is done as the BID model is better than Samnett on power systems dominated by thermal generators, while Samnett has an advantage on power systems with a high share of hydro power generators.

Statnett's work differ from the work currently being done within CenSES by being a power market analysis only, which focused on the European market. In other words, forecasts for fuel prices, CO_2 prices, demand, power generation investment (installed capacities), are bought from secondary sources. A sensitivity analysis is then run, with high and low fuel prices etc.

2.3.8 SUSPLAN/e-Highway 2050

SUSPLAN (PLANning for SUStainability) is a research project founded and supported by the European Union's Seventh Framework Programme, coordinated by SINTEF Energy Research. The SUSPLAN project aims to find the optimal way to integrate renewable energy sources in the European grid, and create recommendations and guidelines to political and industrial actors. In order to scientifically answer their main objective, SUSPLAN created European-wide scenarios with a time horizon of 2030-2050.[16]

The Seventh Framework Programme e-Highway 2050 is building on, amongst others, the results from SUSPLAN. The quantification of the e-Highway 2050 scenarios starts at a European level. An assessment of the electricity demand is done, as well as a calculation of the energy mix based on the scenario descriptions. The energy mix calculations are done first and foremost to decide, for which region the renewable energy sources should be built. The mix itself is a consequence of the scenario description. The results are then disaggregated to a country level, and further to a cluster level. The project uses the market model ANTARES.[17]

2.3.9 TWENTIES

TWENTIES is a Research project supported by the European Commission and the Seventh Framework Programme, where SINTEF Energy Research is responsible partner for the D16.3 deliverable within work package 16.

> *TWENTIES (Transmission system operation with a large penetration of Wind and other renewable electricity sources in Electricity Networks using innovative Tools and Integrated Energy Solutions) is one of the largest renewable energy demonstration projects funded by the European Commission's Directorate-General for Energy under its seventh Framework Programme (FP7)*
>
> *The aim of the TWENTIES project is to advance the development and deployment of new technologies which facilitate the widespread integration of more onshore and offshore wind power into the European electricity system by 2020 and beyond.[18]*

Task 16.3 focuses on the possibilities of mutual benefit of Nordic hydro power and Northern European wind power, as well as identifying obstacles, like grid restrictions. A part of Task 16.3 includes simulating scenarios for 2010, 2020 and 2030 with the EMPS model. The scope of the problem, means only northern Europe is modeled.

2.3.10 CenSES

CenSES is an ongoing research project hosted by NTNU. The scenario development within CenSES uses three models: GCAM, EMPIRE and the EMPS model. The three models will work with each other's results through soft-linking. CenSES will start their analysis at the global level, modeling the global energy markets with the SSPs as input. GCAM (Global Change Assessment Model) will be used for this process. It models all energy markets on a global scale. The time and area resolution is therefore rough. Europe is, for instance, represented as one node as an example. GCAM is a dynamic-recursive model developed by PNNL designed to model the interaction between economy, the energy sector, technology, land-use and climate. Important input to GCAM includes technological development, population growth, economic development etc. The output includes power demand, fuel prices, CO_2 price and installed capacities.

The following model will be EMPIRE (European Model for Power system Investments (with high shares of) Renewable Energy) will be used to disaggregate the results, and study consequences for Europe. EMPIRE is a multi-horizon power market model which also models and optimizes investments. Investments are optimized with uncertainty of future revenue decoupled from the optimization of the operation of the power system. As a power market model, electricity is the only traded commodity in addition to a simplified integration of a CO_2 market. A main advantage with EMPIRE compared to other power market models, is its ability to link short and long-term dynamics. [19]

EMPIRE has a more detailed model than GCAM. It divides the year into 4 seasons, where 2 representative weeks are modeled with an hourly resolution per season. The investment decisions are taken at a time step of 10 years. The results from GCAM will be used as input to EMPIRE. This includes, power demand, fuel, and CO_2 prices, but not the installed capacities. Instead, the European power generation mix - i.e. the percentage of solar, wind and so forth - is imported from GCAM, letting EMPIRE have the freedom to decide the location and scale of power generation.

The third model – the EMPS model – will be used to assess the operational consequences of the future found with GCAM and EMPIRE. The EMPS model is a power market model, known for its ability to handle long-term strategic of hydropower. In addition, EMPS does not use representative weeks, but models the whole year with equal resolution. The EMPS model is further explained in section 2.4.1. Fuel and CO_2 prices, power demand, and installed capacities from GCAM and EMPIRE will be used as input to the EMPS model.

The now finished LinkS (Linking Global and Regional Energy Strategies) research project is connected to CenSES. The LinkS project researched linking of energy market models. The PhD of Christian Skar, Modeling low emission scenarios for the European power sector [7], is part of the LinkS and CenSES research project. Skars research uses the GCAM and EMPIRE models to assess the development of low emission scenarios.

2.3.11 Norwegian Energy Roadmap 2050

Norwegian Energy Roadmap 2050 is a research project coordinated by SINTEF, which started May 2016. Norwegian Energy Roadmap 2050 shares similarities with CenSES in the way it will use and link models. Both projects will as an example use the EMPS model, but Norwegian Energy Roadmap 2050 will use TIMES where CenSES use EMPIRE. In contrast to EMPIRE, TIMES is an energy market model, meaning it models several interconnected energy markets, i.e. both gas, electricity, coal, heat, transport and so on. TIMES uses 4 seasons as EMPIRE, but TIMES divides the seasons into 5 price sections, instead of representative weeks.

2.3.12 Comparable scenarios

This subchapter is intended to show the connection between comparable scenarios in research, described in section 2.3 in tabulated form. The table uses the CenSES scenarios as a reference point, connecting similar scenarios to it.

CenSES	Green Globe	Grass roots	Market led	Current policies	Green governance	National ways
SSP	SSP1		SSP5	SSP2	SSP4	SSP3
WEO			450	Current policies	New policies	
ETP	2DS			6DS	4DS	
TYNDP		Green transition – Vision 3	Money rules – Vision 2	Slow progress – Vision 1	Green Revolution – Vision 4	
EU Energy Roadmap 2050		Energy efficiency	Diversified supply technologies	Reference	Green Revolution	
NORSTRAT	European Hub		European Battery	Carbon Neutral Nordic	Purely RES	
e-Highway 2050	X-7	X-16	X-10		X-5	

2.4 Theory of power market models

In this section, the model EMPS model will be described and put into context. There are several models available for modeling different aspects of energy markets. Power market models is one type of energy market models, which models electric power markets. Within the area of power market models there are also several different types, among others investment models, long-term power market models and short-term production planning models.

The EMPS model is one of several long-term power market models. Long-term power market models usually use fuel prices, CO_2 price and installed capacities as input parameters, and demand as a given pattern of consumption with a slight price sensitive flexibility. The result is usually power prices (different price from area to area) and a production plan. Note that as power market models usually use installed capacities as input, they are different from investment models.

2.4.1 The EMPS model

The EMPS (EFI's Multi-area Power market Simulator also known as Samkjøringsmodellen) model is a market simulator, which optimizes the socioeconomic surplus in the power market. It does so by administer the production plan of thermal and hydro power generators. The way in which the EMPS finds a socioeconomic optimal production plan for hydropower, is one key dividing line between it and other long-term power market models.

2.4.1.1 Multi-area

The EMPS is multi-area, meaning it handles separate price areas, with transmission capacity limits between them. There is also a one-area version of the EMPS available, the EOPS model. This has a slightly different solving procedure as well as area of application then the EMPS, and will not be discussed in further detail.

The multi-area nature of the EMPS also includes modelling of transmission losses, however, these are modeled as linear and not quadratic as in reality. The reason for using linear losses is that the problem description within EMPS is linear. This is done to make the optimal solution easier to find.

2.4.1.2 Input data

The EMPS model uses the following data as input:

- **Area description.** The model uses a description of nodes, how they are linked and the transmission capacity between the nodes.
- **Installed capacities.** The model requires information on all different types of generators, and their installed capacity for every node.
- **Power generator description.** The model requires information describing the different generators, this includes efficiencies, fuel type, energy content of fuel etc.

- **Detailed water course of all hydropower systems.**
- **Demand.**
- **Fuel prices.** The model needs fuel prices for all generator types specified.
- **CO_2 price.**
- **Wind and solar production.** The model uses data series that describes the wind and solar production for an equivalent wind or solar generator. The data series can describe the whole year with an hourly resolution, for several climatic years.
- **Inflow.** The model uses data series that describes the amount of inflow to the reservoirs.

Both data series for wind and solar production, and inflow, can be described with an hourly resolution. They are usually both based on historical data. By using data from several historical years, a stochastic result is possible. The inflow, wind and solar data series are usually linked, as an example, one scenario uses the inflow data from 1982, then that scenario would also use the wind and solar data from 1982.

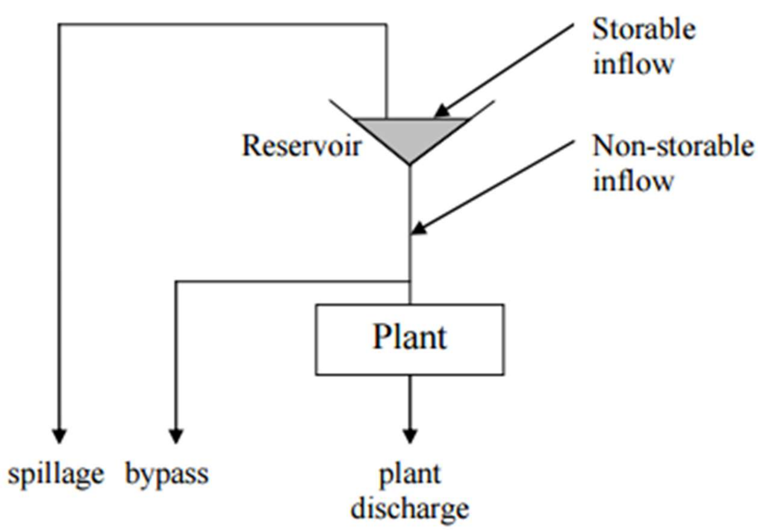

Figure 2: Standard hydropower module.[20]

The EMPS model differentiate between storable and non-storable inflow for hydropower plants. Non-storable hydropower is treated similarly to solar and wind power. Non-storable inflow represents both run-of-the-river hydropower and non-storable inflow within a hydropower system with reservoirs. This includes production required to avoid floods and minimum release of water.

2.4.1.3 *The simulation procedure*

The EMPS is based on the water value method and the theory of perfect competition. The simulation procedure of the EMPS can be divided into two steps. A strategy part and a simulation part. In the strategy part the goal is to obtain water values for each hydro power reservoir. While the goal of the simulation part is to find the detailed generation dispatch as well as the water management.

Both the strategy part and the simulation part are iterative procedures, which means there are control loops that checks the solution and re-runs the optimization part with tweaked input in order to get viable results. This is an example of heuristics in the EMPS model.

2.4.1.3.1 Strategy

In the strategy part, a water value matrix for each reservoir based on stochastic dynamic programming, is found. A water value matrix is a matrix describing all possible water values in the dimensions of time and reservoir level. To use the water value method with acceptable computation time, aggregation is needed. All hydropower with storable inflow within one price area/node is aggregated into one hydropower system with one generator and one reservoir, a standard hydropower module as shown in Figure 2.

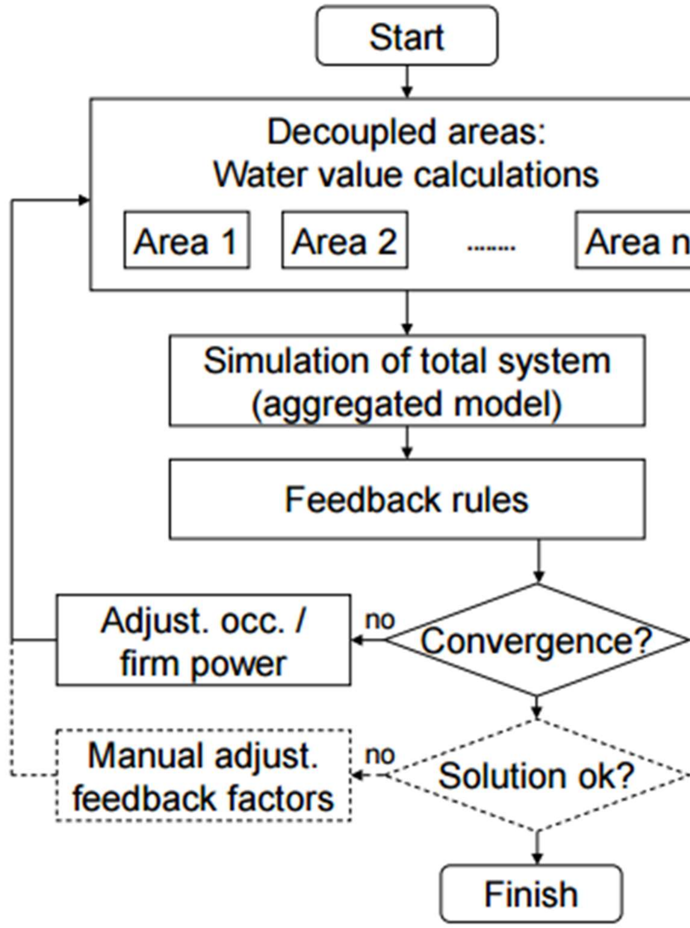

Figure 3: The strategy part. This figure shows the iterative process of obtaining water values in the strategy part.[22]

In addition to aggregating hydropower plants, the water values are calculated with decoupled areas, to obtain reasonable computation time. Figure 3 shows the iterative solution process, starting with decoupled areas. The following step is to simulate the total aggregated system. In this step the power flow between areas are evaluated. The EMPS model bases the power flow between areas on calibration factors. These calibration factors where traditionally controlled manually, and meant that different users would produce different results. Consequently, learning to use the model was time consuming, on the other hand, experienced users would be able to produce even better results. Now, these calibration factors can be controlled automatically. The automatic computation of calibration factors are however a time consuming process, and is thereby not done by default.

When the total aggregated system simulation can't find any increase in optimal value by changing power flow between areas, the process converges and the strategy part finishes. The result is a water value matrix for every area with a time resolution of one week.

2.4.1.3.2 Simulation

In the simulation part, a simulation of the power system is done, with the water values used as the marginal price of hydropower plants. The marginal price of all producers are used to establish price-quantity relationship, and the market is cleared for every time step. In contrast to market models without a hydropower focus, the EMPS model simulates all 52 weeks of the year, with an equal time resolution for all weeks.

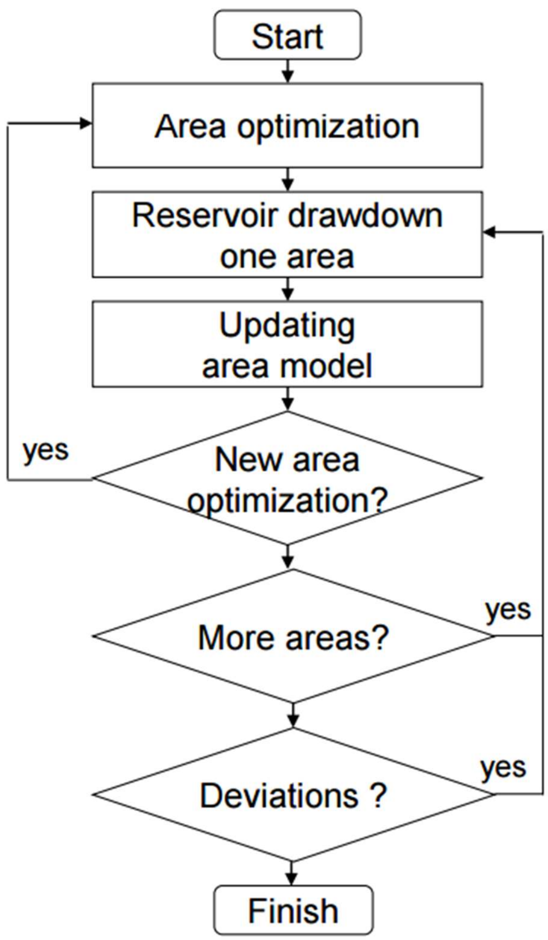

Figure 4: The simulation part. This figure shows the iterative process of the simulation part.[22]

The simulation process in the EMPS consists of two steps; Area optimization and area simulation. Similar to the strategy part, the simulation part uses an iterative process shown in Figure 4. The simulation process is run separately for each area, but with a full description of hydropower systems.

The area optimization uses the aggregated water values for one area, and clears the market for all time steps with the water values as marginal costs of the power plants. This way, the generation dispatch is decided. The results of the optimization are then used in the area simulation. In the area simulation, the reservoir draw-down model is run for each hydropower system. It simulates the consequences within all hydropower systems of the generation dispatch found in the area optimization. Typically, the draw-down model can find that a small reservoir with high inflow will become flood while the generator hasn't produced at its maximum. The area model is then adjusted and the area optimization is re-run.

One important concept in this context of the draw-down model is relative damping, depletion season and filling season. The relative damping is a measure of the remaining unused volume in the reservoir devided by the annual inflow. The ideal in a simplified world is to have the same relative damping in all reservoirs. This is therefore a measure that guides the adjusting of the area model.

The depletion and filling season on the other hand is a way to divide the year into two, one in which the inflow is higher than discharge – filling season – and one where the inflow is lower than the discharge – the depletion season. The filling season typically lasts from the snow starts to melt in the spring until the autumn, while the depletion season typically is in the winter. The reservoir draw-down model divides the year into these two seasons with different main objectives. In the filling season, the main objective is to avoid spillage. The relative damping is a key performance index to achieve this. In the depletion season on the other hand, the main objective is to keep reservoirs from running dry as long as possible in order to avoid a capacity deficit, in addition to have an equal relative damping in the beginning of the filling season. [20]

2.4.1.4 Calibration

The EMPS model will not give an optimal result without user input. The water values of each area are computed separately. The water values are however dependent on possibility to exchange with neighbouring areas. This information is given to the EMPS model through calibration factors. Factors, that needs to be adjusted to achieve an optimal result.

There are three calibration factors per area:

- Feedback factor
- Form factor
- Elasticity factor

The feedback factor controls how much demand should be included in the water value calculations. A larger feedback factor results in larger demand used in the water value calculations. Consequently, the water values will increase. When simulating the system, higher water values results in more restricted use of water, i.e. the risk of emptying the reservoir reduces, but the risk of spillage increases.

The form factor controls the balance between the demand used in the water value calculation in the depletion and filling season. The form factor will in other words determine how much energy is stored from the filling season to the depletion season.

The elasticity factor will control how steep the marginal cost curve of thermal supply is in the water value calculations. If the factor is small, the marginal cost curve gets steeper, and the distance between the percentiles on the reservoir level figure will decrease.

Of the three calibration factors, adjusting the feedback factor is the most important for achieving a good result. The calibration factors are adjusted by running the simulation with water value calculations, validating the result, and adjusting accordingly. The adjustments can be done manually or automatically. The automatic calibration process does however not guarantee an optimal result. Additionally, it will in many situations use more computational time than the manual calibration process, as it does not use the intermediate results to decide which area or which calibration factor to adjust next, and how much the calibration factor should be adjusted, neither does it adjust more than one calibration factor at the time. A well calibrated reservoir is characterised by large utilization of the reservoir, little spillage, and not being emptied. The last characteristic is most important in areas that are depended on hydro power storage to supply winter demand.

2.4.1.5 The results

The most relevant results for this research from the EMPS model include:

- Prices in all nodes
- Production divided into different categories
- Power exchange between nodes
- One water value per node
- One reservoir level per node

All the results given by the model have a time resolution equal to the chosen time step, except the reservoir level and water value. The time step is user decided, and is typically in the range from one week to two hours, while the reservoir level and the water value have a time resolution of one week.

2.4.1.6 Heuristics and simplifications

When describing the shortcomings of an optimizing model, two concepts are used, heuristics and simplification. A simplification is when short-cuts are done in the description of the problem, i.e. the real world and the model is not identical. In this case, the optimization process will find the optimal solution based on the simpler modeled world. A heuristic on the other hand is when short-cuts are done in the optimization process itself. When heuristics prevail in an optimization model, there is usually an agreement that even though the heuristic does not guarantee the optimization process to find the optimal solution, the solution found is good enough.

All hydropower systems within one node are aggregated into one one-reservoir system in the strategy part, i.e. a system with one reservoir and one power plant. This represents a simplification. The water values found in the strategy part are used for all hydropower stations within one node. This is a simplification in the optimization process itself, a heuristic.

There are several issues with aggregation of hydropower systems. Some of the consequences include:

- Difference in the ratio between installed capacity and yearly inflow, gives different amount of production hours per year. This would lead to differences in water value.
- Differences in the ratio between reservoir capacity and yearly inflow, gives differences in how long the filling and discharge seasons of the reservoir are, and hence differences in the distribution of water values throughout the year.
- Differences in inflow patterns will change the time of the filling season. Differences in height of catchment area causes the melting of snow to happen at slightly different times of the year. Note; Some reservoirs are filled with glacier water. These systems will have a very different filling season compared to a hydropower system in the low lands.
- Cascading of hydro power generators is neglected. In many hydro power systems, the water is used by several power stations at different height levels. The production of these stations is therefore depended upon each other. There is also usually a time delay from when the water is used in one power station, until it has found its way down to the next power station. This time delay could be minutes, hours or even days.
- All local restrictions are neglected. This includes minimum release of water, restricted reservoir usage in some periods of the year, restricted capacity usage on warm days due to less cooling available etc.

In addition to the simplifications and heuristics related to hydropower, the EMPS model typically uses the following simplifications, i.e. they are present in the research described in this report, but can be avoided at the cost of longer computation time.

- Ramping is not modeled for either thermal nor hydropower units.
- Startup costs are not modeled for either thermal nor hydropower units.
- Demand response is modeled as an immediate response, which is only partly the case. Industrial consumers which have electricity as one of their main resources would usually respond reasonably immediate, while other residential consumers usually only respond after high prices have been a topic in the newspapers for some days.
- Availability is modeled as an even capacity reduction for the whole year, and not positioned into low price periods.
- Transmission losses are modeled linearly.
- One year has 52 weeks with 7 days, i.e. 364 days.
- The height difference utilized by a hydro power generator, and thereby the energy generated per cubic meter of water, varies with the reservoir level of the intake reservoir. This connection is not modeled.

2.4.1.7 Strengths and weaknesses

The EMPS model models thermal units in a quite simplistic way, by not including ramping, startup costs and planned unavailability. In addition, hydropower units can regulate faster within the model than in the real world. The result is that the EMPS model predicts smaller short-term price variations than what can be observed in the spot market.

The EMPS model is on the other hand designed to use multiple inflow, wind and solar scenarios. These scenarios cause the EMPS to present a sample space of the prices. The combination of these scenarios and the fact that the EMPS models for 52 weeks instead of some representative weeks each season, is the basis for one of the EMPS models strengths, long-term price variations and the sample space due to wet and dry years.

Hydropower production is difficult to model due to its nature. The hydropower modeling is an important part of the EMPS, and is considered one of its strengths, even though there are heuristics and simplifications related to the hydropower modeling.

2.4.1.8 How is EMPS used?

The EMPS model is used as the main long-term market model in the Nordic region. It is however not very widespread in continental Europe. This is a consequence of the two regions dependent on hydro power and thermal power respectively, and the strength and weaknesses of the model. The EMPS model is, amongst others, used

- By consulting companies for price forecast.
- By hydro power and thermal producers for price forecast and production planning.
- By power producers to assess long-term prices and investments in new power plants.
- By TSOs to assess the socio-economic benefit of grid reinforcement.
- By NVE to assess the reliability of supply.
- By researchers to do market research.

Note, that as the pricing of hydro power is highly dependent on opportunity cost, the success of a model effects the market, i.e. since hydro power producers use the model to decide what their water is worth, and at which price they are willing to produce, the model itself is influencing the price.

3 Method of research

This chapter describes how the research executed. The goal is to document the work done in the project, and show basis for the datasets made.

The research described in this report uses the EMPS model (Samkjøringsmodellen) to assess two future energy scenarios based on ENTSO-E TYNDP. They are called V4-16 and DoubleRES. The results from the modelling within TYNDP Visions are soft-linked with the EMPS model, i.e. the results from TYNDP Visions are used as input data to the EMPS model. This is an example of a top-down approach, as the TYNDP Visions is a study with lower resolution and wider scope than the study presented in this report.

In addition to the EMPS simulations, a net load analysis has been carried out. This analysis focus on some of the important input data used by the EMPS model, and aims to increase the understanding of how the power market will develop with an increased penetration of RES.

3.1 EMPS settings

This chapter show the input parameters used, how the EMPS model was run and what version was used.

The simulated area consisted of Europe, divided into 25 areas. The geographical division is presented in subchapter 3.2.2. Simulation time was 1 year, with 75 years of inflow. 7.1 Copy of EMPS input parameters shows a print out of the parameters used.

The week was divided into 28 different periods. Each period consisting of 6 hours. Period 1 describes the first 6 hours of Monday, period 2 the consecutive 6 hours and so forth. Consequently, period 1 to 4 describes Monday, while period 5-8 describes Tuesday and so forth. The 7 days of the week is, in other words, divided into night, morning, afternoon, and evening. A tabulated presentation of the price periods is found in Table 16, appendix 8.3.

The EMPS was started with 50 % filling in every reservoir. The calculations were executed in series, such that each inflow year starts with the end reservoir level of the previous inflow year. Thus, the assumption of 50 % filling has little impact on the overall result.

Detailed draw-down simulation of all hydropower systems was not used, as a detailed description of the hydropower system was not used. This data is not part of the ENTSO-E Vision data set, and using them from TWENTIES would not an option due to the commercial nature of TWENTIES.

The version of the EMPS was 9.6.0/9609 Beta_Trunk - 2014.05.05.

3.2 Description of datasets

This subchapter describes the available datasets used on which this study is based, as well as the process of making the new EMPS datasets that this study analyses.

3.2.1 Available datasets

This study is based on five available datasets:

- ENTSO-E TYNDP Vision 4 2016
- An EMPS dataset based on Vision 4 2014
- An EMPS dataset based on Vision 4 2016
- An EMPS dataset based on TWENTIES 2010
- An EMPS dataset based on TWENTIES 2030.

From TYNDP the 2016 version of Vision 4 the following data was used:

- Installed generation capacities per technology and country.
- Consumption profiles.
- Border reference capacities.
- Key assumptions for generator efficiencies, fuel prices and CO_2 price.

TWENTIES includes data from 2010 and 2030, representing the current situation, and a future scenario. From TWENTIES 2010, the following data was used:

- Demand
- Production profiles of RES
- Inflow
- Detailed hydropower description

From TWENTIES 2030, the following data was used:

- Transmission capacities within the Nordic area
- Installed capacity of RES

From the TYNDP 2014 EMPS dataset, the following data was used:

- Hydro power description
- Thermal power description

3.2.1.1 ENTSO-E TYNDP Vision 4 2016

The TYNDP project by ENTSO-E publishes free datasets on their webpage. The newest version is the 2016 version. The dataset consists of 4 scenarios or Visions, of which Vision 4 is the most interesting for this study. The TYNDP 2016 dataset consists of:

- Installed generation capacities per technology and country.
- Consumption profiles.
- Border reference capacities.
- Key assumptions for generator efficiencies, fuel prices and CO_2 price.

The installed generation capacities are divided into biofuel, gas, hard coal, lignite, nuclear, oil, others non-RES, others RES, solar and wind, for 35 European countries. The 35 countries are listed in Table 20, appendix 8.5. The TYNDP dataset states fuel prices for gas, hard coal, lignite, nuclear, light oil, shale oil and heavy oil. In addition, a price on CO_2 is given in €/ton. The generator efficiencies are stated as ranges, and efficiency ranges for conventional gas, CCGT gas, OCGT gas, hard, coal, lignite, nuclear, light oil, shale oil and heavy oil are included.

In terms of border reference capacities and consumption profiles, TYNDP 2016 uses slightly different areas than in description of installed capacities. Now 39 areas are used, i.e. 4 more than for the installed capacities. One of the extra areas comes from dividing Denmark into Denmark East and Denmark West, another from dividing Italy into Italy North and Italy South Central, and the two last extra nodes originates from dividing Luxemburg into Luxemburg Belgium, Luxemburg France and Luxemburg Germany.

The border capacities are given for all the links between areas that will be present in 2030 according to ENTSO-E. The capacities need not to be equal in both directions. There are, in other words, two values presented per link.

The consumption profiles or demand series are given as a series of 8760 values per area. In other words, an hourly resolution for one year. All demand series starts on a Monday, except for the Czech Republic,

3.2.1.2 TWENTIES 2010 and 2030

The available TWENTIES datasets consisted of two complete EMPS datasets, i.e. all necessary files and assumptions needed to simulate with the EMPS model.[23]

The two datasets within TWENTIES are called TWENTIES 2010 and TWENTIES 2030. TWENTIES 2010 aims to describe the present situation of when the study was conducted, while TWENTIES 2030 aims to describe a future, where extensive measures is taken in order to increase the flexibility of Nordic hydropower to support wind power in northern Europe. In other words, TWENTIES has increased transmission capacities from between the Nordic hydro power and the northern European wind power, as well as a considerable increase in installed capacity (MW) of Nordic hydro power. The TWENTIES 2030 also differentiates from TWENTIES 2010 in terms of installed RES and thermal capacities, as these were expected to change from 2010 to 2030.

The geographic resolution and scope of the TWENTIES are shown in Figure 5. As the figure shows, Norway is divided into 11 nodes, while Sweden is represented by 6. The geographic scope consists of northern Europe, including the Nordics.

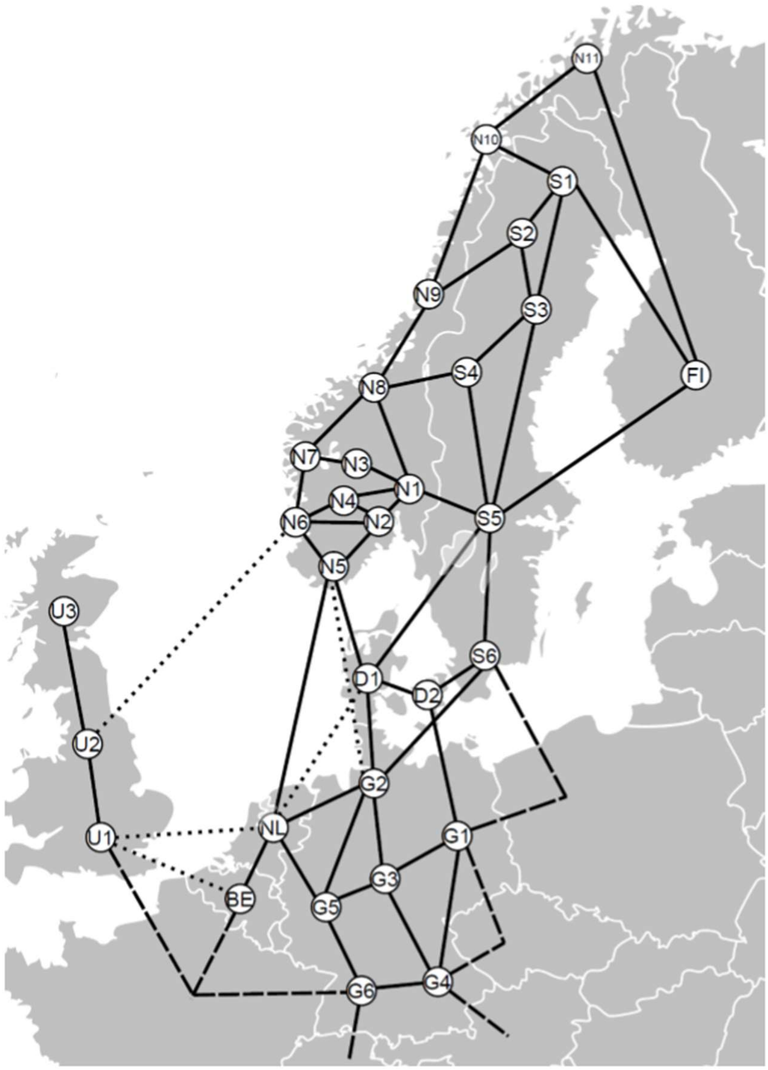

Figure 5: Geographic overview of the EMPS dataset used in TWENTIES.[23]

The TWENTIES includes a detailed hydro power description as well as a detailed thermal description. In other words, both in terms of hydro power and thermal power, each power plant is modelled individually.

There are however restrictions of the use of the TWENTIES datasets, as they are commercial products. As this study is available to everyone for free, and aims to provide datasets for future free to read research, using the full resolution of the TWENTIES dataset was never an option. Therefore, this master thesis cannot use the detailed description of hydro and thermal power, and it cannot use the full geographical resolution.

As the inflow to hydro power plants are tightly connected to the location of the catchment area, all regulated and unregulated inflow in the TWENTIES dataset is in absolute numbers. This choice is further justified by the small likelihood of a substantial increase in catchment areas used for hydro power in the Nordics.

3.2.1.3 ENTSO-E TYNDP Vision 4 2014 EMPS

The ENTSO-E TYNDP Vision 4 2014 EMPS dataset is a construct of an earlier master thesis [24]. It is an EMPS dataset based on the 2014 version of ENTSO-E TYNDP Vision 4. The TYNDP Visions dataset is not enough to make a complete EMPS dataset. In addition to the Visions dataset, one would need to implement the following:

- Marginal cost of biofuel and Others non-RES
- Reservoir sizes
- Amount of regulated and unregulated inflow.
- Time series for regulated and unregulated inflow, as well as wind power, solar power, and offshore wind power generation.
- How much offshore compared to onshore wind.
- How to represent thermal power plants based on a range of efficiencies.

3.2.1.4 Specialization project – TYNDP Vision 4 2016 EMPS

The Norwegian Energy Scenarios Specialization project updated the ENTSO-E TYNDP Vision 4 2014 EMPS dataset with the newest data from the 2016 version of TYNDP. In other words, the Specialization project used the same data and assumptions as the TYNDP Vision 4 2014 EMPS dataset in terms of:

- Marginal cost of biofuel and Others non-RES
- Reservoir sizes
- Amount of regulated and unregulated inflow.
- Time series for regulated and unregulated inflow, as well as wind power, solar power, and offshore wind power generation.
- How much offshore compared to onshore wind.
- How to represent thermal power plants based on a range of efficiencies.

3.2.2 Datasets created for this Master thesis

There are two datasets or scenarios created for this master thesis, V4-16 and DoubleRES. Where the V4-16 is based on the 2016 edition of TYNDP Vision 4, and aims to preserve the consistency of the Vision 4 2016 dataset, while creating a dataset with a geographical resolution and hydro power description interesting for research with a Nordic viewpoint. DoubleRES is

V4-16 where the installed capacity of solar, wind and offshore wind power have been doubled. Thereby aiming to show some of the consequences of a European grid, with a very large RES penetration.

To create EMPS datasets, the following has been implemented:

- **Area description.** A description of nodes, how they are linked and the transmission capacity between the nodes.
- **Demand.** Time series
- **Fuel prices**
- **CO_2 price**
- **Wind and solar production.** Time series that describes how much energy an equivalent unit of 1 GW installed capacity produces.
- **Inflow.** Time series
- **Installed capacities.**
- **Power generator description.**
- **Detailed water course of all hydropower systems.**

This has been done with extra – commercially justified – restrictions on the use of the TWENTIES datasets.

3.2.2.1 Area description – Price areas

A key motivation for creating a new dataset was to get a more suitable areal resolution. This subchapter presents the price areas used, and how they are related to the price areas in the available datasets.

Table 2 compares the areas used in the Norwegian Energy Scenarios master project with the areas used in the available datasets. The specialization project used the same price areas as the ENTSO-E Vision 4 2014 EMPS dataset.[5] The country codes of the specialization project were based on the ISO-3166-2 (2 Letter Country Code).[25] The description of the areas in Norway, Sweden and Denmark refers to the price areas used in power trade at Nord Pool Spot as of May 2017.

Table 2: Comparison and description of price areas used in the specialization and master projects.

Area master project	Description	Equivalent area in the specialization project	Equivalent area in TWENTIES
NO1	NO1. Eastern Norway	Part of NO	N1, N3
NO2	NO2. South Western Norway	Part of NO	N2, N4, N5, N6
NO3	NO3. North Western and Middle Norway	Part of NO	N8
NO4	NO4. Northern Norway	Part of NO	N9, N10, N11
NO5	NO5. Middle Western Norway	Part of NO	N7
SE1	SE1. Northern Sweden	Part of SE	S1
SE2	SE2. Middle Northern Sweden	Part of SE	S2, S3, S4
SE3	SE3. Middle Southern Sweden	Part of SE	S5
SE4	SE4. Southern Sweden	Part of SE	S6
DK-E	Denmark East. DK2	Part of DK	D2
DK-W	Denmark West. DK1	Part of DK	D1
FI	Finland	FI	
BAL	The Baltics. Estonia, Latvia, Lithuania	EE, LV, LT	
PL	Poland	PL	
CZ	Czech	CZ	
DE	Germany and Luxemburg	DE, LU	
NL	The Netherlands	NL	
BE	Belgium	BE	
GB	Britain. The United Kingdom of Great Britain and Ireland	GB, NI, IE	
FR	France	FR	
IB	Iberia. Spain and Portugal	ES, PT	
CH	Switzerland	CH	

AT	Austria	AT
IT	Italy and Slovenia	IT, SI
SEE	South East Europe. Albania, Bosnia and Herzegovina, Bulgaria, Greece, Croatia, Hungary, Montenegro, Makedonia, Romania, Serbia, Slovakia.	AL, BA, BG, GR, HR, HU, ME, MK, RO, RS, SK

3.2.2.2 Area description – Transmission capacities.

The transmission capacities are based on 2030 reference capacity of the TYNDP Vision 4 2016. As this would not be sufficient for the current area configuration in the Nordics. The TWENTIES 2030 was used for every transmission line connected to a Norwegian, Swedish, or Danish price area. As TWENTIES uses a finer areal resolution than Norwegian Energy scenarios, transmission capacities from the TWENTIES has been merged to fit the areal resolution of the Norwegian Energy Scenarios. Vision 4 and TWENTIES differentiates between ingoing and outgoing capacities. In other words, the transmission capacity from Germany to France does not need to be equal to the transmission capacity from France to Germany.

3.2.2.3 Demand

The demand series used is a combination of data from ENTSO-E TYNDP 2016 Vision 4 and TWENTIES. The demand series in Vision 4 has an hourly resolution for one future year, divided into 39 areas. In other words, there are 8760 data points for each of the 39 areas. Where the 39 areas represent – with some minor exceptions - countries within Europe. As this areal resolution deviates from the price areas used in this study, total demand from TWENTIES was used to divide the demand series of Norway, Sweden, and Denmark from Vision 4 into NO1, NO2, SE1 etc. Where this study uses a coarser areal resolution than TYNDP, demand series from TYNDP Vision 4 were simply added.

The demand series has then been converted to fit the format of EMPS by creating the input files LASTPROFIL.ARCH and EFFEKTPROFIL.ARCH.

In addition to the demand series from TYNDP, price sensitivity has been added. The price sensitivity linearizes the relation between the demand used in final simulation and the demand stated in the input files, between three data points. Table 3 shows the relation between the price and final demand.

Table 3: Price sensitive demand

	Price [€/MWh]	Final demand [% of input demand]
1	2990	75
2	30	100
3	0.1	110

3.2.2.4 Fuel and CO_2 prices

The CO_2 price and fuel prices used in this study are from ENTSO-E TYNDP 2016 Vision 4. The CO_2 price and fuel prices within Vision 4 originates from IEA World Energy Outlook. The prices from Vision 4 2016 originates from IEA WEO 2013, where fuel prices are from scenario 450 and CO_2 price from UK FES High.[26]

The fuel prices are given for nuclear, lignite, hard coal, gas, and different types of oil. The fuel prices of bio and others non-RES is therefore not available. Biofuel power generation and others RES was modelled as zero marginal cost production, that follows a given pattern, such that the production during winter is higher than the production during summer. Other non-RES was modelled with a marginal cost of € 195.

3.2.2.5 Wind, offshore wind, and solar production, regulated and unregulated inflow.

The wind, offshore wind, and solar production scenarios as well as the inflow scenarios - also called energy series - for Norway, Sweden, Denmark, and Finland comes from TWENTIES 2010, while the data from the rest of Europe are provided by the Vision 4 EMPS dataset.

Where Vision 4 EMPS has a finer geographical resolution than needed, the series from the dominant node was used. For instance, the combined node of Italy and Slovenia uses the series from Italy. The major exception being Iberia, where the solar series for Spain were heavily based on concentrated solar power, i.e. solar power with storage. This was appraised to be unrealistic, therefore, the solar series for Portugal was used in Iberia. The dominant node within SEE – South-East Europe – was decided to be Romania.

The energy series based on TWENTIES 2010 needed a geographical conversion. As the energy series is read by the EMPS models as binary files, manipulation involves some file conversion.

In the process of adding energy series within the Nordics, the energy series were also transformed from absolute to relative values. This choice was made to have the Nordic energy series in the same format as the rest of the European energy series.

The wind, offshore wind and solar data have an hourly resolution in terms of time. While the inflow data have a weekly resolution. The data is connected to a specific year from 1931 to 2005. As the wind, offshore wind, and solar data are based on measurements for the second half of this period, the wind, offshore wind, and solar data of the second half is copied into the first half. In other words, the wind, offshore wind, and solar and inflow data that is used for the second half of the period 1931 to 2005 occurred at the same time. This is however, not true, for the first half of the period 1931 to 2005.

3.2.2.6 Installed capacities

The installed capacity data of Vision 4 describes the installed capacity per country of biofuels, gas, hard coal, hydro, lignite, nuclear, oil, other non-RES, other RES, solar and wind. Total production per technology from TWENTIES was used to determine how to divide the data from Vision 4 within Norway, Sweden, and Denmark. The total amount of installed capacity is therefore equal in V4-16 and Vision 4 2016. An important reason to use this approach is to retain the consistency of the Vision 4 2016 dataset in V4-16.

TWENTIES 2010 was used to determine how to divide installed capacity of thermal and hydro power, while TWENTIES 2030 was used to divide installed capacity of wind, offshore wind, and solar. TWENTIES 2030 was chosen for RES as the development of RES is more mature in the 2030 dataset, this way, an inappropriately disproportionate distribution is avoided. As the TWENTIES dataset does not include solar power in Sweden. All Swedish solar power was included in SE4. The Swedish node with the best conditions for solar power.

The only difference between V4-16 and DoubleRES is in terms of the installed capacities of RES. The installed capacity of solar, wind and offshore wind have been doubled in DoubleRES compared to V4-16. Hydro power on the other hand is kept equal in both scenarios.

3.2.2.7 Thermal power generation description

The efficiencies of different types of generation are described in Vision 4 as a range of efficiencies per generation type. The efficiencies are the same for Europe as a whole. There are in other words no information connecting different efficiencies to different countries. To represent the range of efficiencies, the total installed capacity of one generator type within a country was divided into three power plants with different efficiencies.

As an example, the nuclear efficiency is given as 30 – 35 % within Vision 4 2016. If a node has 3000 MW of nuclear power, its nuclear power would be modelled as three 1000 MW plants with an efficiency of 30 %, 32.5 % and 35 %. In other words, the lowest, the average and the highest value within the range.

The efficiency of gas power is divided into conventional, CCGT and OCGT. To accommodate this information, a nodes gas power is modelled as nine plants, where the installed capacity is divided equally between conventional, CCGT and OCGT, and equally between the lowest, the average and the highest value in the efficiency range within conventional, CCGT and OCGT.

3.2.2.8 Hydro power description

The TYNDP Vision have an insufficient description of hydropower for accurate modelling with the EMPS model. The installed capacities for each country are the only measure given. To model each node with one standard hydropower module (Figure 2), total inflow, the ratio between regulated and unregulated inflow and reservoir size is needed in addition to installed capacity. For Norway, Sweden and Finland, Vision 4 2016 was used for installed capacity, while TWENTIES 2010 was used to divide them into the finer areal resolution in addition to find the ratio between regulated and unregulated inflow. The total inflow and reservoir size of the nodes in Norway, Sweden and Finland was found by adding reservoir sizes from equivalent nodes in TWENTIES 2010. As TWENTIES 2010 is based on the present situation, the total inflow and reservoir size were multiplied with 1.02 to take consideration of future development. For the rest of Europe, installed capacities is from Vision 4 2016, while the Vision 4 2014 EMPS dataset is the source of the values needed for a one reservoir representation per node.

3.3 Net load analysis

To further increase the foundation on which to discuss the results of this master project, a net load analysis has been carried out. Net load is obtained by subtracting intermittent power production from demand. In this project, wind, offshore wind, solar and run-of-the-river hydro power have been included in the intermittent power production category. A key motivation for this analysis is to figure out if the current price variations through the week and through the year, that we are currently used to will change and eventually how they will change. In addition, the net load analysis have made it possible to access the input data, and made it possible to discover potential errors.

The energy series for the four intermittent power producing technologies are all implemented as binary files in the EMPS model, thus requiring conversion. Four Excel-documents functioning as databases have been created, storing the energy series per node for each of the four intermittent power producing technologies, as well as one document for demand. Other Excel-documents imports data from these five database documents, and processes the data into results and figures. All Excel-documents used in the net load analysis have been created by the author.

3.4 Post-simulation data processing

Results from the EMPS model have been gathered through the programs samutskrv and pckurvetegn. Where samutskrv gives a detailed report of the simulation, and pckurvetegn has been used to retrieve power flow on the transmission lines.

Excel have been used as a tool for processing, filtrating and visualization of the output data. All Excel-documents used in the analysis in this project, have been created by the author.

4 Results and analysis

This chapter contains the result and analysis of this study. It starts with an introduction, showing some overall results. Then the results from the net load analysis is presented, including how RES behaves. After the net load analysis follows the results from EMPS simulations. Firstly, reservoir levels are presented. Secondly, the power prices and power flows are analysed and presented, followed by subchapter discussing the correlation between power price and import. Finally, a subchapter is included to highlight some issues regarding demand that was found during the analysis.

The result presentation relies heavily on figures, a consequence of the large amount of result data produced by the EMPS model. And explanation of these figures can be found in appendix 8.4. Reading this appendix will make it easier to understand the information displayed by the figures. This is especially the case for the map, so much so that it is a prerequisite to read the explanation of the map in appendix 8.4.1 before reading subchapter 4.4, where power flows and power prices are presented.

As the EMPS model produces a large amount of result data, presenting all relevant result figures in the result and analysis chapter is not viable. Therefore, appendix 8.7 exists. This appendix starts with its own table of contents, and includes all figures of weekly and seasonal net load profiles and power price profiles plus all reservoir curves for all areas in both V4-16 and DoubleRES.

4.1 Introduction

This subchapter is made to highlight some of the fundamental characteristics of the analysed power system, as well as to function as an introduction for the reader, to familiarize with the system.

First, we will look at the market equilibrium on a European level, in other words, all areas included. Figure 6 shows the market equilibrium of V4-16, while Figure 7 market equilibrium of DoubleRES. Documentation for the market equilibrium figure is found in appendix 8.4.2.

The intersection between the black and the red graph in Figure 6 and Figure 7 indicates the average power price in the two scenarios. From Figure 6, an average power price of around 100 €/MWh in V4-16 is to be expected. Note the jump in the supply curve from 5 €/MWh to 70 €/MWh, happening at around 300 GW in Figure 6 and 400 GW in Figure 7. The CO_2 price causes this jump. In Figure 7, the red graph intersects the black graph at this jump. Hence, stating an approximate power price for the DoubleRES scenario, is difficult, but we expect the power price of DoubleRES to be lower than the power price of V4-16. Part of this lower power price in DoubleRES will manifest in more hours – compared to V4-16 – where the demand and supply curve intersect on the left side of the jump. Also note how the variation in RES production is more influential in DoubleRES than in V4-16.

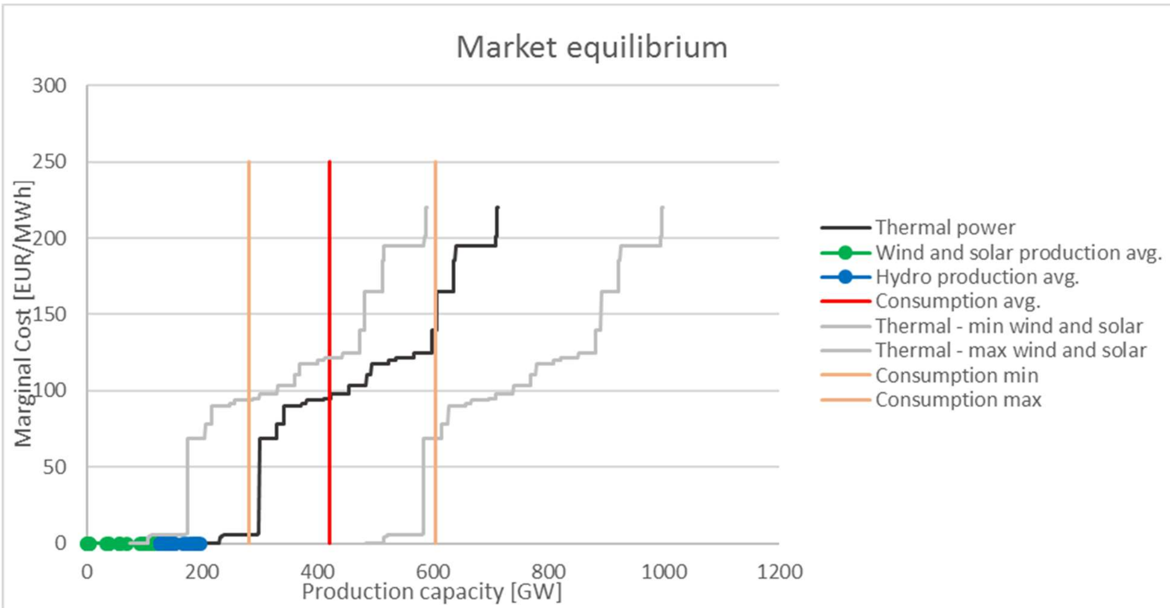

Figure 6: Market equilibrium all areas – V4-16

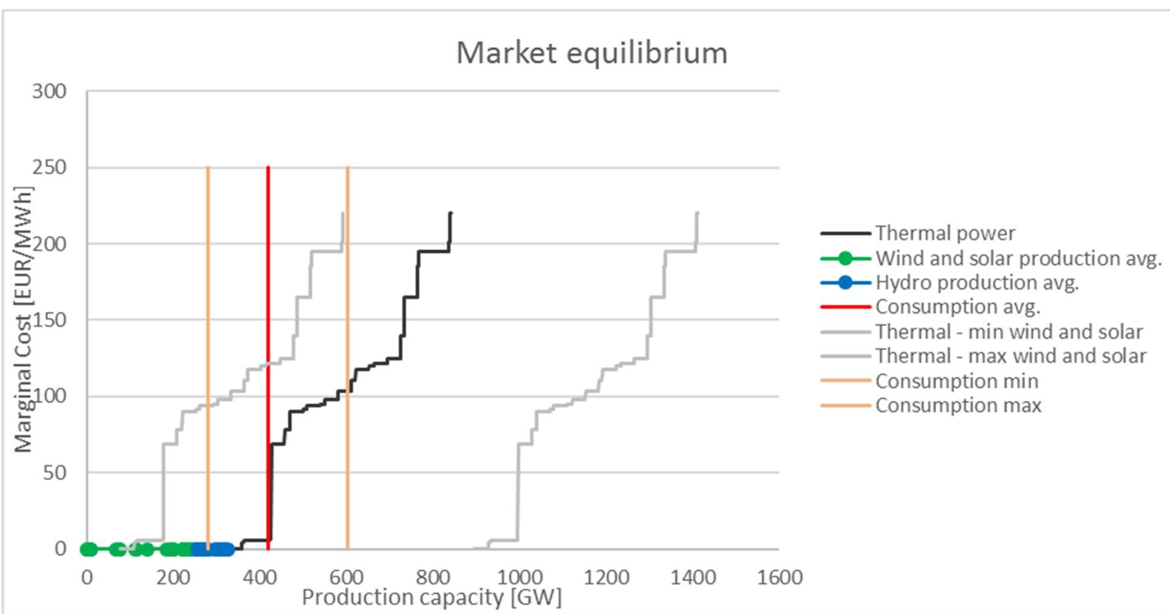

Figure 7: Market equilibrium all areas – DoubleRES

Figure 6 and Figure 7 does not differentiate between the different types of thermal power production. This is however shown in Figure 8. Figure 8 corresponds to the black graph in Figure 6. The black graph in Figure 6 and Figure 7 are equal - as the thermal production is modelled equally in V4-16 and DoubleRES - except for a left-right shift caused by RES production. Figure 8 clearly shows how a price on CO_2 creates a jump in the supply curve. It also shows a situation where gas, hard coal and lignite power operates in an overlapping area of marginal cost. Noting the marginal cost of around 170 €/MWh for the most expensive gas generators, is useful for further analysis.

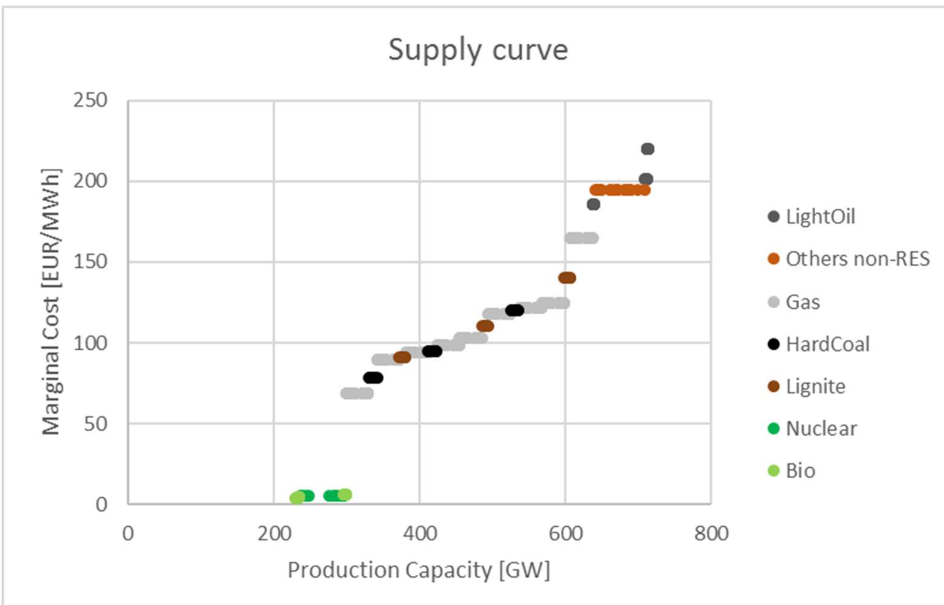

Figure 8: Supply curve all areas – V4-16

To highlight the consequences of a price on CO_2 Figure 9, has been added. Figure 8 and Figure 9 is equal in every way, except Figure 8 uses the CO_2 price of 76 €/tCO_2 from Vision 4, while Figure 9 uses a CO_2 price of 0 €/tCO_2. In addition to increasing the marginal cost of CO_2 emitting power production technologies and creating a jump, the CO_2 price shifts the competition between CO_2 emitting technologies. The addition in marginal cost, caused by the CO_2 price is largest for the technologies that emits the most CO_2 per MWh. In common speech, saying something like "gas will become cheaper than coal with a (decent) CO_2 price" are not too uncommon. Figure 8 however, clearly shows that all lignite power plants are not equal, all coal power plants are not equal and all gas power plants are not equal. Even at a CO_2 price of 1000 €/tCO_2, the cheapest hard coal power plant will have a lower marginal cost than the most expensive gas power plant. On the other hand, the figures show that a price on CO_2 will increase the amount of gas power used, at the expense of hard coal and lignite, but primarily the hard coal and lignite power plants with the lowest efficiency.

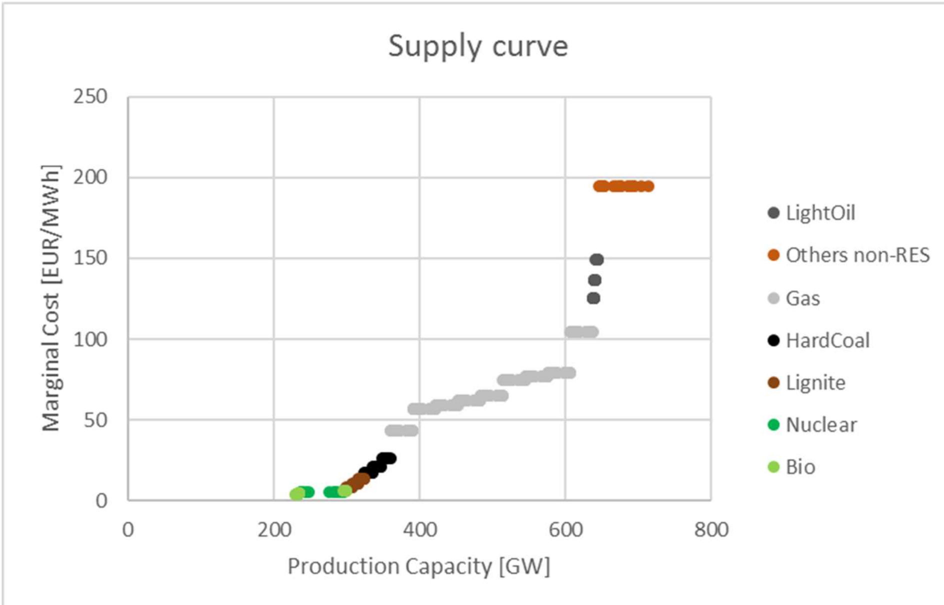

Figure 9: Supply curve all areas – V4-16. CO_2 price of 0 €/tCO_2

To further show the sensitivity of the CO2 price, the Figure 10 is included. It shows the supply curve with a CO_2 price of 150 €/tCO_2. We observe how the larger CO2 price will increase the competitiveness of gas power at the sacrifice of hard coal and especially lignite power. From Figure 6, we have a demand of around 400 GW, which result in a power price of around 100 €/MWh at a CO_2 price of 76 €/tCO_2. Where the CO_2 price to become 150 €/tCO_2 instead, 400 GW of demand would result in a power price of around 140 €/MWh in V4-16. Its noteworthy how – in the situation of Figure 10 – no hard coal or lignite power would operate at 400 GW demand with average RES production.

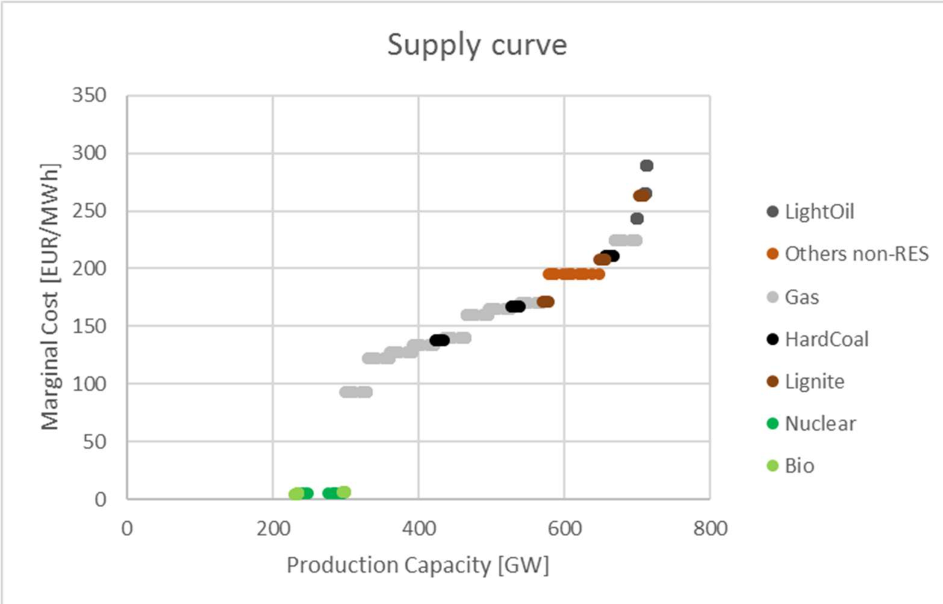

Figure 10: Supply curve all areas – V4-16. CO_2 price of 150 €/tCO_2

4.1.1 Demand, production, and RES

To further increase our knowledge of the system, an understanding of demand, production and RES production within each node is useful. At the end of this subchapter, there are two tables - Table 4 and Table 5 – which present these data for V4-16 and DoubleRES respectively. Table 4 and Table 5 shows energy production from wind, offshore wind, solar and run-of-the-river hydro, as a percentage of demand. In addition, Table 4 and Table 5 have a column called "RES" which represents the sum of energy production from the from wind, offshore wind, solar and run-of-the-river hydro, and a column called "Production" which represents the total energy production within the given node - i.e. including thermal etc., both as a percentage of demand. Note that within this subchapter, storable hydro power is not included within the term "RES".

The following paragraphs will highlight some of the most significant results from Table 4 and Table 5. If not specified, the results highlighted applies to both V4-16 and DoubleRES.

The system analysed, consisting of most of Europe, consumes 3700 TWh each year, out of which RES produces 39 % in V4-16 and 69 % in DoubleRES. The nodes with the largest demand are Germany, France, Iberia, Great Britain, Italy, and South-East Europe, in that order. 71 % of the total demand are from these six nodes. One would, hence, assume that the power production in these nodes, have a large influence on the total system.

In terms of non-storable RES, run-of-the-river hydro dominates the Norwegian nodes. SE1 and SE2 an even higher percentage run-of-the-river hydro compared to Norway, and has a considerable share of wind power as well. SE3 is among the nodes with the highest demand in the Nordic area together with Finland. Their demand is both comparable to the demand of NO1 and NO2 combined.

SE3 has the lowest share of RES of all nodes. Other nodes with a low share of RES includes the adjoining nodes Finland, the Baltic area, Poland, and Czech. Next to these nodes, are the adjoining nodes SE4, DK-E, DK-W, and GB. They have all a high share of RES, especially Denmark, and they are all dominated by wind power. In fact, most nodes have a larger combined wind power share than solar share. Notable exceptions are Italy, with more solar power production than wind power production, and Iberia, where the share of wind and solar are about equal in size. Other nodes with a significant share of solar power includes, Germany, the Netherlands, Belgium, and South-East Europe, where the rate of solar power to wind power is roughly 1:3.

The production of energy from solar, wind and offshore wind is doubled in DoubleRES, compared to V4-16. Run-of-the-river hydro power production on the other hand, is identical in the two scenarios. As a consequence, the impact of run-of-the-river hydro power is reduced compared to other RES, especially in Sweden, and Austria, Finland and the Baltics. Note that the share of wind, offshore wind and solar are so low in the Norwegian nodes, that even in DoubleRES, run-of-the-river hydro power is the dominant non-storable RES.

In V4-16, the highest share of RES production in any node is 83 %, in DK-W. In DoubleRES, on the other hand, DE, SE4, and IB, are close to meet their energy demand by RES. GB produces 11 % more energy from RES in DoubleRES than they consume. The two Danish nodes, produces considerably more energy than their demand in DoubleRES, 49 % and 67 % more RES production than demand for DK-E and DK-W respectively.

Considerable energy deficit areas include the adjoining nodes NO1, NO3 and SE3, as well as CZ, PL, BAL and FI, and NL and BE. Note the connection between low RES production and low total production. Considerable energy surplus areas include the adjoining nodes SE1 and SE2, as well as SE4, DK-E and DK-W. Considering its size, GB should also be included as a noticeable surplus node. The same can be said for DE and IB, even though their surplus is more prevalent in DoubleRES. Note that none of the largest nodes (DE, GB, FR, IB, IT and

SEE) have large deficit in any of the scenarios, the largest being IT in DoubleRES with 2 % deficit.

The only node that changes between deficit and surplus node from V4-16 to DoubleRES is Italy. It is also among the few nodes that reduce their total energy production in DoubleRES compared to V4-16, the others being CZ, AT, and DK-E. On the other side, DK-W and SE4 increase their surplus significantly. The surplus of DE, GB and IB also sees an increase from V4-16 to DoubleRES. Due to their size, the increase in total production in DE, GB and to some degree IB, should be noticeable.

Table 4: V4-16 – Demand and production as a percentage of demand. NB: RES does not include regulated hydro power in this table.

Area	Demand [TWh/year]	Wind [%]	O. wind [%]	Solar [%]	Run-of-the-river [%]	RES [%]	Production [%]
NO1	42	0	0	0	21	21	55
NO2	43	1	3	0	17	20	105
NO3	25	3	1	0	16	21	57
NO4	18	4	0	0	12	16	106
NO5	17	0	2	0	19	22	124
SE1	9	23	0	0	33	56	195
SE2	19	14	3	0	45	62	196
SE3	91	2	3	0	3	8	73
SE4	28	19	25	2	8	53	155
DK-E	17	30	41	4	0	75	169
DK-W	25	35	45	4	0	83	129
FI	92	4	3	1	13	21	90
BAL	32	11	3	0	11	25	78
PL	175	6	8	1	2	17	82
CZ	73	2	0	5	5	12	75
DE	555	24	12	10	4	50	103
NL	123	8	13	7	0	28	81
BE	93	7	10	5	2	23	64
GB	411	14	36	3	5	58	113
FR	496	11	7	4	11	33	102
IB	441	22	1	19	7	49	108
CH	70	1	0	1	20	22	83
AT	74	10	0	4	32	46	119
IT	371	10	1	15	7	33	104
SEE	356	16	0	6	15	38	99
ALL	3695	14	9	7	9	39	101

Table 5: DoubleRES – Demand and production as a percentage of demand. NB: RES does not include regulated hydro power in this table.

Area	Demand [TWh/year]	Wind [%]	O. wind [%]	Solar [%]	Run-of-the-river [%]	RES [%]	Production [%]
NO1	42	0	0	0	21	21	55
NO2	43	1	5	0	17	23	106
NO3	25	7	2	0	16	25	62
NO4	18	8	0	0	12	20	109
NO5	17	0	5	0	19	24	125
SE1	9	46	0	0	33	79	216
SE2	19	28	7	0	45	79	213
SE3	91	4	5	0	3	12	74
SE4	28	37	49	3	8	98	188
DK-E	17	60	82	8	0	149	164
DK-W	25	69	89	8	0	167	172
FI	92	8	7	3	13	30	94
BAL	32	21	5	1	11	39	78
PL	175	11	16	3	2	32	82
CZ	73	4	0	10	5	19	66
DE	555	47	25	20	4	96	117
NL	123	16	26	14	0	56	84
BE	93	13	19	9	2	44	65
GB	411	29	73	5	5	111	127
FR	496	21	14	8	11	55	105
IB	441	45	2	38	7	92	115
CH	70	1	0	2	20	24	83
AT	74	21	0	8	32	61	111
IT	371	21	1	29	7	58	98
SEE	356	32	1	13	15	61	100
ALL	**3695**	**27**	**18**	**15**	**9**	**69**	**106**

4.2 Net load

The result presentation of the net load analysis will start with presenting results on an aggregated level, before looking at more specific areas. In this study, we define net load as demand minus wind, offshore wind, solar and run-of-the-river power production.

When the amount of RES is doubled from V4-16 to DoubleRES, the total volume of net load decreases. The net load changes from 2274 TWh/year to 1157 TWh/year, a reduction of 49 %.

As the thermal power supply curve is equal in the two scenarios, lower prices are expected in DoubleRES. The peak net load does, on the other hand, change from 527 GW to 511 GW, a 3 % reduction. Subchapter 0 will investigate the possibilities to lower the peak net load with storage.

In addition, the amount of excess energy increases. Both in terms of how many hours there are too much energy in the system, and the amount of excess power at these hours. This is easily observable on Figure 11, which shows the net load duration curve for all areas, in both scenarios. Note how large the downward blue spike on the right of the figure is. While excess power is almost non-existing in V4-16, in DoubleRES, the negative net load at the hour with the lowest net load, is almost as large as the net load at the hour with the highest net load. Consequently, power prices dropping to zero is to be expected. Although the power price will be non-zero in between 7500 and 8000 hours according to Figure 11.

Another consequence of introducing more RES is more variations in the net load. This can be observed on Figure 11 in two ways. Firstly, the slope on the blue curves are steeper than the slope on the orange curves. Secondly, the distance between the 0 % and 100 % percentiles are larger on the blue curves than on the orange. This is a consequence of DoubleRES' larger variations from year to year.

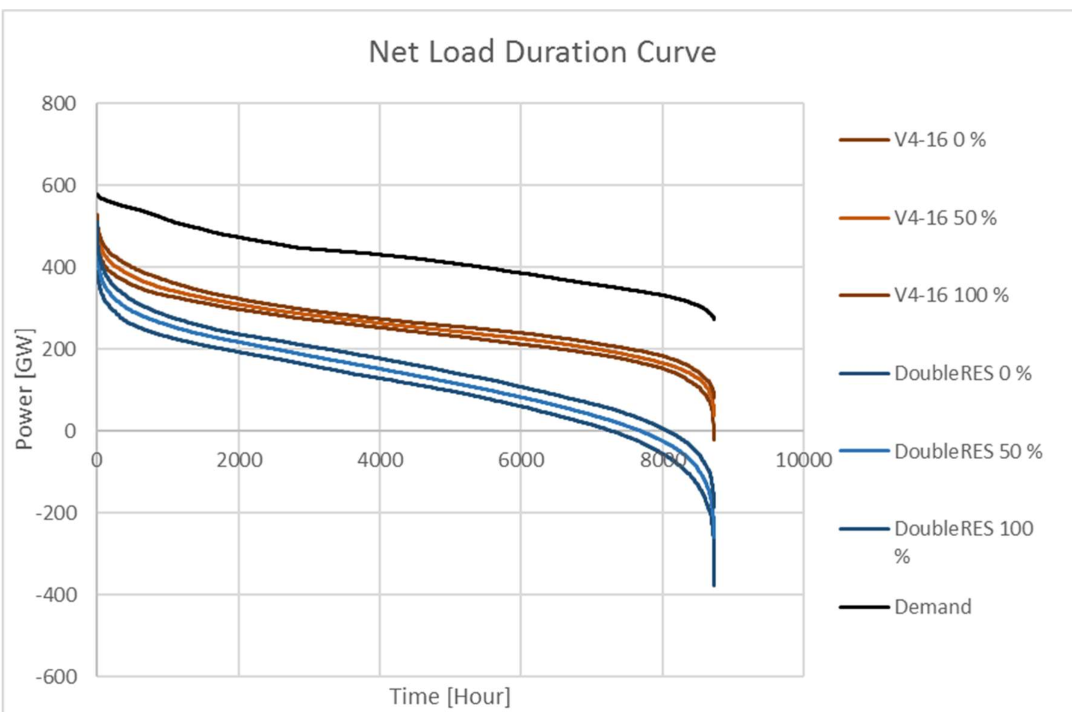

Figure 11: Net load duration curve – All areas

To be able to estimate the resulting power prices based on Figure 11, Figure 12 have been added. It shows the supply curve for thermal power, i.e. the “Power [GW]” of Figure 11 can be compared directly to “Production Capacity [GW]” of Figure 12. Note that storable hydropower is not accounted for in these two figures. Using 200 GW, causes a power price of around 100 €/MWh, where the cheapest lignite power plants and the average to cheapest hard coal power plants will run. A net load of at least 200 GW happens for 7000 hours a year in V4-16, a number which is reduced to just above 2000 hours in DoubleRES.

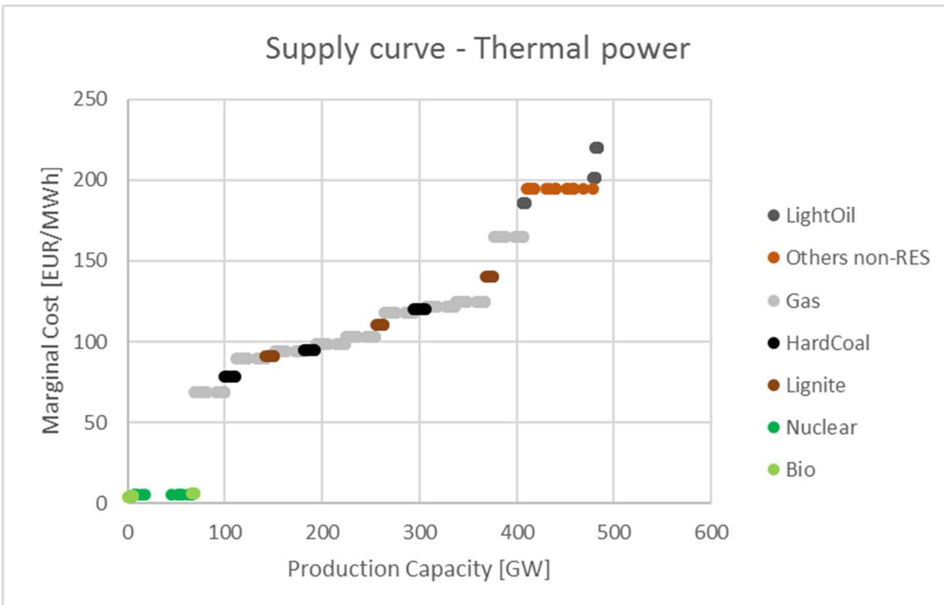

Figure 12: Supply curve all areas – thermal power only.

One key goal of the net load analysis was to identify patterns through the year and week, and thereby finding drivers for a changing price pattern. The results show that the seasonal variation present in the current market, with higher net load in winter than summer, will be present in V4-16. This seasonal change in net load will however be reduced as more RES is installed, and by DoubleRES, the seasonal change is almost non-existent. This is shown by Figure 13 and Figure 14 respectively. Note however that the 100 % percentile is almost identical in the two scenarios. There are in other words a seasonal change in the maximum net load in DoubleRES. The cause of the loss of seasonal variation is higher production from wind and offshore wind power at winter. This is further explained in subchapter 4.2.1. There is also another seasonal pattern appearing in both Figure 13 and Figure 14, the lowest average net load is during spring, while autumn also have lower average net load than summer. In DoubleRES these low net load sections is further away from the summer than in V4-16. The spring low net load is for instance lowest between week 18 to 23 in V4-16, while it is lowest between week 15 to 18 in DoubleRES. The cause of this seasonal pattern is described in subchapter 4.2.1.

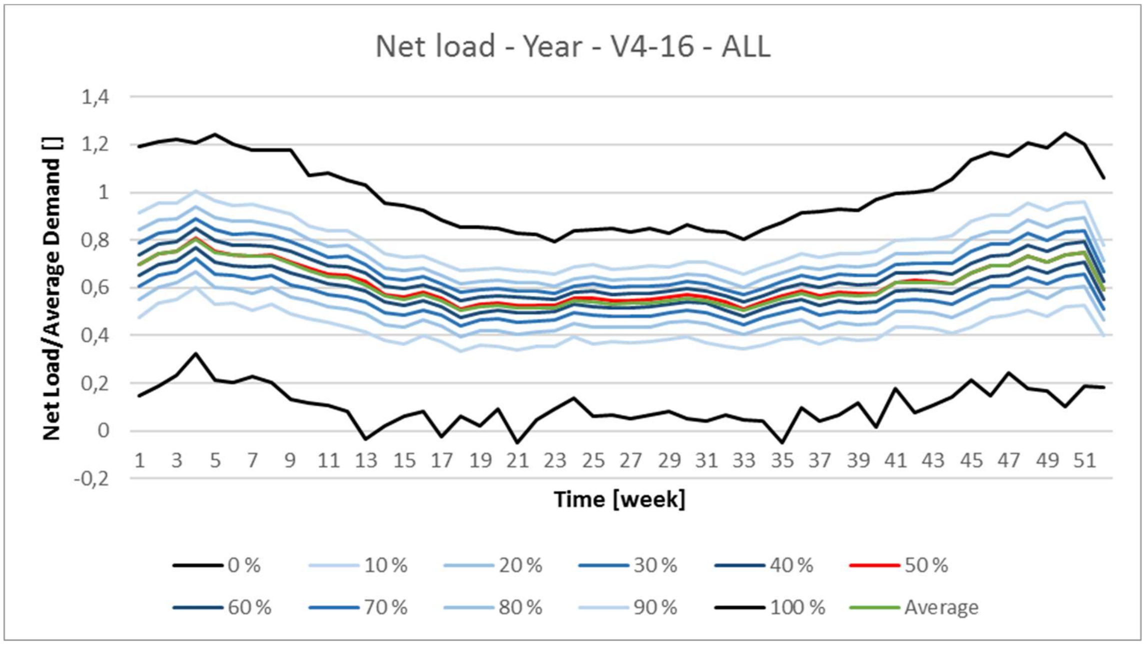

Figure 13: Net load – V4-16 – all areas

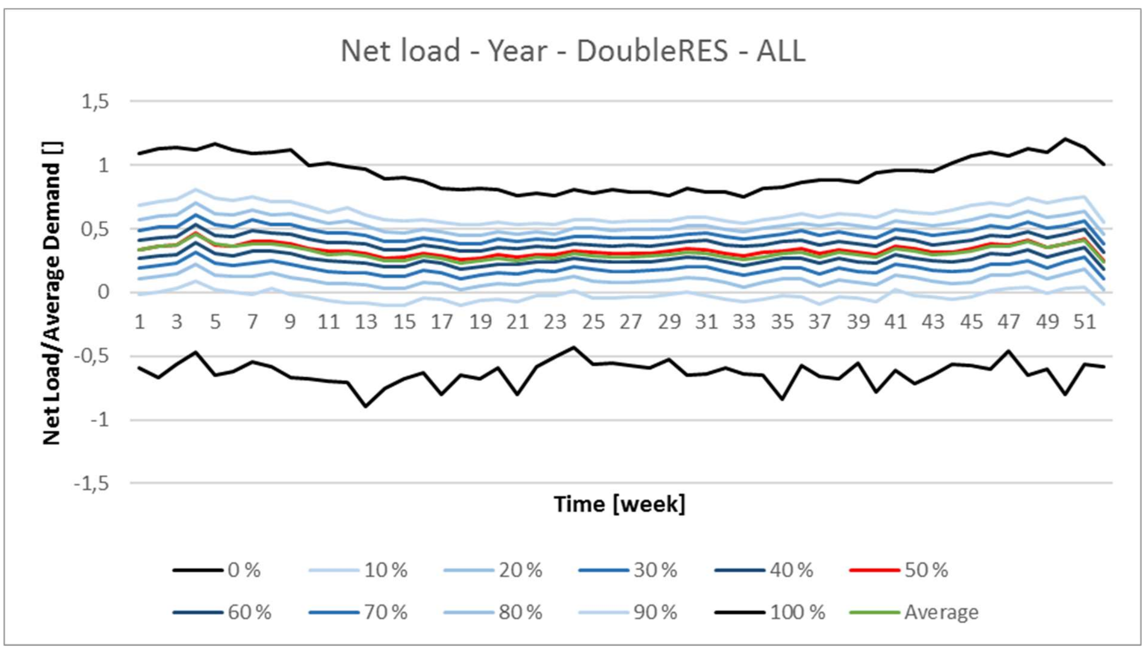

Figure 14: Net load – DoubleRES – all areas

In terms of net load changes through the week, there are also interesting results. There is still a variation from day to day, with the weekend representing lower net load then the rest of the week. There are, however, changes in the weekly pattern compared to the present. Solar power production reduces the net load during the morning and afternoon. In V4-16 this reduction causes the morning and afternoon to have an equally low net load, with Sunday morning being the time of the week with the lowest net load. These trends are visualized by Figure 15. In DoubleRES this reduction has such an imprint that noon is the time of the day with the lowest net load, seen in Figure 16. This has some noteworthy implications. In the present of this reports writing, the norm is low net load during the night and high net load during the day. In other words, during a day, there will be a short period with low net load, and a long period with high net load. This is turned upside down in V4-16, where a day consists of a long period with low net load, and short period with high net load. This changes again in DoubleRES, where the pattern is similar to the present, with the exception of the short low net load period being in the middle of the day rather than at night. These changes are interesting because it changes peak power market, as peak power plants usually have considerable start-up costs, and start-up times. Unfortunately, start-up costs and start-up times are not included in this study. Considering how the price on CO_2 influences the competition among the thermal power plants, the end result is that power plants will be run differently than originally designed, potentially causing increased wear and lower efficiency.

Figure 15 shows that Sunday morning is the only time of the week where the net load is negative in V4-16. In DoubleRES, on the other hand, negative net load happens at all hours during the week according to Figure 16, and at all weeks during the year according to Figure 14. At a DoubleRES Sunday morning, the norm is in fact negative net load.

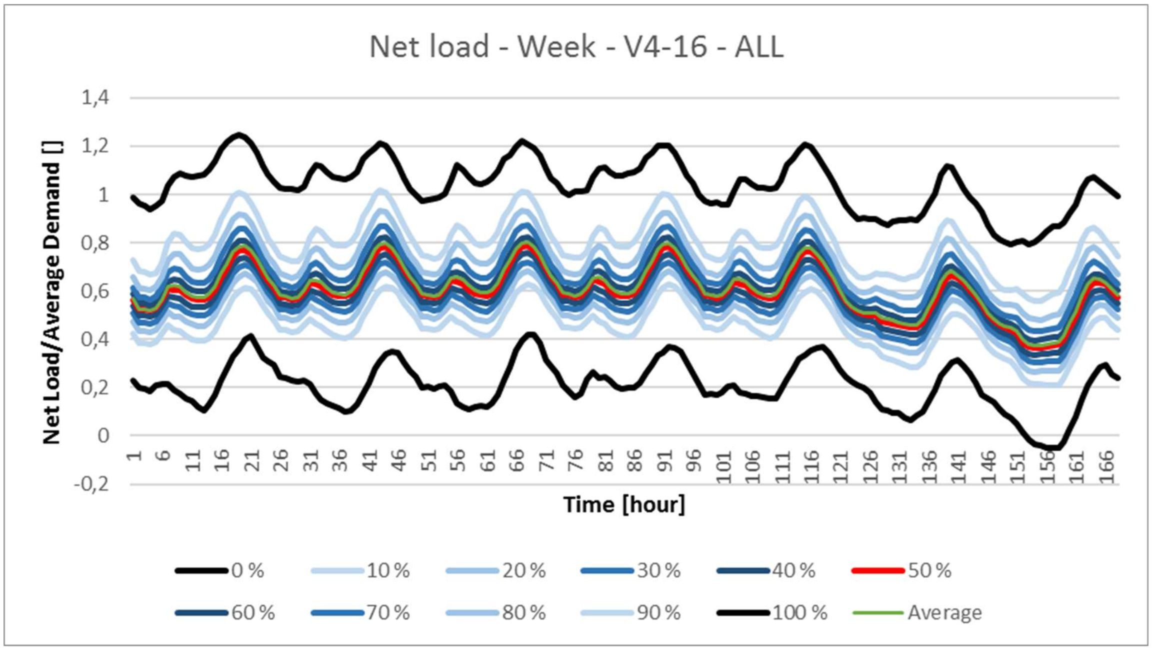

Figure 15: Net load – V4-16 – all areas

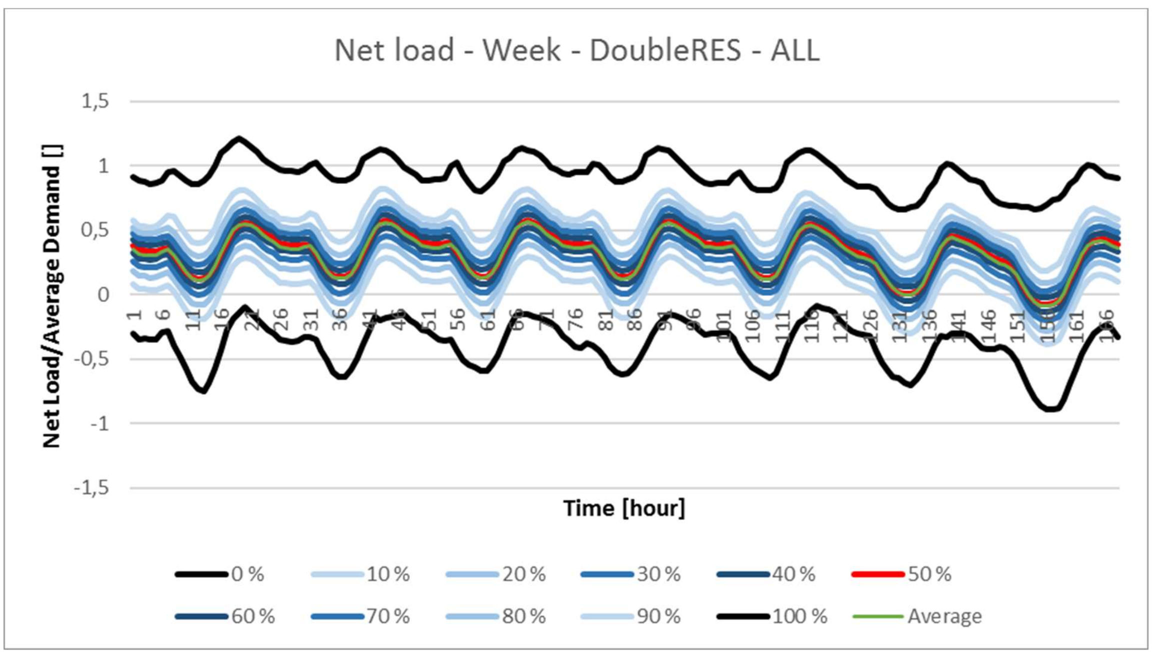

Figure 16: Net load – DoubleRES – all areas

4.2.1 RES behaviour

This subchapter will consider the RES production series, highlighting the different technologies production pattern. We will use energy series from DK-W to represent wind and offshore wind power, while energy series from IT represents solar power.

The yearly and weekly production patterns of wind power is shown in Figure 17 and Figure 18 respectively. From these figures, four key observations are made:

- Maximum production can occur all year round.
- The average production is considerably higher in winter than in summer.
- The production is slightly higher during day than night.
- Zero production can occur at all times.

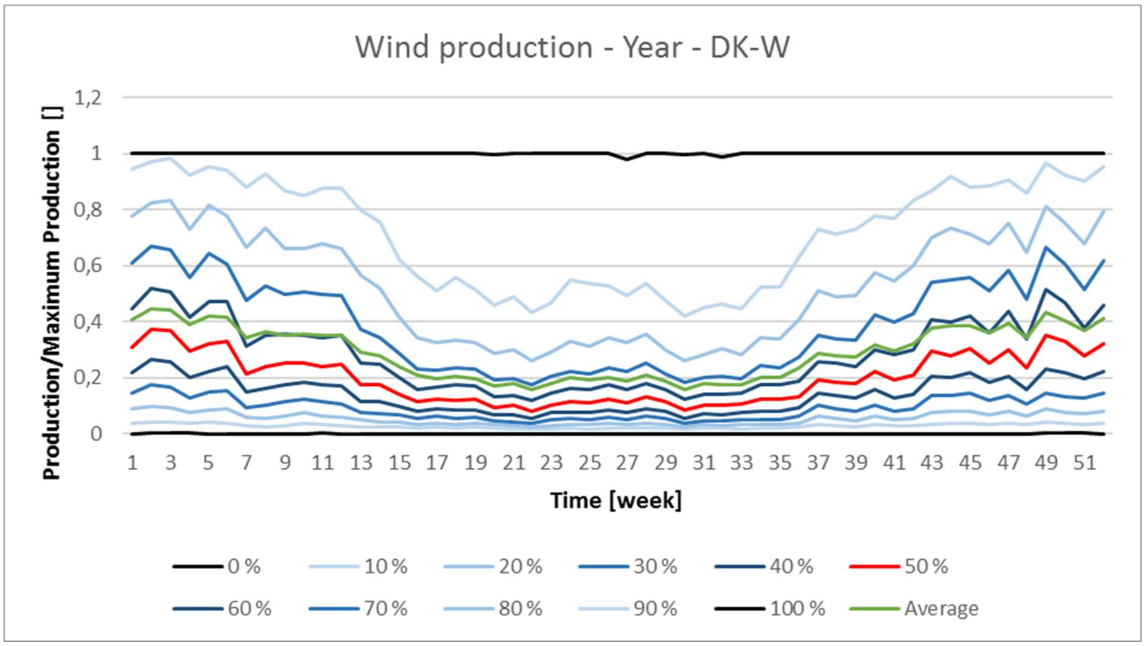

Figure 17: Wind production – year

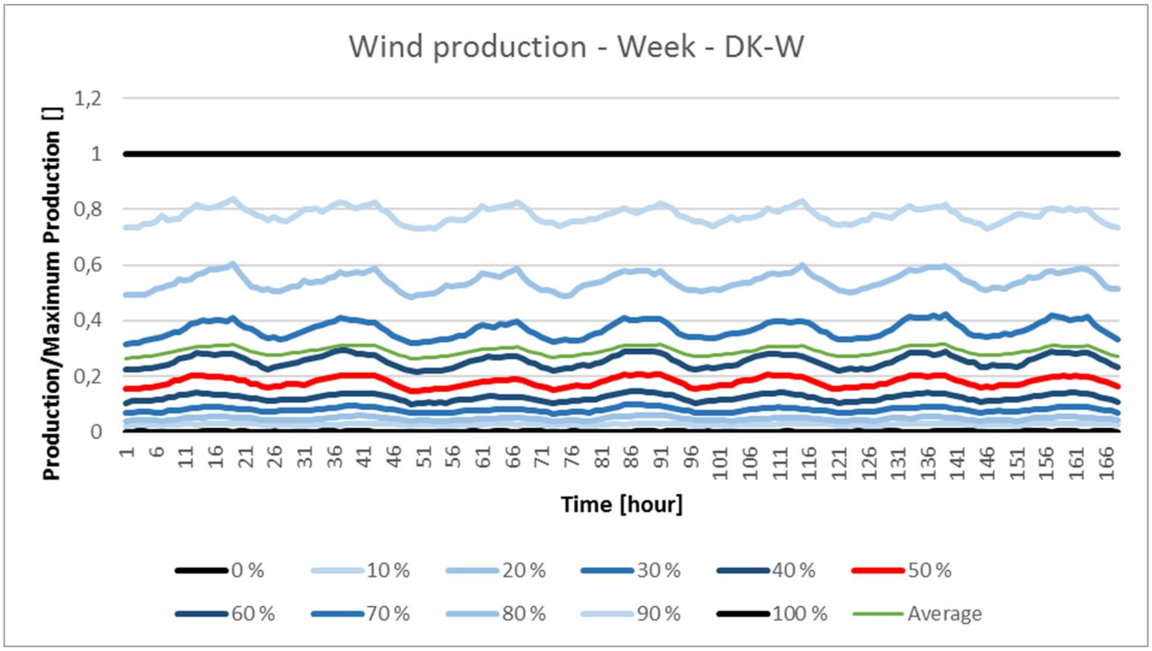

Figure 18: Wind production - week

Figure 19 and Figure 20 show the yearly and weekly – respectively - production patterns for offshore wind power. From these figures, offshore wind production is found to share the same four key characteristics as onshore wind production. There are however some important differences between the two types of wind power production. Firstly, the offshore wind power plants have a better utilization of their capacity, i.e. the amount of equivalent full-load hours is higher. Where onshore wind utilizes 25 % to 30 % of its capacity on average, offshore wind utilizes around 50 %. This has some noteworthy consequences that can be seen by comparing the red median and the green average on Figure 17 to Figure 20. For onshore wind, the average is always higher than the median. For offshore wind, on the other hand, the median is highest in winter, while the average is highest in summer. Figure 20 shows that the median and average is almost on the same level for offshore wind, when seasonal variation is neglected. Consequently, in a country with both offshore, and onshore wind, the difference between median and average in winter time will cancel each other out, while the difference between median and average in summer will reinforce each other. The reason to bring this up, is to highlight that the most likely situation and the average situation is two separate things. When the average is higher than the median, there will be more situations where the production is significantly higher than the median, then significantly lower than the median.

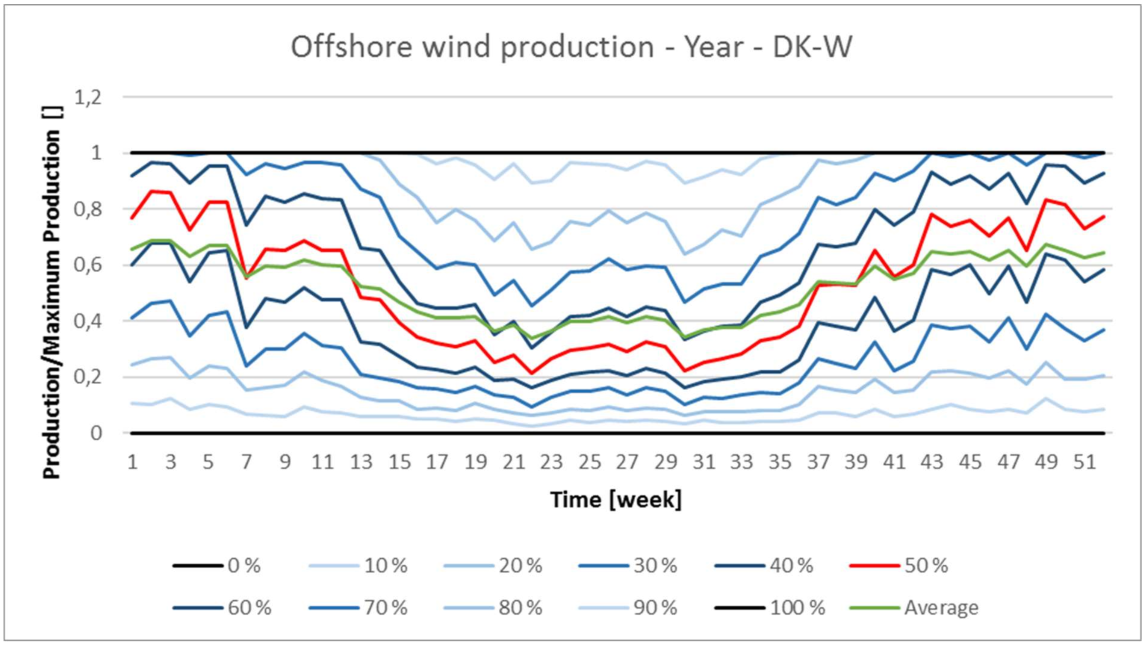

Figure 19: Offshore wind production - year

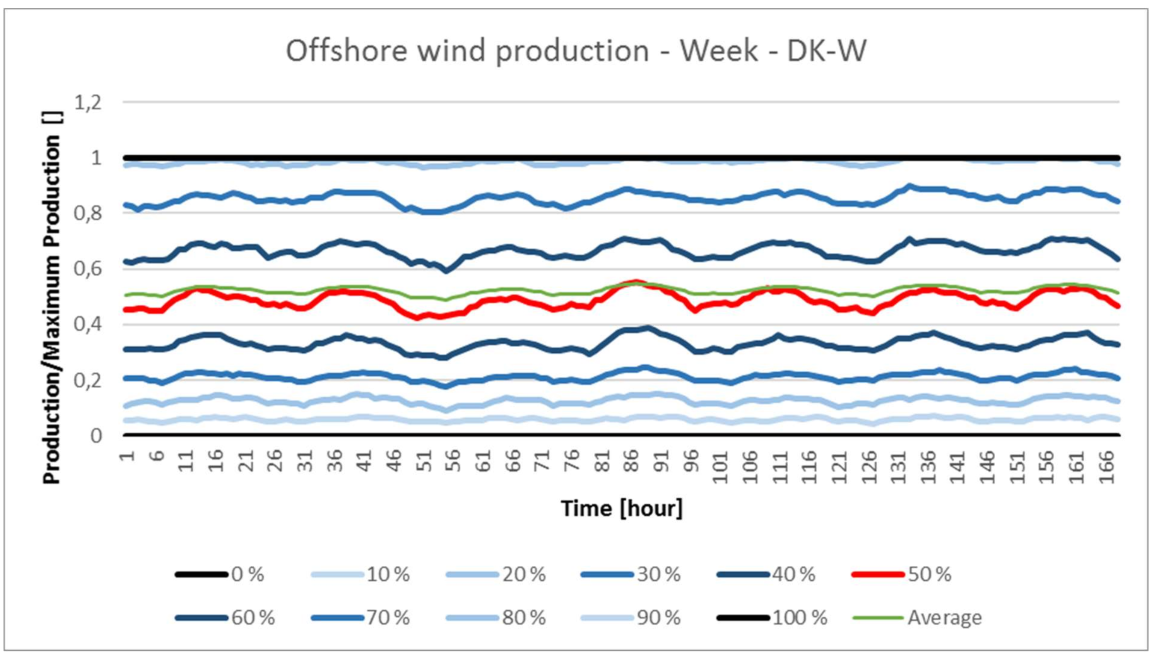

Figure 20: Offshore wind production - week

The third intermittent renewable energy source, solar power, has characteristics very different from wind power. Figure 21 and Figure 22 show the yearly and weekly – respectively - production patterns for solar power. Note that the production pattern discussed here is based on photovoltaic cells, not concentrated solar power. In fact, all solar power produced in all areas within this study is PV cell based.

The solar energy series has some key characteristics. Firstly, the clear day – night pattern on Figure 22 is observed, underpinning the fact that we are discussing PV cells. From Figure 22 we also note that the production during day can be almost zero. From Figure 21, we observe that the zero production can occur at all times of the year, unsurprisingly as nights appear all through the year. This is, however, a key to understand Figure 21. Because the sun is not up for a significant number of hours during a year, there is a large amount of entries in the solar energy series with zero production, causing the median in Figure 21 to be very low.

Secondly, the seasonal variation of the maximum solar power production is prominent. The maximum production is significantly higher in spring and autumn compared to summer and winter. The maximum production in summer is around 80 % of the maximum production of all seasons. This is contradictory, although perfectly explainable, as the irradiance is higher the closer one is to the summer solstice, and smaller the closer one is to the winter solstice. Where the summer and winter solstice occurs in week 20 and 51 respectively. The seasonal variation in maximum production has two causes, temperature, and tilt. Firstly, a PV panel produces more energy when it is cold. As the temperature is highest during summer, this will reduce the maximum production during summer. Secondly, PV panels are typically tilted, either by the slope of the roof or by an optimal angle, calculated to generate the most energy during a year. If an optimal angle is chosen, it will not be optimal at the extremes. I.e. an optimal angle will favour the noon conditions of spring and autumn.

Thirdly, the average production is highest in summer. It should however be noted that the seasonal change of the average is significantly smaller than those of the 60 %, 70 % and 80 % percentiles. This is a consequence of the reduced maximum summer production. Consequently, the seasonal variation of the average solar production may be smaller than the intuition leads one to believe.

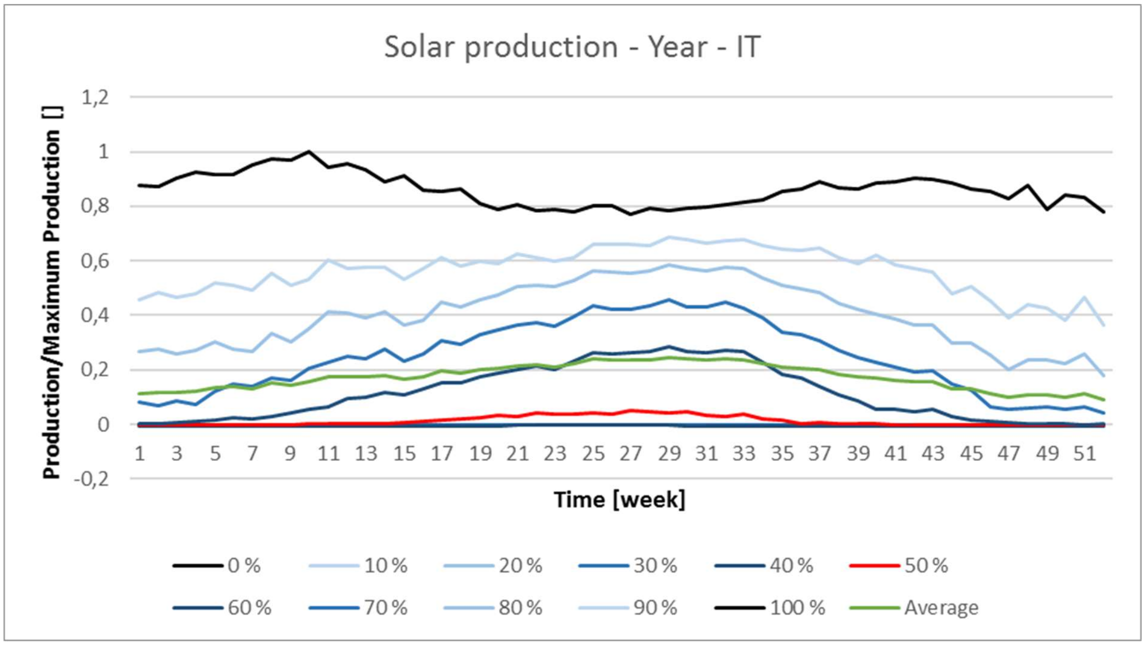

Figure 21: Solar production - year

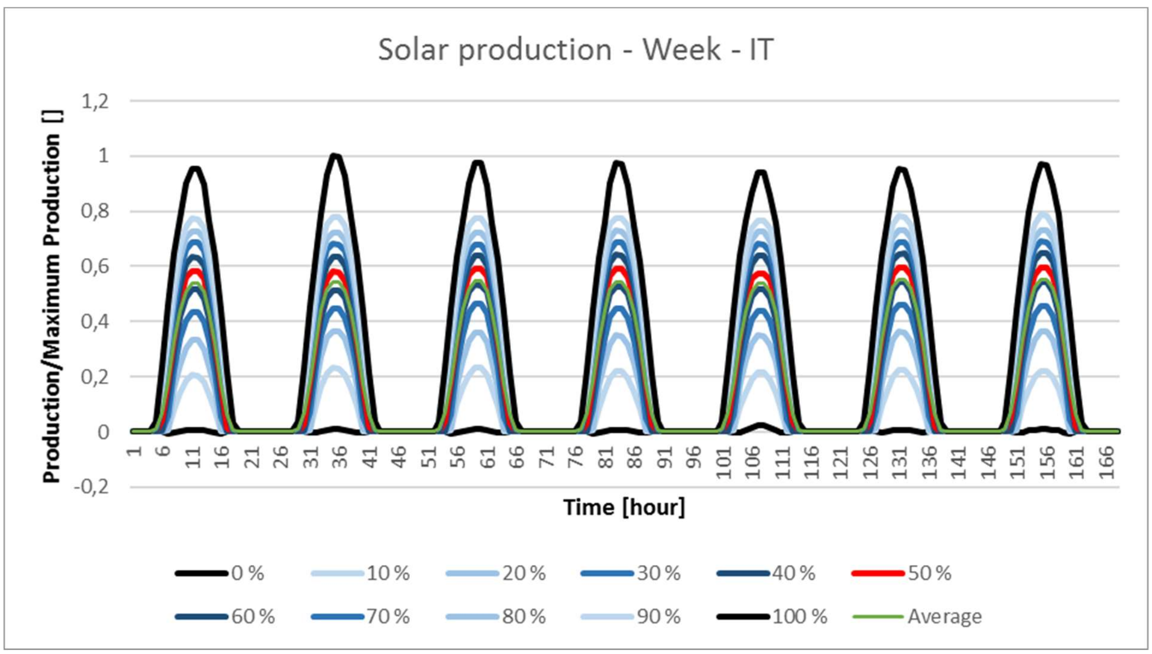

Figure 22: Solar production - year

The fourth intermittent RES – run-of-the-river hydro power – has a profound impact in the Nordic area. The Nordic areas with the largest production from run-of-the-river hydro power is NO1, NO2 and SE2 based on data in Table 4. Additionally, SE1 has a very large share of run-of-the-river hydro power compared to demand.

Winter and snow is typically very important aspects of run-of-the-river power production. During the winter, precipitation manifests as snow. This precipitation will not be counted as inflow before the snow melts, typically during spring, causing a strong seasonal variation in production. The snow melts later in the spring, the colder the catchment area is. The temperature is typically reduced the further above sea level and the further north the catchment area is located.

Figure 23 to Figure 26 shows the run-of-the-river hydro power production in some selected areas. They show a melting season starting in around week 17, which corresponds to the end of April. The melting season of NO2 starts later than that of NO1, as NO2 is more mountainous. The melting season of SE2 starts later than that of NO1, as SE2 lies further to the north. The start of the SE1 melting season isn't as clearly defined, but the large amount of inflow starts around week 23, later than the three others.

The Nordic areas has a noticeable difference concerning the difference between the inflow in the spring and late summer/autumn. In NO1, SE1 and SE2 the considerably higher inflow during spring. While NO2, as well as NO5, NO4 and NO3 has a late summer/autumn inflow closer in magnitude to the spring inflow. Seasonal variations in precipitation will influence this, but one should also be aware that some of the water systems of NO2, NO5 and NO4 utilizes glacial melting water, in other words a source of inflow that will contribute through the summer.

The y-axis of Figure 23 to Figure 26 is normalized to the average demand. In the Norwegian areas, run-of-the-river hydro power production do not exceed the average demand. The two northernmost Swedish areas on the other hand, will experience times where run-of-the-river hydro power production greatly exceeds average demand. Additionally, spring usually have lower or on average demand, requiring either large transmission to other areas or curtailing. Much of this excess energy will however be transported to SE3.

Also note that the run-of-the-river hydro power is the only RES with a non-zero 0 % percentile through the year. This is to some degree a cause of inflow series with a weekly resolution. With hourly resolution, like the other types of RES presented in this subchapter, one would expect this to be less prominent.

During the study of the run-of-the-river hydro power production, it was found that unregulated inflow series of originating from the Vision 4 2014 EMPS dataset is not unique to every area. BAL, PL, CZ, DE, NL, BE, FR, ES, CH, AT, IT, and SEE uses the same unregulated inflow series. There are in other words only the Norwegian and Swedish areas plus FI and GB that uses unique unregulated inflow series. The regulated inflow series, has not been checked as they are not part of intermittent RES, but similar results could be found there.

The continental Europe common inflow series shown in Figure 27, has a profound seasonal variation, although not as prominent as seen in the Nordic areas. Important distinctions from the Nordic unregulated inflow series includes larger winter inflow, and less sudden start of the melting season.

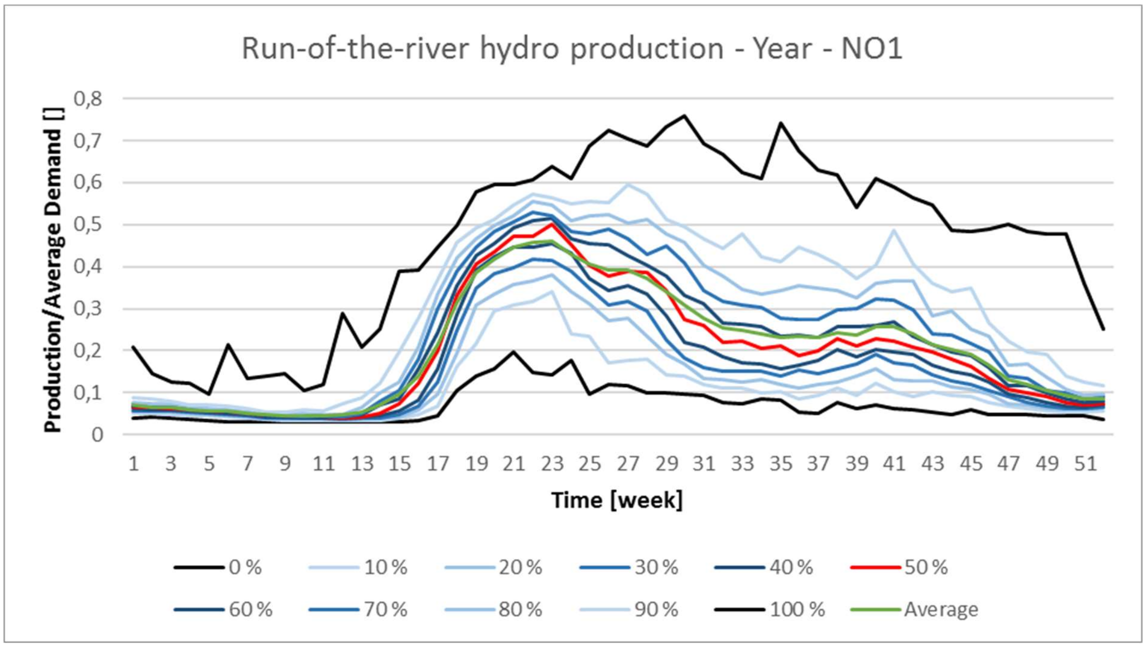

Figure 23: Unregulated inflow – NO1

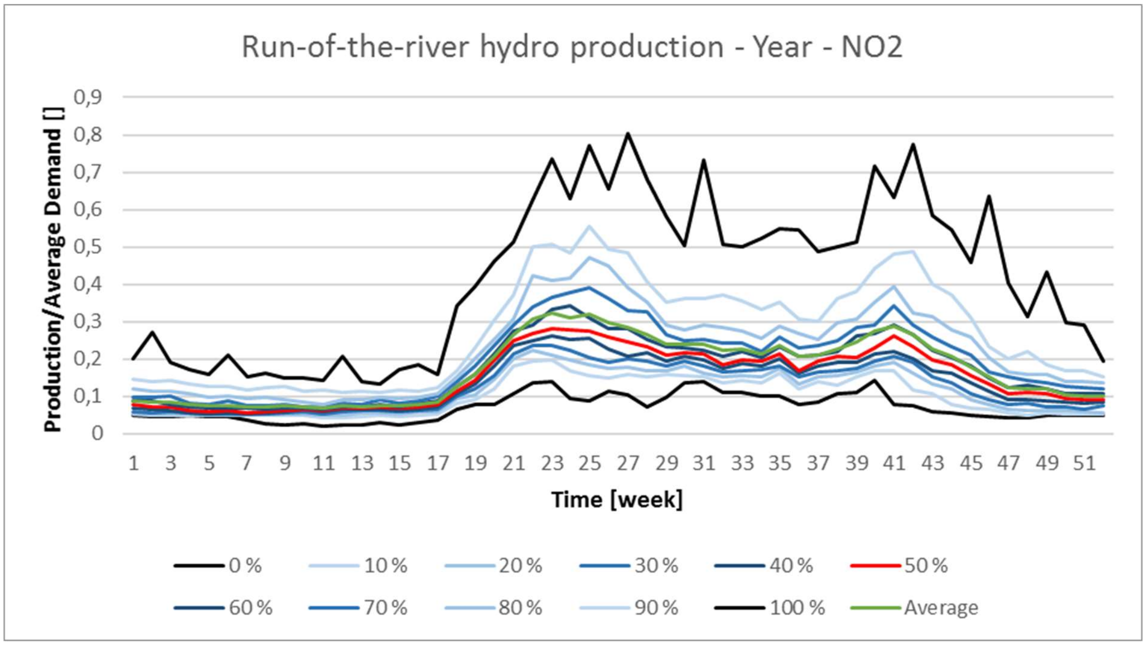

Figure 24: Unregulated inflow – NO2

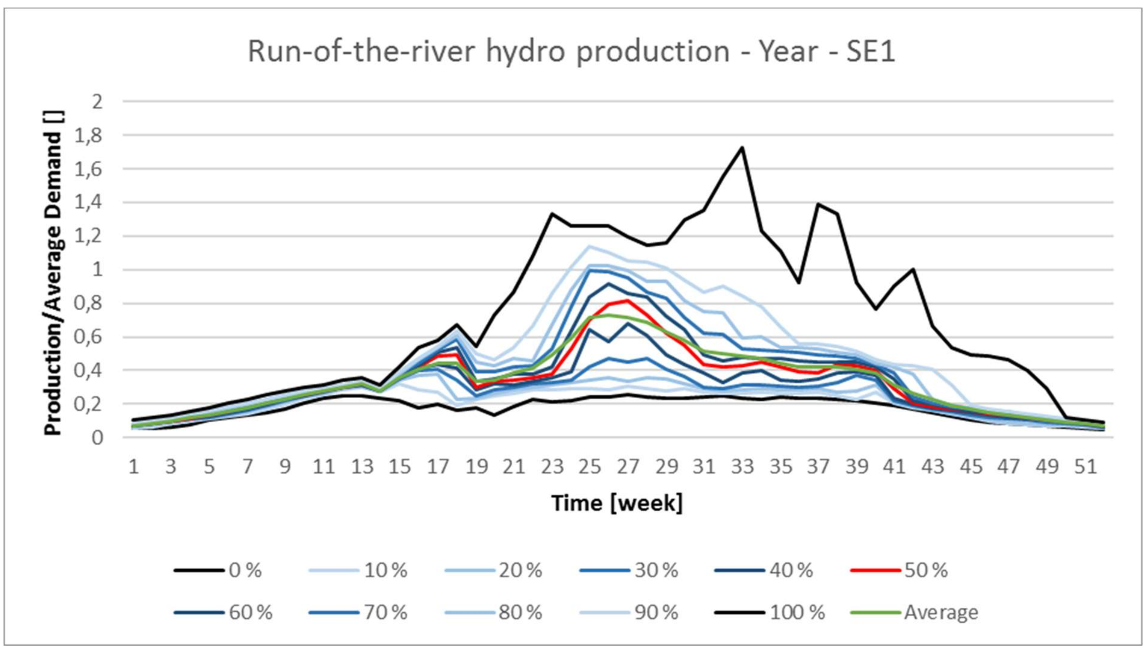

Figure 25: Unregulated inflow – SE1

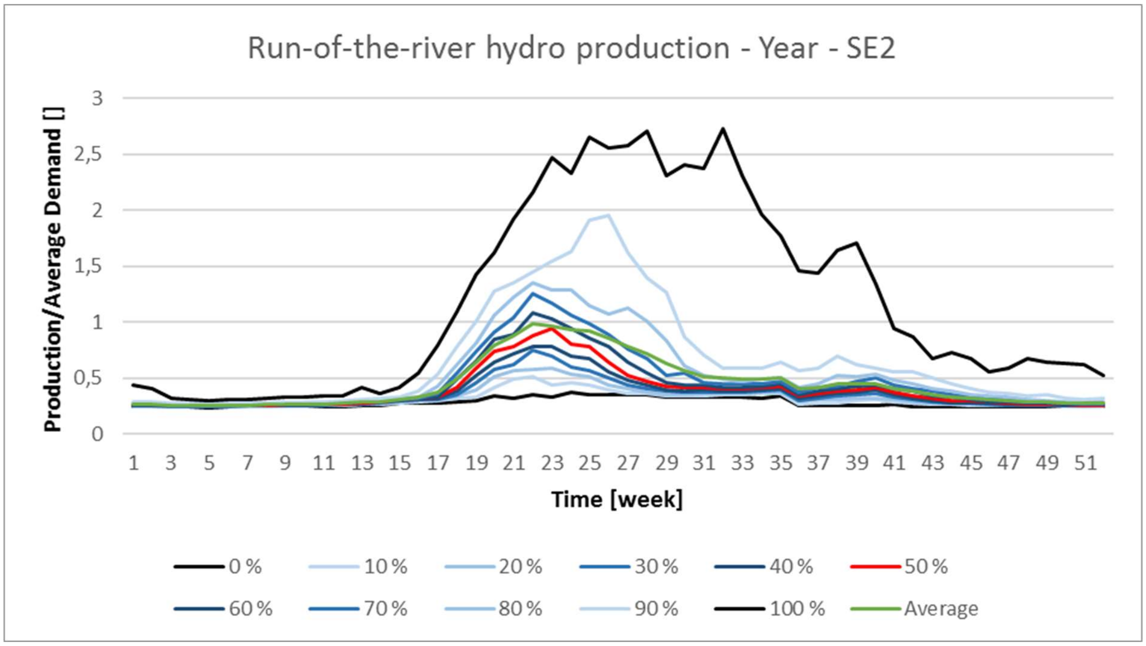

Figure 26: Unregulated inflow – SE2

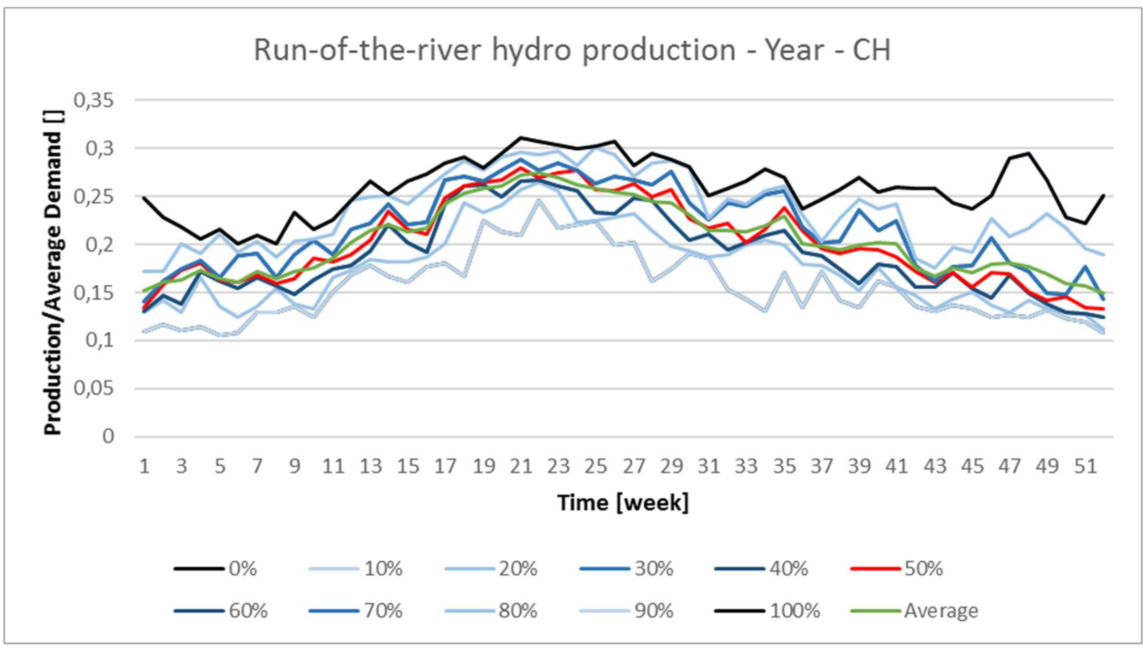

Figure 27: Unregulated inflow – CH.

The average demand, wind, offshore wind, and solar production has a sinusoidal nature, with a period of one year. We have already seen how the RES behaves. Now we will compare the sinusoidal nature of these four series, to better understand the implications of merging them into the net load of an area. The sinusoidal comparison is based on averages of the series from GB. To obtain a fruit bearing comparison, we would like each sinusoidal to be oscillate around zero, with an amplitude of 1. This is achieved by first subtracting the average of the series from all entries. Secondly, the maximum and minimum value of each series with zero as average is found. Thirdly, the average of the absolute value of the maximum and minimum is found. Finally, all entries are divided by this average extreme value. The result is Figure 28. For comparative reasons, solar power production is multiplied with -1, and a cosine with its highest point in medio January has been added.

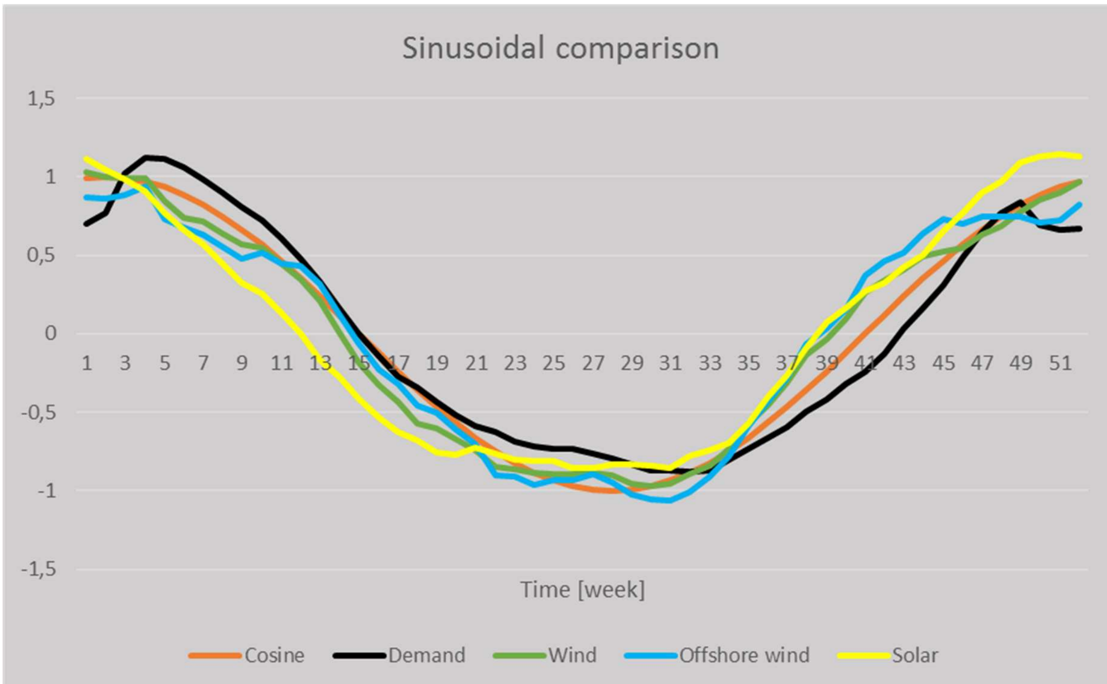

Figure 28: Comparison of the sinusoidal nature of demand, wind power production, solar power production and offshore wind power production.

Figure 28 shows two important coherences that will have implications on the net load. Firstly, the distance between solar one side, and wind, offshore wind, and demand on the other in week 9 to 19. Secondly, the distance between solar, wind, and offshore wind on one side, and demand on the other in week 36 to 45. The consequence of these discoveries is as follows:

- In an area with an amount of wind power large enough to cancel out the sinusoidal nature of demand in the net load, the net load will be low in autumn.
- In an area with a balance between wind power and solar power such that the sinusoidal nature of the two, cancel each other out, and there will be a contribution towards low net load in spring.

Consequently, the low autumn net load will appear as the share of wind power increases, and then fade away as the share increases above a certain level. The low spring net load on the other hand will continue to increase as the RES share increases, given the right balance between wind power and solar power. Because the impact of the sinusoidal nature of demand is reduced when the RES share increases.

The discoveries found in the sinusoidal comparison is the cause of the low spring and autumn average net load found in Figure 13 and Figure 14. How the week with the lowest average net load was changed from V4-16 to DoubleRES is a natural consequence of adding sinusoids with a slight phase displacement. Air conditions is another factor causing higher net load during summer than spring and autumn. This is visible on the demand of some areas, but only those in the south, like IT, IB and SEE. FR does for instance not have lower spring demand than summer demand.

4.2.2 Year and week profiles

This subchapter will present net load result from some major markets, including Norway, Sweden, Denmark, and DE. All figures describing the net load week and year profile of all areas are available in appendix 8.7.

Typical for the Norwegian areas are a seasonal variation. These areas have the strongest seasonal variation of all areas included in this study. The fact that electricity is used for heating to a much larger degree in Norway than other European countries, is a major reason for the uncommon net load profile seen in Figure 29 - representing Norway. Around week 27 the Norwegian net load is negative for some inflow scenarios, indicating the presence of RES production. Figure 30 presents the Norwegian net load with run-of-the-river hydro power taken out of the equation. Comparing Figure 29 and Figure 30, we observe that run-of-the-river hydro power adds to the already strong seasonal variation. Not surprising, considering the results from subchapter 4.2.1. The data presented in Figure 29 and Figure 30 is from V4-16. DoubleRES is however very similar, because of the low percentage of installed solar and wind power.

In the Nordic region, the difference between “wet years” and “dry years” are important. The terms refer to fact that the inflow differs from year to year. How this is changed when solar and wind power is added– which also have varying production from year to year – is an important question for the Nordic system. This was checked by adding RES production and inflow, and comparing all the inflow years from 1931 to 2005. In V4-16, the maximum and minimum years differs with 50 TWh from the average year. In DoubleRES this number is increased to 52 TWh. In other words, the RES added in Norway and Sweden from V4-16 to DoubleRES requires 2 TWh of storage in the reservoirs used for storage of more than one year.

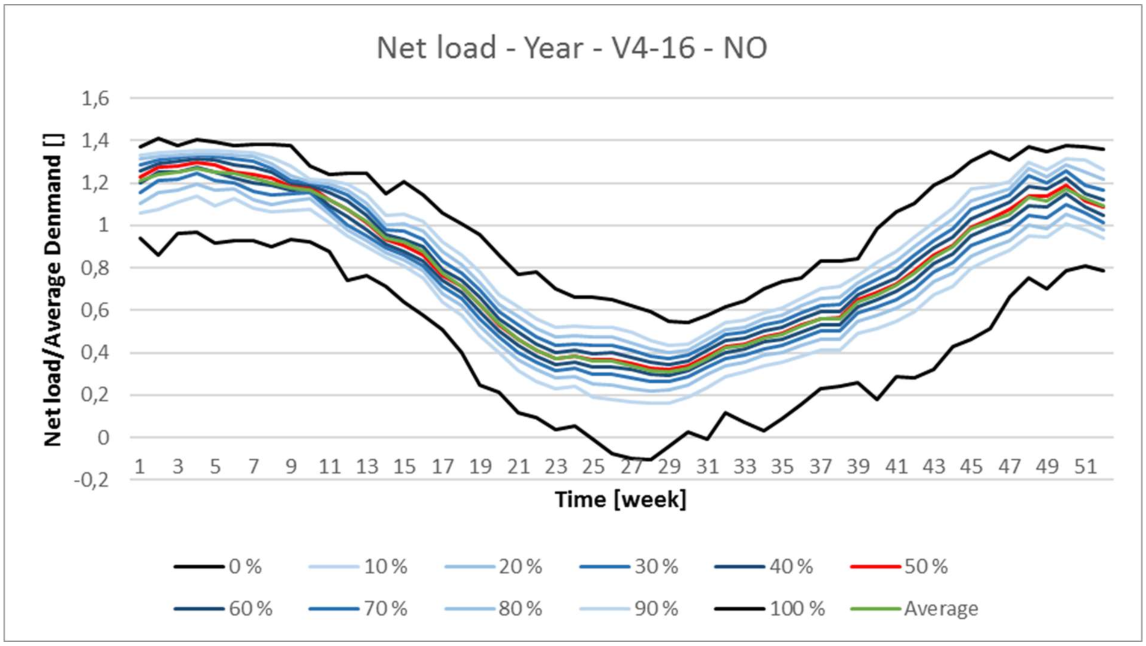

Figure 29: Net load of the five Norwegian areas combined.

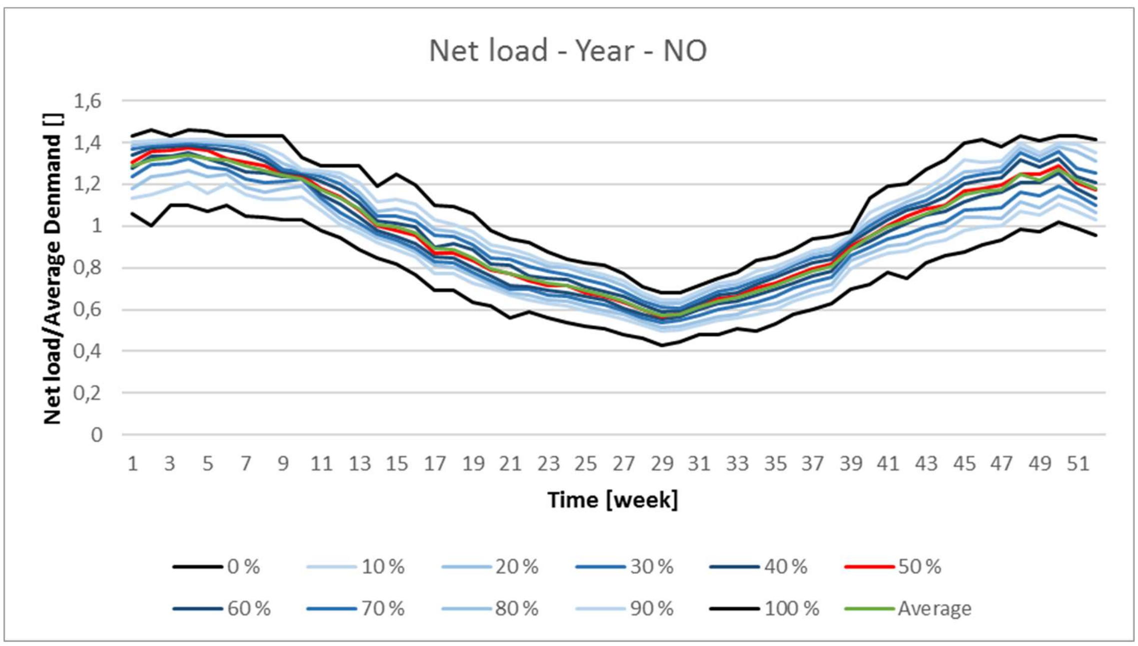

Figure 30: Net load of the five Norwegian areas combined. Run-of-the-river hydro power not included.

In addition to a seasonal net load variation, close to what is normal in 2017. Norway has a weekly net load variation similar to what we are used to in the present, visually presented by Figure 31. This includes low net load during night compared to day, and low net load during weekend compared to the rest of the week. Note that the seasonal variation is a major cause of the relatively large distance between the percentiles in Figure 31.

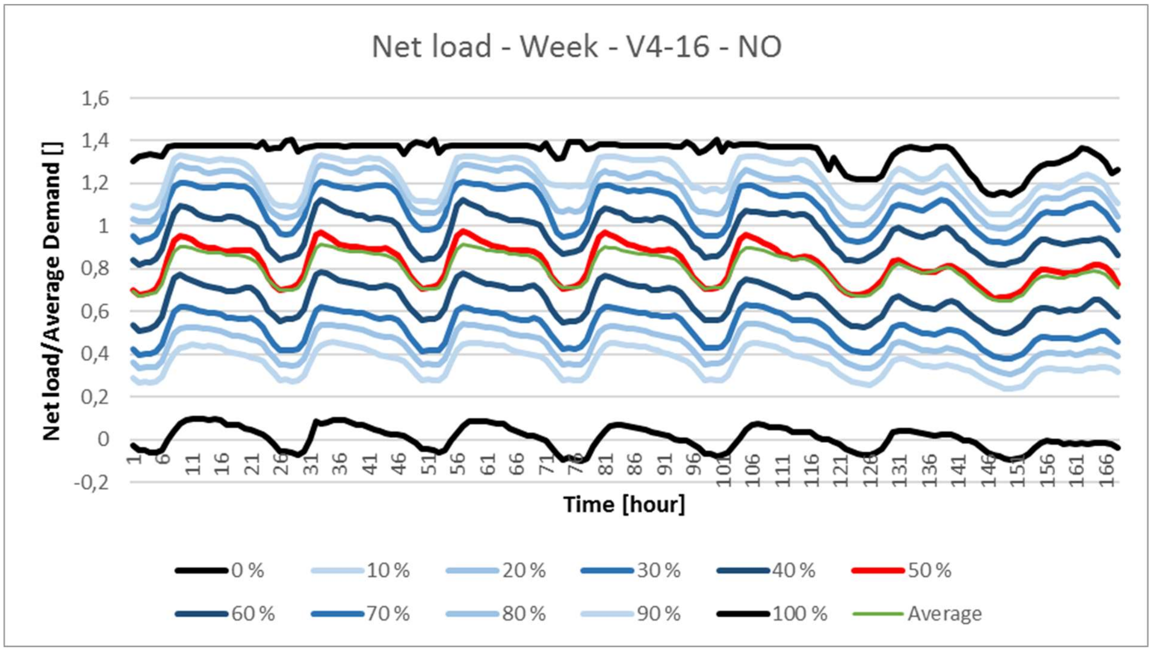

Figure 31: Net load of the five Norwegian areas combined.

The net load of the Swedish areas has many similarities with that of Norway. There are however some differences, one of the main being less seasonal variation than Norway. This has 3 causes. Firstly, Sweden has less seasonal variation in the demand. Secondly, Sweden has a lower share of run-of-the-river hydro power than Norway. Thirdly, Sweden has a higher share of wind and offshore wind power than Norway.

Sweden also has a slightly different average seasonal variation than Norway. Where the Swedish net load steadily decreases from week 9 to week 22, the Norwegian net load decreases faster and faster. We observe that the seasonal average variation of Sweden in Figure 32 is more similar to the average variation of Figure 30 than Figure 29. In other words, removing the run-of-the-river contribution to the Norwegian net load makes it more similar to the Swedish net load in terms of average seasonal variation. The difference between Figure 29 and Figure 30, making Figure 30 closer to the Swedish net load, can be identified to start at week 15-17. This is from subchapter 4.2.1 known as the start of the Norwegian melting season. What we observe, is in other words, an imprint in the net load of the fact that Norway has a more dominant run-of-the-river power production than Sweden.

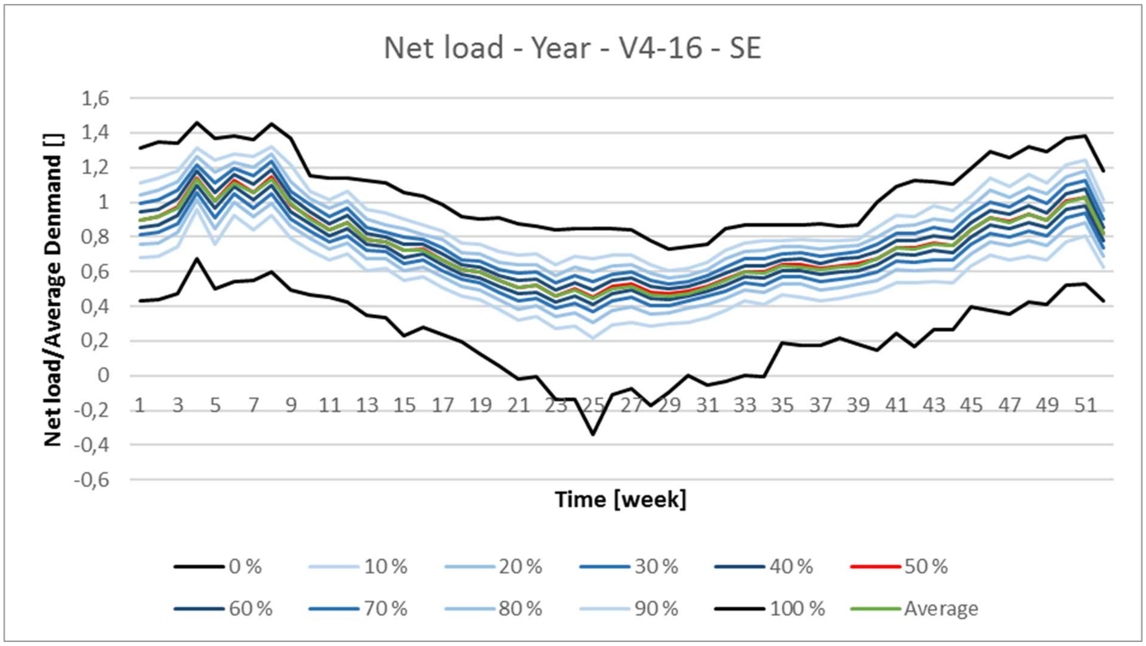

Figure 32: Net load of the four Swedish areas combined.

The Swedish net load of DoubleRES has many similarities with that of V4-16, with the most prominent difference being larger distance between the 100 % and 0 % percentile. Where all the other percentiles adjust to the changes in the extreme percentiles. Based on the results presented in subchapter 4.2.1 we know that solar, wind and offshore wind production changes the 100 % percentile minimally, i.e. the changes are in the 0 % percentile.

In terms of the net load variation through the week, the Swedish areas are similar to the Norwegian in terms of night-day and week-weekend relationships. The most prominent difference is a tighter spacing between percentiles in Sweden caused by less seasonal variations. Figures showing net load of the week and year for all Swedish areas and both scenarios can be found in appendix 8.7.

The net load of Denmark is characterized by its large share of wind and offshore wind production. Denmark is in other word a good example of what happens to the net load in a wind dominated area. The seasonal variation of the Danish net load in V4-16 is shown in Figure 33.

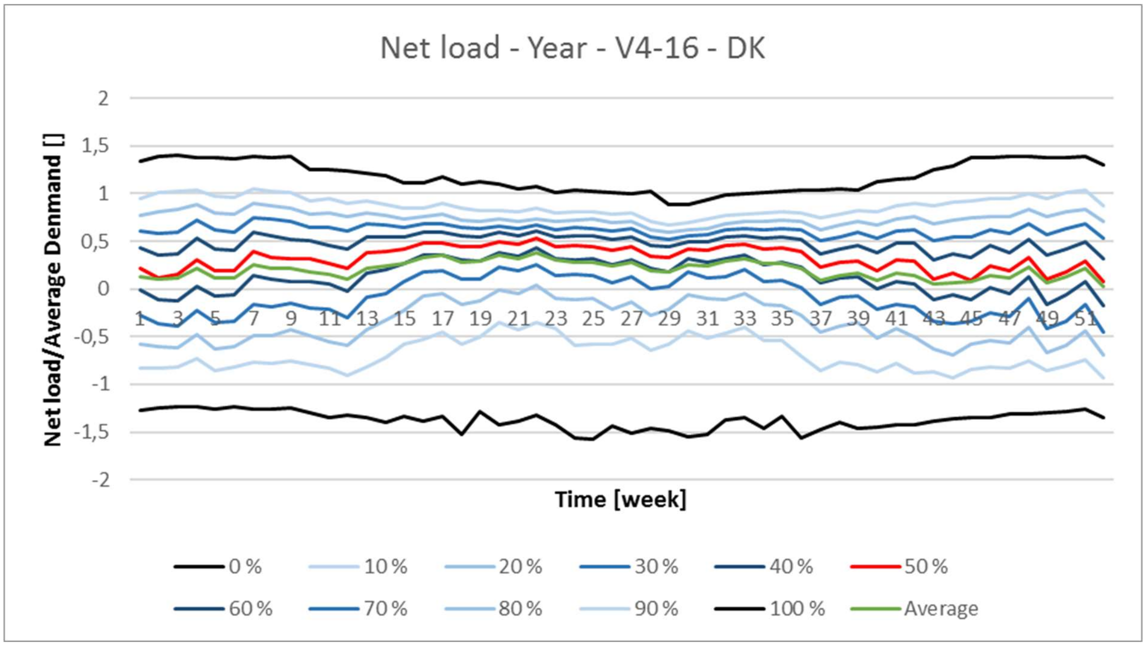

Figure 33: Net load of the two Danish areas combined.

As seen in subchapter 4.2.1, wind power does not change the seasonal or hourly variations in the 100 % and 0 % percentiles. Wind power does, however, change the seasonal variation of the median and average, making the average Danish net load higher in summer than winter. It also increases the distance between the percentiles, meaning Denmark has up to 1,5 times its average demand in excess power production during extreme hours. The characteristics cause by wind power is even more prominent in DoubleRES.

GB is also a wind dominated and have a similar net load profile to Denmark. Although GB has a lower RES share than Denmark, the average net load is higher in summer than winter. Other areas with net load profiles imprinted by wind power production is BE and NL. Although the wind power share of NL and BE is not high enough for average summer net load to be higher than average winter net load.

The net load week profile of Danmark in V4-16 shown in Figure 34, presents a net load profile with low net load at night and high net load at day. It may at first glance look like the difference between day and night are smaller than those observed in Figure 31 for Norway. Checking against the numbers on the y-axis one would however observe that the difference between night and day is largest in Denmark. This is the case even though subchapter 4.2.1 have shown that both types of wind power produces more during day than night.

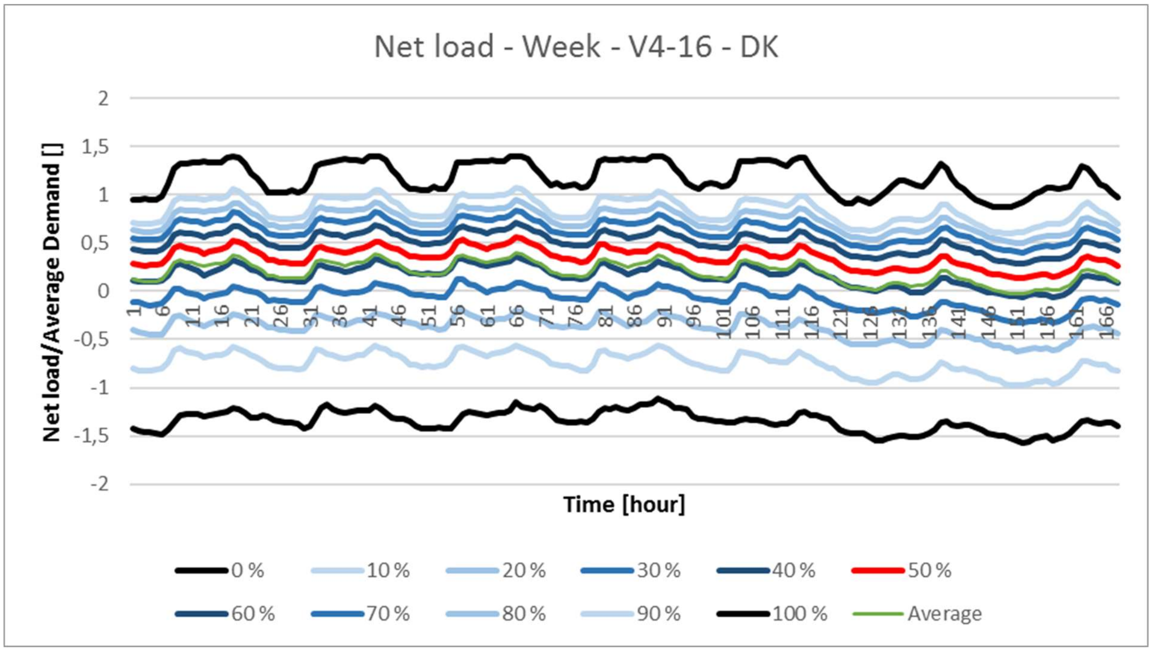

Figure 34: Net load of the two Danish areas combined - V4-16.

Comparing the Danish net load week profile of V4-16 in Figure 34 and DoubleRES in Figure 35, we observe what happens when a large amount of wind power is added. Primarily, the distance between the percentiles is very large in DoubleRES, with a negative net load of almost four times the average demand. Consequently, making storage or transmission capacity to nearby areas critical if the energy is to be utilized. In DoubleRES Denmark has a negative net load on average. It looks like the day-night differences are reduced in DoubleRES. This is to some degree correct, as solar and both wind power types contribute in that direction. One should however be aware the difference in the scale on the y-axis. The 100 % percentile is after all almost identical.

Figures showing net load of the week and year for GB, NL, BE and both Danish areas in both scenarios can be found in appendix 8.7.

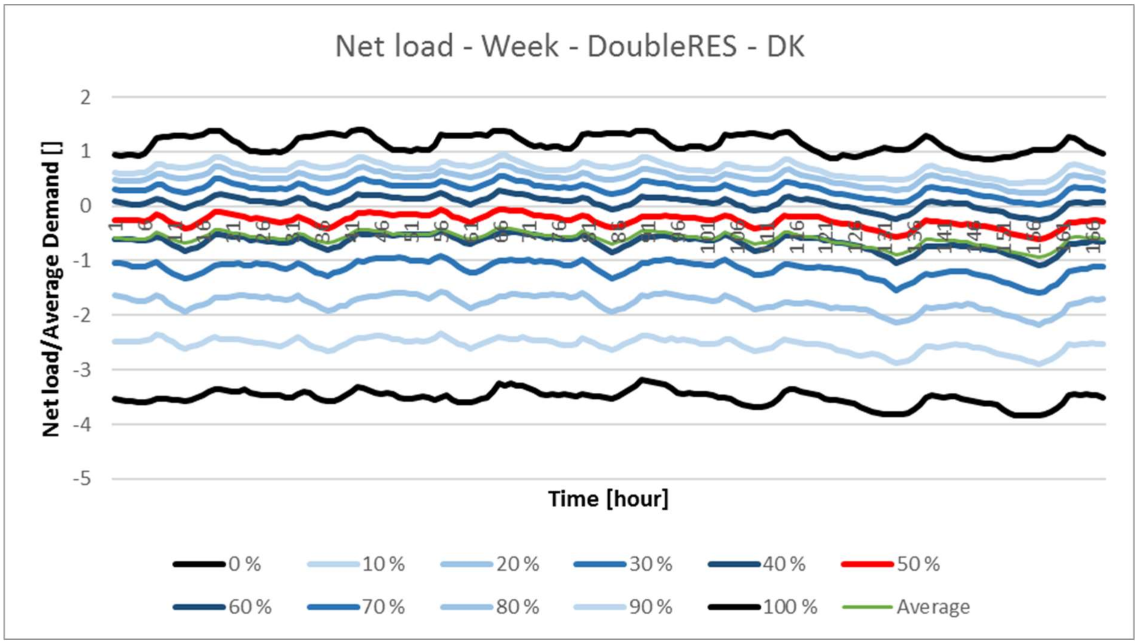

Figure 35: Net load of the two Danish areas combined – DoubleRES.

DE represents a type of area with mixed RES production, i.e. a considerable share of both solar and wind power. Another similar area is IB, although its ratio between installed solar power and installed wind power is tilted more towards solar power. DE has almost no seasonal variation in the average net load in V4-16, as seen in Figure 36. Although the spring average net load is slightly lower than that of the rest of the year, the cause is discussed in the the sinusoidal analysis in subchapter 4.2.1. In DoubleRES on the other hand, the summer average net load is higher than the winter average net load - Figure 37. Note how the distance between the percentiles in these figures are larger during winter than summer. Especially onshore wind contributes in this direction. A similar pattern is found on in Denmark - Figure 33.

From Table 5, DE produces 96 % of its energy demand through RES. This picture is confirmed from Figure 37. An inescapable consequence is the large negative net load that occurs in some hours. Figure 38 and Figure 39 identifies these extreme hours as noon, when the solar power produces at maximum. The week profile of the German net load in DoubleRES shown in Figure 39, has a similar average as Norway - Figure 31. Both include lower net load during weekend, and both have a long period of high net load and a short period of low net load each day. Although with a major difference, the short period of low net load happens during night in Norway and at noon in DE. In V4-16 the impact of solar power production is smaller. Figure 38 nevertheless shows that the noon DE net load is lower than that of the night. Also notice how there is a morning peak and an evening hump, a typical result of sizable share of solar power.

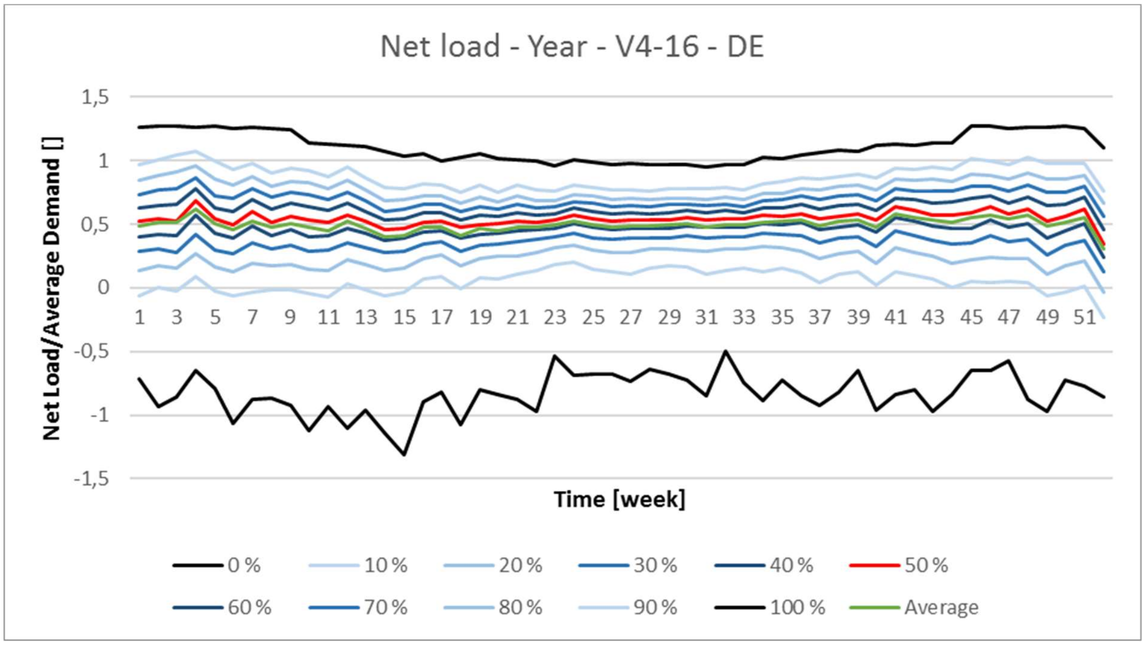

Figure 36: Net load DE – V4-16

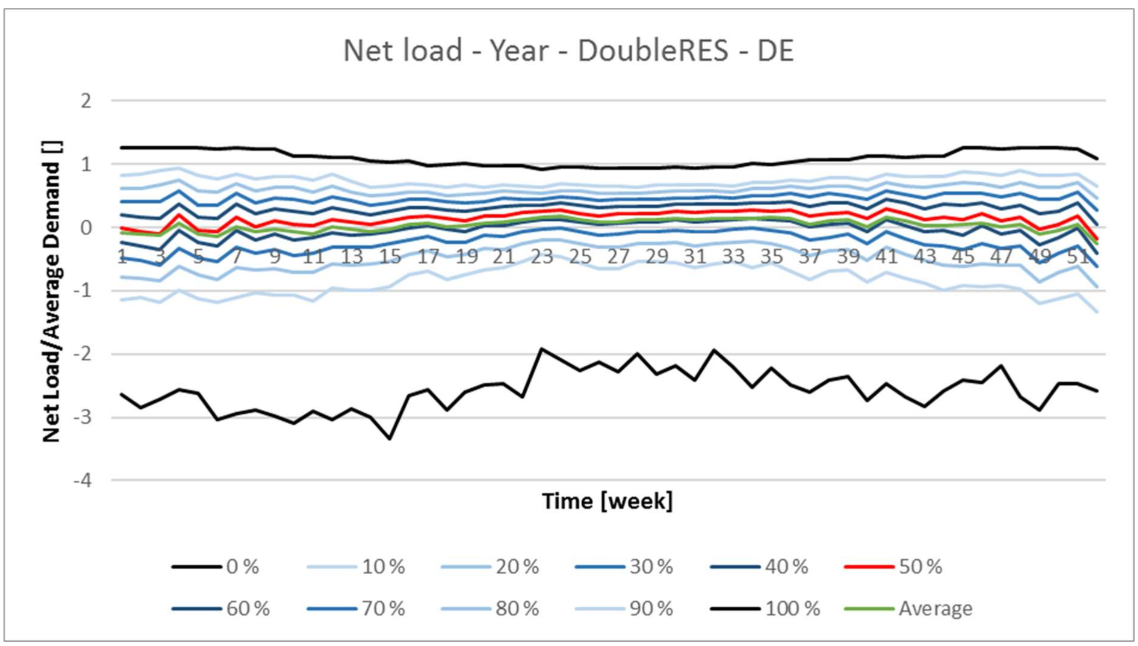

Figure 37: Net load DE - DoubleRES

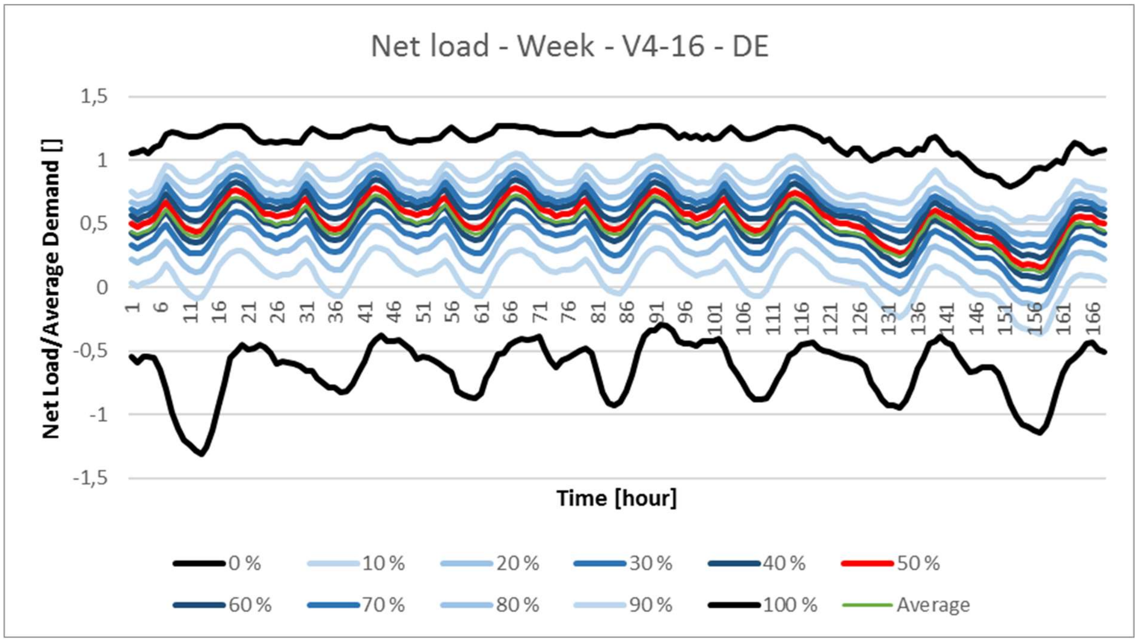

Figure 38: Net load DE – V4-16

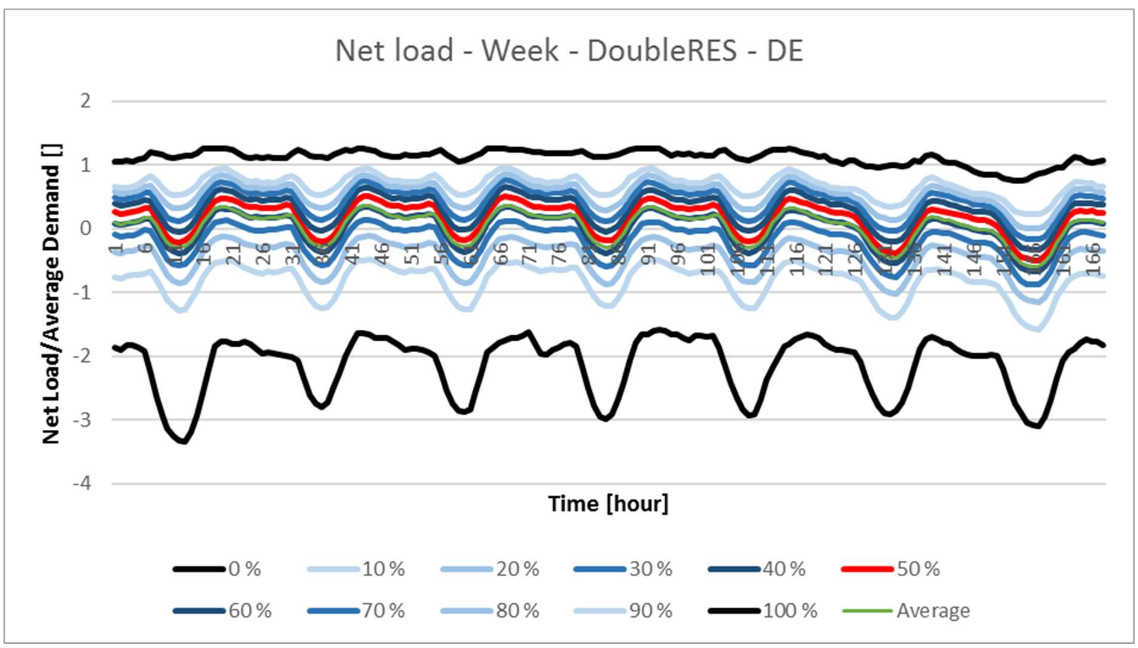

Figure 39: Net load DE – DoubleRES

4.2.3 Storage

We have seen how DoubleRES leads to a reduction of total net load of 49 % and a reduction of peak net load of 3 %, compared to V4-16. This subchapter will consider the possibilities of reducing the peak net load further with storage.

To help the description of this analysis, the concept "storage incident" is introduced. Firstly, net load cap is set. Secondly, all periods that exceeds the net load cap is identified. Thirdly, starting at the last hour of the year in the last inflow scenario, an algorithm counts backwards from the last hour to the first hour, starting at zero. 1 hour is used as the smallest time step in this analysis. When it comes across an hour which exceeds the net load cap, it adds the deviations from the net load cap in the subsequent (backwards in time) hours, until it reaches back to zero. When the algorithm is back to zero, it has found a storage incident. The storage incident requires in other words that the energy needed is drawn from the electricity grid, drawn from the grid before the net load cap is exceeded, and drawn from the grid as close in time to the time of the net load cap being exceeded. Important measures of a storage incident include how long it last, and how much energy was required to store, also called storage requirement. When a storage incident is connected to a time of the year, the last hour of the storage incident is the presented value. I.e. if a storage incident starts 1. March and ends 1. April, it will be shown on 1. April.

To assess the amount of storage needed in the system, we are interested in the storage incident with the highest storage requirement for a given net load cap. This is presented in Figure 40 for some selected areas. Note that eacy area is represented by one colour, the curve to the right is always the DoubleRES scenario. IB and GB is selected as they have a similar share of RES, 49 % and 58 % respectively in V4-16, while IB are more dominated by solar power than GB. In terms of Figure 40, the behaviour of GB and IB are similar. Although comparing V4-16, the IB curve is to the right of the GB curve, with GB having the highest share of RES. Indicating that solar power benefits more from storage than wind power. PL on the other hand have a low share of RES, and steeper behaviour in Figure 40. The reduction in peak net load will in other words be greater – keeping the amount of storage constant – when the share of RES is greater. This is also confirmed by every DoubleRES scenario being on to the right of their respective V4-16 scenario.

The red curves representing all areas, lies in between the PL on one side and IB and GB on the other. This is expected, as PL is one of the areas with the lowest share of RES, while IB and GB is one of the areas with high share of RES.

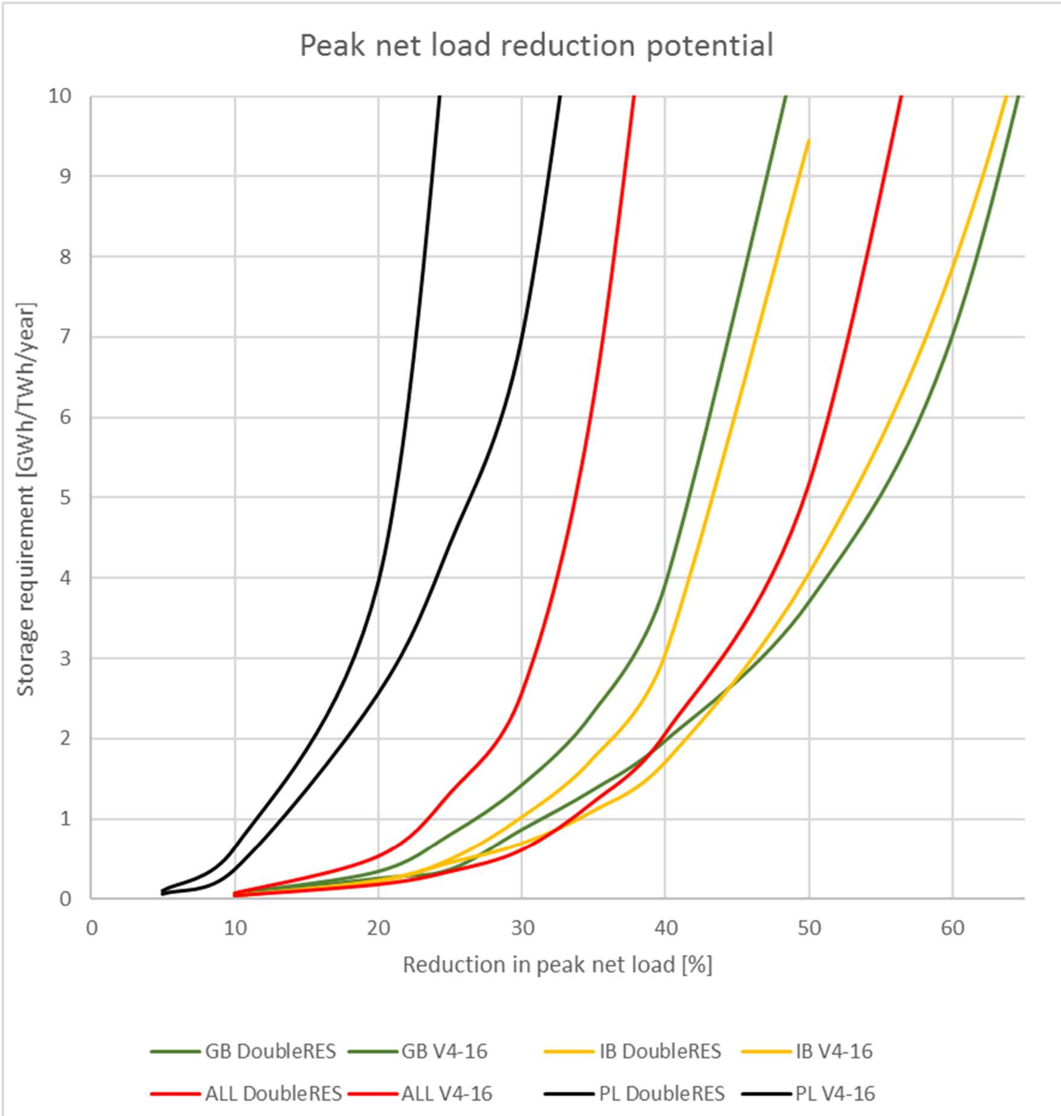

Figure 40: Peak net load reduction potential of selected areas. Each area is represented by one colour, the curve to the right is always the DoubleRES scenario.

To make sense of the y-axis of Figure 40, some comparative numbers is helpful. Hydro power reservoirs are both large scale and clean in terms of CO_2, meaning it represents one important storage technology that will be part of the future power system. The combined storage of the Norwegian hydro power reservoirs is 594 GWh per TWh of power produced in Norway each year. The equivalent number for Sweden is 232 GWh/TWh/year. Dividing the total of all hydro power reservoirs in all areas by the average yearly production in the all areas, gives 70 GWh/TWh/year. It should however be noted that there are limitations to the use of hydro power reservoirs. Especially in terms of transmission capacities, but also in terms of inflow uncertainty.

Other types of storage, which could be influential in the future power system includes batteries. If each German (not to be confused with each German household) installed a Powerwall battery pack of 14 kWh, it would result in a storage capacity of 2.04 GWh/TWh/year compared to the German consumption. From Figure 40, we have that storage of 2 GWh/TWh/year could reduce peak net load of the combination of all areas in DoubleRES by 40 %.

DE shows a slightly different behaviour in peak net load reduction potential than IB and GB. DE was not included in Figure 40 to make it easier to read. On the other hand, having familiarized with Figure 40, we can include DE, and not make it to complicated by focusing on DE and how it differs from the others. Figure 41 is exactly DE included to Figure 40. DE seems quite similar to ALL, but has a high storage requirement in the range of 10 % - 30 % reduction of peak net load. DE does however have a RES share of 50 % in V4-16, in other words close to the RES share of IB and GB. In terms of the balance between solar and wind power, DE is in between IB and GB. DE is however different from IB and GB in terms of demand. DE has less variation in the 100 % percentile of the week profile of the demand. This can be seen in appendix 8.7. Consequently, there are fewer low demand periods to break up the consecutiveness of the extreme hours where energy from storage is most needed, causing the German storage incidents to become longer and larger. Why DE has a different week profile of demand is outside the scope of this study. Low variation in the 100 % percentile of the week profile of the demand is also present in the Norwegian areas, the Swedish areas, FI, PL, CZ, BE, FR, CH, and AT.

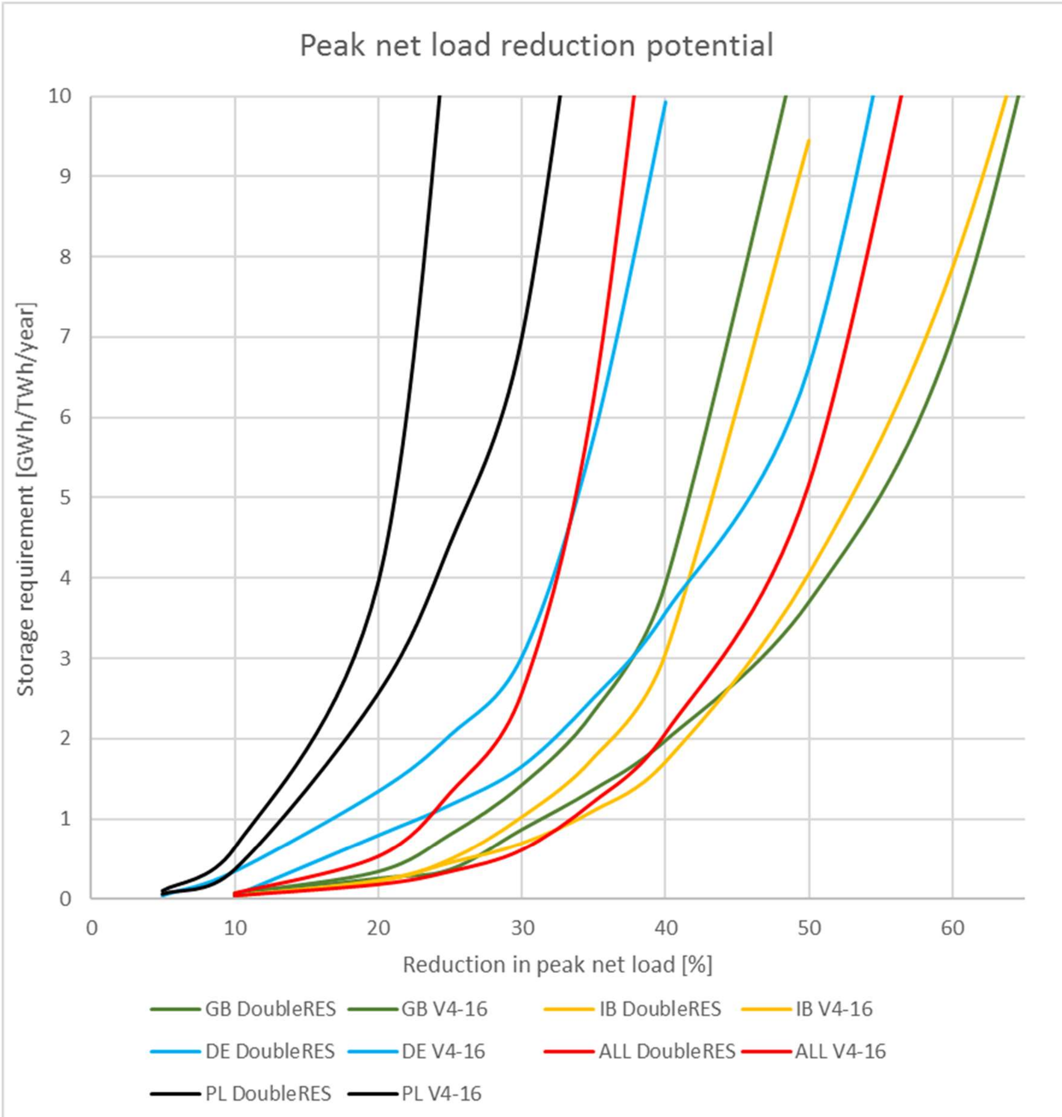

Figure 41: Peak net load reduction potential of selected areas. Each area is represented by one colour, the curve to the right is always the DoubleRES scenario.

To further increase the understanding of storage, knowing when the storage incidents happen and their size would be desirable. Firstly, the case of full utilization of all hydro power reservoirs is discussed. In V4-16 the storage incident with the largest storage requirement will be 70 GWh/TWh/year, when the net load cap is set to a reduction of 49,5 % from the peak net load. This can be seen in Figure 42. There is an accumulation of storage incidents with large storage requirement around week 10, i.e. from end of February to beginning of April. Most of them have a length between half a year and one year. This is, in other words, storage used to meet winter demand. In addition, there are storage incidents that last longer than a year, these naturally have the highest storage requirement. Figure 42 describes a storage usage not to differently from how Nordic hydro power reservoirs are used today.

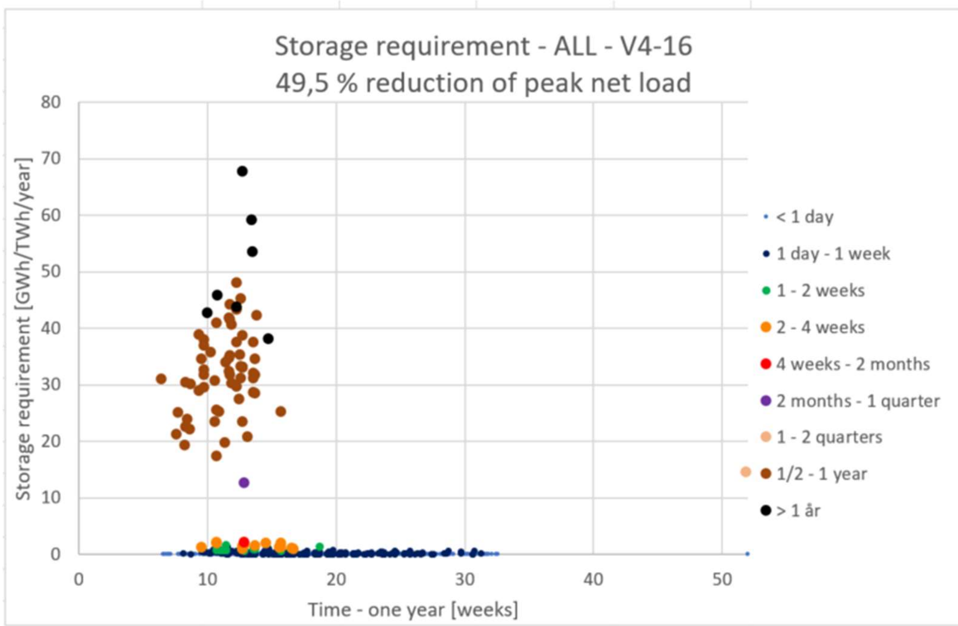

Figure 42: Storage requirement with a 49,5 % peak net load reduction – ALL areas, V4-16

In DoubleRES the storage incident with the largest storage requirement will be 70 GWh/TWh/year, when the net load cap is set to a reduction of 71,5 % from the peak net load. A considerably larger peak net load reduction than that of V4-16. The storage requirements at a 71,5 % peak net load reduction in DoubleRES are presented in Figure 43. In DoubleRES, the storage incidents lasting longer than one year are still present, and the storage incidents with the largest storage requirments happens around the month of march, but there are significant changes among the ½ - 1 year storage incidents. Their quantity in the 30 to 50 GWh/TWh/year range is significantly reduced. On the other hand, DoubleRES have more storage incidents at a storage requirement of 5 – 20 GWh/TWh/year throughout the year. Note how V4-16 have no storage incidents from week 35 to week 5. This is not the case in DoubleRES. In other words, the storage usage changes from V4-16 to DoubleRES, storage for the winter demand becomes less prominent in DoubleRES. This is in line with the reduction of seasonal variation of the average net load found by comparing Figure 13 and Figure 14.

Figure 43: Storage requirement with a 71,5 % peak net load reduction – ALL areas, DoubleRES

A problem left unaddressed is, if there are any differences between the countries regarding storage usage, and how long the storage incidents last. The following paragraphs will discuss the storage usage of different countries, specifically NO1, PL, DE, IB and GB. To get comparable results in areas with different share of RES, each area will be tuned to a maximum storage requirement of 6 GWh/TWh/year. The storage usage figures of these areas are included in the end of this subchapter where Figure 44, Figure 45, Figure 46, Figure 47, and Figure 48 corresponds to NO1, PL, DE, GB and IB respectively.

In NO1 an 11,2 % reduction in peak net load give a maximum storage requirement of 6 GWh/TWh/year. NO1 has a low reduction in peak net load per storage unit compared to other areas. This can be seen by comparing the 11,2 % reduction of peak net load at 6 GWh/TWh/year found in Figure 44 by Figure 41. NO1 would have a very steep curve in Figure 41. NO1 has a very different net load profile than PL, DE, IB and GB, with large seasonal variations. Consequently, storage incidents last longer for the same storage requirements compared to other area, and storage incidents are almost exclusively happening at winter time. PL, which is a cold winter low RES area, but in contrast to NO1, without a large share of run-of-the-river hydro power, has storage usage more like DE, GB and IB than NO1. Underpinning how different NO1 is from the other continental European areas.

Comparing PL with a low RES share on one side and DE, GB and IB with a high RES share on the other side. We observe that PL has a stronger seasonal difference in storage usage than the others, and that storage incidents of PL last longer for the same storage requirement.

Comparing GB and DE, where GB is more dominated by wind power than DE, we observe that storage is more needed in summer time in GB. Also, note the presence of summer time storage incidents lasting longer than a week in GB. They are not present in DE - or PL and IB.

Comparing IB to GB and DE, where IB has the highest share of solar power, we observe that the light blue storage incidents lasting less than a day, occurs at higher storage requirements in IB. In other words, indicating more need for day-night storage in a solar dominated area.

Also note how there is a significantly larger need for storage during winter than summer. This is despite the average net load almost has no variation throughout the year of DE and IB, and is larger in summer than winter in GB.

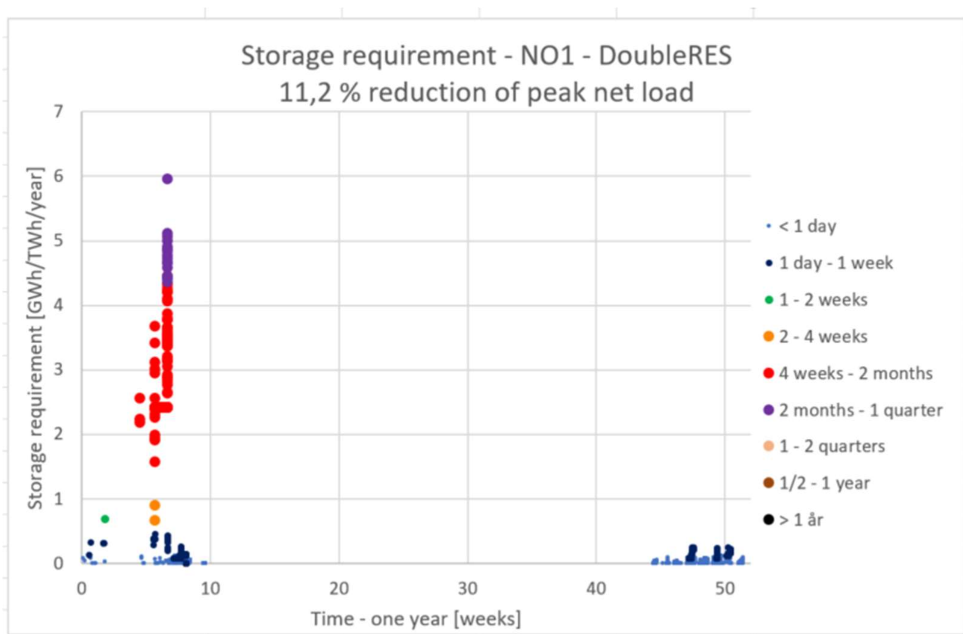

Figure 44: Storage requirement with a 11,2 % peak net load reduction – NO1, DoubleRES

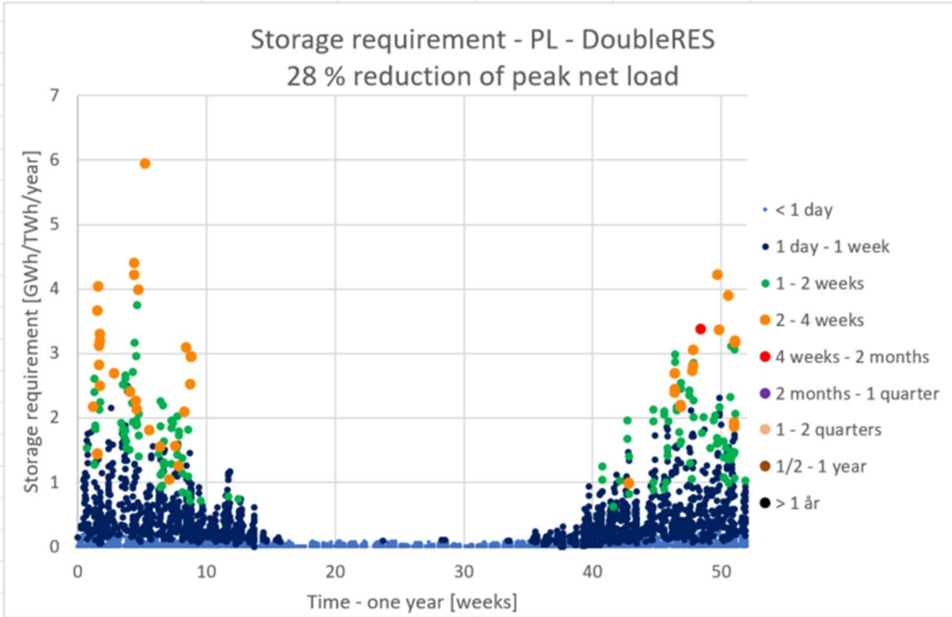

Figure 45: Storage requirement with a 28 % peak net load reduction – PL, DoubleRES

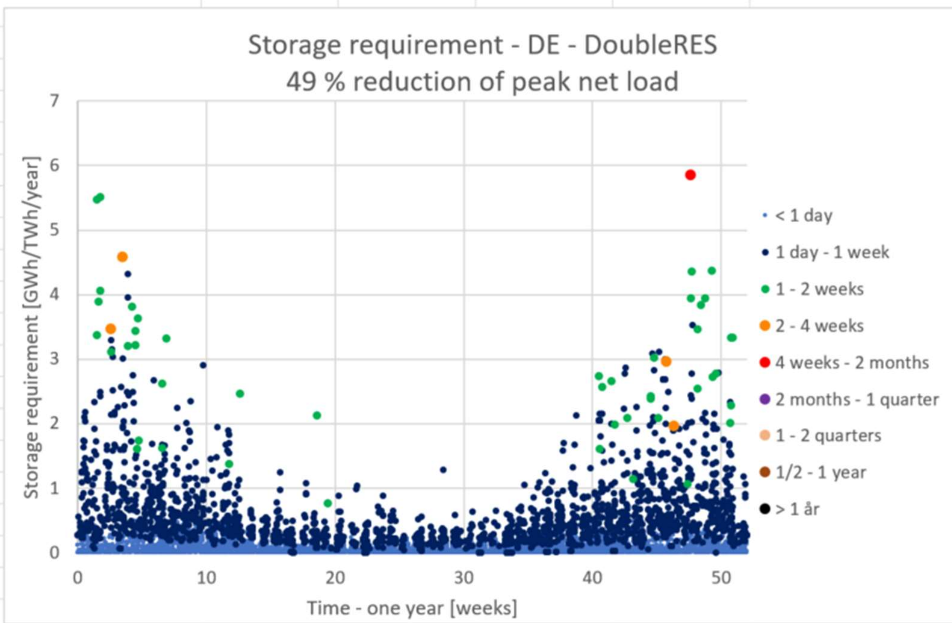

Figure 46: Storage requirement with a 49 % peak net load reduction – DE, DoubleRES.

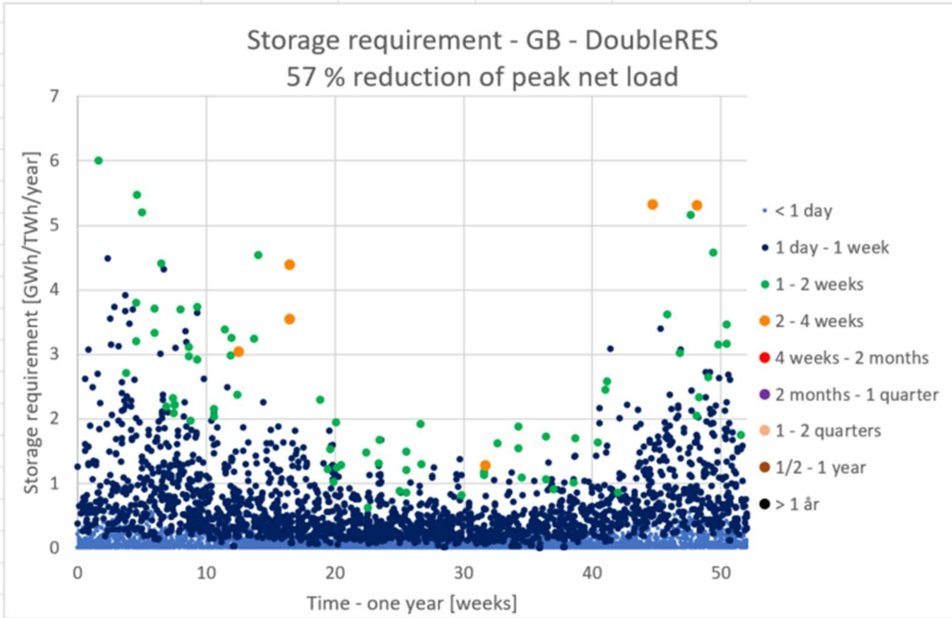

Figure 47: Storage requirement with a 57 % peak net load reduction – GB, DoubleRES.

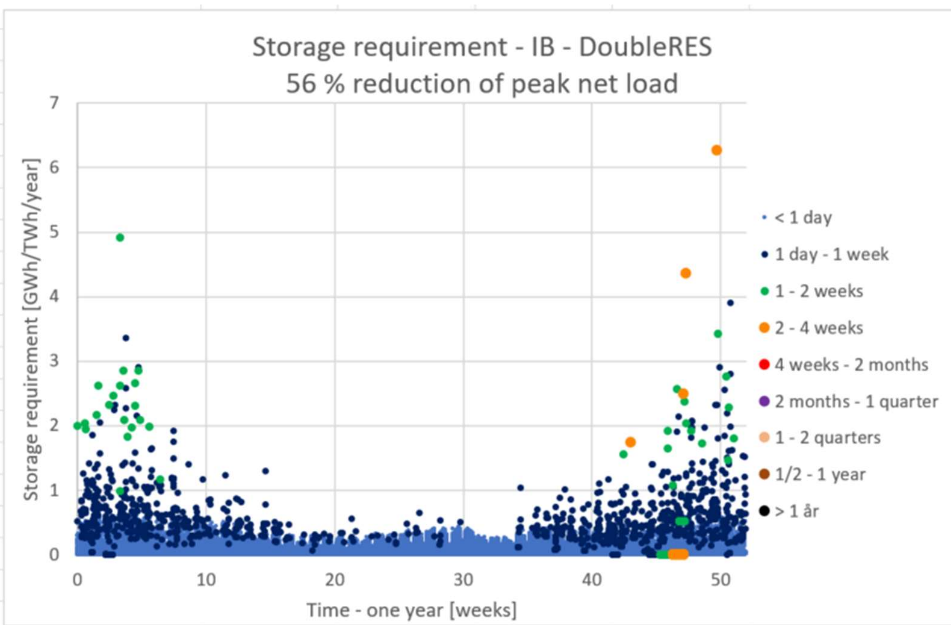

Figure 48: Storage requirement with a 56 % peak net load reduction – IB, DoubleRES

4.3 Reservoir levels

In this subchapter, some central reservoir level figures will be presented. All reservoir level figures can be found in appendix 8.7. The coherent calibration factors used to achieve these reservoir profiles is found in appendix 8.2.

All reservoirs in both V4-16 and DoubleRES has a seasonal pattern, where the reservoir is the emptiest in early spring, and fullest in summer. How strong this seasonal relation is, differs from area to area. SE3 is an example of an area where the seasonal relation is very strong. It's a trend that the seasonal relation is stronger in V4-16 than DoubleRES. AT has for instance a difference between the highest and lowest point on the 50 % percentile of 25 % of total reservoir size in V4-16, and 10 % in DoubleRES. This is also a trend in the Nordic area, although reservoir handling of V4-16 and DoubleRES are in many ways similar.

In the Nordic area, reservoirs are the most empty in week 17 to 19, and when overflow happens, it starts in between week 27 and 31, cf. Figure 49 and Figure 50.

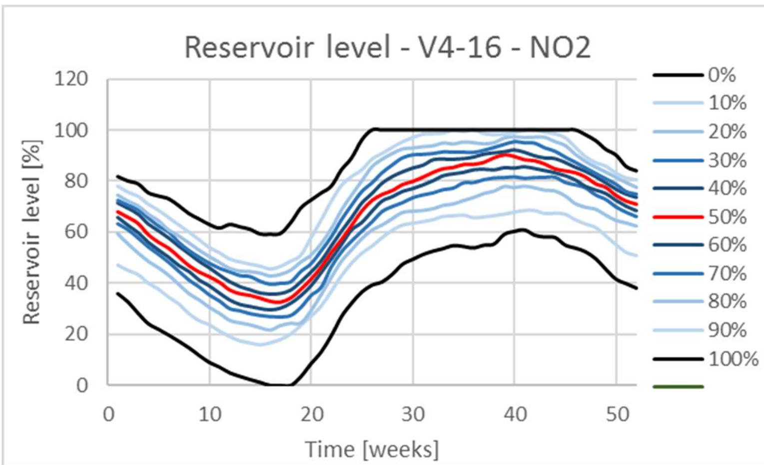

Figure 49: Reservoir level – V4-16 – NO2

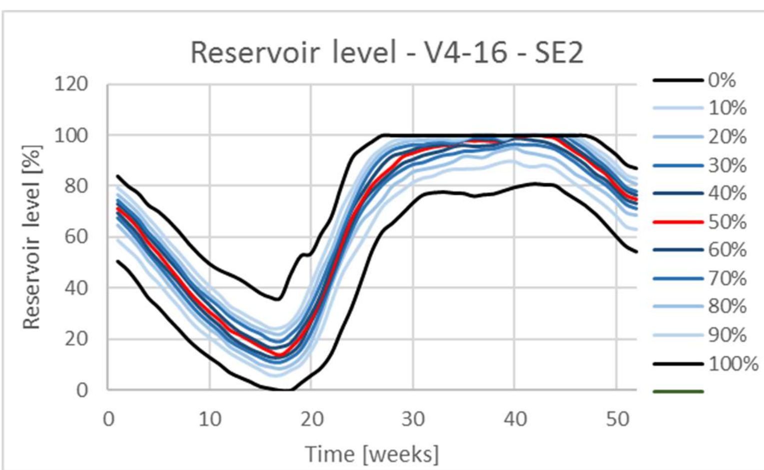

Figure 50: Reservoir level – V4-16 – SE2

CH and IT are the two areas where there is a considerable difference in the reservoir management of V4-16 and DoubleRES. These two areas are highlighted because calibration causes the difference. The differences in the reservoir management is in other words not a product of the differences in the scenarios. It is the reservoir management of V4-16 CH and DoubleRES IT, the author would like improved. The smallest possible modification of CH and IT in the two respective scenarios made the situation worse, therefore, the suboptimal solutions were used. The reservoir level of V4-16 CH and DoubleRES IT can be seen in Figure 51 and Figure 54. Their counterparts in the opposite scenarios is found in Figure 52 and Figure 53.

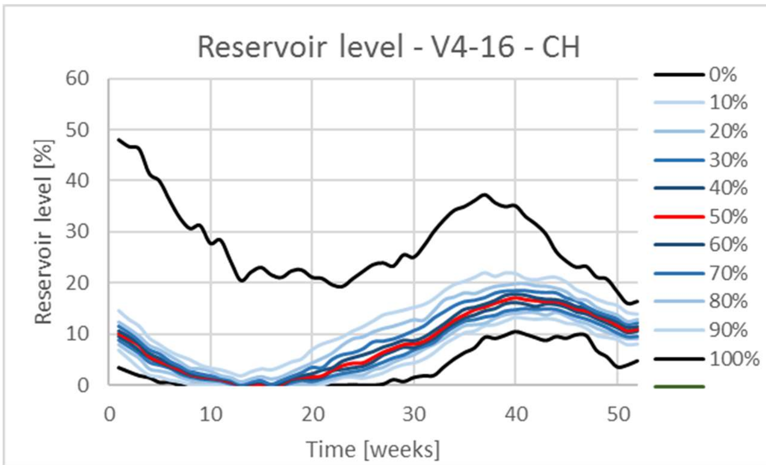

Figure 51: Reservoir level – V4-16 – CH

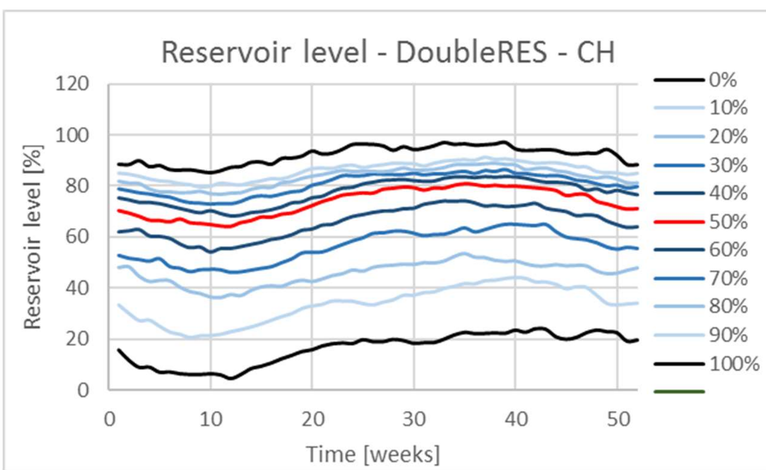

Figure 52: Reservoir level – DoubleRES – CH

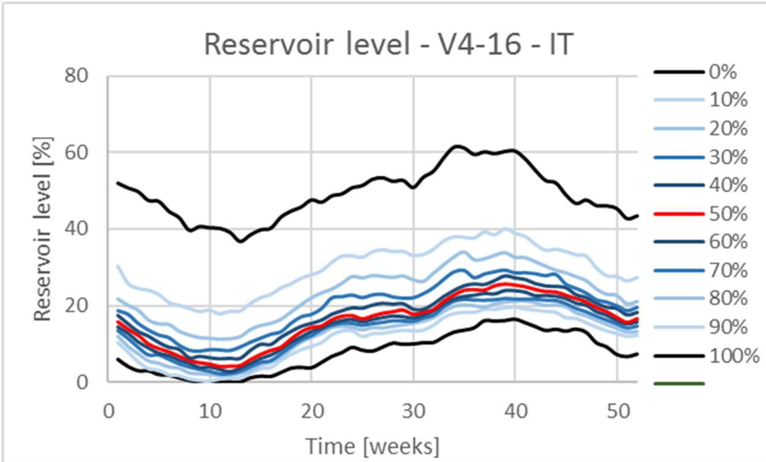

Figure 53: Reservoir level – V4-16 – IT

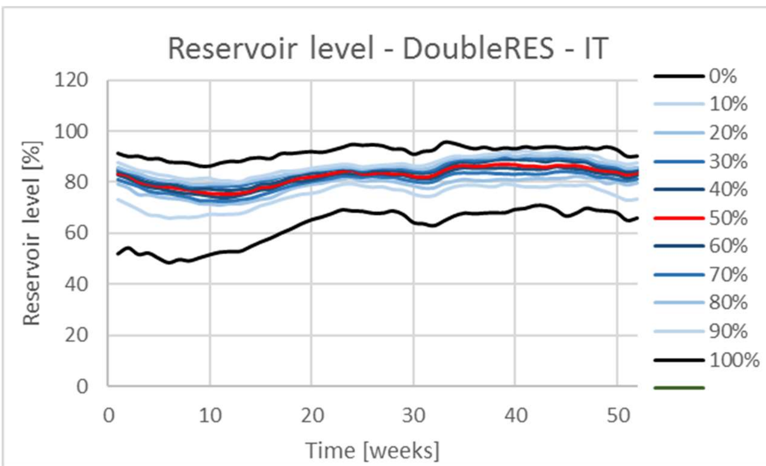

Figure 54: Reservoir level – DoubleRES – IT

4.4 Power prices and power flows

This subchapter will present result from the EMPS model regarding power flow and power prices, as well as identifying power surplus and deficit areas at different price periods. Week profile and year profile power price figures for all areas in both scenarios can be found in appendix 0.

4.4.1 Average situation

Production as a percentage of demand was presented for all areas in Table 4 and Table 5 for V4-16 and DoubleRES respectively. These data are important to understand the dynamics in the power market, and a derivative of them is therefore presented again as production surplus in Figure 55. This figure identifies power surplus and deficit areas as well as present the difference between the two scenarios.

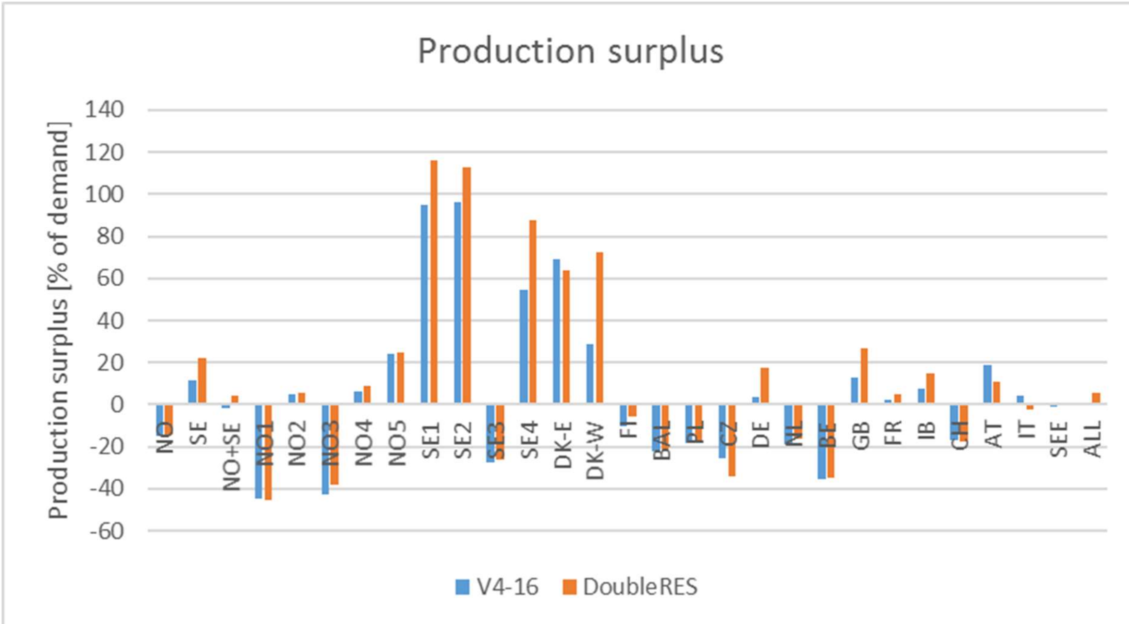

Figure 55: Average production surplus for all areas, including Norway, Sweden and the combination of the two, as a percentage of that areas average demand.

From Figure 55 we see that SE1, SE2, SE4 and the Danish areas, are large surplus areas, while NO1, NO3, SE3. FI, BAL, PL, CZ, NL, BE, and CH have considerable power deficit. Even though not large on Figure 55, due to the size of their demand, the surplus from DE, GB and IB are large in absolute terms, and will be influential.

All the Norwegian areas combined has, as seen on the figure, a power deficit, while the Swedish areas have a combined surplus. The Norwegian power deficit is 15 % of demand in V4-16, with a yearly demand of 146 TWh/year, this is equivalent to 22 TWh. Sweden on the other hand has an almost equal surplus, which means the power surplus of the combination of Sweden and Norway is almost neglectable.

The classification of power surplus and deficit areas does not change significantly from V4-16 to DoubleRES. The most typical pattern is that areas get larger surpluses in DoubleRES than V4-16. This is a symptom that more power production is curtailed in DoubleRES than V4-16. This can also be seen on the ALL bar to the right on Figure 55. The areas that sees the largest surplus increase is the areas with the largest share of RES, due to the way the DoubleRES scenario is created. CZ and IT sees a reduction in power surplus, thermal power generation in these countries are in other words losing the competition to produce.

The values in Figure 55 of the Norwegian, Swedish and Danish areas (NO1 to DK-W) are larger than those of the rest of the European areas (FI to SEE). One major cause, is that

European countries typically has a policy of or close to power self-sufficiency, while the three Nordic countries are divided to make the largest bottlenecks appear on the borders. Consequently, the areas of the grid with power surplus and power deficit are typically separated into different nodes. There are in other words no policies to make NO1 self-sufficient with power.

We would expect power surplus areas to have lower prices, and power deficit areas to have higher prices, as power flows from lower to higher prices. Where the magnitude of the price difference is linked to the limitations in transmission capacity. Figure 56 shows the average power prices for all areas.

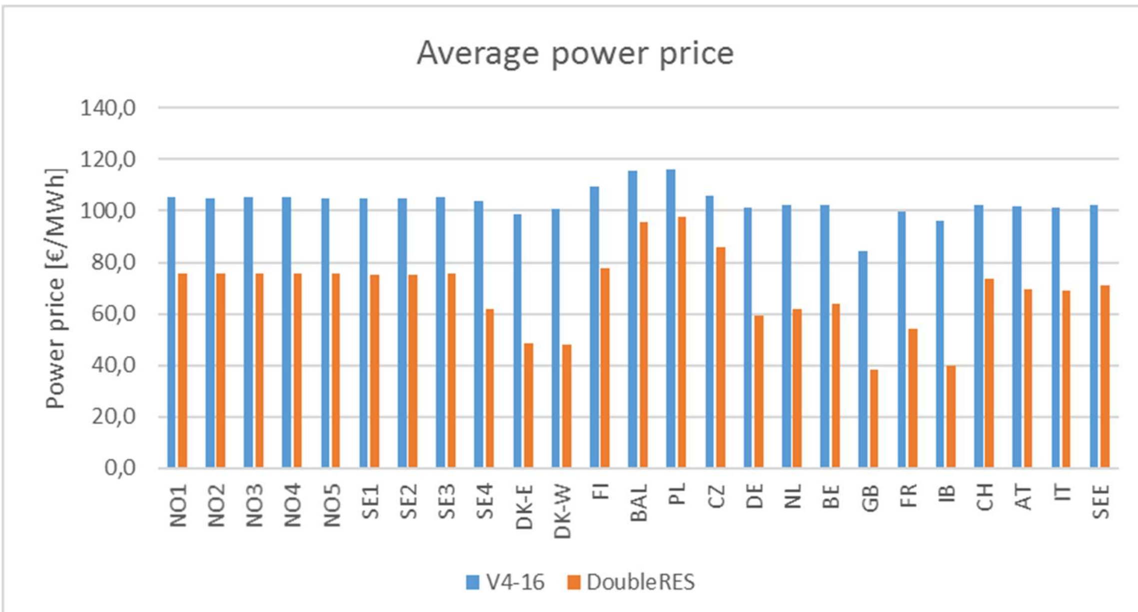

Figure 56: Average power price for all areas.

Immediately we identify the deficit areas BAL and PL to have the highest prices. Their neighboring deficit areas CZ and FI, also have higher than average prices. On the other side, we identify GB and IB to have lower prices than their adjacent nodes, while being surplus areas, this is also almost the case for the Danish areas, but they import from GB. GB is in fact the node with the lowest prices. The deficit areas NL, BE and CH has higher prices than their neighbors. Within the Norwegian and Swedish areas, the price differences are minimal, indicating small limitations in transmission capacity. All observations mentioned by this paragraph applies to both V4-16 and DoubleRES. How the prices compare across areas are remarkably similar in V4-16 and DoubleRES, the prices are however significantly lower in DoubleRES than in V4-16 across all areas.

The 5 Norwegian areas, as well as SE1, SE2 and SE3 has very similar prices. One interesting question to understand the future of the Nordic power market is how this area constellation compare to their neighboring areas in terms of prices. This area constellation has 7 adjacent nodes: GB, NL, DE, DK-W. DK-E, SE4, FI. Of these 7 adjacent nodes, FI is the only node to have higher prices than the constellation of Norwegian-Swedish areas in both V4-16 and DoubleRES.

To see the implications of the power flows, we use a map. Reading the explanation of the map in appendix 8.4.1 is a prerequisite to understand the map, and what information it displays. Not all information readable from the map will be discussed in this subchapter, the focus will be the power flows and deficit/surplus areas.

Figure 57 is a map showing a snapshot of the average situation in V4-16. A discussion of its results follows the figure.

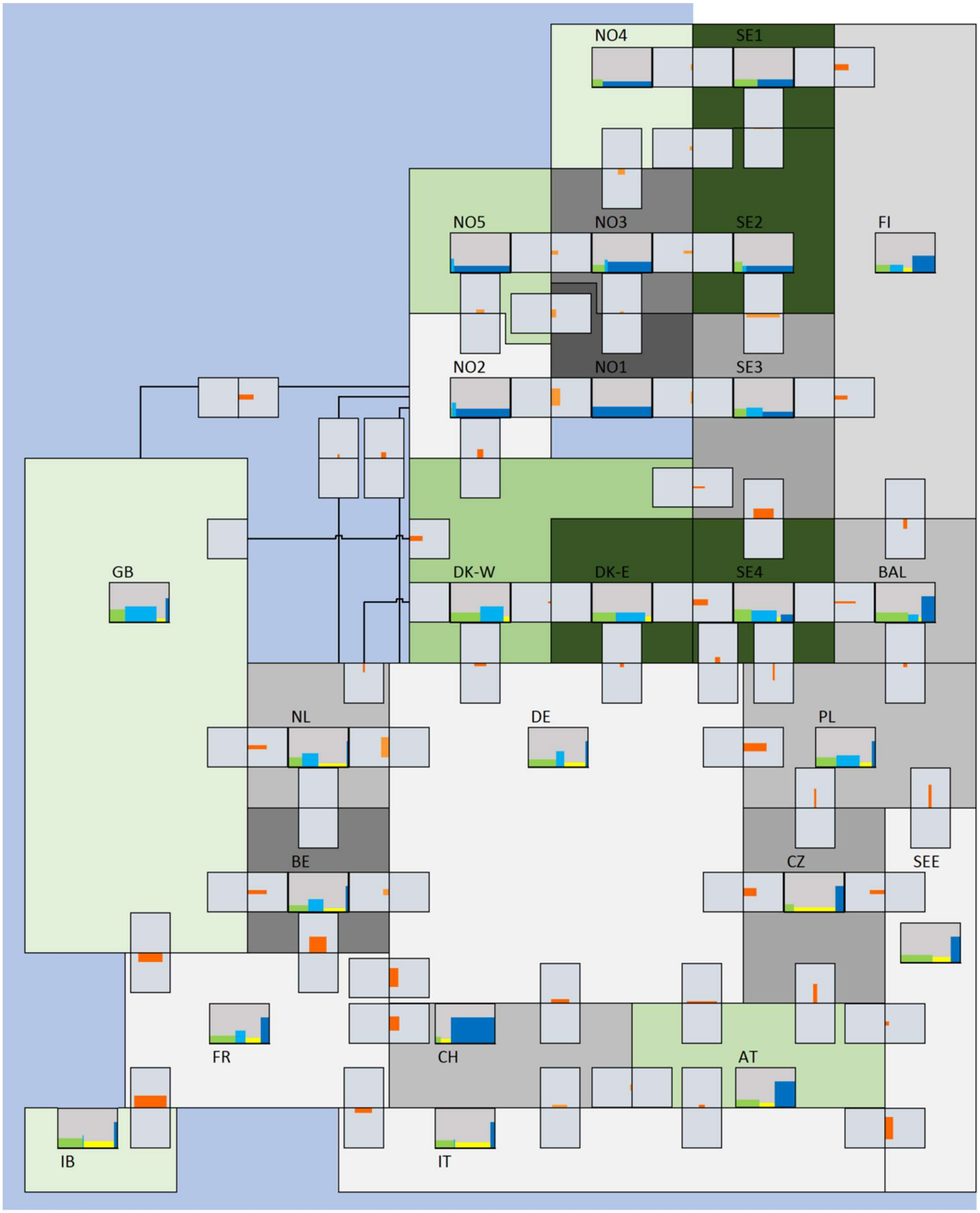

Figure 57: Map – V4-16 - All price periods

The background colour of the areas in Figure 57 resembles the production surplus displayed in Figure 55. PL, the area with the highest prices, has power flowing into it on all interconnections. FI, BAL and CZ, which are also deficit areas also acts as transit areas to PL. Other areas were power is only flowing inn includes NO3, NL, and BE. CH, although being a power deficit area, has power flowing to DE, this is the case even though the CH average price is higher than that of DE. On the other hand, power is flowing out on all interconnections from GB, IB, DK-E and SE1. GB and IB are both connected to FR, which acts as a transit area for cheap renewable energy from GB and IB. Consequently, the power price in FR is relatively low. Some of this power supplies the deficit of BE/NL and CH, while some flow towards PL through DE or IT and SEE. Surplus from DE also plays an important role in supplying the deficit areas of BE/NL and PL and its adjacent nodes.

In the Nordic area, power flows south from SE1 and SE2 to SE3. Additionally, SE4 plays an important role in supplying SE3, both by its surplus and import. SE1 and SE2 also supplies NO3 both through direct contact, but also by using NO4 as a transit area. NO2 imports power from all its sea cables, and exports to the deficit area of NO3-NO1-SE3. In addition to its own surplus, NO5, imports from NO2 to supply NO3 and NO1. Sweden supplies Norway, FI, BAL, and PL through all direct interconnections. Denmark does however supply Sweden. DK-W receives energy from the cheapest area – GB – and acts as a transit area and surplus area to support the NO3-NO1-SE3 deficit both directly and through NO2. Denmark also exports to DE.

As with the power prices and surplus/deficit areas, DoubleRES resembles V4-16 in many ways despite some differences. Figure 58 is a map of the average situation of DoubleRES, and is followed by a description of the main differences between Figure 57 and Figure 58.

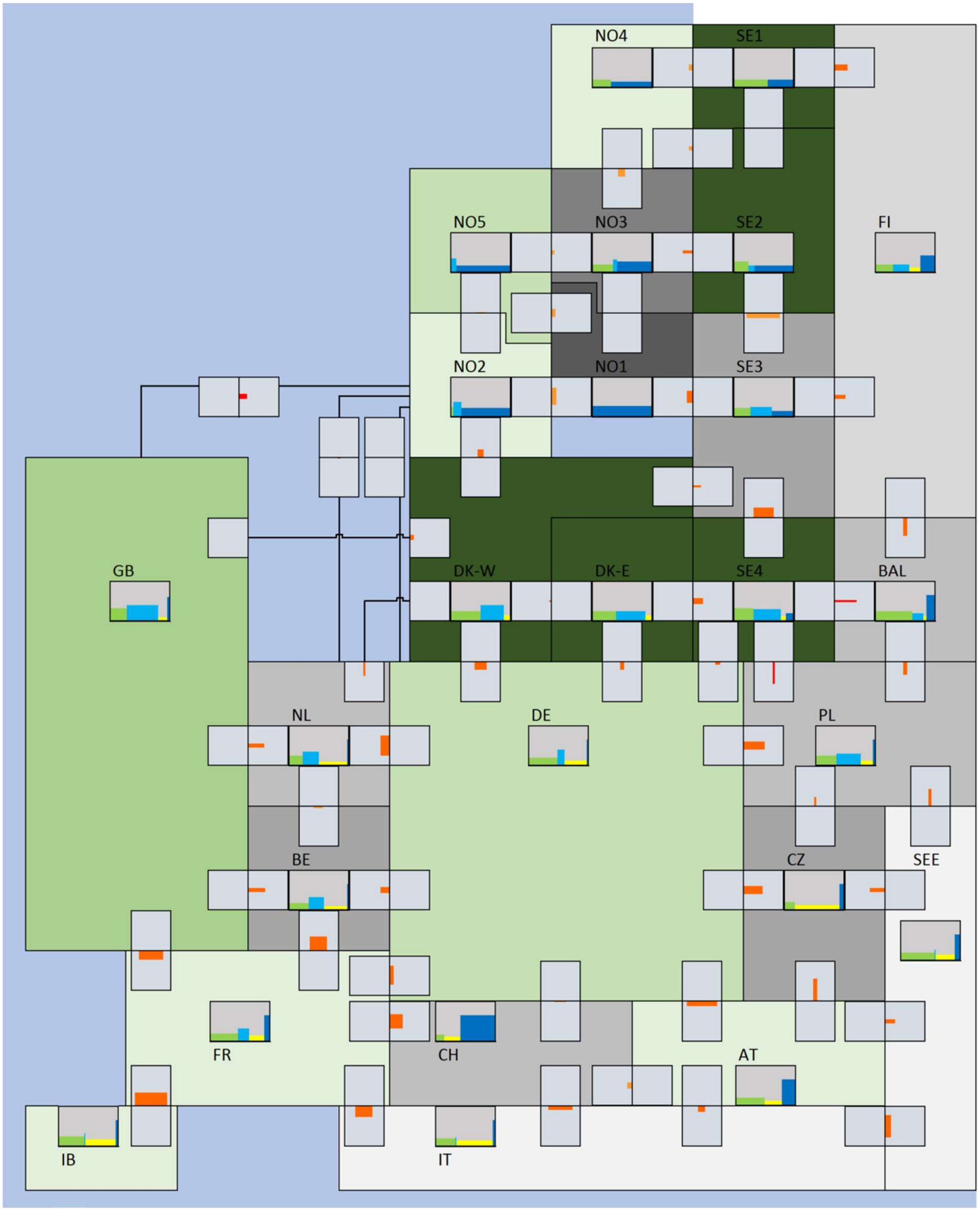

Figure 58: Map – DoubleRES -All price periods

As already described, the production surplus in DE, GB and IB is increased compared to V4-16. Despite this, GB is exporting less in DoubleRES than V4-16. Consequently, more power production is curtailed in GB in DoubleRES. IB on the other hand increases export slightly. The surplus in FR increases and it still functions as a transit area. However, the power flow from FR to BE and DE is reduced, while the flow from FR to CH and IT increases. The power production in IT is significantly reduced, and IT imports more. In DoubleRES CH and AT even functions as transit areas for power from DE to IT. Consequently, the amount of power flowing from FR through IT and SEE to PL is reduced. As the power surplus in DE has increased, the export from DE to BE and NL is increased at the expense of export from GB.

PL is still the highest priced area, but in DoubleRES more of the import is coming from SE4 and BAL, and less from DE, CZ and SEE. In DoubleRES SE4 does not work as a transit area for power from DE to PL any longer.

In DoubleRES Sweden exports less to FI, but FI exports more to BAL. Sweden does on the other hand export more to Norway, and the power flow to NO2 through the sea cables is reduced. In DoubleRES Denmark exports more to DE and less to SE4, while SE4 exports more to BAL ad PL.

4.4.2 Daily variations

This subchapter presents how the power prices change though the day. There are two main types of daily price pattern emerging in the result data. Firstly, the demand dominated price pattern, where there is a distinct difference between the higher prices during the day (Morning, afternoon, and evening), and lower prices during the night. Secondly, a solar dominated price pattern, where the lowest average prices occurs during the morning, and the highest average prices occur at evening. The more sun dominated the prices are, the lower the afternoon prices will be compared to the night prices. In the result data of this study, the solar dominated pattern influences areas with demand dominated price pattern to such that the morning power prices are lower than those of the afternoon and evening.

In Table 6, the average power prices of the night, morning, afternoon, and evening are shown for each area in V4-16. It shows that only FI, BAL, PL and GB has a demand dominated price pattern. All other areas have their lowest prices during morning. Looking at Norway and Sweden as a united area, we observe that their neighbouring areas, FI, BAL, PL, and GB all has a demand dominated prices. As the share of solar power in Sweden and Norway is very low, cf. Table 4, this price pattern is imported from the Netherlands, Germany, and Denmark. Note how small the difference between night, morning, afternoon, and evening power prices in Norway and Sweden are compared to other areas.

Table 6: Average power prices per country – V4-16. Colours shows the high and low prices within each area, where red represents high prices, and green represents low prices.

V4-16	Night	Morning	Afternoon	Evening
NO1	104,6	104,2	105,7	106,1
NO2	104,3	103,8	105,3	105,8
NO3	104,8	104,4	105,9	106,3
NO4	104,6	104,2	105,7	106,1
NO5	104,4	104,0	105,5	105,9
SE1	104,5	104,1	105,6	106,1
SE2	104,4	104,0	105,6	106,0
SE3	104,5	104,2	105,9	106,3
SE4	102,9	102,1	105,2	106,0
DK-E	96,5	94,6	100,2	103,7
DK-W	99,8	94,8	102,1	106,3
FI	106,0	107,6	111,9	112,0
BAL	107,5	114,0	120,7	120,2
PL	109,5	113,1	120,4	120,6
CZ	104,4	101,1	107,5	110,9
DE	100,8	94,4	102,6	108,1
NL	101,0	95,2	103,3	108,6
BE	101,7	95,8	103,3	108,6
GB	70,5	79,2	93,1	94,7
FR	99,8	93,0	100,3	106,2
IB	95,1	90,7	96,5	102,4
CH	102,0	96,4	103,3	106,8
AT	101,4	95,7	102,8	106,5
IT	100,8	93,7	102,7	106,9
SEE	101,5	95,7	103,8	107,6

In DoubleRES the solar dominated prices are even more profound, as seen in Table 7. In DoubleRES, BAL is the only area with demand dominated prices. The power prices of FI, PL and GB are still less solar dominated than other areas, but their lowest average prices are now at morning. Examining the colours of the night and afternoon columns in Table 6 and Table 7 reveals that all areas have more solar dominated prices in DoubleRES.

In DoubleRES the price differences between morning and evening in Norway and Sweden is larger than in V4-16. Not including SE4, the price difference was around 2 €/MWh in V4-16 and 6.5 €/MWh in DoubleRES. This pattern is also prevalent across the other areas.

Table 7: Average power prices per country – DoubleRES. Colours shows the high and low prices within each area, where red represents high prices, and green represents low prices.

DoubleRES	Night	Morning	Afternoon	Evening
NO1	76,3	72,2	76,5	78,7
NO2	76,2	72,0	76,4	78,6
NO3	76,2	72,3	76,5	78,6
NO4	75,8	72,0	76,2	78,3
NO5	76,1	72,1	76,4	78,5
SE1	75,3	71,4	76,1	78,2
SE2	75,3	71,4	76,1	78,2
SE3	75,4	71,6	76,3	78,4
SE4	62,0	53,9	62,8	68,3
DK-E	52,1	38,4	45,9	57,7
DK-W	52,5	33,9	45,7	60,4
FI	76,1	72,2	80,3	82,9
BAL	87,2	89,8	101,4	103,4
PL	94,4	88,7	101,9	106,3
CZ	93,2	63,4	87,0	99,5
DE	67,3	37,8	55,0	76,9
NL	68,3	41,4	57,8	79,2
BE	71,9	43,3	59,1	81,2
GB	36,4	30,6	40,0	46,9
FR	63,1	34,8	47,7	71,4
IB	40,2	30,8	36,5	52,9
CH	84,1	46,0	72,6	92,2
AT	78,8	43,8	68,3	87,6
IT	82,0	32,5	68,5	92,3
SEE	82,7	36,7	72,6	92,0

To show the effect of the power prices on the power flows, four maps showing the power situation in V4-16 of the night, morning, afternoon, and evening respectively, will follow this paragraph. A written description of the situation depicted by the maps, will follow the maps.

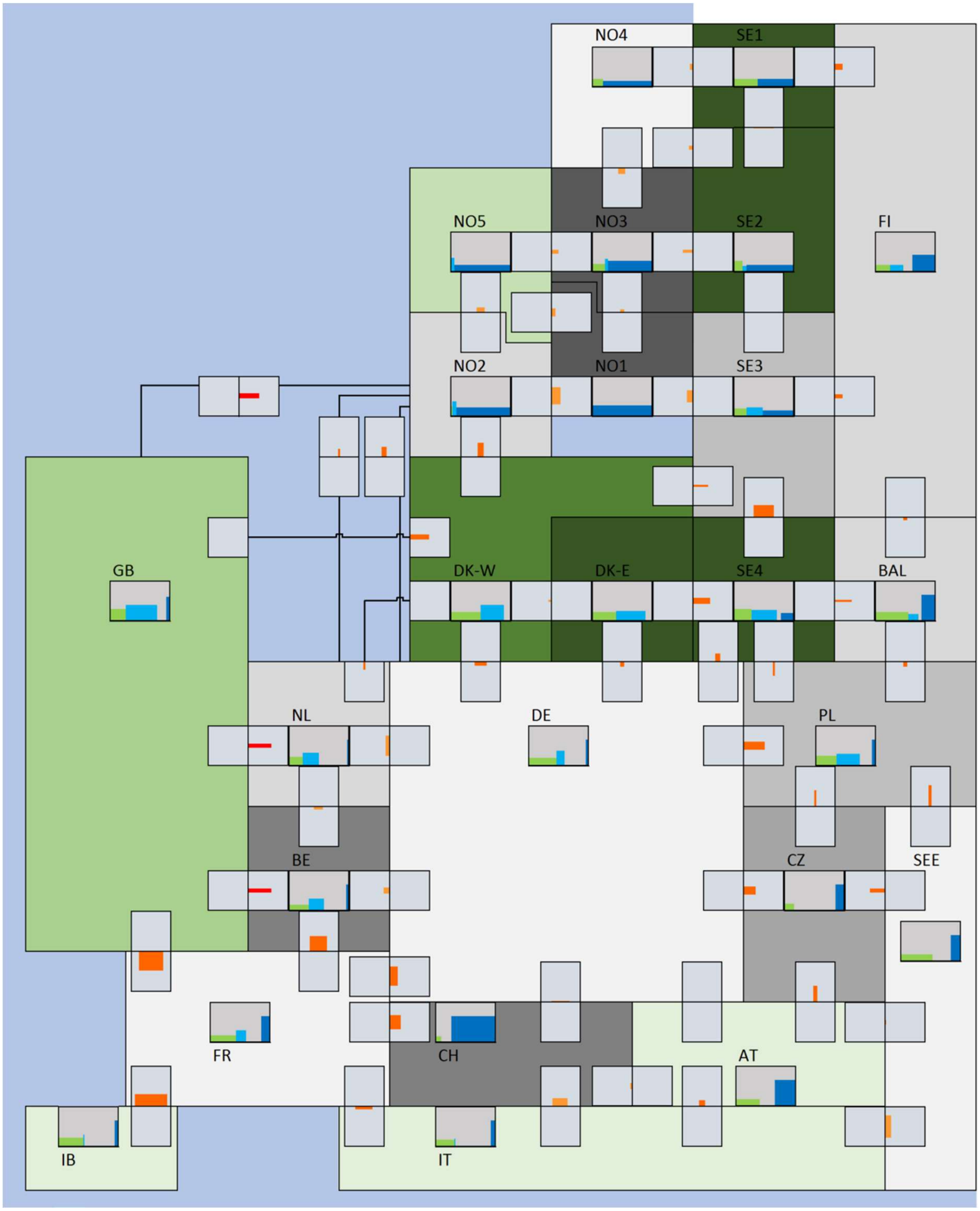

Figure 59: Map – V4-16 - Night

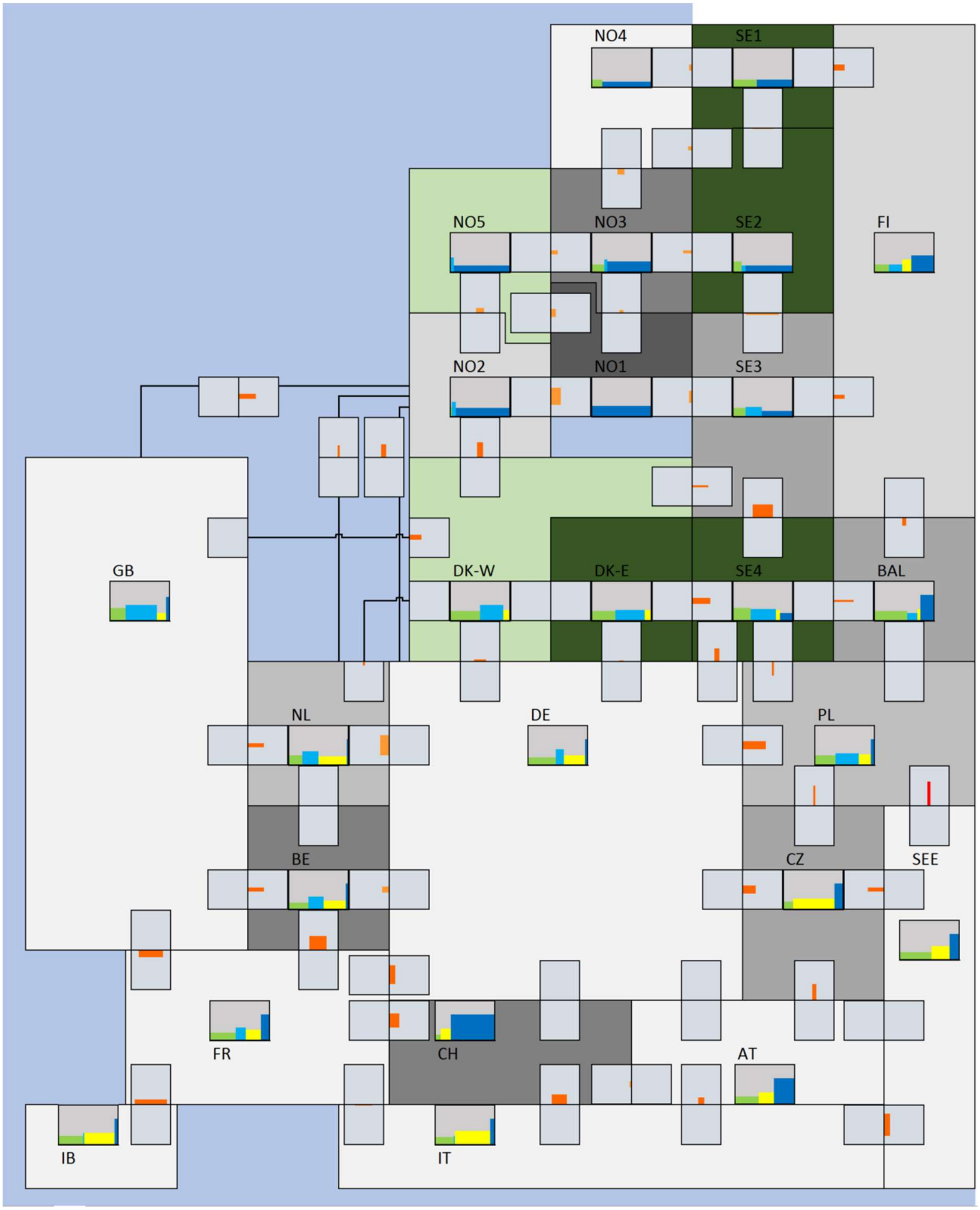

Figure 60: Map – V4-16 - Morning

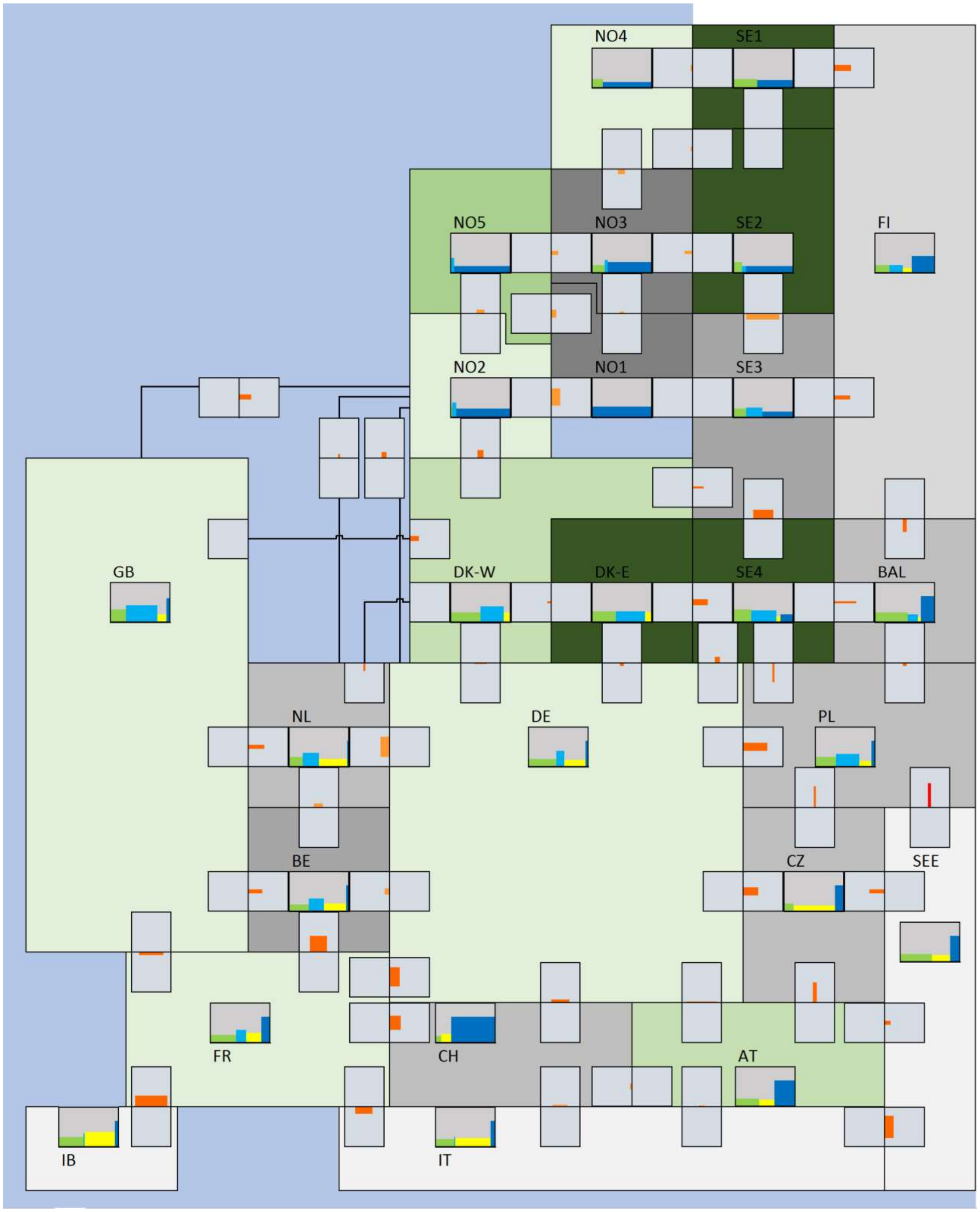

Figure 61: Map – V4-16 - Afternoon

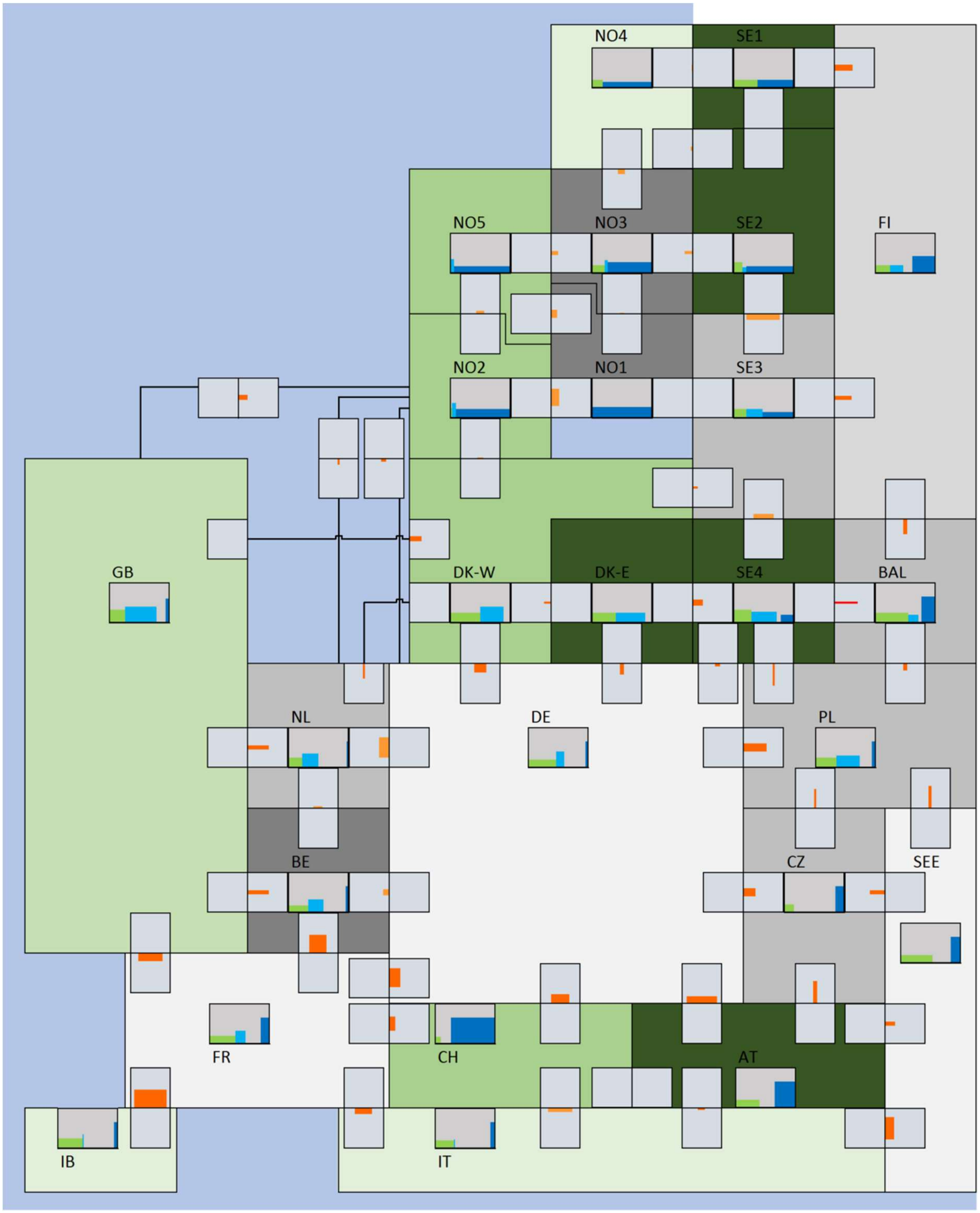

Figure 62: Map – V4-16 - Evening

Figure 59 to Figure 62 show several interesting dynamics of the European power system. First, while the transmission between the Norwegian areas barely change, all Norwegian areas are greener in the evening than at night. Additionally, the import to Norway is reduced from night to evening. Norway is in other word importing less, when the Norwegian power prices are high, thereby contributing to reduced price differences in neighbouring areas. Interestingly there is a difference between the NO2-GB cable on one side, and the NO2-NL, NO2-DE, and NO2-DK-W cables on the other. On the NO2-GB cable, the import to Norway is highest at night, followed by morning, afternoon, and evening. Thereby introducing a demand dominated prices pattern to NO2. On the NO2-NL, NO2-DE, and NO2-DK-W cables on the other hand, the import to Norway is highest in the morning, followed by night, afternoon, and evening. Introducing a solar dominated price pattern to NO2.

Sweden follows some of the same pattern as Norway, with export being highest at the evening, i.e. at the highest Swedish prices. The power flow on the interconnections between from SE4, DK-E, and DK-W to DE all contribute to reduce the solar domination of the power prices in DE. Or in other words increase solar domination of power prices in SE4, DK-E and DK-W. Also note how SE3 is supplied from SE4 during night and morning, while SE2 start to contribute more as the prices increase. In this way, more of the surplus of Denmark and SE4 can be exported to the south during the higher prices of evening.

The RES chart of each country shows minimal variations in wind, offshore wind, and run-of-the-river hydro power production for the four periods of the day. Solar power production on the other hand changes dramatically. The maps also show difference between east end west regarding solar power production in the morning vs the afternoon. In FI, PL, CZ, SEE, DE, AT and IT, solar power production is higher in the morning than afternoon. This is also the case in NL, BE, and FR even though the changes are smaller. IB on the other hand has higher solar production in the afternoon than in the morning.

In addition to the Nordic region, CH and AT contributes to reducing price variations in neighboring areas. They are both greyest when the prices are lowest and greenest when the prices are highest. They import significant amount of surplus solar power from IT during morning, and exports especially to DE but also to IT during the high price evening hours. Note that CH imports from FR at all periods.

GB is one of few areas with a demand dominated price pattern, as a result, its export is highest during night, followed by evening, morning, afternoon. This correlates to the power price in

GB, with high export at low power price. There is however one exception, the highest GB power price is at evening, thus the lowest export should be at evening. This is not the case because the solar power does not produce in the evening, thus creating an extra demand for export from GB. Note the similarities in how GB and DK-W changes background colour. Both areas with large share of wind power.

In the Table 6, we have seen that the highest average prices will be at the evening, not surprising considering the high evening net load for all areas found in Figure 15. The most prominent contributors to this high evening net load is DE, NL, FR, IB, IT and SEE, as can be seen in appendix 0. We have already discussed how the Nordics, GB and CH and AT is contributing to supply the high evening net load. Additionally, IB is contributing. In fact, IB is exporting most when its profound solar power industry does not produce any energy. This is contradictory, and needs a proper explanation.

IB is an area with a high RES-share where the amount of wind energy produced is roughly equal to the amount of solar energy produced. IB is a surplus area producing 8 % more than its demand in V4-16, and has one connection through the rest of the simulated area – to FR. IB has a lower power price than FR in all four periods of the day. Imagining a snapshot in time where the average power prices occurred, the IB-FR interconnection would transfer energy to FR at full capacity. For this power transfer to turn, the power price of FR needs to be lowered to a value below the IB power price, or the IB power price needs to be increased to a value above the FR power price.

The import from FR to IB seems to be correlated to the net load of FR found in Figure 146 in appendix 0. A net load that has its lowest values at morning, due to solar power production. This rises one important question, if the cause is that French solar power production lowered the French price below the IB price, why would not IB solar power lower the IB price even further? This is an especially intriguing question as there is 18.2 GW installed solar power in FR, compared to the 57.4 GW installed in IB. The answer can be found in the thermal supply curve of each area. The average prices of IB and FR is 96.2 €/MWh and 99.8 €/MWh respectively. That gives an average operating point 7.40 GW in FR and 33.22 GW in IB to the right of the jump caused by the CO_2-price. These numbers originate from the data that makes up the thermal supply curve of FR and IB, depicted in Figure 63 and Figure 64. 7.40 GW is for comparison 40.7 % of full solar production in FR, while 33.22 GW is 57.9 % of full solar production in IB. In other words, domestic solar power production would make the power price reduce below the jump caused by the CO_2-price in FR before it happens in IB. Another important factor is the interconnection capacity, which is 8 GW between IB and FR. The interconnection is in other words large enough to significantly change the French power price, thus making the amount of energy transferred depended on the situation in the French power market.

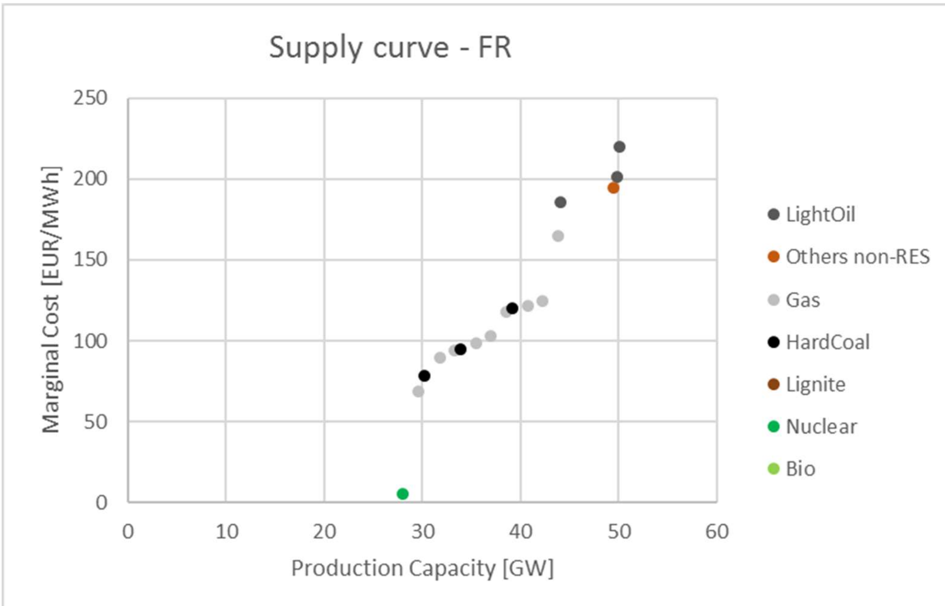

Figure 63: Thermal supply curve of FR

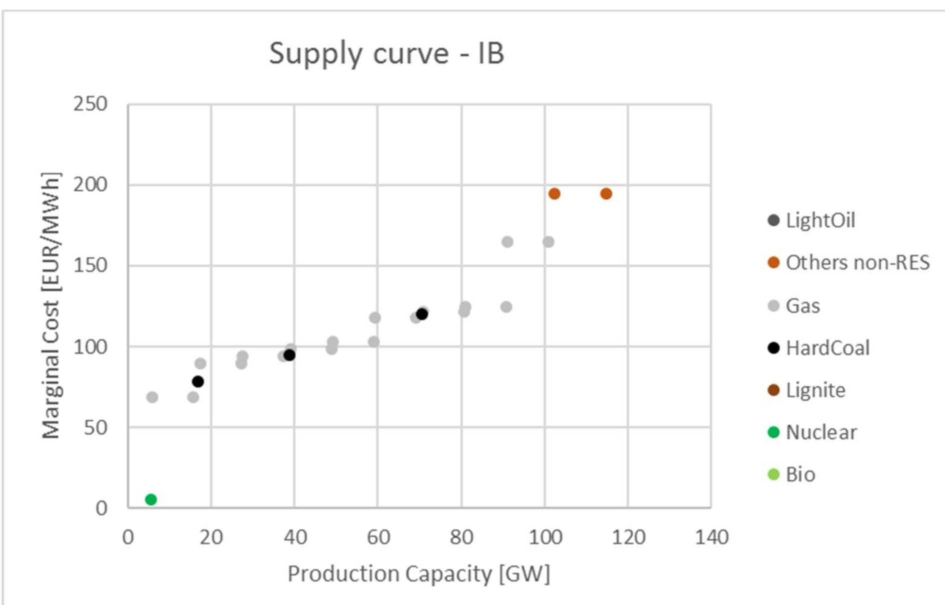

Figure 64: Thermal supply curve of IB

4.4.3 Seasonal variations

This subchapter will consider the seasonal variations in the power price, and the effect on the power flows. First, four distinctive price patterns represented by NO1, DE, GB and PL is presented for V4-16, then DoubleRES will be presented more thoroughly. The reason for this choice is that price variations are more prominent in DoubleRES, making them easier to spot. Then the power flows will be presented based on DoubleRES. Figures displaying the year profile of the power price for all areas in both scenarios can be found in appendix 0.

The four areas used to present the V4-16 power prices are chosen as they also represent other areas. I.e. the yearly power price profile of neighbouring areas is similar. NO1 has a similar yearly power price profile to NO2, NO3, NO4, NO5, SE1, SE2, and SE3, while DE has similar profile to NL, DE, FR, IB, IT, CH, AT, and SEE. Additionally, the yearly power price profile of PL and BAL are similar. Some areas have not yet been mentioned, most of these have a yearly power price profile that is a mix of that of NO1, DE and PL. SE4 and the Danish areas have a power price profile close to that of DE, but with a lower summer prices as seen in NO1. GB on the other hand has a yearly power price profile, unique to GB.

The NO1 yearly power price profile, seen in Figure 65, is a consequence of the net load profile combined with the hydropower system. When the inflow to the regulated and unregulated hydro power begins around week 17 the potential for close to zero prices opens. This does not end before precipitation starts to come as snow around week 45. In the period between week 17 and 45, the average price and the 50 % percentile is reduced compared to the rest of the year. How large this reduction is, is linked to the net load. The NO1 yearly power price profile also show a low variation in prices during winter and early spring compared to other areas like DE, PL, and GB. This is a consequence of an energy restricted and not power restricted system, with the amount of energy available well known in advance. The NO1 yearly power price profile has a spike or hump in the 100 % percentile around week 16, at the end of the depletion season. This is a consequence of emptying – or nearly emptying – the Nordic hydro power reservoirs. How high, and for how often high prices occur around week 16 is dependent on how aggressively the hydro power producers are utilizing their seasonal reservoirs.

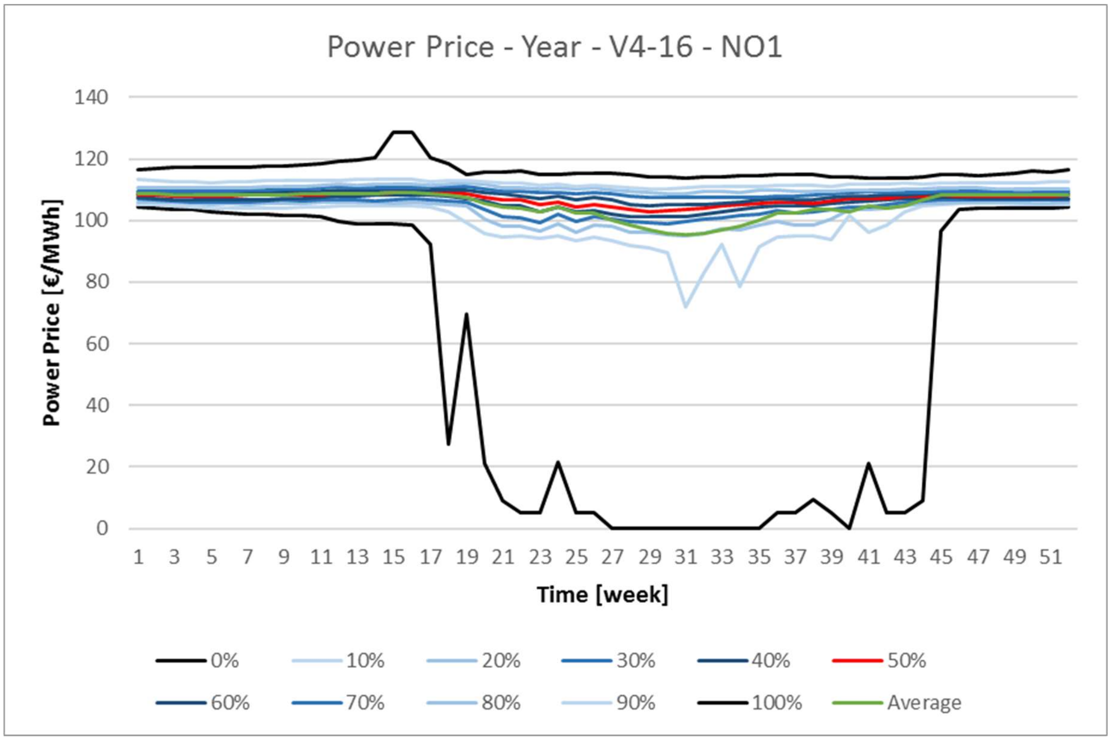

Figure 65: Yearly power price profile – NO1 – V4-16

The PL yearly power price profile, seen in Figure 66, is a product of a demand dominated, fossil fuel based power market connected to areas with large share of RES. PL has a strong seasonal variation in the power price, with high prices at winter and low prices at summer, resembling the seasonal variation in the PL net load seen in Figure 133 in appendix 0. Note how the 100 % and 0 % percentile have stronger seasonal variation than the 50 % percentile. Also note that the 0 % percentile of NO1 is high for a longer time during winter than the PL 0 % percentile. Consequently, PL can be surrounded by low prices during summer, but not in winter. In winter, there will not be low prices to the north from the Nordics through BAL and FI, contributing to the PL winter power price not falling below the jump caused by the CO_2-price. Also note that PL is the only area – of the four presented for V4-16 – which experiences power prices above 170 €/MWh. Additionally, BAL and FI experience power prices above 170 €/MWh. In other words, these are the only areas where the most expensive gas power plants ever get used.

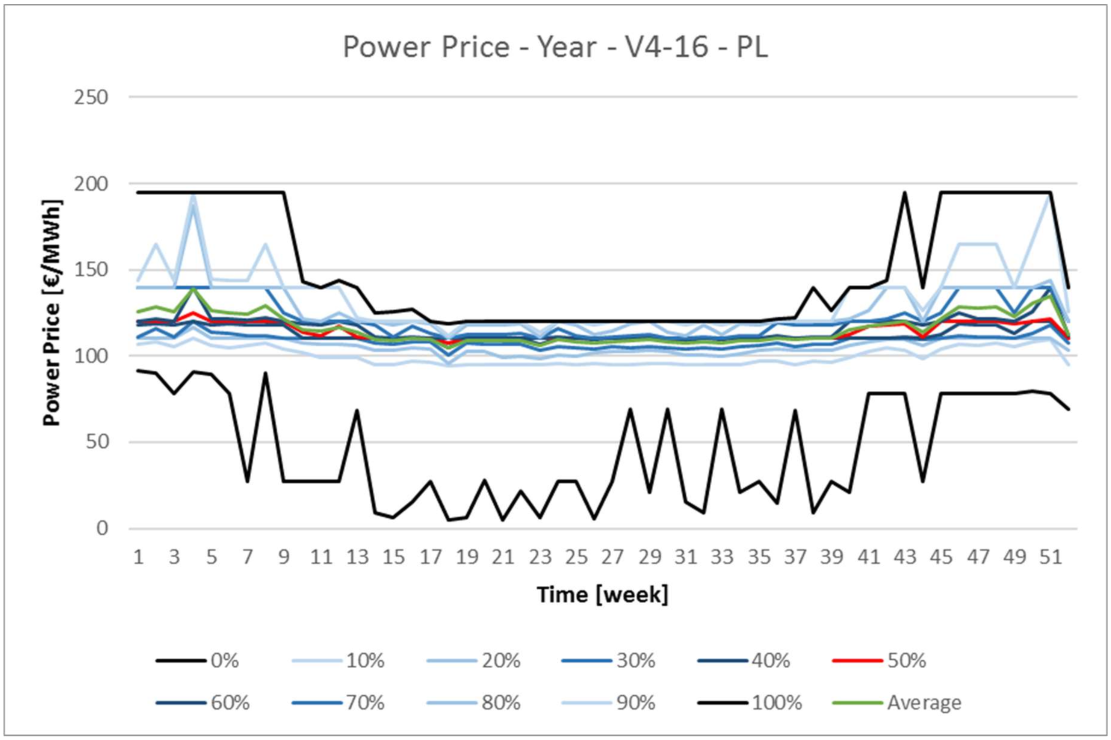

Figure 66: Yearly power price profile – PL – V4-16

The DE yearly power price profile, seen Figure 67, shows potential for zero prices through the whole year, potential for high prices in winter, highest average price in winter, and lowest average price in spring. The low spring prices are a consequence of the RES share and the balance between installed solar power and wind power as discussed in subchapter 4.2.1. Also note the short distance from the 50 % percentile to the 100 % percentile compared to the long distance from the 50 % percentile to the 0 % percentile. This is a consequence of the thermal supply curve jump caused by the CO_2-price, and an operating point normally to the right of the jump.

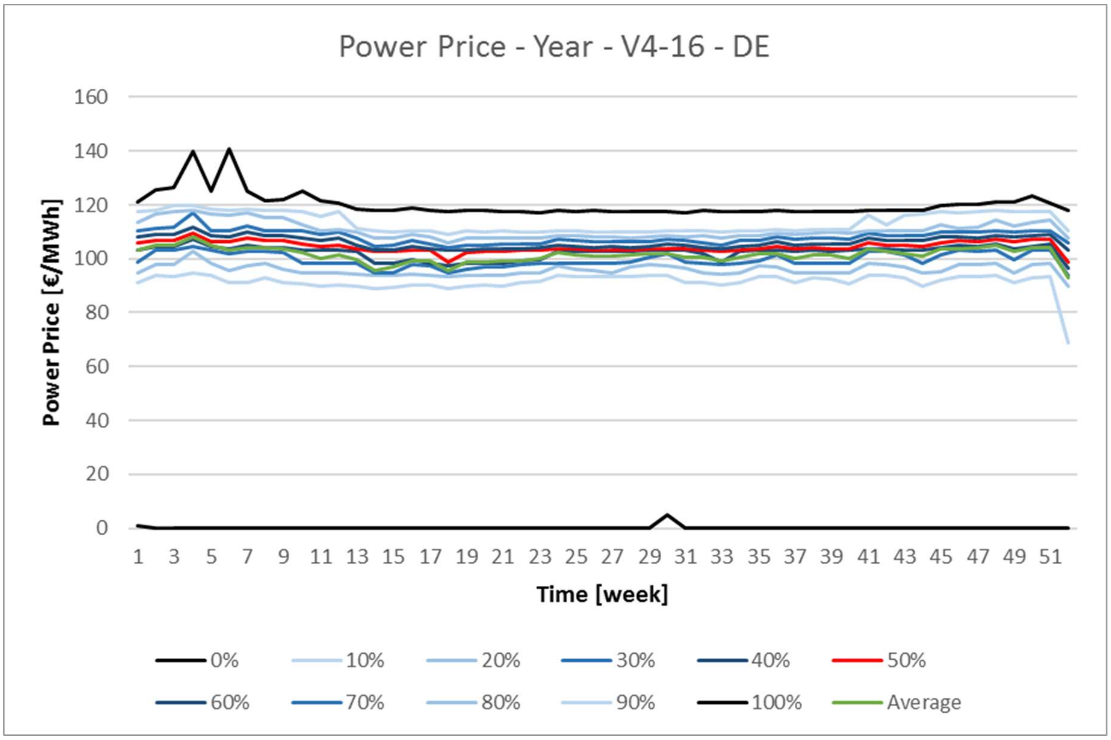

Figure 67: Yearly power price profile – DE – V4-16

The GB yearly power price profile, seen in Figure 68, has many similarities with the DE yearly power price profile. These include the 0 €/MWh 0 % percentile, the shape and level of the 100 % percentile, and the normal situation being closer to the 100 % percentile than the 0 % percentile. There are however also some differences. There is more variation in the GB power price, and the GB power price is powered without CO_2-emmiting power production more often than DE. A less central location, with less neighbouring areas, a lower amount of thermal power capacity at 46 GW compared to 69 GW and a larger share of RES of 58 % compared to 50 %, all works in that direction. Finally, GB has its lowest average power prices in autumn, in line with the GB average net load, seen in Figure 143. The low autumn power price is a consequence of GB having a low share of solar power, while having a perfect balance between demand and wind power (both on and off shore). This causes low autumn prices because wind power production increases towards high winter production earlier in spring than demand increases towards high winter demand. This shown in the sinusoidal analysis in subchapter 4.2.1.

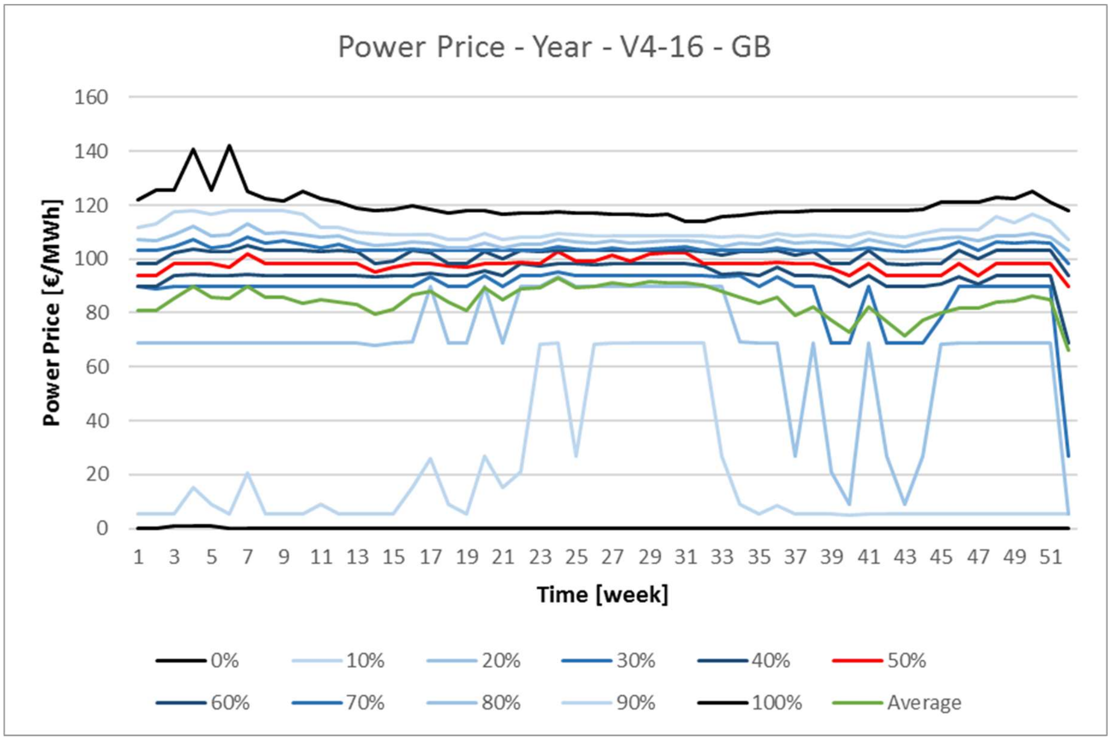

Figure 68: Yearly power price profile – GB – V4-16

In DoubleRES, as already seen, the net load and power prices are lower than those of V4-16. On the subsequent pages, follows a description of how this is visible in the yearly power price profiles of DoubleRES.

The NO1 power price profile is similar in V4-16 and DoubleRES, but has one major difference. In DoubleRES NO1 experiences lower average winter prices than in V4-16. In other words, the magnitude and frequency of low winter prices is higher in DoubleRES than V4-16.

NO1 and SE3 had similar yearly power price profiles in V4-16. In DoubleRES they still resemble, but now there are differences that makes it worth presenting both. The two price profiles are almost identical except for the extreme cases during winter. Where SE3 has potential for price increases in the middle of the winter, like the one in early spring. Additionally, the non-low winter prices we saw in V4-16 in Norway and Sweden is not present in DoubleRES SE3. This is a consequence of the situation in PL and FI. The yearly power price profile of NO1 and SE3 is shown in Figure 69 and Figure 70 respectively. In DoubleRES, the power price profile of NO1 represents all the Norwegian areas, while SE3 also represents SE1 and SE2.

Note that the lowest average power price does not happen at the exact same time as the inflow peak. The lowest average price in NO1 and SE3 happens at week 29, while the unregulated inflow peaks between week 21 and 27 depending on area. The lowest average price is however caused by the reservoirs in Norway and Sweden getting full. This can be seen in subchapter 4.3.

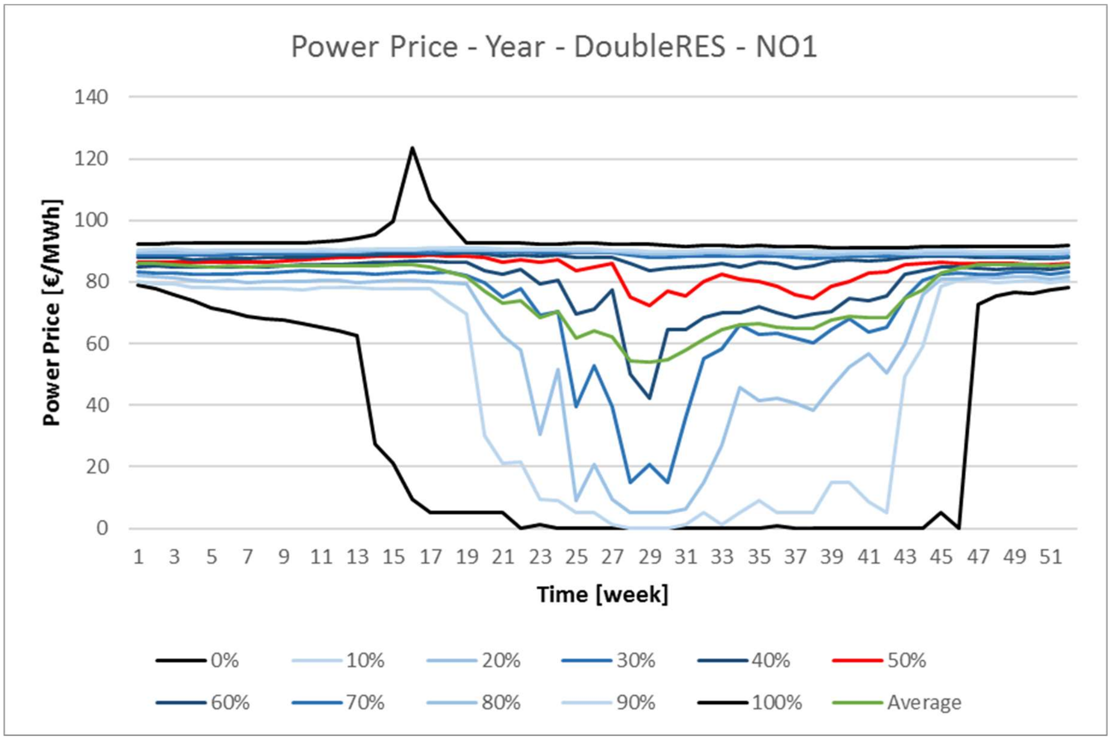

Figure 69: Yearly power price profile – NO1 – DoubleRES

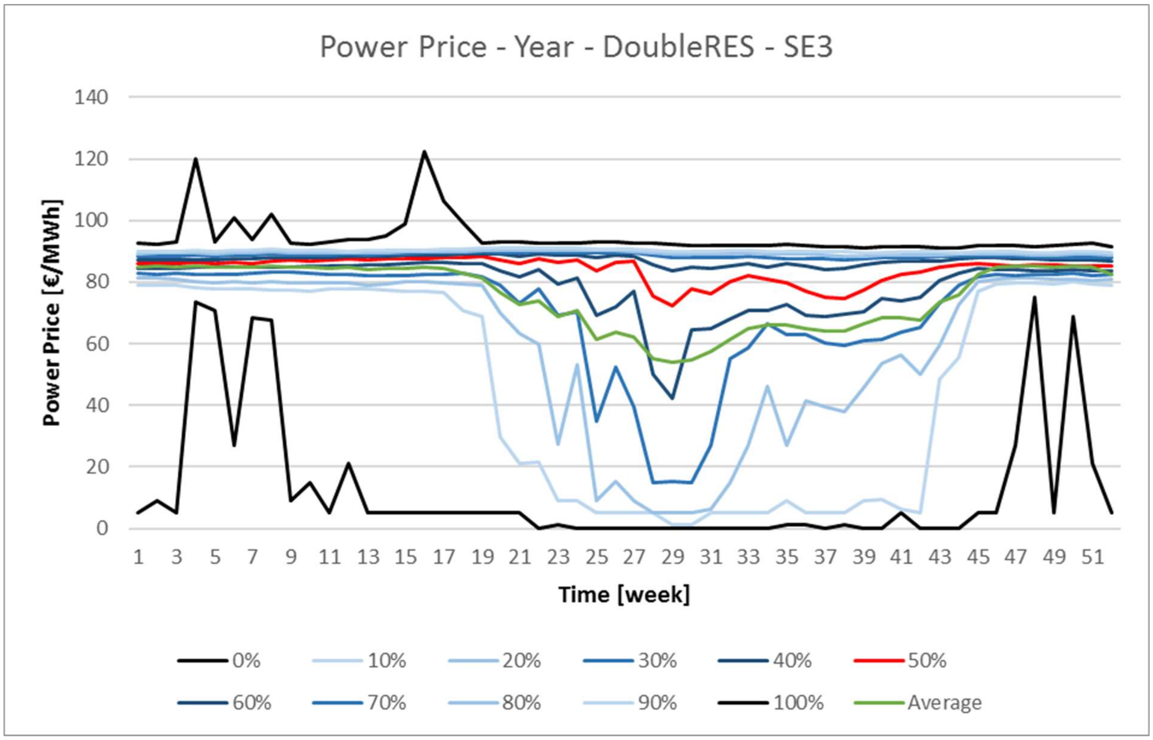

Figure 70: Yearly power price profile – SE3 – DoubleRES

The yearly power price profile of DoubleRES PL also resembles that of V4-16, although with one substantial difference. The 0 % percentile is almost zero during the whole year in DoubleRES. This is not surprising considering that the 0 % percentile of the net load of the whole of Europe is below zero through the whole year, cf. Figure 14. It is however worth noting that this has implication in PL, one of the areas with the lowest share of RES. The power price profile of PL is depicted in Figure 72. In Figure 71, we see the power price profile of FI. This resembles PL in many ways, especially during winter. FI and PL is for instance still using the most expensive gas power plants occasionally during winter. In summer FI however, FI has more similarities with NO1 and SE3 than PL. It shows the same fall in average summer price as NO1 and SE3.

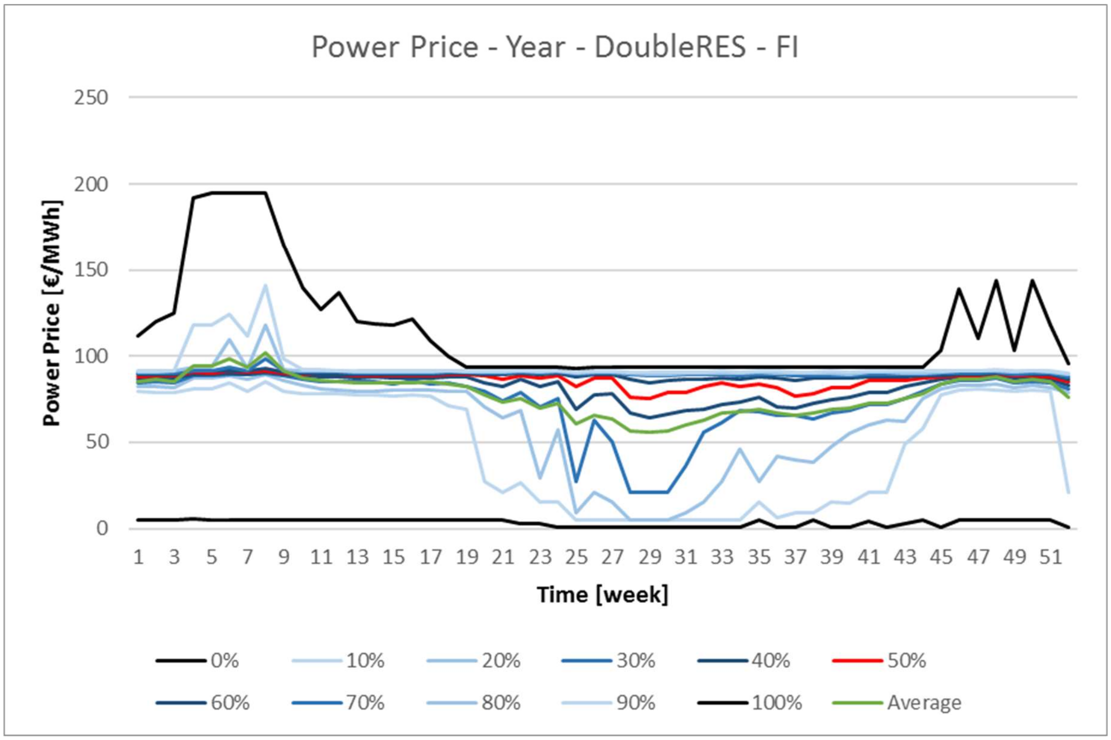

Figure 71: Yearly power price profile – FI – DoubleRES

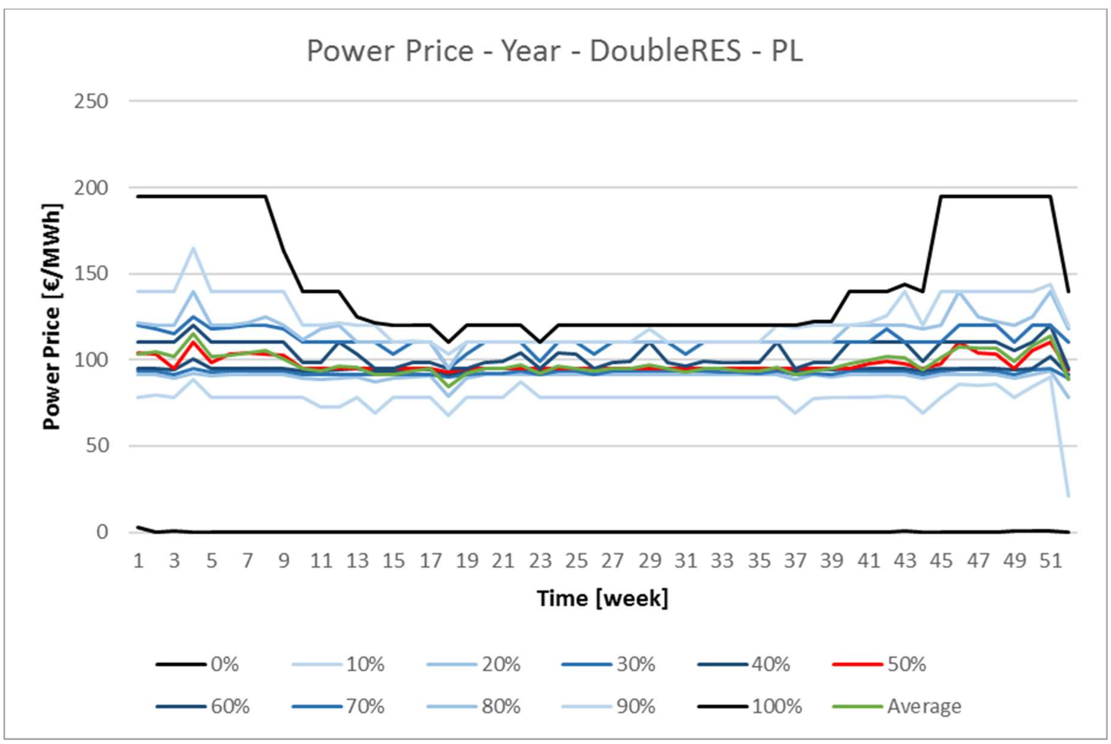

Figure 72: Yearly power price profile – PL – DoubleRES

DK-W and GB are two areas with large share of wind power, and high total share of RES. Their yearly power price profile shares some common characteristics, cf. Figure 73 and Figure

74. Firstly, the average power price is highest during summer. Secondly, the power price volatility is highest during winter. These two characteristics are a consequence of the production profile of wind power discussed in 4.2.1, also seen in the net load profile of GB and DK-W, which can be found in appendix 0. The net load profiles also suggest that the largest percentage of production is curtailed during summer, while the power price profiles suggests that power curtailing happens more often during winter.

Finally, the average price almost never happens. I.e. price periods where the power price is around 90 €/MWh and around 0 €/MWh is quite common, but the price is almost never around 40 €/MWh. This is a consequence of the marginal cost jump in the thermal power supply caused by the CO_2-price. We will see this pattern in the rest of the areas discussed in this subchapter. Also note that GB has lower average prices than DK-W, and more often operates on the low power price side of the jump in the thermal marginal cost supply curve. Despite DK-W having the larges RES share, with 167 % compared to 111 %. This is a consequence of DK-W being better interconnected, compared to its demand.

In V4-16, the lowest average power price in GB was identified to happen during autumn. This is however not the case in DoubleRES. As discussed in the sinusoidal analysis in subchapter 4.2.1, the low autumn net load will fade away as the share of wind power (both types) is increased above a certain level. This is exactly what GB is an example of.

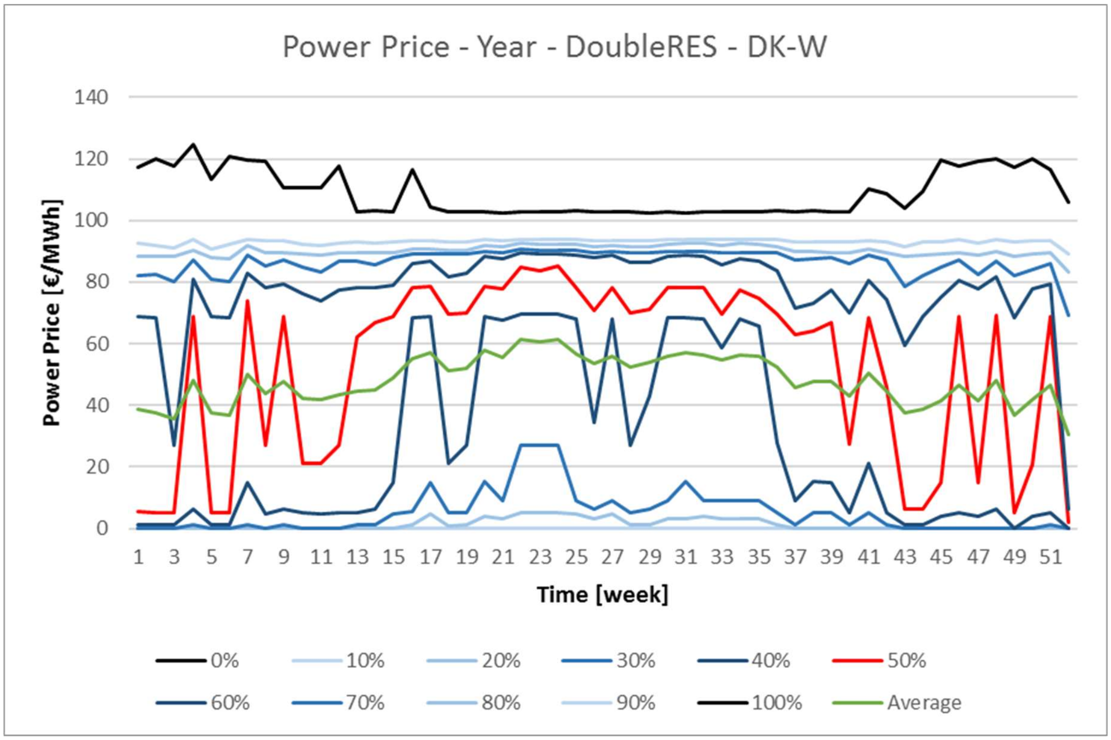

Figure 73: Yearly power price profile – DK-W – DoubleRES

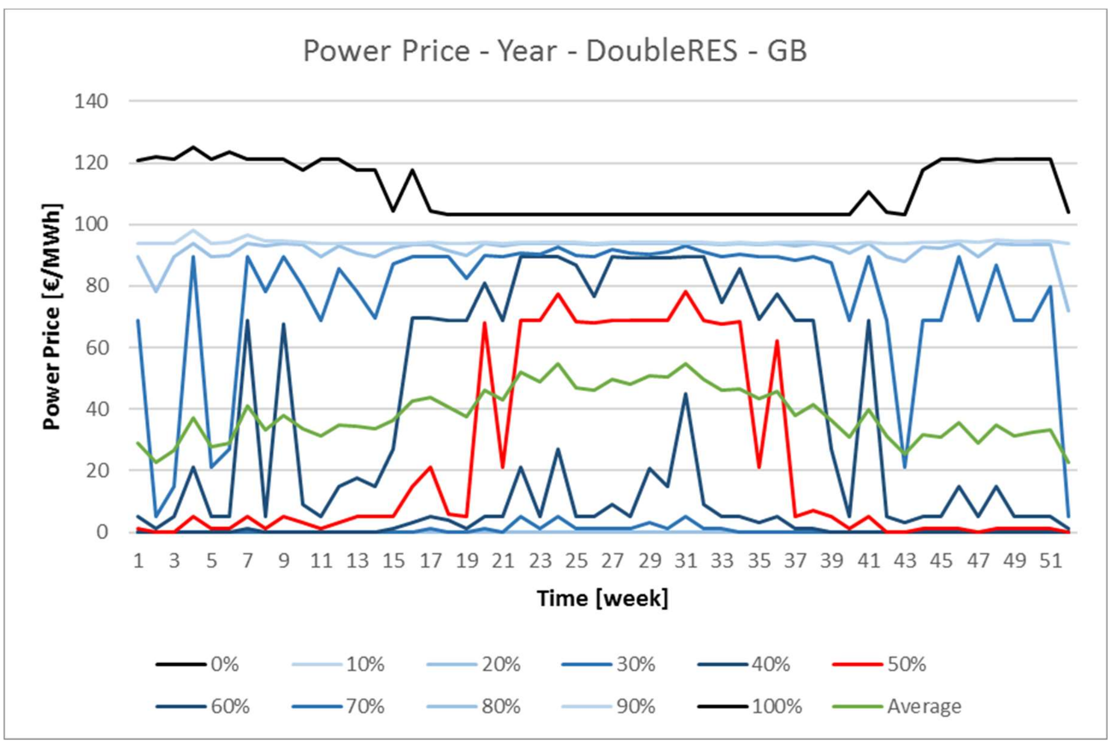

Figure 74: Yearly power price profile – GB – DoubleRES

The DE yearly power price profile, cf. Figure 75, has some resemblance with that of GB and DK-W regarding higher average summer prices than winter prices, and more volatility during winter. DE does however not operate to the left of the CO_2-price jump as often as GB and DK-W, hence higher average prices. In contrast to GB and DK-W, the average price in winter and spring is also almost equal in DE. In IB and IT, on the other hand, the average prices is lowest in spring, cf. Figure 76 and Figure 77. As discussed in the sinusoidal analysis in subchapter 4.2.1, low spring average net load will appear when there is a right balance of installed solar and installed wind (both types) power. In addition, the share of RES needs to be high enough for the sinusoidal nature of the demand profile to have low influence on the net load. Of the three areas IT has the lowest share of RES at 58 % of demand, this is however enough to create low spring prices. Regarding the balance of solar and wind power production, DE has 3.6 times more energy produced from wind turbines than from solar power. That number is 1.24 for IB and 0.76 for IT, cf. Table 8. In other words, DE has too many wind turbines to have spring being the lowest priced period of the year. The low spring prices are most prominent in IB in week 11 to 18, while most prominent in IT in week 14 to 20. This is also, as discussed in 4.2.1, something we would expect, as IT has the lowest wind power production to solar power production ratio.

Table 8: Balance between solar and wind power production. Extraction of Table 5 - DoubleRES

Area	**Wind power (both types) production as share of demand**	**Solar power production as share of demand**	**Wind power production divided by solar power production**
DE	72 %	20 %	3.60
IB	47 %	38 %	1.24
IT	22 %	29 %	0.76

Despite their share of solar power, IB has higher average summer prices than winter prices. Resembling the trend on the IB net load profile. IT on the other hand has its highest average prices during winter. This is in other words an example of two areas on the same latitude, where seasonal variation of the average price is different because of the amount of wind power and solar power installed, and the ratio between them.

The yearly price profile of CH, AT and SEE is like that of IT. IT and SEE does in other words have good connections to the hydro power of CH and AT. Hence, the flat 100 % percentile of the IT power price profile. Also note how the low spring prices happen at the end of the depletion season. This contrasts with the price hump seen in the same period in the Nordics. Hydro power is in other words not needed when it is hardest for them to contribute.

A curiosity is the week 33 low prices appearing in both IT and IB. This is also included in the net load of both areas, and is most likely a consequence of summer holiday.

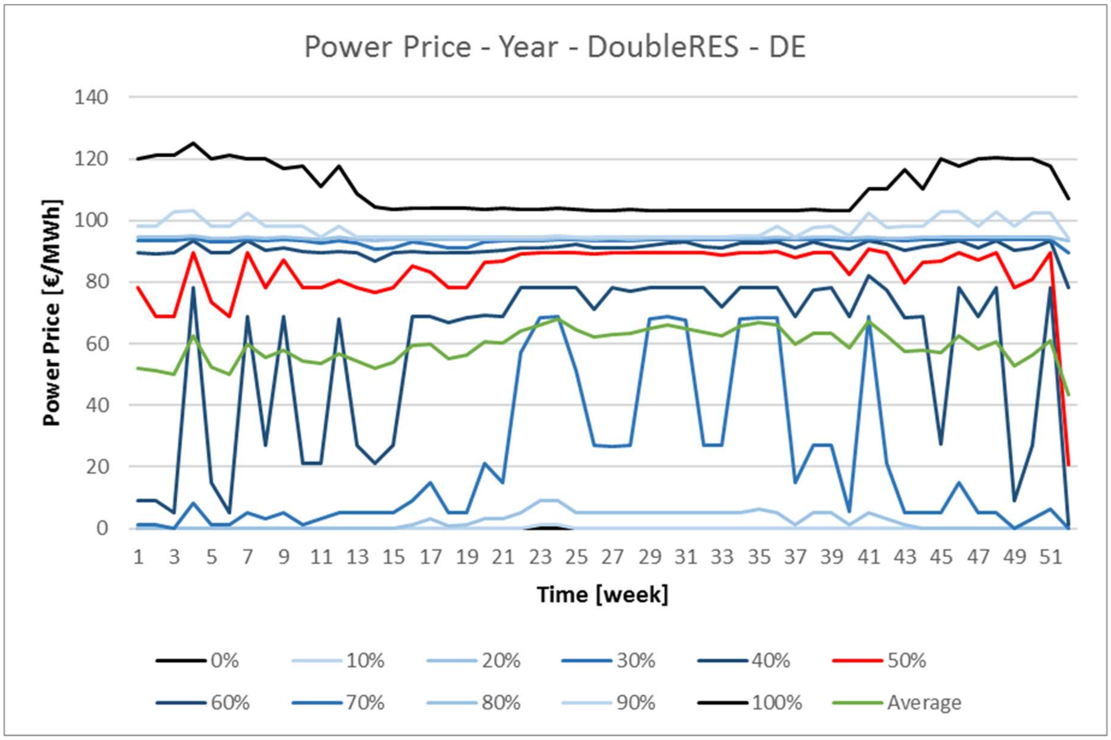

Figure 75: Yearly power price profile – DE – DoubleRES

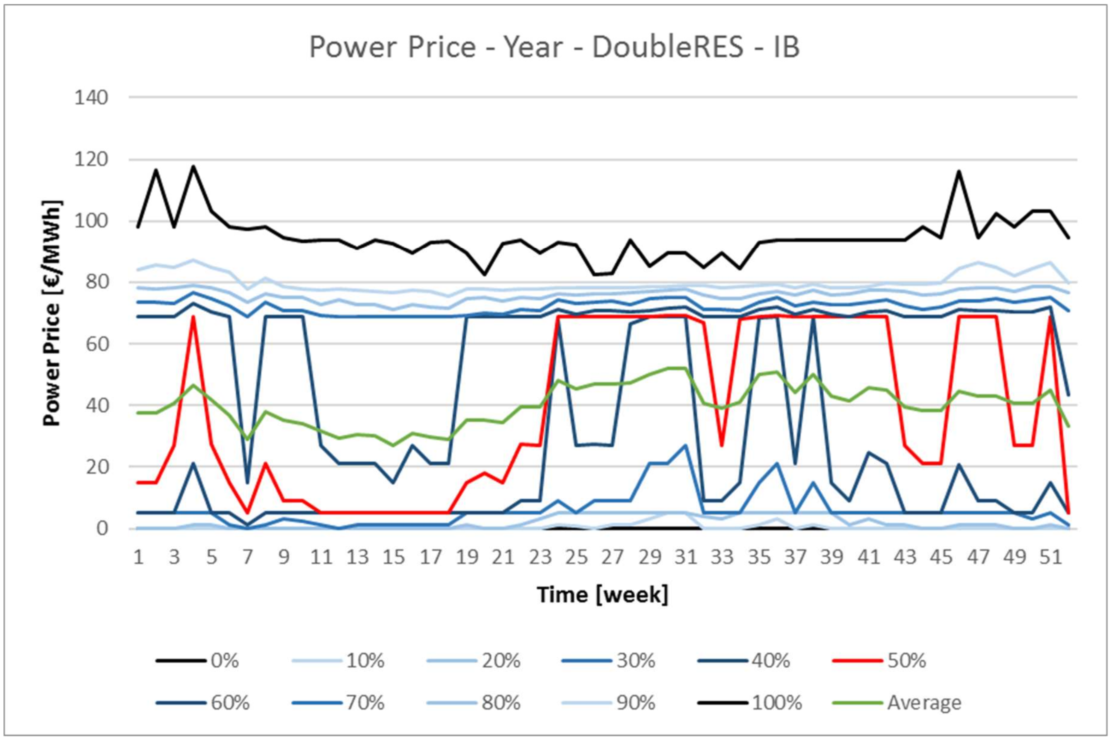

Figure 76: Yearly power price profile – IB – DoubleRES

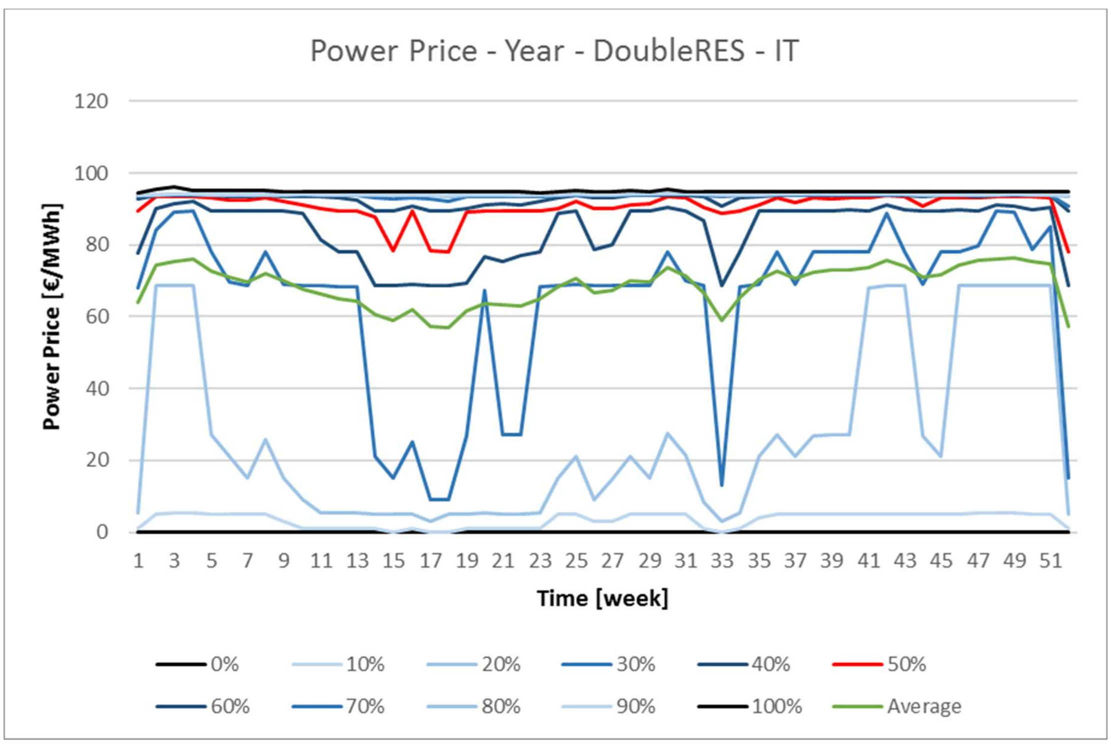

Figure 77: Yearly power price profile – IT – DoubleRES

Now we will look at how the power flows are affected. This will be achieved by using maps. First maps showing the average situation in four different seasons are displayed. Then a table of the respective prices, and then follows a discussion of the most important findings from the maps and table. Based on the results previous in this chapter, it has been decided to divide the year into four periods – winter, spring, summer, and autumn. Which weeks are included in these periods is shown in Table 9.

Table 9: Division of the year into four periods.

Season	First week	Last week
Winter	48	8
Spring	9	21
Summer	22	34
Autumn	35	47

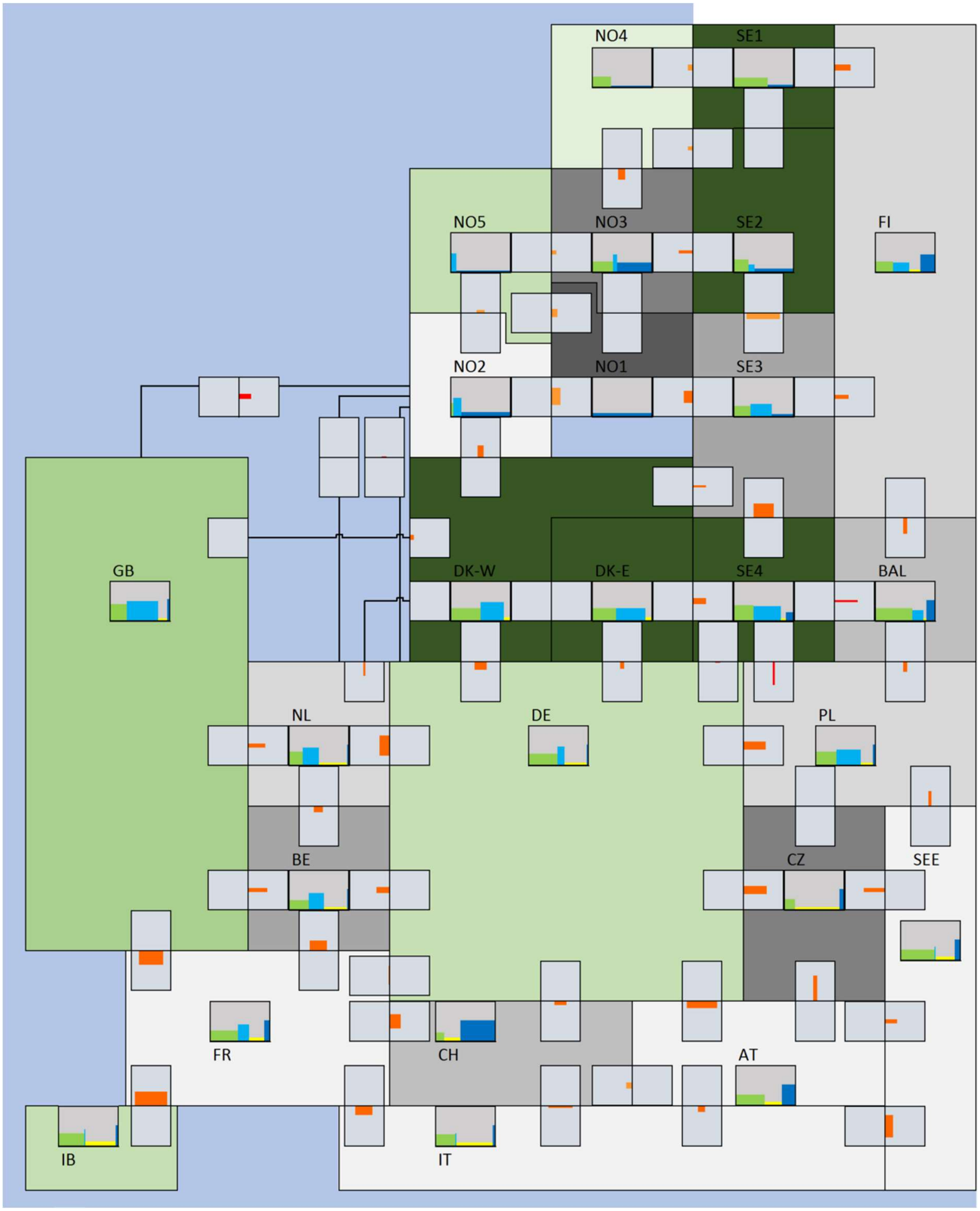

Figure 78: Map – DoubleRES - Winter

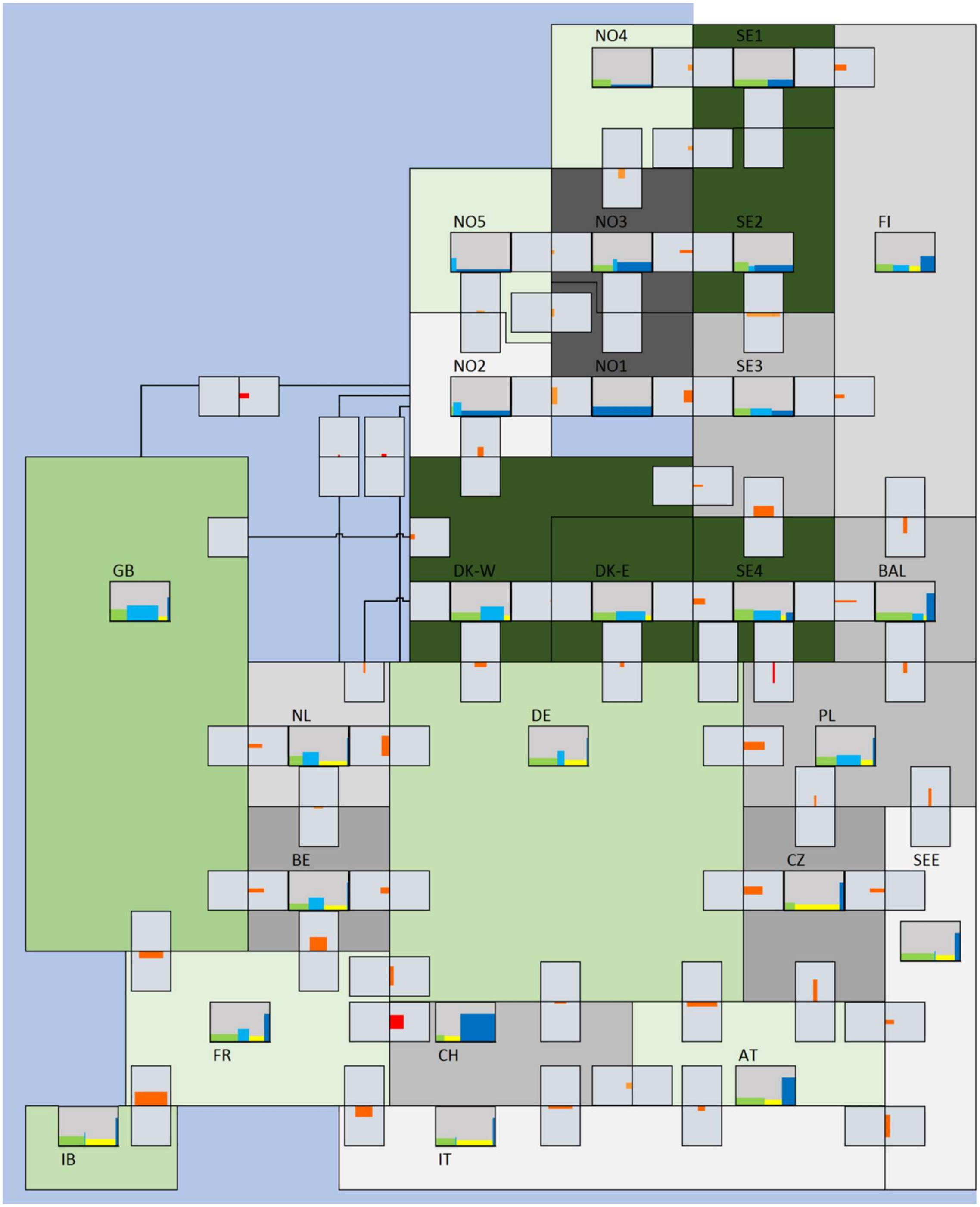

Figure 79: Map – DoubleRES - Spring

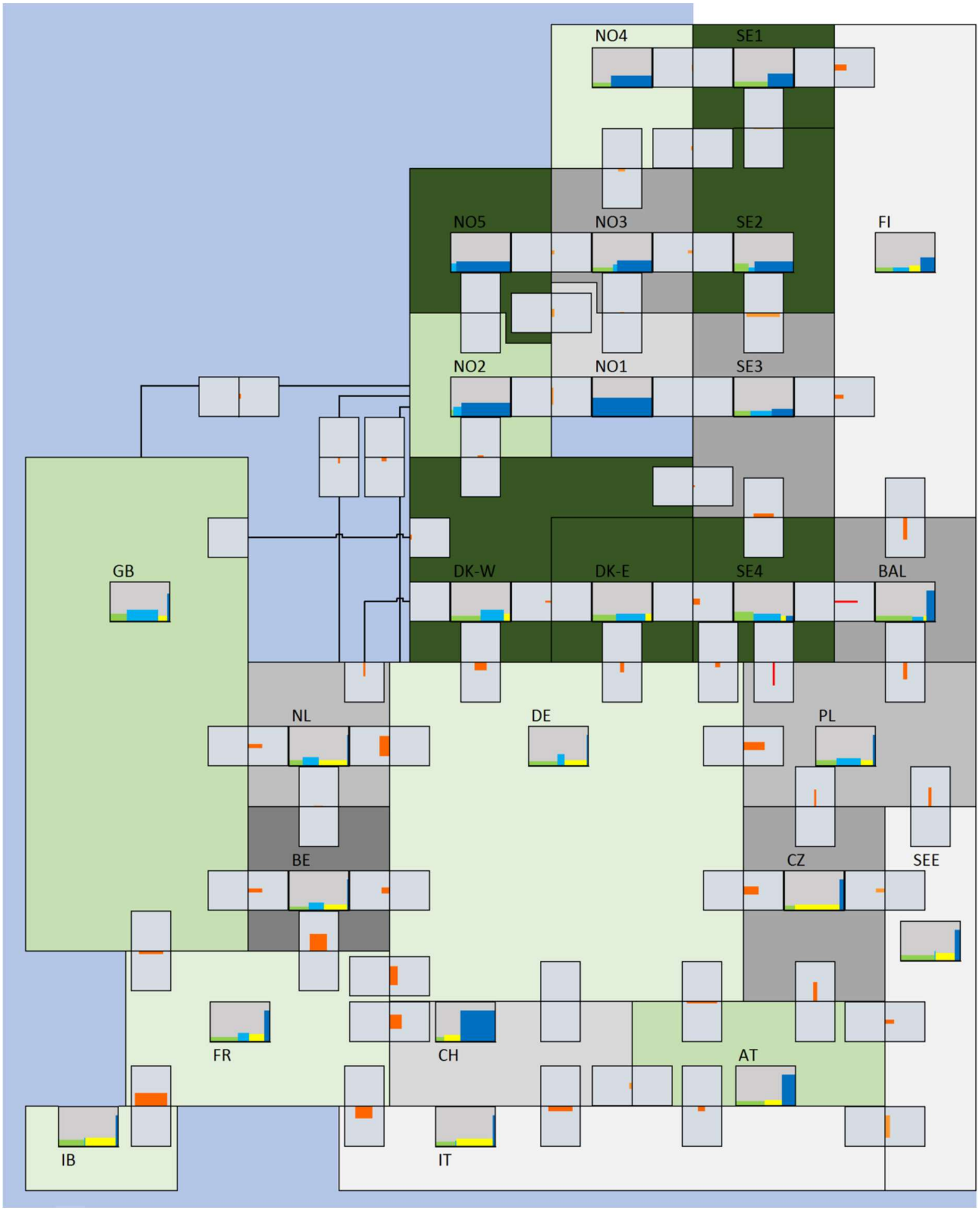

Figure 80: Map – DoubleRES - Summer

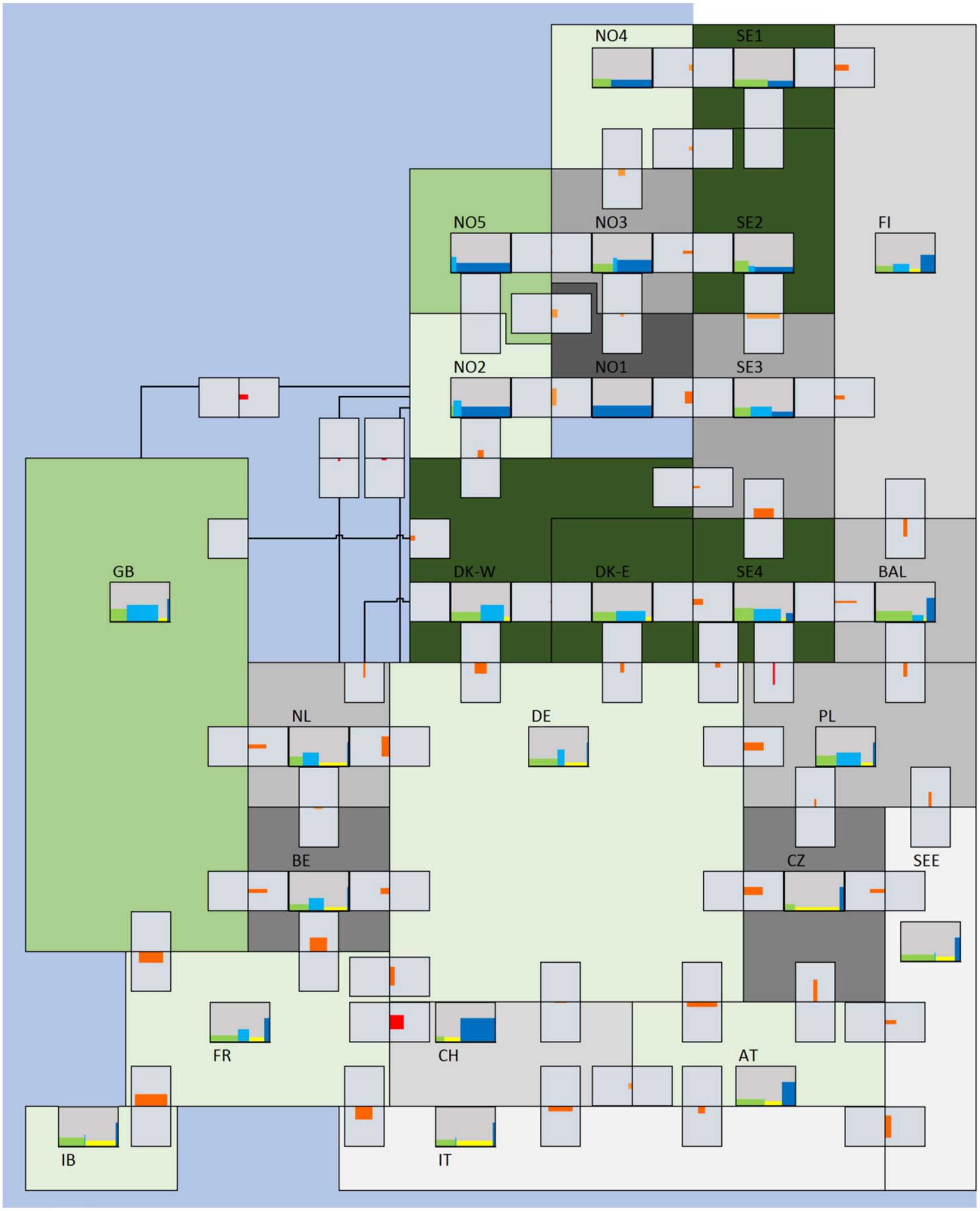

Figure 81: Map – DoubleRES - Autumn

Table 10: Average power prices per country – DoubleRES. Colours shows the high and low prices of all areas, where red represents high prices, and green represents low prices.

DoubleRES	Winter	Spring	Summer	Autumn
NO1	85,4	83,3	62,6	72,3
NO2	85,1	83,2	62,7	72,1
NO3	85,4	83,3	62,6	72,3
NO4	85,1	83,0	62,4	71,9
NO5	85,2	83,2	62,5	72,1
SE1	84,6	82,5	62,4	71,4
SE2	84,6	82,5	62,4	71,4
SE3	84,8	82,7	62,6	71,6
SE4	60,6	68,0	60,3	58,1
DK-E	43,7	52,3	52,6	45,6
DK-W	40,9	49,4	56,6	45,6
FI	89,3	83,8	64,3	74,2
BAL	102,8	93,6	91,0	94,4
PL	104,3	93,8	94,7	98,4
CZ	100,5	79,1	75,6	87,9
DE	54,5	56,4	64,6	61,6
NL	57,9	58,7	66,7	63,5
BE	62,6	60,1	67,0	65,7
GB	30,8	38,1	49,6	35,4
FR	56,0	48,2	57,6	55,2
IB	39,3	31,7	45,3	44,1
CH	77,9	68,5	70,9	77,5
AT	71,7	64,0	68,8	73,9
IT	71,9	62,9	67,5	73,0
SEE	76,0	63,9	68,7	75,4

One of the main findings of the maps in Figure 78 to Figure 81 is that which areas are – on average – power surplus and which are power deficit does not change trough the year. The same picture is found in Table 10, where the colours of an area is similar independent of season. The magnitude of deficit or surplus does however change.

The Nordics and AT+CH is the two regions in the system with the most hydro power storage. Although it is more prominent in Norway then Sweden, both regions are greener in summer, and greyer in winter, exporting more during summer than winter. Despite the need for winter storage found in subchapter 4.2.3. This topic will be revisited and further discussed in chapter 0, Discussion.

GB and DE are two examples of areas that have larger surplus and export more when they have cheap power and low net load, and vice versa. This can be seen on the maps in Figure 78 to Figure 81. GB is lighter green and exports less during summer, while DE is darker green and exports more during winter and spring. These two areas are not the only examples, areas with similar behaviour can be identified from the results show in chapter 4.5.

4.4.4 Most used interconnections

In this subchapter, the 10 most used interconnections in V4-16 and DoubleRES are presented. This is an indication of where upgrades would be most useful. Additionally, the number of power flow direction changes per year is presented per interconnection. A number which indicates what type of use the interconnection is sub-missioned to. Few power flow direction changes indicate energy transfer from a surplus to a deficit area or reduction of seasonal variations to be the main function of the interconnection, while many power flow direction changes indicate reduction of daily variations to be the main function of the interconnection.

There are three interconnections including a Norwegian area among ten most used interconnectors in both V4-16 and DoubleRES, cf. Table 11 and

Table *12*. They are NO2-GB, NO2-DE, and NO2-NL. A total of six of the top ten most used interconnections are between the combined region of Norway and Sweden and its neighbours in V4-16. In DoubleRES this number is seven, and includes all the six most used interconnections. The three interconnections connected to NO2, all has a high number of power flow direction changes, while the SE4-BAL has few. SE4-PL also has few changes, to some degree, especially in DoubleRES.

Other interconnections worth mentioning is PL-SEE and the interconnections connecting BE, GB, FR, and CH. The BE, GB, FR, and CH includes, firstly, an area with power deficit and demand dominated net load, BE. Secondly, an area with power surplus and wind dominated net load, GB. Thirdly, an area with storage exposed to influence of solar power, CH. And Finally, in the middle, an area with a relatively steep thermal marginal cost supply curve around the operating area, FR. Note that power flows unrealistically easy through SEE in the system analysed. The use of the PL-SEE interconnection could therefore be overestimated.

Table 11: 10 most used interconnections - V4-16

	Interconnection	Equivalent full load [%]	Number of power flow direction changes per year
1	PL - SEE	60	27
2	NO2 - GB	59	120
3	SE4 - PL	56	91
4	NO2 - DE	55	168
5	SE4 - BAL	55	27
6	NL - GB	55	63
7	NO2 - NL	55	181
8	BE - GB	54	61
9	SE3 - DK-W	53	117
10	BE - FR	53	41

Table 12: 10 most used interconnections - DoubleRES

	Change from V4-16	Interconnection	Equivalent full load [%]	Number of power flow direction changes per year
1	↑	SE4 - PL	62	48
2	–	NO2 - GB	62	133
3	↑	NO2 - DE	61	225
4	↑	NO2 - NL	61	215
5	–	SE4 - BAL	60	22
6	↑	SE4 - DE	59	208
7	↑	FR - CH	59	178
8	↓	PL - SEE	58	93
9	–	SE3 - DK-W	57	177
10	–	BE - FR	56	91

4.5 Hydro power production

This subchapter presents the hydro power production in two regions. The Nordic region, here including the Norwegian and Swedish areas, and the Alp region, here including CH and AT. The yearly production profiles are for the Nordic region is given in Figure 82 and Figure 83 for V4-16 and DoubleRES respectively, while the equivalent figures for the Alp region is given in Figure 84 and Figure 85.

Common for both scenarios is larger winter production than summer production in the Nordic area. Additionally, the peak production happens during summer. This is a result of trying to avoid spillage. The production during spring could be higher if avoiding spillage was a great concern. The relatively low spring production is however a consequence of not knowing how much precipitation will come in the spring and summer. The most optimal solution is in other words to have overflow in some years. The disadvantage of having spillage in some years is smaller than the advantage of having more optimal production profile in most years.

The difference between average winter production and average summer production is smaller in DoubleRES than V4-16. On average V4-16 have 11 TWh more production during winter than DoubleRES.

In the Alp region, the average winter production is highest in V4-16, while the highest peak production is occurring in the DoubleRES winter. Indicating that there is a larger need for winter production capacity in DoubleRES, while the need for energy in the winter is reduced. This is coherent with the changing storage requirement found in 4.2.3. The maximum hydro power production in the Alp region is in fact largest in DoubleRES across seasons. The Alp region also shows a difference in which seasons stored energy supplies. In V4-16, the trend is to store energy in spring and summer, and producing during winter. In DoubleRES, on the other hand, the winter, summer and autumn average production is close to equal. This will of course mean that energy is stored to the winter season, as the winter inflow is small. On the other hand, avoiding production during the low spring prices is a new important use of the reservoirs. This trend does have not reached the Nordic power system in DoubleRES, but it is an indication of what can be the reality in the Nordic system beyond DoubleRES.

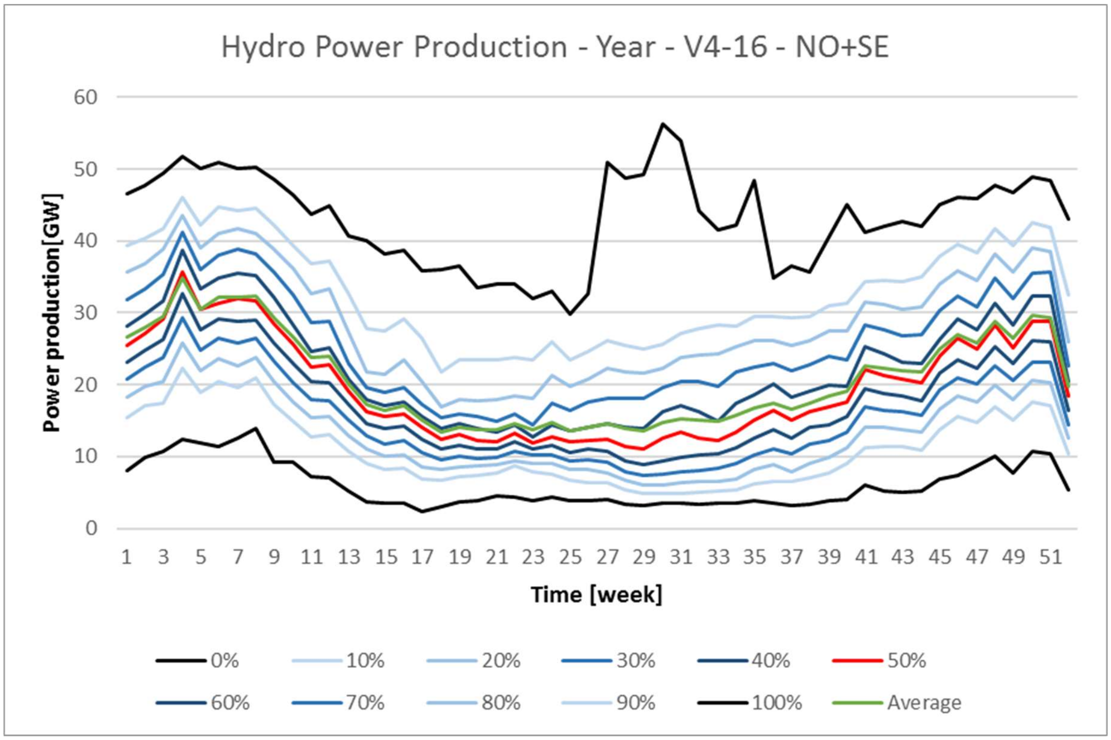

Figure 82: Hydro power production in Norway and Sweden, V4-16.

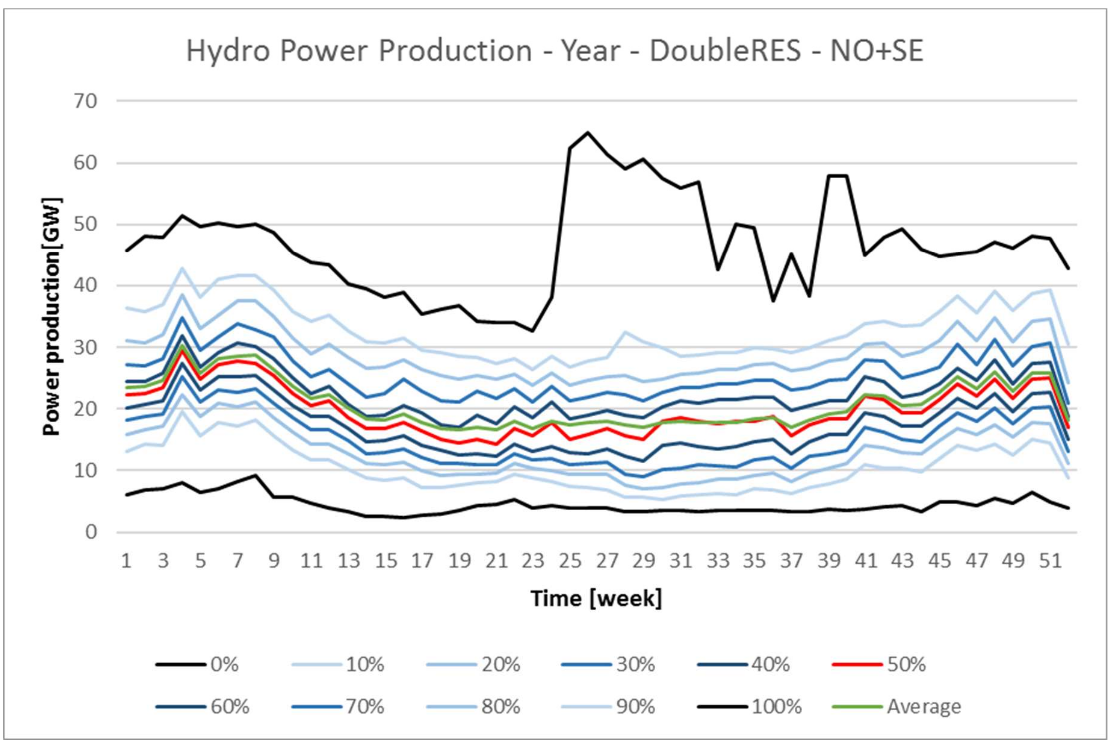

Figure 83: Hydro power production in Norway and Sweden, DoubleRES.

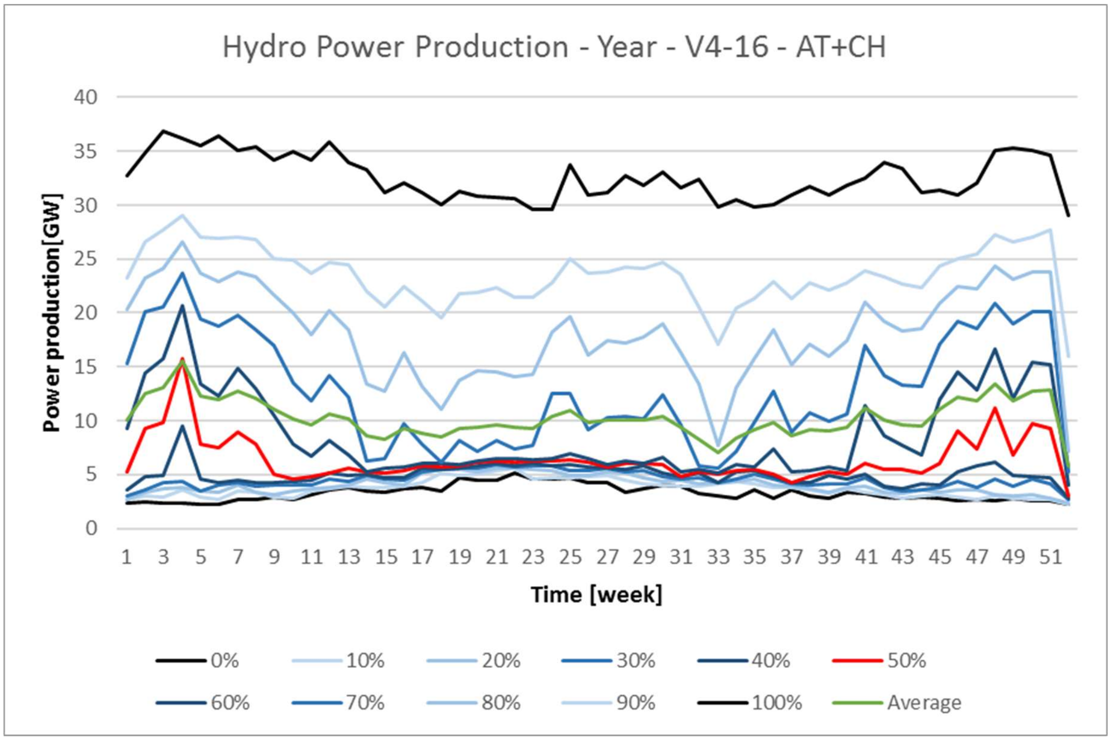

Figure 84: Hydro power production in Austria and Switzerland, V4-16.

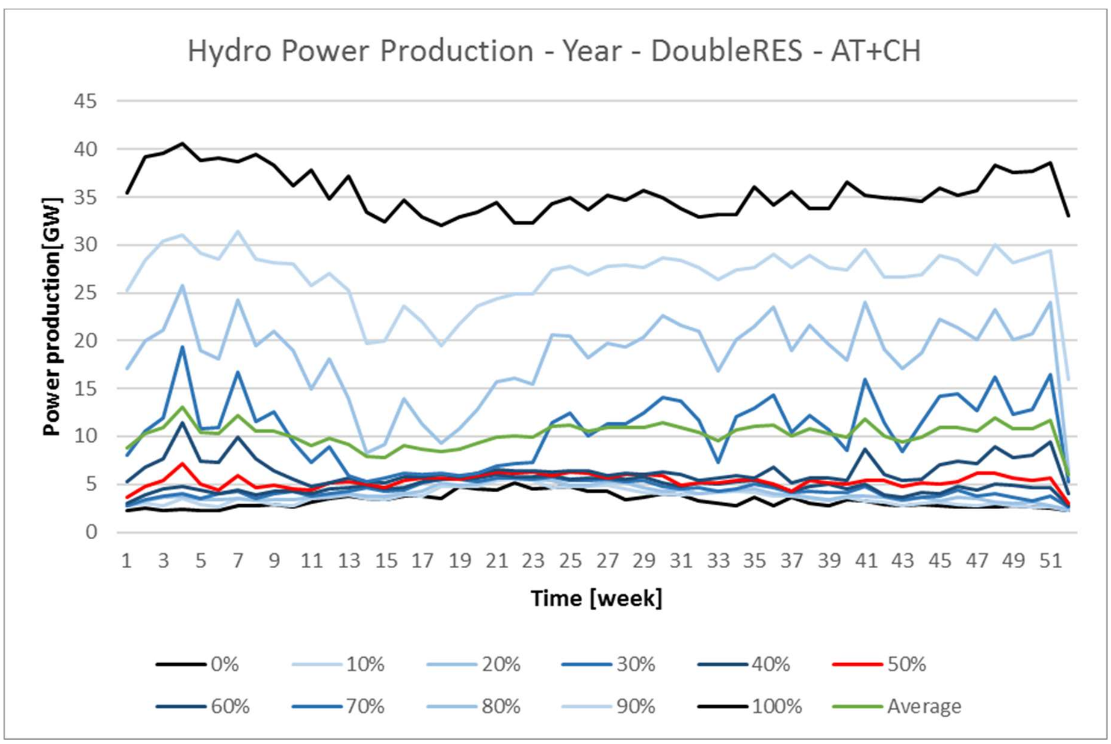

Figure 85: Hydro power production in Austria and Switzerland, DoubleRES.

4.6 Correlation – Import and power price

This subchapter aims to answer the question "Are the areas importing and exporting because they can, or because they have to?". Correlation between import and the power price is used to answer this question.

The idea is the following:

- If an area imports at high prices and exports at low prices, then its import pattern is a cause of necessity, and pushes its own price differences onto neighbouring areas.
- If an area imports at low prices and exports at high prices, it exploits a possibility, and reduces price differences in the system.

Because the correlation between import and power price is studied, and export is accounted for as negative import, a negative correlation means an area is exploiting a possibility, while a positive correlation means an area is creating price volatility in the system.

There are two main ways of achieving negative correlation:

- Storage
- Having a flatter thermal supply curve (around the operating point) than your neighbouring areas

Note that the thermal power producers in an area with a flat thermal supply curve, which must stop production because of price reduction, probably do not see this as exploiting a possibility. They are however contributing to reduce price differences in the system.

To differentiate variations daily variations and seasonal variations, the power price series for each area have been split into two, "weekly average power price" and "power price minus weekly average". In "weekly average power price" all power price entries within one week are equal, equal to the average power price of that week. This power price series, therefore, only includes the seasonal variations.

In "power price minus weekly average" each power price entry has been subject to the subtraction of the average power price of the week it is in. "Power price minus weekly average" therefore only includes variations within the week. Put in another way, adding "power price minus weekly average" and "weekly average power price" will give the original power price series.

The results are given in Figure 86 and Figure 87, for V4-16 and DoubleRES respectively. The general difference between V4-16 and DoubleRES is that most correlations are stronger in DoubleRES than V4-16. Additionally, some areas have specific changes, amongst others IT, where a negative correlation regarding seasonal price variations in V4-16 is turned positive in DoubleRES, and the correlation regarding daily price variations is increased drastically. This is connected to the use of the hydro power reservoirs in IT, they are used more in V4-16 than in DoubleRES. This can be seen in subchapter 4.3.

Except for IT, CH and AT are the two areas with largest negative correlations. Not surprisingly, as they have large hydro power reservoirs. This is also coherent with how we have seen them behave in subchapter 4.4.2 and 4.4.3. The increase in CH negative correlation from V4-16 to DoubleRES is caused by better reservoir management in DoubleRES. It is in other words a product of calibration. This can be seen in subchapter 4.3.

The typical pattern in the Nordic region, the other region with large hydro power reservoirs, especially the Norwegian areas plus SE1 and SE2, is negative correlation regarding daily variations and positive correlation regarding seasonal variations. This is coherent with how we have seen them behave in subchapter 4.4.2 and 4.4.3. As we have seen, this region exports more during summer, when its internal prices are low, and importing more during winter when its internal prices are high, causing the positive correlation.

Among the areas with the highest positive correlations are GB and DE, both with direct connections to Norway, both connections which are among the most used.

The last section of the 4.4.2 subchapter was dedicated to the daily variations of the FR-IB interconnection. IB was exporting less when the solar power production was high, and prices low. Consequently, IB has a negative correlation regarding daily power price variations. In 4.4.2 it was shown how import from IB had to be restricted not to push the French power price to the left of the CO_2-jump. Expressed in another way, IB has a flatter thermal supply curve (around the operating point) than its neighbouring area.

The negative correlation seen for Czech weekly variations are most likely a consequence of the error found in the demand data from TYNDP, shown in 4.7.

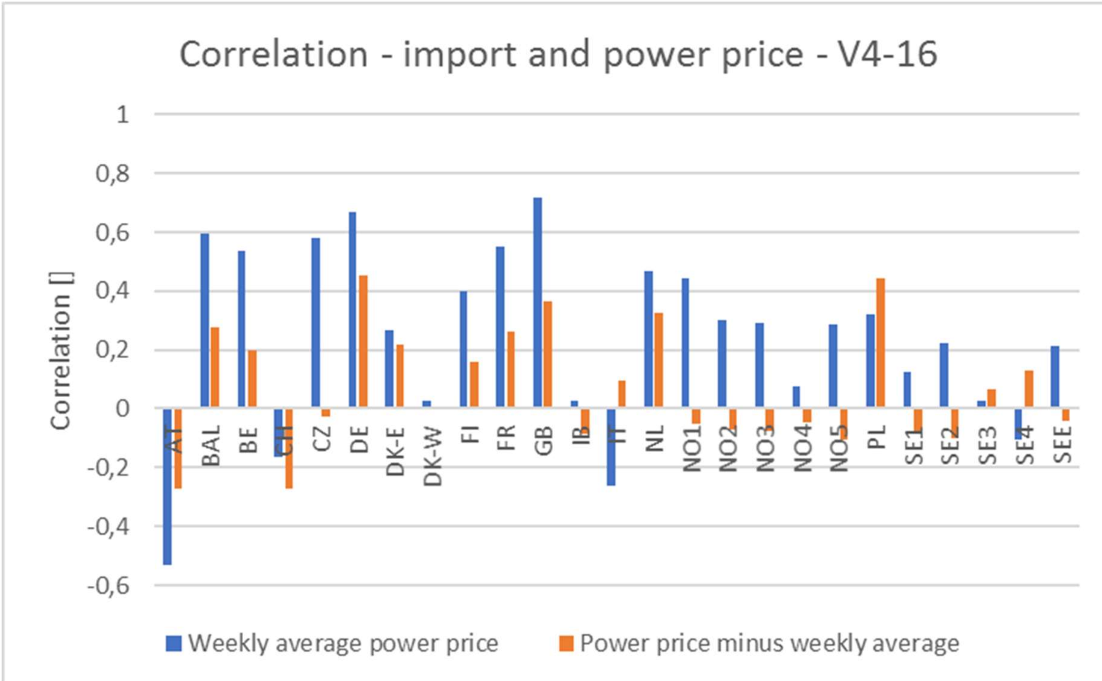

Figure 86: Correlation of import and power price per area – V4-16

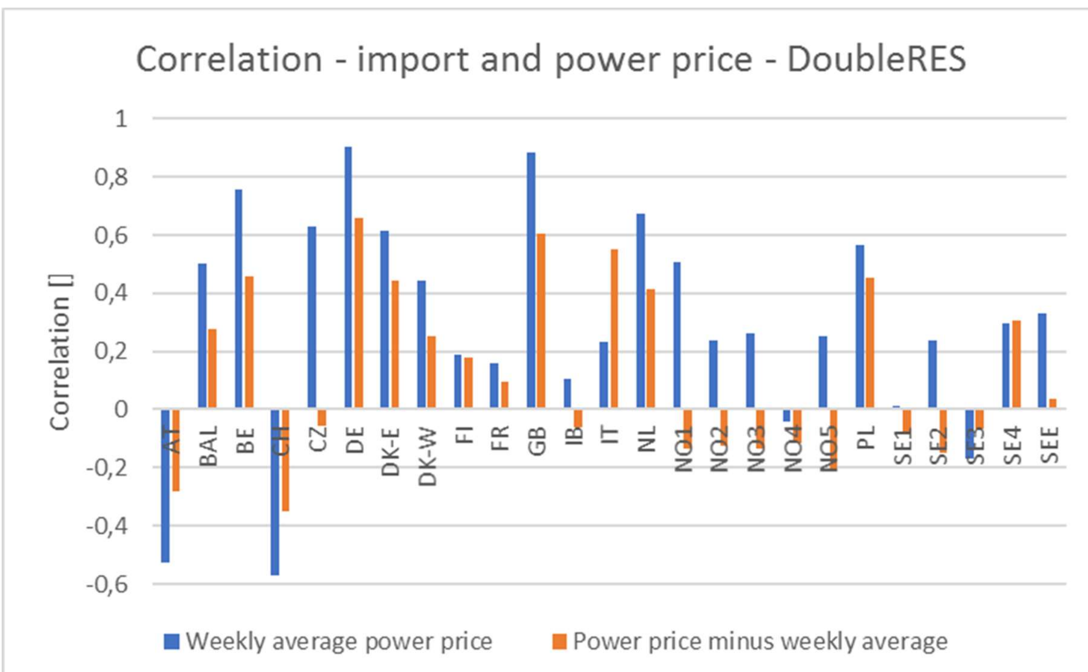

Figure 87: Correlation of import and power price per area – DoubleRES

4.7 Demand input versus output

In this subchapter, two errors will be presented. The first, is an error in the TYNDP Vision 4 2016 dataset. In other words, an error in the data provided by ENTSO-E TYNDP. The second error concerns differences in input and output demand from the EMPS model.

The error in the TYNDP dataset is in the Czech demand series. The Czech weekend happens in the middle of the week. Saturday are dislocated to Tuesday, and Sunday are dislocated to Wednesday. This can be seen on the demand input profile for CZ displayed in Figure 88.

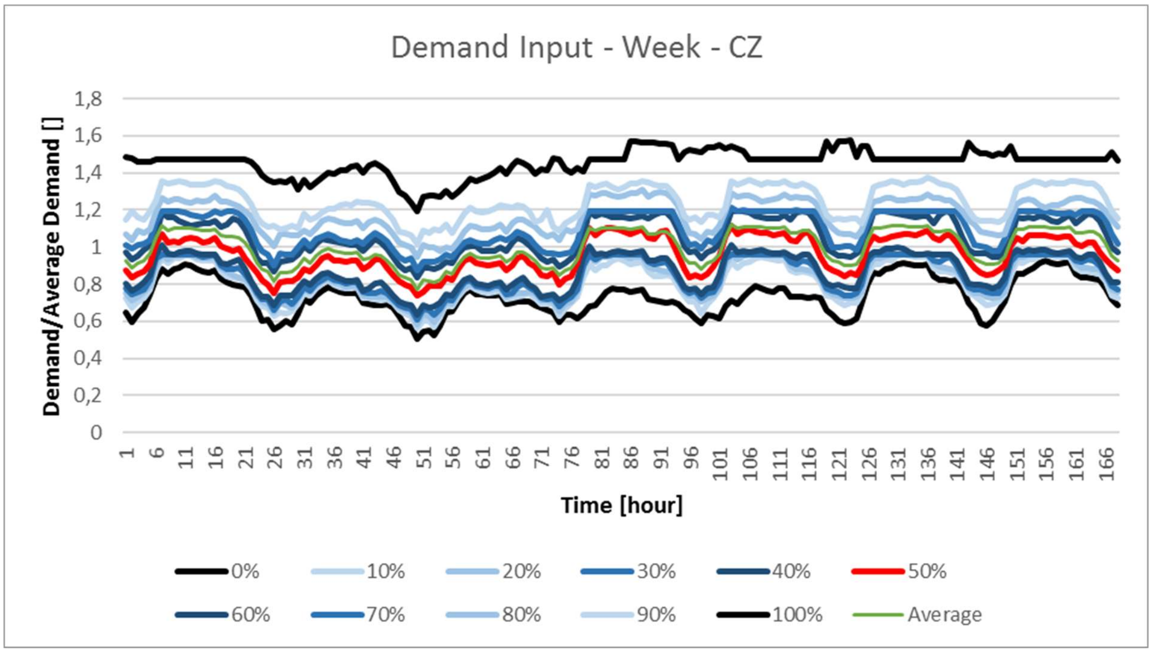

Figure 88: Demand input – NO1

The error regarding input and output demand, can be seen on the demand input and output profiles of Poland in Figure 89 and Figure 90. Note that we would not expect the two figures to be exactly equal as the EMPS model has a demand series with hourly resolution as input, while simulating with 28 price periods per week. The output demand series should and is therefore coarser. The major error separating Figure 89 and Figure 90 is the Monday profile. There are two little demand in the output series on Mondays. The author has two theories of what could be going on. Number one, the week could have somehow been shifted one day, such that the low demand Monday pointed out is actually the Sunday. Number two, the EMPS model is somehow making an error when calculating the Monday demand.

Because of the error in the CZ demand, there is a way to substantiate which of the two theories are wrong. If theory number one was to be true, expect low CZ demand on Wednesday and

Thursday is expected. In figure Figure 91, the output CZ demand series is presented. This series has low demand on Monday, Tuesday, and Wednesday. Theory number one is therefore considered not true.

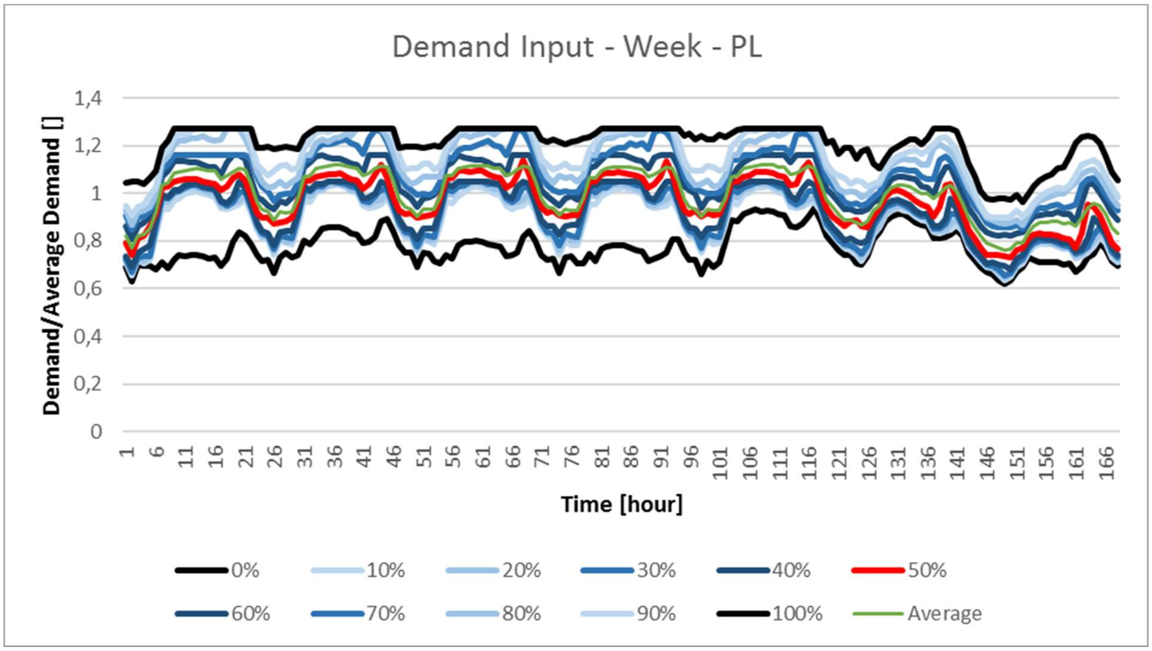

Figure 89: Demand input – NO1

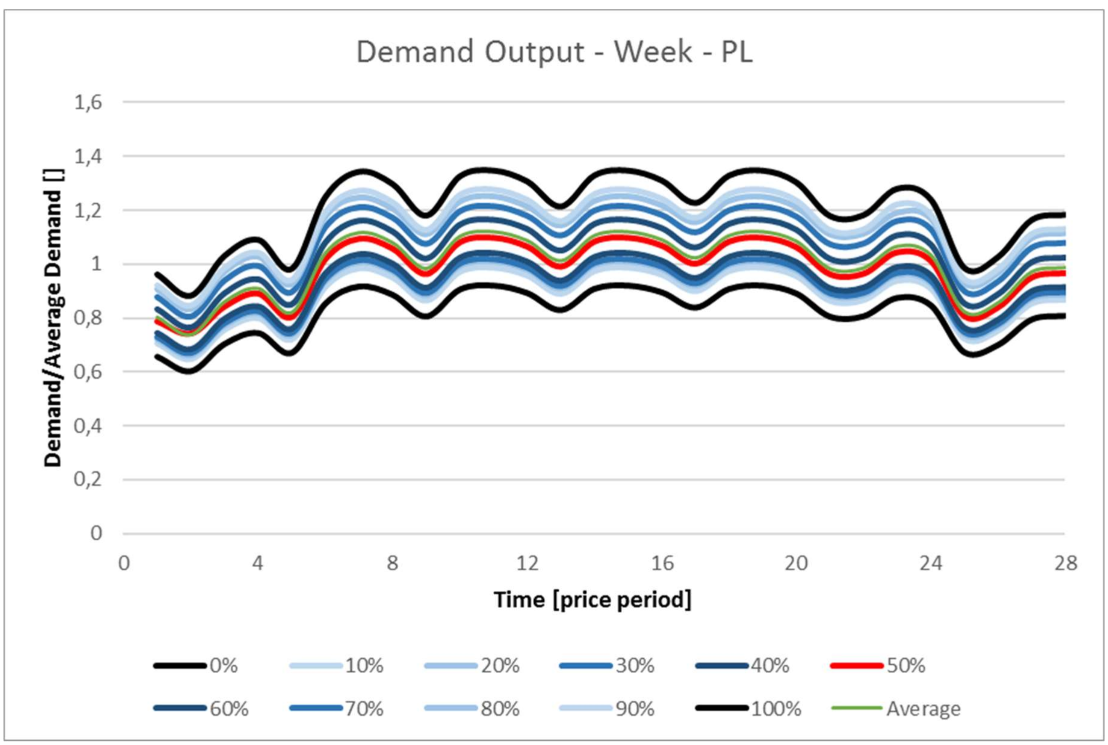

Figure 90: Demand output – NO1

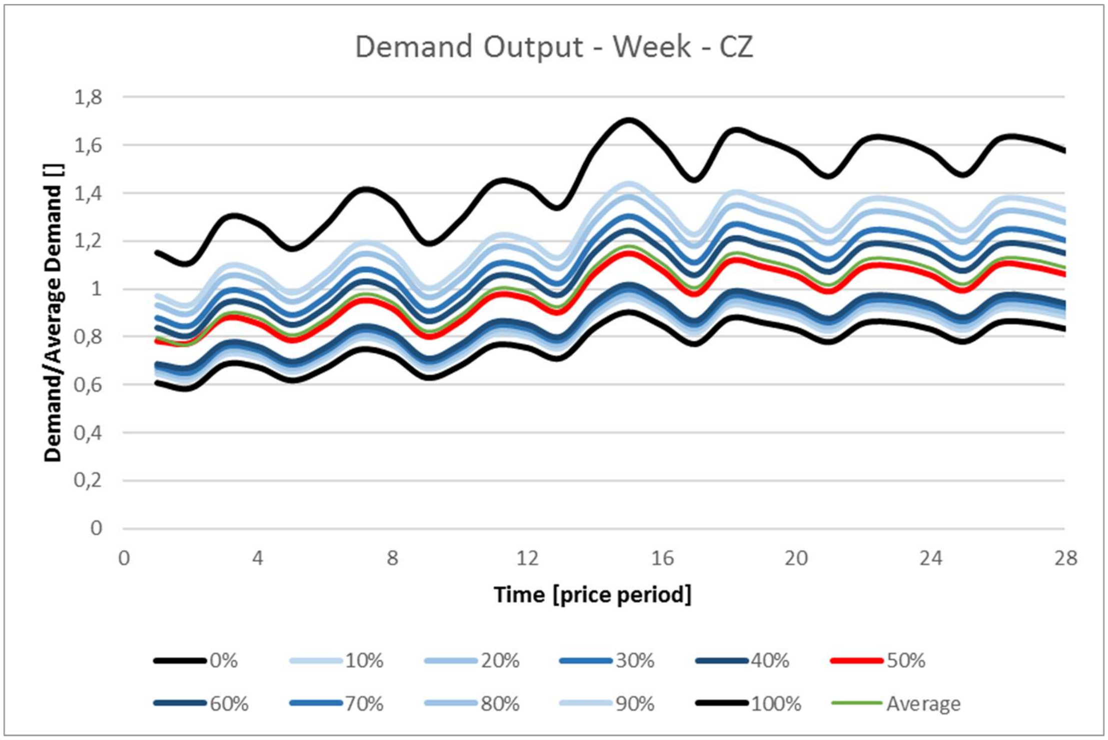

Figure 91: Demand output – NO1

The low Monday demand does however not happen in all areas. NO1 is an example of an area where the input and output demand are adequately similar, cf. Figure 92 and Figure 93. The areas which suffer from low demand on Mondays are:

- SE1
- SE2
- SE3
- SE4
- FI
- BAL
- CZ
- DE
- NL
- BE
- GB
- FR
- IB
- CH
- AT
- IT
- SEE

The areas where the output Monday demand is as it should be, are:

- NO1
- NO2
- NO3
- NO4
- NO5
- DK-E
- DK-W

The Monday demand is in other words as it should in the Danish and Norwegian areas. Note that the origin for the demand series of all Norwegian areas is the same demand series from TYNDP Vision 4. Then they are scaled separately using data from TWENTIES. The same is true for the Danish areas

Unfortunately, both errors described in this subchapter is present in the final simulations, and therefore the result data. Both errors were considered to have small significance for the overall results. CZ is one of the smallest areas in the simulated system, and not of the highest importance in this study. The most important reason for it to be a separate area, is not to leave out transmission restrictions. The low Monday demand, although unfortunate, is on the same level as a normal Sunday. When considering that most Fridays have lower demand than the rest of the week, a trend which seems not to be included in the data from TYNDP, the end result is a quit realistic demand data after all. It is however unfortunate that the Norwegian-Danish weekend happens on different days than that of the rest of Europe. Consequently, the power flow and price difference between weekdays and weekends have not been included in this study.

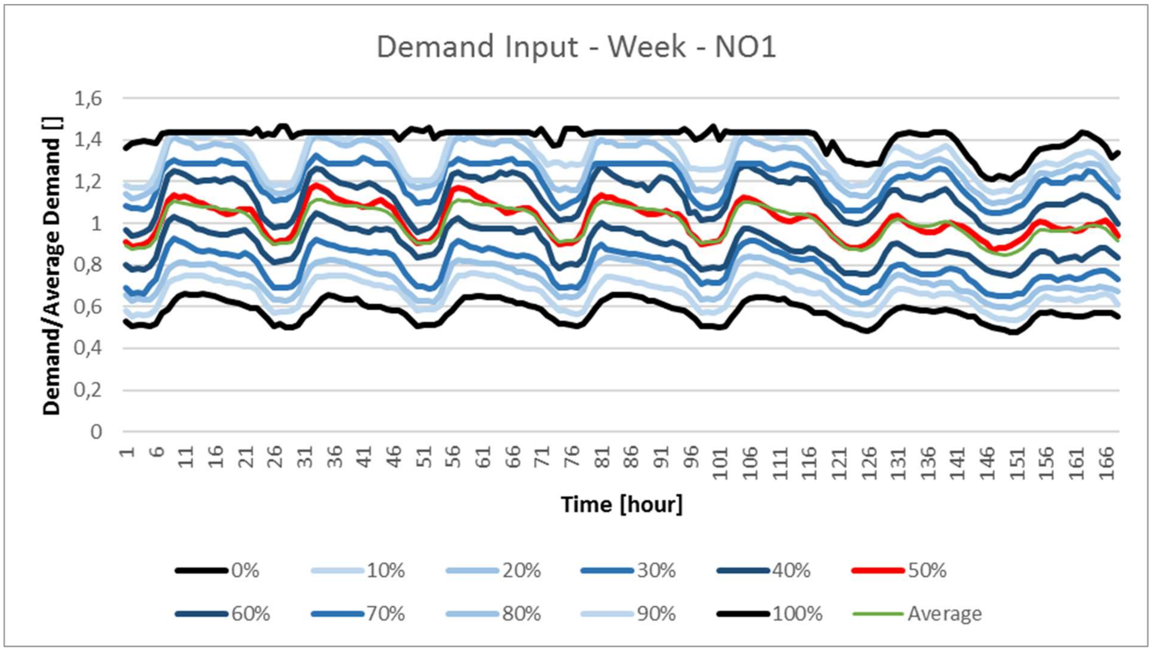

Figure 92: Demand input – NO1

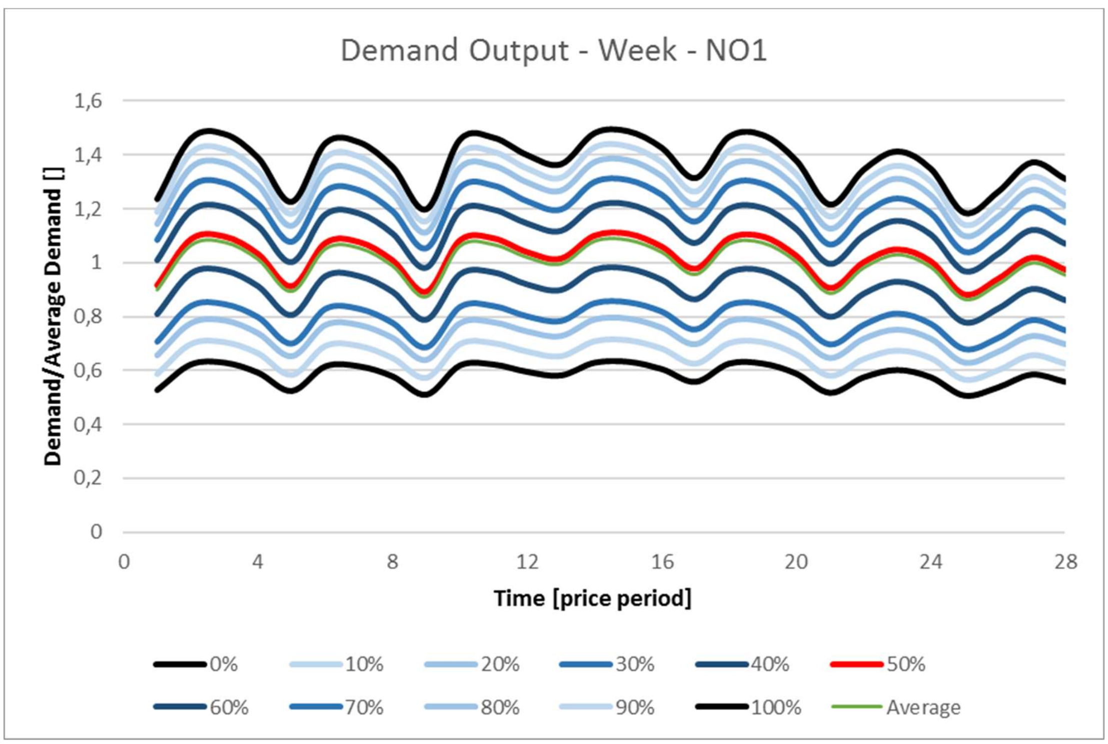

Figure 93: Demand output – NO1

5 Discussion

The chapter starts with discussing limitations of this study. Thereafter follows a discussion of power prices, both the overall level, seasonal and daily variations and how they relate to surplus and deficit areas. The third topic discussed is the Nordic situation. Here the consequences of the increased RES penetration are evaluated from a Nordic power system point of view. Fourth, how wind power and solar power balance each other is discussed. The fifth topic of this chapter is storage capacity. Here the feasible amount of battery capacity is discussed.

5.1 Limitations

In this subchapter three limitations regarding the datasets developed and the EMPS model will be highlighted and discussed.

The first limitation is that Germany is not divided into two areas, North Germany and South Germany. In the present of writing this report, Germany is one power market, but there are internal congestions. Consequently, loop flows are generated. Typically, power flows from Northern Germany to Southern Germany via The Netherlands, Belgium, France on the western side, and Poland and Czech on the eastern side. As Germany is treated as one area in this study, these loop flows will not appear.

If Germany were to be divided, sufficient data sources would be required. TYNDP Vision 4 does not distinguish between northern and southern Germany. An additional dataset would therefore be needed, to decide how to split the data from TYNDP Vision 4. This could be done in the same way the Nordics was split into more areas than used in TYNDP. A consequence would be that more effort is needed to keep the dataset up to date. If new versions TYNDP Visions where to be simulated.

The second limitation is regarding distribution of RES in DoubleRES. To create the DoubleRES scenario, the installed capacity of solar, wind and offshore wind was simply doubled in every area. The results of this study show that there is a connection between RES share, energy surplus and power prices. PL is an example of an area with low RES share, large energy deficit and high power prices. The situation is opposite in GB for instance. This suggests that the scale of implementation of RES is not driven by the power price alone. The level of subsidies however greatly affects it. In DoubleRES Denmark produces more than 1.5 times its demand from RES. The question then arises, would a country continue to subsidize RES beyond the point where it supplies its own demand? One could also argue that an area does not supply its own demand even if RES production is 100 % of demand, as power in such a high RES situation would need to be curtailed from time to time. Supplying its own demand would therefore require a RES production above 100 % of demand.

The third limitation is the thermal modelling used in this study. Thermal power plants have been modelled without start-up cost and ramping requirements. This is highly unrealistic, but a consequence of keeping computational times reasonable. This limitation reduces price volatility in the results, compared to what would be reality. We would therefore expect price differences, especially through the day, to be larger than the results convey the impression of. One of the benefits of hydro power is therefore underappreciated in the results presented in this report. One should be aware that this is related to one of the future challenges of thermal power production operation. There will be strong economic incentives to ramp up or down on short notice, as weather changes.

5.2 Power prices under influence of RES

In this subchapter, the future power prices will be discussed. As DoubleRES is V4-16 with extra RES, how RES impacts the power prices can be seen amongst others from the difference between the two scenarios. The RES share (not including biomass) of electricity production was 23 % in 2014. [27] While it is 39 % in V4-16 and 69 % in DoubleRES. The change from the present situation to V4-16 is in other words smaller than that from V4-16 to DoubleRES in terms of installed capacity of RES.

In addition to the share of RES, the CO_2-price is of major importance to the power price. The CO_2-price makes the marginal cost of all CO_2-emitting power plants higher, creating a jump in the thermal marginal cost supply curve. This has two results. Firstly, the overall power prices increase. Secondly, the power prices become more volatile, especially in DoubleRES where the operating point is closer to this jump.

5.2.1 Overall power prices

The overall future power prices are of major importance to investors, who look to invest in power production. It directly affects the expected income, and therefore profitability of a project. On the most general level more RES leads to lower power prices. Contrary, the CO_2-price – and possibly, a reduction in installed thermal power generation – contribute to higher power prices. The price at which investing in RES makes economic sense, is therefore an important factor for the long-term power prices. IRENA have made predictions regarding the

LCOE of the RES types doubled in DoubleRES. Their predicted LCOE for solar, wind, and offshore wind power is found in Figure 13.[3]

Table 13: LCOE development for solar and wind power in €/MWh. [3]

Technology	2015	2025
Solar PV	122	56
Onshore Wind	66	47
Offshore Wind	169	113

According to IRENAs 2025 predictions, both solar and onshore wind power production investments are profitable in all areas in V4-16, while offshore wind only is profitable in PL and CZ. In DoubleRES on the other hand, GB and IB has too low average power price for any RES investment to be profitable, indicating that their RES shares are unrealistically high in DoubleRES. The DoubleRES power price in the Danish areas is on the borderline of want would be needed for a profitable onshore wind investment, while all other areas have power prices high enough for both profitable solar and onshore wind investments. This indicates that even though the share of RES may be realistic in DoubleRES, the distribution between areas would have to be adjusted.

As already mentioned the CO_2-price, increases the overall power price. This was shown in the project thesis,[5] and is indicated by the thermal marginal cost supply curves of subchapter 4.1.1. One could therefore argue that there is a balance between CO_2-price and installed RES capacity. Up until now, subsidies have been an important factor in determining the amount and location of installed capacity of RES in the European power system. Subsidies interferes with the balance between CO_2-price and installed RES capacity. If extensive use of subsidies is continued to such a degree, that the reduced CO_2-emissions from the power sector is enough to keep the European CO_2-emissions well below the emission cap in the EU ETS, the installed capacity of RES can be high at a low CO_2-price. In other words, the overall power prices can be below the LCOE of RES predicted by IRENA. I would however argue that the LCOE of RES indicates an upper limit for how high the power prices can be over a long period of time. The power industry is prone to the effects of business cycle, and as seen in this thesis, power production from RES differs from year to year. This limit does in other words indicate an equilibrium in the investment market.

Another important factor for the overall power prices is the amount of installed thermal power generation. Less thermal power generation will make the thermal marginal cost supply curve steeper, which will result in more price volatility and higher power prices. There are two main causes that leads to decommissioning of thermal power plants. Firstly, regulation can make operation forbidden. There could for instance be put an upper limit on how much CO_2 a generation unit can emit per kWh produced. Secondly, further operation is no longer economically viable. Note that a generation unit can be economically viable to run even if it loses money. A large share of the cost of a thermal power plant is capital cost, i.e. paying off the mortgage which financed the investment. This capital cost will not be eliminated if the power plant is decommissioned, hence are irrelevant to the question of continued operation. A thermal power plant will not be economically viable when the owners believe the future revenue will not be sufficient to cover the future cost of operation and maintenance. Investing in a thermal power plant and decommissioning of the same thermal power plant will in other words happen very different expected future power prices. The result is that when the need for thermal power plants are reduced faster than the planned decommissioning rate due to age, there will be movement away from the equilibrium in the investment market. This results in a surplus of thermal power plants in the system. There is in other words not a production capacity problem in such a system, and the prices will never be extraordinarily high.

Increasing the storage in a power system, will reduce the net load peak, as storage units pursue to exploit price differences. This will contribute to keep the thermal power plants with the highest marginal cost from running, hence making them unable to cover operation and maintenance cost. A legitimate question is however if price differences are high enough to result in storage investments before thermal power plants are decommissioned.

5.2.2 Seasonal power price variations

In addition to lowering the power prices, RES changes the daily and seasonal variations of the power prices. Regarding the seasonal variations, RES creates more volatility. Additionally, solar and wind power have the opposite contribution to the balance between summer and winter prices. While solar power creates lower summer prices, wind power creates lower winter prices. If solar and wind power are combined in an area, at the right balance, the result is lower spring prices. The cause is that wind power production is reduced from high winter level to low summer level later in the spring than solar power production increases from low winter level to high summer level. This is explained in subchapter 4.2.1. Low spring prices was observed in IB, IT, SEE, AT, CH and to some degree FR and DE. This effect gets larger and larger as the RES share increases. In the same subchapter, it was shown how a wind power dominated area would experience low autumn prices as in some situations. The low autumn prices would be most present when the difference between summer and winter prices was about zero. If the share of wind power exceeded that point, the effect fades away. This happens with GB. It experiences low autumn prices in V4-16, a pattern which is reduced in DoubleRES.

Both types of wind power produce 23 % of demand in V4-16, while solar power produces 9 % of demand. As there is more wind power than solar power in the system, the wind power affects seasonal variation of the net load and the power prices more than the solar power. As wind power produces more during winter, its contribution cancels out the traditional seasonal variations caused by demand. Consequently, the average price difference between the summer and winter is reduced. This is especially the case in V4-16. In DoubleRES the share of RES becomes so large, the RES production becomes a key factor in determining the seasonal price differences, for instance in GB and the Danish areas which have higher average summer than winter prices.

5.2.3 Power surplus and deficit

In this study three regions have been identified as deficit regions, BE+NL, NO3+NO1+SE3 and FI+BAL+PL+CZ. Of these three regions, the North-Eastern European region is the only one with demand driven power prices. The Nordic deficit area has demand driven net load, but the Nordic hydro power system reduces the price difference between summer and winter considerably.

Areas with major energy surplus compared to demand includes DK-E, DK-W, SE1, SE2 and SE4. The energy surplus from GB, IB, and DE are also considerable, due to their size. In the results, we have seen that there is low mobility between surplus and deficit for the areas, both considering different times of the day, different times of the year, and between DoubleRES and V4-16. Not surprisingly, the power prices are on average higher in deficit areas, and lower in surplus areas. This is however also related to how and how well the areas are interconnected. While the power price differences between the Nordic deficit area and SE1 and SE2 is small, especially compared to the power price difference between GB and the North-Eastern European deficit area. Even though which areas are surplus and deficit areas hardly changes within this study, the situation described here has significant differences from the present situation. In the present of writing this report, Norway and Sweden have a combined power surplus, and SE4 is typically the Swedish area with the highest price. Both because of low power production in SE4, but also because it is connected to DE, PL and BAL which contributes to the price increase. Surplus power from SE1 and SE2 is in other words transmitted through SE3 and SE4 into continental Europe. In V4-16 and DoubleRES however, SE4 is a part of a significant power surplus region. The Nordic power prices is also considered one of the lowest in Europe in the present. This is however not the case in V4-16 or DoubleRES, where there are only three areas with a power price larger than those of the Nordic areas, FI, BAL, and PL. The Nordic areas are hydro power dominated areas. The marginal cost of hydro power, the water values, are depended on marginal cost of connected thermal power production. They set the alternative income hydro power producers can achieve if the change which hours they produce. In other words, the connection between the Nordic areas and FI, BAL, and PL is the reason for the – in a European scale – relatively high Nordic prices. In the future of V4-16 and DoubleRES, larger interconnection capacity to FI, BAL and PL would lead to higher prices in the Nordics, while larger interconnection capacity to GB, NL, DE, DK-E, and DK-W would lead to lower prices in the Nordics. This is contrary to the present. As Norway and Sweden are a surplus region in the present with minimal transit, increasing the interconnection capacity in any direction would lead to higher prices. The results of V4-16 and DoubleRES do however show that the region of Norway and Sweden, and especially Norway, will not necessarily be a power surplus area in the foreseeable future.

5.2.4 Daily power price variations

In addition to the seasonal variations of the average price level, there are seasonal variations in the extreme prices. The largest difference between the most extreme high prices and most extreme low prices happen almost without exceptions during winter. This is mainly because the combination of two things. Firstly, most extreme low price that can occur is 0 €/MWh, the model simply curtails overproduction. Secondly, all areas have a high winter, low summer 100 % percentile of net load. This percentile describes the hours where RES production is minimal, consequently demand is the main driver for the shape of the 100 % percentile of net load. As a result, the potential for the highest prices and for the highest price volatility is during winter. Note however that the Nordic areas have highest price volatility during summer. This is further explained in subchapter 5.3.

Regarding the daily variations, solar power production reduces the noon net load and prices. This does have such a profound effect that all areas in V4-16, except for GB, FI, BAL, and PL, have their lowest average price of the day at noon. In DoubleRES, BAL is the only exception. The impact of the solar power production increases from V4-16 to DoubleRES. Both, as we just discussed, in the amount of areas, but also in terms of scale. In DoubleRES the price differences between morning and evening in Norway and Sweden is larger than in V4-16. Not including SE4, the price difference was around 2 €/MWh in V4-16 and 6.5 €/MWh in DoubleRES. The same pattern is visible across areas. As the solar power production influences the daily power prices more and more, evening becomes the new high price period of the day. In the transition from the present where the night is the low-price period of the day, to the DoubleRES, where the period around noon is the low-price period of the day, there will be a time where the average night, morning and early afternoon price is equal. In this scenario, the number of low-price hours per day is higher than what we are used to now, and what will be the situation of DoubleRES.

Wind power on the other hand change every hour of the week almost equally. It does however introduce volatility on a day to day and hour to hour level, but with minimal bias towards certain days or times of the day. It does therefore show up on the week profile figures used in this report as larger distance between the percentiles. Wind power does in other words create power price fluctuations that one would need a precise weather forecast to know when will happen. This makes planning of small scale storage difficult, both batteries and small hydro power reservoirs.

5.3 Nordic hydro power in a RES dominated system

This subchapter will discuss reservoir management, power prices, import, storage requirement and correlation between import and power prices, and how they are all related from a Nordic perspective.

From the results:

- Higher price in winter than summer in the Nordic area.
- Higher prices in summer than winter in GB, NL, DE, and the Danish areas.
- Larger export from the Nordic area during summer than winter.
- Positive correlation between import and seasonal power price in the Nordics.
- Storage requirement largest in winter across all areas.
- Almost flat average seasonal net load in the total system.
- Storage requirement in winter is reduced in DoubleRES compared to V4-16.
- Norway and Sweden stores 11 TWh less for the winter in DoubleRES.

- Norway and Sweden have larger price differences between summer and winter price in DoubleRES.
- AT+CH also export more during summer, but have negative correlation between import and seasonal power price.
- Interconnections between the Nordic areas and continental Europe are among the most used.

The storage requirement of subchapter 4.2.3 is largest in winter across all areas despite an almost flat average seasonal net load in the total system. This is a result of how storage requirement is defined in subchapter 4.2.3. The whole purpose of storage in the perspective of subchapter 4.2.3 was to reduce the peak net load. While the average net load was almost flat, the 100 % percentile had significant seasonal variations, being highest during winter, causing the need for winter storage.

While Norway and Sweden stores 11 TWh less on average for the winter in DoubleRES, 2 TWh extra storage is needed for more than one year storage purposes within Norway and Sweden. The extra internal requirement for more than one year storage is in other words not enough to explain the reduced winter production. This is despite a stronger economic incentive to store more for the winter in DoubleRES. To understand this contradiction, one must know that the calibration hugely affects the hydro power production and reservoir handling. DoubleRES and V4-16 is calibrated in such a way that the Nordic reservoirs do not completely empty even during the worst winter. This is because this area is dependent on its hydro power reservoirs to supply the demand at the end of the winter. Empty reservoirs will in other words mean load shedding. One major difference between DoubleRES and V4-16 regarding the surroundings of Norway and Sweden is the increased volatility of the DoubleRES Finnish winter prices. More precisely the share of hours with low Finnish prices during the winter is fluctuating from year to year. Were low prices in this case means lower than 70 €/MWh, which is low enough to induce import from FI towards Norway during most winter situations. This share is 1.7 % and 15 % in the two most extreme years. The Norwegian and Swedish hydro power reservoirs is in other words calibrated such that they will not empty, not even in the year were the Finnish winter price is only low in 1.7 % of the time. The potential for low Finnish winter prices is increased in DoubleRES. Because of the way Norwegian and Swedish hydro power reservoirs are handled, the import from Finland increases in the years were the Finnish winter price is low in more than 1.7 % of the time, thus reducing the average amount of power production in Norway and Sweden during winter. The reduced seasonal storage observed in

Norway and Sweden is in other words a consequence of the increased need for more than one year storage. Although not to cover internal year to year fluctuations, but to cover internal demand in a situation with external year to year fluctuations. The changing storage need from seasonal to more than one year storage seen in the Nordic areas is coherent with the overall storage requirements seen in 4.2.3 for V4-16 and DoubleRES. There is was shown how the number of storage incidents ending in spring with large energy requirements was reduced from V4-16 to DoubleRES when the peak storage requirement was kept constant. In other words, the number of years were large seasonal storage is needed is reduced from V4-16 to DoubleRES, Consequently, some storage will be occupied for the purpose of supplying the most extreme years, reducing the amount that can be used for seasonal storage in non-extreme years. A consequence of the different way the Nordic hydro power reservoirs is handled in DoubleRES is higher – on average – filling, and an increased risk of overflow during summer. Hence the increased potential for low summer prices in Norway and Sweden. Note that this means increased RES production in Europe will increase the economic incentive to install storage, including storage used to store energy from summer to winter in the Nordic areas. This should be taken into consideration when planning new hydro power reservoirs and rehabilitation of old hydro power dams.

As observed, most Nordic areas have a positive correlation between import and seasonal prices. This is a consequence of the average prices being highest in winter, and average import highest in winter, while average prices and import both are lowest during summer. To have negative correlation, these areas would need to not experience overflow during summer. This way, the water values of the depletion and filling season could be equal, and hydro power would not need to sell production at a lower price during some periods of the year. The summer overflow is in other words the cause of the positive correlation.

Note that both AT+CH and the Nordic areas import more during winter and less during summer. The Nordic areas even uses larger percentage of their reservoirs for seasonal storage. Despite all this the Nordic areas have positive correlation between import and seasonal prices, while AT+CH have negative. This has everything to do with internal prices. Also note that AT+CH do not experience overflow, i.e. a driver to create differences in water values through the year is gone.

Another peculiar observation is comparing Nordic import to the power prices in GB, NL, DE, and the Danish areas. Their average power prices are higher during summer and lower during winter. Nordic import would therefore be to their benefit, helping to reduce their seasonal price differences. The import pattern is however not driven by what suits GB, NL, DE, and the Danish areas, it is driven by what suits the Nordic areas, to avoid wasting zero marginal cost power in overflow. Therefore, the positive correlation in the Nordic areas. Note that if the Nordic areas have had a larger export during winter and negative correlation, this would imply increasing the seasonal differences of GB, NL, DE, and the Danish areas.

In subchapter 4.6 it was shown how DE and GB have the highest positive correlation between seasonal power price and import of all areas, meaning they are pushing their seasonal prices onto nearby areas. Both these areas are connected to NO2 and both are among the largest in the system, meaning their influence is significant, and both have high average summer prices. Could higher summer prices than winter prices also occur in the Nordic areas? First, the power prices are a driver for hydro power reservoir handling. The whole purpose of grid connected storage is to collect at times where energy is abundant and cheap, and release at times where energy is scarce and expensive. Price differences is in other words the economic foundation of storage. If the power prices were on average higher during summer than winter, reservoirs would not be used to store large amounts of energy for the winter, i.e. other energy sources than stored hydro power would need to supply the Nordic areas with power during the winter. There is in other words a massive resistance in the Nordic system towards higher summer than winter power prices.

In subchapter 4.4.4, we saw that the interconnections connecting the Nordic areas to GB, DE, NL, and the Danish areas, are among the most used in the system. Note that the export from Nordic areas help reduce the daily price differences in GB, DE, NL, and the Danish areas, and that these two regions have opposite seasonal variations. Highly used interconnections are therefore not surprising, at least when the addition of large storage in the Nordic areas are accounted for. These results are an indication that expansion of the interconnections between these two regions are among those interconnection expansions that would benefit the system the most.

5.4 Solar in the south – wind in the north.

In this subchapter the idea that solar power in the south, and wind power around the North Sea will interact and balance each other is discussed. As shown in subchapter 4.2.1, the solar and wind power have opposite seasonal average production variations. This idea is therefore primarily related to seasonal variations. How daily variations from solar production is absorbed by the system, is a related topic that also will be discussed.

The three areas with the largest share of solar production is IB, IT, and DE, in descending order. As DE is part of the North Sea region, the power flow between the North Sea region and IT and IB are the focus.

From subchapter 4.6, we have that IB and IT behave opposite of each other in terms of correlation between import and power price in V4-16. Note that the DoubleRES behavior of IT was found to be influenced by suboptimal calibration. IT was found to absorb seasonal price differences in V4-16. There is in other words not a large power flow from IT to the North Sea region during the high solar production period of summer. IT is exporting most during winter. Looking at the maps of seasonal variations in 4.4.3, we see that the extra export from IT during winter goes via SEE to PL and CZ. What happens is that the hydro power in IT exploits the high prices occurring in the North-Eastern deficit area, and the contribution from hydro power is considerably more influential than that of solar power.

IB on the other hand was found to create seasonal price differences. Note however, that the average net load of IB, even in DoubleRES is not smallest during summer. It is smallest during spring. A consequence of the combination of installed solar and wind power. Looking at the maps of seasonal variations in 4.4.3, we see that the reason for the positive correlation is higher export during spring, than during summer and autumn. The export from IB is in fact a little higher during winter than summer, the opposite of what we would expect from an area with high share of RES and positive correlation regarding seasonal varitations. If one compares winter to spring and summer to autumn in maps of seasonal variations in 4.4.3, one would find that the import from IB to FR and the import from GB to FR behaves opposite of each other. In other words, North Sea region and IB balances each other. Note however that the variation on the GB-FR interconnection is far greater than that of the IB-FR connection. As, discussed in subchapter 4.6, FR is blocking import from IB during low net load periods. In terms of seasonal variations, low net load periods in FR is spring and summer. In IB, spring is the most significant low net load period. In GB, the low net load periods are winter and autumn. FR is in other words blocking IB import, when IB has low prices, but not blocking GB, when GB has low prices. The wind power production of the North Sea region is in other words balanced against FR demand, more than IB solar power production.

As, already mentioned FR is blocking import during low net load periods. This has been found to be the cause of the negative correlation between IB import and the daily variations of IB power prices. IB does in other words have a flatter marginal cost of supply curve around the operating point than FR. Therefore, the high noon solar production from IB is not absorbed by the whole of Europe. It is absorbed internally.

IT has positive correlation between daily price variations and power prices. IT has its lowest weekly average net load around noon. Meaning IT pushes a solar dominated day-night power price profile onto its neighbors. Looking at the maps of daily variations in 4.4.2, we do not see pattern in the power flows on the AT-DE and CH-DE interconnections, but it is present on the IT-AT and IT-CH interconnections. There are two reasons for this. Firstly, the daily price variations of IT are absorbed by hydro power in the Alp region. Secondly, DE the same amount of solar power production as IT. In V4-16, DE solar power produces 55.5 TWh, while IT solar power produces 55.7 TWh. There will in other words be several occasions where IT has cheap power due to solar power production, while the same is true in DE, reducing the driver behind power flows.

Even though the balancing between North Sea wind power and Southern European solar power is not significant, there are other balancing trends to be noticed. In As discussed, GB wind power balances with FR demand. GB wind power balances with DE solar power through NL and BE. And DE solar power balances with DK-W, DK-E, SE4, and the Nordic hydro power system.

5.5 Storage capacity

In this subchapter storage capacity will be discussed. One important question about the future is how much storage capacity could be installed.

In subchapter 4.2.3 we found if every German installed a Tesla Powerwall, i.e. 14 kWh of storage, that would result in a total of 2.04 GWh of storage per TWh produced each year in Germany. From Figure 48: Storage requirement with a 56 % peak net load reduction – IB, DoubleRES, we have that storage incidents lasting shorter than one day, has a maximum storage requirement of around 0.5 GWh/TWh/year. This value is highest for IB, compared to the other areas presented in subchapter 4.2.3. A natural consequence of IB having the largest amount of solar power installed of the areas presented. The value of 0.5 GWh/TWh/year of storage is important because it says how much storage can be used to reduce differences within a day. Having more than 0.5 GWh/TWh/year means the storage capacity would also be used for storage incidents of more than one day. This reduces the amount of charging cycles per year. At least when discussing batteries, a high enough amount of charging cycles per year would be important for it to be economically feasible. I would therefore argue that 0.5

GWh/TWh/year is an upper limit for how much battery storage is feasible in the DoubleRES scenario. 0.5 GWh/TWh/year of storage would give a reduction in peak net load of 20 % in V4-16 and 30 % in DoubleRES.

In subchapter 4.2.3 we found that the total storage capacity of hydro power reservoirs in Europe is 70 GWh/TWh/year. 70 GWh/TWh/year of storage would be enough to reduce the peak net load of 49.5 % in V4-16 and 71.5 % DoubleRES. Note that in this calculation, regulated hydro power inflow is not accounted for. Hydro power reservoirs ability to reduce peak net load would therefore be smaller than 49.5 % and 71.5 %. Additionally, the areal distribution of hydro power and coherent transmission capacity restrictions reduces these numbers.

6 Conclusion

This thesis set out to investigate the implications of a European large-scale development of RES to the Nordic power system. The conclusion will be divided into two in addition to suggestions for further work. First, the trends that will not change from the present is presented. Second, the new trends that are implications of the increased RES capacity is presented.

Current trend that will continue in the future includes:

- High winter price compared to summer price in the Nordics.
- Energy will be stored in hydro power reservoirs from spring/summer to the winter.
- Overflow will happen during some summers.
- The Nordic area will have a on average higher export during summer, and higher import during winter.
- There will be power deficit in NO3, NO1, and SE3.
- There will be power surplus in SE1, SE2, NO2, NO4, and NO5.
- FI, BAL, PL will on average have higher prices than the Nordic areas, and they will have a traditional demand dominated net load profile and price profile.

New trends that will occur with increased penetration of RES:

- SE4 will emerge to a power surplus area, with export from SE4 to SE3 becoming more and more normal.
- Denmark and SE4 will make up a considerable wind dominated surplus region with lower average power prices during winter than summer.
- Norway is no longer a surplus region in Vision 4 2016. Norway has a 22 TWh deficit in V4-16.
- The Nordics have among the highest average power prices in Europe, only exceeded by the average power prices of FI, BAL, PL and CZ. The Nordics does in other words have higher average power prices than GB, NL, DE, and the Danish areas. Consequently, the balance between interconnection capacity to the South-East and South-West will determine the power price level in the Nordic areas.
- As the Nordic power surplus is reduced, the use of the transmission cable to NO2 for balancing daily price variations will increase. This will come at the expense of one way energy export.

- Peak net load is reduced with 3 % from V4-16 to DoubleRES, while the total net load is reduced with 49 %. Consequently, price volatility will increase.
- Peak net load can be reduced with storage. An upper limit of battery storage is estimated to 0.5 GWh/TWh/year. That would reduce the peak net load with 20 % in V4-16 and 30 % in DoubleRES
- Some of the power price fluctuations originating from RES will be known only a short time ahead of them occurring. This makes small scale storage planning difficult.
- There will be a surplus of CO_2-emitting power plants in the system. Consequently, the danger of power capacity shortage and accompanying high power prices is slim. This reduces the economic incentive to install storage in the system. PL, BAL and FI are for instance the only areas where the most inefficient gas power plants ever gets used.
- NL, GB, DE, and the Danish areas will get on average higher prices during summer than winter. Their production capacity need is however largest during winter.
- Solar and wind power production varies from year to year, just like inflow. This increases the need for more than one year storage. Norway and Sweden stores 11 TWh less from summer to winter in DoubleRES compared to V4-16. 2 TWh of this is to compensate for the year to year variations of internal solar and wind power production. The rest is to make room for storage that can compensate for year to year variations of neighbouring areas. Consequently, there is more overflow and larger price differences in the Nordics in DoubleRES than V4-16. As a result, storage will be more valuable as RES penetration increases. This should be taken into consideration when rehabilitating old hydro power dams, or building new ones.

Regarding the overall power price level, increased RES penetration contributes to overall lower power prices. It is however unjustifiable to conclude concisely about what the average future power prices will be, based on this thesis. There is on the other hand a fundament to argue that the LCOE of RES will be important for the equilibrium in the investment market, and therefore the long-term power prices. Although it should not be left unmentioned that subsidies can reduce long-term power prices below the level of LCOE of RES.

6.1 Further work

The following further research are suggested:

- Research the cause of the difference in input and output demand.
- Divide Germany into a northern and a southern area.

- Check and update the regulated and unregulated inflow series of Europe.
- The net load dataset can be used to serve as a basis for further research. This could include:
  - A more detailed analysis of the difference between years with large and small RES production.
  - Analysing whether RES requires faster and/or more frequent ramping of power plants than what is required by demand.
  - What would be required of installed storage and RES capacity to remove all CO_2-emitting production from the European power system.
- The dataset can serve as a basis for future master theses based on the EMPS model. Note that a detailed water course description can be added for research where that is required. The future research could include:
  - Sensitivity study of changing interconnection capacity.
  - Investigating the transmission profiles of specific interconnections.
  - Studying the consequences of reserve requirement.
  - Research the implication of an increased installed generation capacity in the Nordic hydro power system.
  - Investigating the result of increasing installed capacity of wind power in Norway. What if the wind resources of Finnmark was exploited?
  - As RES becomes ever cheaper, one could imagine a future where the Nordic power prices is no longer a competitive advantage for power intensive industry. What would be the consequence of outsourcing power intensive industry on the Nordic power system?
  - What would happen if large scale development of data processing centre happened in the Nordics? What would happen if data processing centres and an equivalent amount of RES production was added in the Nordics?
  - Investigate the extremes even further. What is the average situation when solar power produces above 90 % of capacity? What is the average situation in the 10 % of hours where the overall net load is the highest? Etc.

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8 Appendix

8.1 Copy of EMPS input parameters

GENERELLE DATA: DIVERSE STYREPARAMETRE

****

ANTALL VERK SOM SKAL SAMKJ\RES NVERK : 25

ANTALL TILSIGSALTERNATIV SOM SKAL SIMULERES NSIM : 75

]RSTALL FOR F\RSTE TILSIGSALTERNATIV STAAR : 1931

]RSTALL FOR F\RSTE]R I DATAPERIODEN INNAAR : 2030

NUMMER P] SISTE UKE I DATAPERIODEN NUKE : 52

F\RSTE UKE SOM SKAL SIMULERES JSTART : 1

SISTE UKE SOM SKAL SIMULERES JSLUTT : 52

SERIESIMULERING=T, PARALLELLSIMULERING=F, SERIE : T

REALRENTE (%) : 0.0

REALRENTE BRUKES I SAMUTSKRV : NEI

8.2 Calibration factors

Table 14: Calibration factors used for V4-16

Omr}de nummer	Navn p} omr}de	Tilbake- koplings- faktor	Form- faktor	Elasti- sitets- faktor
1	NO1	4.240	1.130	1.000
2	NO2	4.250	1.955	1.000
3	NO3	4.550	1.486	1.000
4	NO4	4.650	2.509	1.000
5	NO5	4.660	1.532	1.000
6	SE1	4.430	1.907	1.000
7	SE2	4.350	1.181	1.000
8	SE3	4.400	0.694	1.000
9	SE4	4.020	0.738	1.000
10	DK-E	0.000	0.000	1.000
11	DK-W	0.000	0.000	1.000
12	FI	3.890	0.931	1.000
13	BAL	0.909	0.000	1.000
14	PL	0.909	0.000	1.000
15	CZ	4.000	0.413	1.000
16	DE	4.010	0.254	1.000
17	NL	0.911	0.002	1.000
18	BE	0.907	0.000	1.000
19	GB	4.060	0.407	1.000
20	FR	3.693	0.439	1.000
21	IB	3.494	0.861	1.000
22	CH	3.506	1.488	1.000
23	AT	3.675	1.151	1.000
24	IT	2.955	1.000	1.000
25	SEE	3.630	0.514	1.000

Table 15: Calibration factors used for DoubleRES

Omr}de nummer	Navn p} omr}de	Tilbake-koplings-faktor	Form-faktor	Elasti-sitets-faktor
1	NO1	3.100	1.130	1.000
2	NO2	3.000	1.955	1.000
3	NO3	3.000	1.486	1.000
4	NO4	3.000	2.509	1.000
5	NO5	3.100	1.532	1.000
6	SE1	3.100	1.907	1.000
7	SE2	3.200	1.181	1.000
8	SE3	3.500	0.694	1.000
9	SE4	3.000	0.738	1.000
10	DK-E	0.000	0.000	1.000
11	DK-W	0.000	0.000	1.000
12	FI	2.000	0.931	1.000
13	BAL	0.909	0.000	1.000
14	PL	0.909	0.000	1.000
15	CZ	3.600	0.413	1.000
16	DE	3.400	0.254	1.000
17	NL	0.909	0.002	1.000
18	BE	0.906	0.000	1.000
19	GB	3.000	0.407	1.000
20	FR	3.000	0.439	1.000
21	IB	2.300	0.861	1.000
22	CH	2.900	1.488	1.000
23	AT	2.900	1.151	1.000
24	IT	2.500	1.000	1.000
25	SEE	2.900	0.514	1.000

8.3 Subdivision of the week

Table 16: Price periods

Hour	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
1	1	5	9	13	17	21	25
2	1	5	9	13	17	21	25
3	1	5	9	13	17	21	25
4	1	5	9	13	17	21	25
5	1	5	9	13	17	21	25
6	1	5	9	13	17	21	25
7	2	6	10	14	18	22	26
8	2	6	10	14	18	22	26

9	2	6	10	14	18	22	26
10	2	6	10	14	18	22	26
11	2	6	10	14	18	22	26
12	2	6	10	14	18	22	26
13	3	7	11	15	19	23	27
14	3	7	11	15	19	23	27
15	3	7	11	15	19	23	27
16	3	7	11	15	19	23	27
17	3	7	11	15	19	23	27
18	3	7	11	15	19	23	27
19	4	8	12	16	20	24	28
20	4	8	12	16	20	24	28
21	4	8	12	16	20	24	28
22	4	8	12	16	20	24	28
23	4	8	12	16	20	24	28
24	4	8	12	16	20	24	28

8.4 Explanation of figures

8.4.1 Map

As a part of the work with this master thesis, a map has been made, built to visualize results from the EMPS simulations. The objective of the map is to show how areas interact with each other, based on one or several price periods. The map displays a lot of data at the same time. To make it easier to read, colours are used extensively. The reader should be aware that the objective of the map is not to show exact numbers, but to give an overview of the whole power situation. The map is also built in such a way, that the most important information is easily readable, while at the same time including more information that could be studied. In other words, all the information that is possible to discuss, is not necessarily important, every time the map is used in this thesis.

It should be noted that the map shows a snapshot of the power situation. In other words, no dynamics. Which time periods to include in the map is on the other hand easily changed. The map can for instance show only price period 14 in week 34 in inflow year 1963, or an average of all price periods in all weeks in all years, or only night price periods at wintertime etc. When more than one price period is used, an average of the used price periods is displayed.

To make it easier for the reader to read the map, a presentation of the different building blocks of the map will follow. These include an area, a transmission graph, a RES graph.

8.4.1.1 An area

Each area is represented on the map as a rectangle, the only exception being DK-W, which have a slightly more intricate shape.

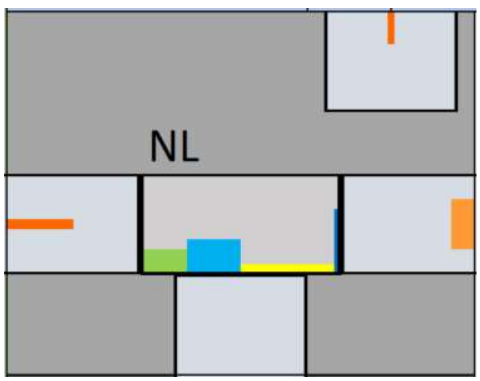


Figure 94: An area, represented by the Netherlands.

Each area includes a two or three letter code, stating which area it is in accordance to the price areas used in this study. On Figure 94 the Netherlands is identified with the two-letter code "NL". Within each area, there is a RES diagram. The RES diagram is a rectangle surrounded by black, displaying a green, blue, yellow, and dark blue bar. The rectangles surrounded by black displaying an orange bar is the transmission diagram.

The background colour of an area – the colour surrounding "NL" in Figure 94 – displays information regarding production and consumption within the area. The colour is connected to the ratio of dividing production by consumption. In Table 17, the relationship between background colour and consumption-production ratio is shown. In essence, an area has a greener background colour, if it produces more than it consumes, and a greyer background colour if it produces less than it consumes.

Table 17: Area background colour. The background colour of each area is linked to production divided by consumption.

Interval of production/consumption	Colour
>1.45	
1.35 – 1.45	
1.25 – 1.35	
1.15 – 1.25	
1.05 – 1.15	
0.95 – 1.05	
0.85 – 0.95	
0.75 – 0.85	
0.65 – 0.75	
0.55 – 0.65	
0 – 0.55	

8.4.1.2 Transmission diagram

The objective of the transmission diagram is to show the power flow between two areas. A transmission diagram consists of two squares surrounded by a black border, connected by a common line. The common line is outlined in Figure 96. This common line lies in most cases on the borderline of the two areas in question (with some exceptions in the North Sea). Figure 95 is an example of a transmission diagram as it is seen on the map.

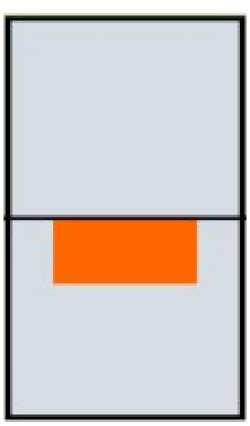


Figure 95: Example of transmission diagram

The grey background colour of the diagram does not represent any information. All information is displayed via the orange bar. Both the width, height, which square the bar is in and colour of the bar contains information.

As the orange bar is in the bottom square of Figure 95, power is flowing from the upper area to the bottom area – or from north to south. The orange bar can only be in one of the two squares.

For further explanation, a definition of width and height is needed. This definition is made in Figure 96.

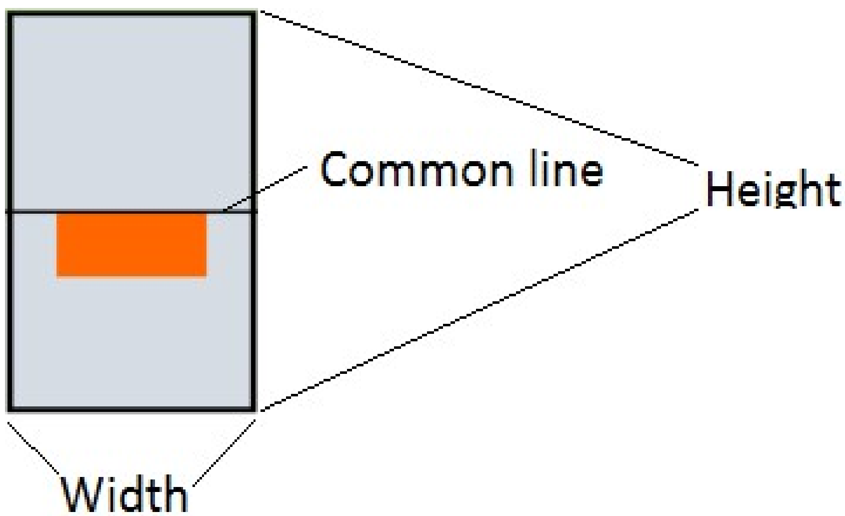


Figure 96: Example of transmission diagram with explanation.

The width of the orange bar displays how large the transmission capacity between the countries are. If the orange bar is as wide as the common line – using the whole width of the diagram – the transmission capacity is 10 000 MW. The transmission line used as an example in Figure 95 and Figure 96 have a transmission capacity of 6100 MW.

The height of the orange bar displays how many percentages of the total capacity is used. If the orange bar fills the height of one square, power is flowing from one are two the other at maximum capacity for all price periods included. As a consequence, the area of the orange bar is the average power flow, between the two areas in absolute values. The area of the orange bar is in other words comparable between transmission diagrams. The transmission line used as an example in Figure 95 and Figure 96 have an average net power flow of 1987 MW, which is roughly one third of the total capacity.

If a transmission line is used a lot, but in both directions, so that the average net power flow is small, the area of the orange bar would be small. To show the difference between a transmission line that is used just little, and one that is used a lot in both directions, colours is used. The colour of the bar changes depending on how many equivalent hours of full transmission its actual transmission corresponds to. The colour of the bar will in other words show how much a transmission line is used, not taking into consideration which way the power is flowing.

Table 18: Colour of transmission diagram as a function of equivalent hours of usage.

Equivalent hours [%]	Colour
0 – 30	
30 – 60	
60 – 85	
85 – 100	

8.4.1.3 RES diagram

Within each area, there is a RES diagram. The objective of the RES diagram is to show the state of the RES production within each area. Figure 97 is a RES diagram as used in the map.

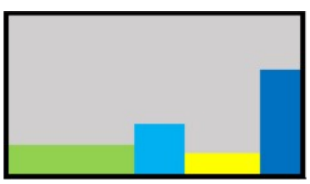


Figure 97: Example of RES diagram

The RES diagram includes 4 coloured bars representing four different types of RES, explained by Figure 98. The grey background colour represents no additional information.

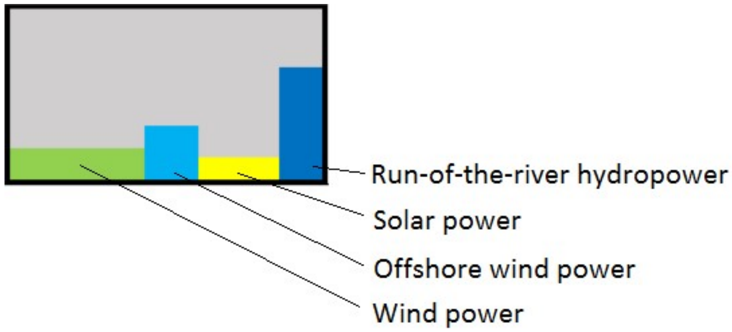


Figure 98: Example of RES with explanation.

The width of each bar represents how much installed capacity this RES has, as a percentage of the total installed RES capacity in the area. This means that the four bars will fill the width of all RES diagrams. Consequently, the RES production is not comparable between areas in absolute numbers. The height of each bar represents how much the RES type is producing compared to its capacity. A bar that fills the diagram from bottom to top, describes 100 % production. Consequently, the area of each of the four bars are comparable within a RES diagram, where the area will describe how much energy each RES type is producing.

Table 19 presents - in tabular form - the same values as Figure 97

Note that as the TYNDP dataset does not differentiate between regulated and run-of-the-river hydropower, the installed capacity of run-of-the-river hydropower is simply equivalent to the week with the maximum unregulated inflow.

Table 19: RES production presented in tabular form.

RES type	Capacity as percentage of total RES capacity within area.	Power production as percentage of full production	Power production in absolute numbers
Wind power	45 %	19 %	6072 MW
Offshore wind power	17 %	32 %	3889 MW
Solar power	25 %	13 %	2392 MW
Run-of-the-river hydropower	13 %	69 %	6378 MW

8.4.1.4 What area is where?

To make it easier for the reader to see how this map of rectangular areas are connected to the real areas. Some important areas will be highlighted in this section. In Figure 99, Figure 100 and Figure 101 shows a cutout of Norway, Sweden, and Denmark respectively. Knowing the shape of these areas should make it easier for the reader to find his/her way around the map. Note that the blue areas connected to Norway, seen in Figure 99 is the sea.

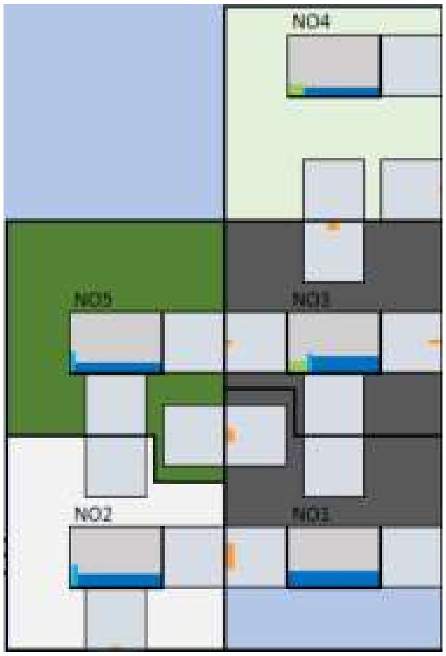


Figure 99: The five areas of Norway

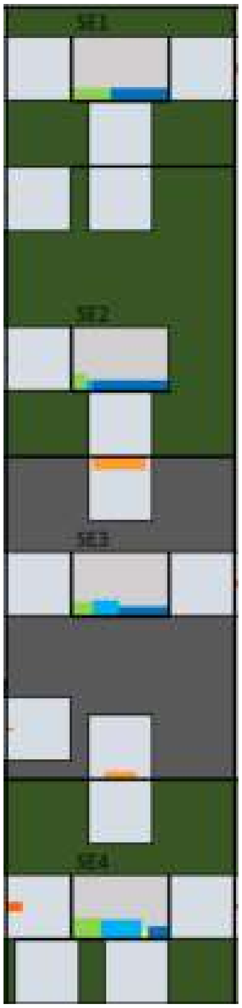


Figure 100: The four areas of Sweden

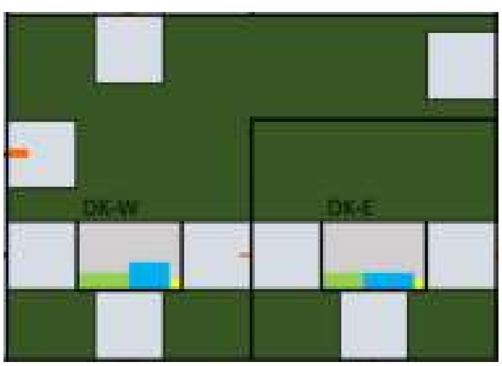


Figure 101: The two areas of Denmark

Figure 102 displays an example of a full map. In addition to locating Norway, Sweden, and Denmark. Identifying the British Isles ("GB") in the left part of the map, and Germany ("DE") in the middle of the map, makes understanding what is where easier. Germany stands out by being the largest area on the map, with a white background colour on Figure 102.

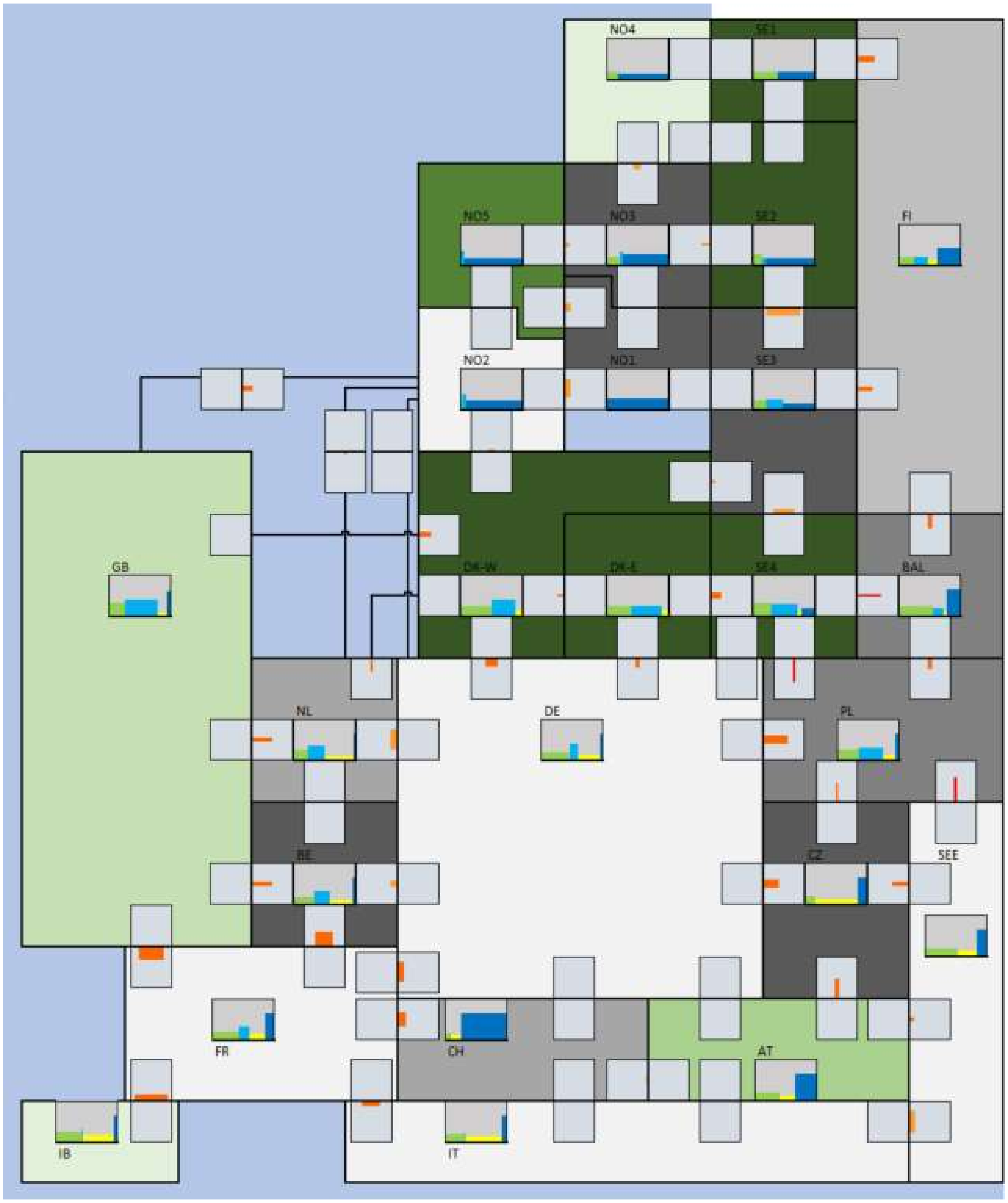


Figure 102: Example of map

8.4.2 Market equilibrium

To show the connection between production, consumption and price, a market equilibrium figure is used.

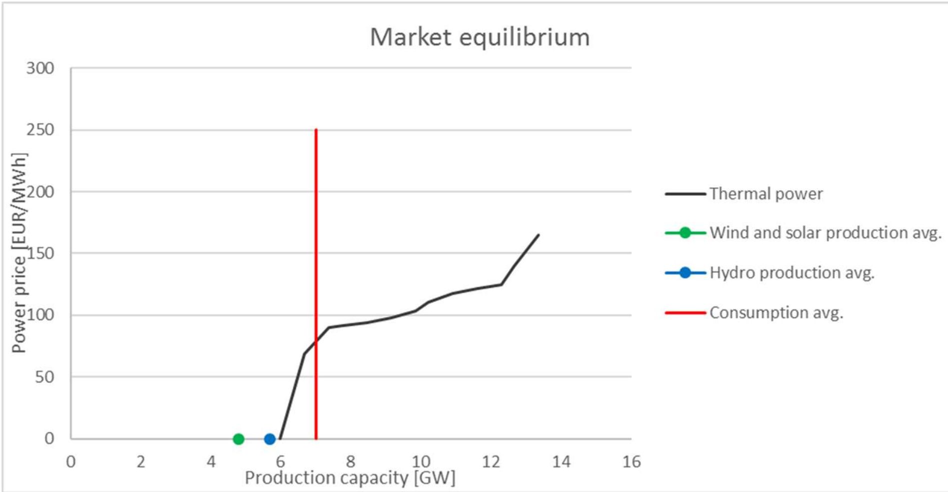


Figure 103: Market equilibrium – Greece Vision 4 2016

Figure 103 is an example of a market equilibrium curve. To be consistent with the use of colours, green and blue are used for wind and solar power and hydro power in the same way as with the power generation chart.

Note that this chart is a combination of production capacity and actual production. Hydro production, wind production and consumption are average values, while the thermal power curve represents the bidding curve of thermal generators. The marginal price of hydro power is set to 0 €/MWh, i.e. the marginal cost of running the power plant. This is chosen to better show how the market price is changed with consumption and RES fluctuations and changes in consumption and RES averages, as the hydro power operational marginal cost is a function of these variables.

To display sensitivity in the market equilibrium, a version with high and low consumption, and shifted bidding curve due to high and low wind and solar production is used.

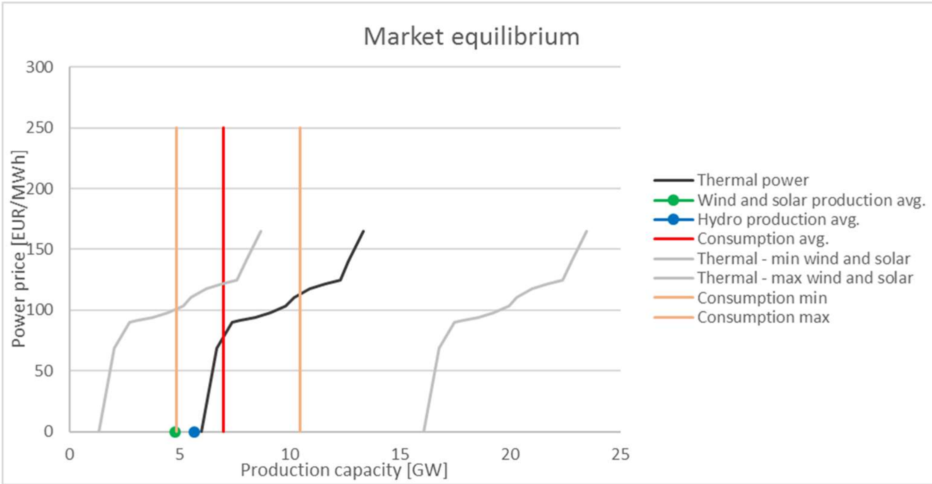


Figure 104: Market equilibrium sensitivity - Spain Vision 4 2016

Figure 104 is an example of sensitivity version of the market equilibrium figure. The low and high values of consumption derive from the week with the lowest average value, and the week with the highest average value respectively. The high and low values for wind and solar production are given in the same way. The sensitivity version of the market equilibrium figure is the only one that will be used in this master's thesis.

Note that the market equilibrium figures don't take exchange into account.

8.5 Explanation of EXCEL documents

This appendix exists to make it possible for other users to take advantage of the excel sheets made for this master thesis.

Results from the EMPS model have been gathered through the programs samutskrv and pckurvetegn. Where samutskrv gives a detailed report (Table 1) of the simulation, and pckurvetegn has been used to retrieve power flow on the transmission lines. The results from samutskrv is saved as "… - samutskrv.txt", and the results from pckurvetegn is saved as "… - utv.txt". The detailed simulation report from samutskrv needs some manual adjustments to work. It can only have one row of headers at the top. Therefore, the line containing units most be manually deleted, and the first lines of the document, containing information about the EMPS parameters must be deleted.

The simulation reports from samutskrv contains too many rows to import directly to Excel. Therefore, simulation reports have been imported to Power Pivot. Pivot tables have then been used to import relevant data from Power Pivot to Excel sheets.

As the detailed simulation report includes a lot of data, using one Excel-document for all data processing is not viable. It would be too big and slow for the computer to handle. There have therefore been generated several Excel-documents each solving specific problems. The nature of the analysis done requires some of these Excel-documents to be interconnected, i.e. importing data from each other. Consequently, the user may need to update the paths used in some formulas.

The following excel documents are included:

There are four documents containing the production profiles of each type of RES:

- RES master profiles – offshore vind.xlsx
- RES master profiles – uregulert.xlsx
- RES master profiles – sol.xlsx
- RES master profiles – vind.xlsx

These documents contain the production profiles, and scales them according to the installed capacities.

There is one document for containing the demand series:

- Demand.xslx

There are two documents used for the net load analysis.

- RES Analysis.xlsm
- Battery storage requirement.xlsm

These two documents can import data from different areas depending on the value of a cell. They amount of onshore wind, offshore wind, demand, solar and unregulated hydro can be adjusted without changing the RES master profile documents.

There is one document for importing simulated transmission usage from "… - utv.txt" (does not use Power Pivot):

- Utveksling.xlsx

There is one document preparing information for the map:

- Kart input.xlsx

There is one document creating the map:

- Kart.xlsx

The structure of the excel documents are as follows.

RES analysis.xlsm and Battery storage requirement.xlsm imports from the four RES master profiles documents and Demand.xlsx

Kart.xlsx imports from Kart input.xlsx

Kart input.xlsx imports the samutskrv results from Power Pivot, and imports from Kart.xlsx, Utveksling.xlsx, the four RES master profiles documents and Demand.xlsx

A future user should also be aware the relationship between Kart.xlsx and Kart input.xlsx. The task of Kart.xlsx is to import exactly the data it needs to display a map, and display it as a map, as well as deciding which price periods, weeks, and years to include. Which price periods to include are decided from the sheet "Siling". Kart input.xlsx collects which price periods, weeks, and years to include from Kart.xlsx. Kart input.xlsx also collects all necessary data Kart.xlsx needs, this happens both through connections to other Excel-documents (including the five database Excel-documents made for the net load analysis) and Power Pivot. Kart input.xlsx then processes the data, in such a way that Kart.xlsx can import everything it needs and exactly what it needs from Kart input.xlsx. Consequently, one would need to run the calculation of Kart input.xlsx every time one wants to change the map, thus having both documents open simultaneously is desirable.

Note that the increased RES production of DoubleRES is taken care of by multiplying the RES production values by two in Kart.xlsx. To achieve this a value in "Siling" at Kart.xlsx needs to be adjusted.

8.6 Countries of ENTOS-E TYNDP

Table 20 presents the 35 countries used in ENTSO-E TYNDP, with country name and country code.

Table 20: The 35 European countries used in TYNDP

Country Code	Country
AL	Albania
AT	Austria
BA	Bosnia and Herzegovina
BE	Belgium
BG	Bulgaria
CH	Switzerland
CY	Cyprus
CZ	Czech

DE	Germany
DK	Denmark
EE	Estonia
ES	Spain
FI	Finland
FR	France
GB	Great Britain
GR	Greece
HR	Croatia
HU	Hungary
IE	Ireland
IT	Italy
LT	Lithuania
LU	Luxemburg
LV	Latvia
ME	Montenegro
MK	Macedonia
NI	Northern Ireland
NL	The Netherlands
NO	Norway
PL	Poland
PT	Portugal
RO	Romania
RS	Serbia
SE	Sweden
SI	Slovenia
SK	Slovakia

8.7 Figures

Table 21: Table of content for 8.7 Figures. Displays the page number at which the different figures are located.

8.7.1 Net load – V4-16

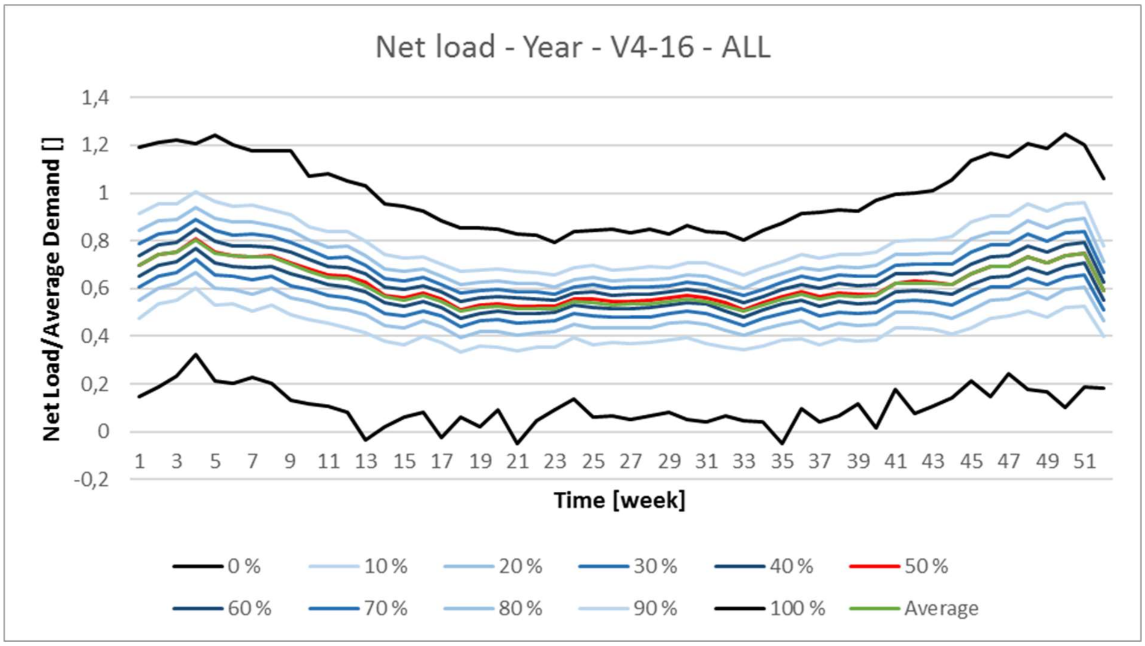
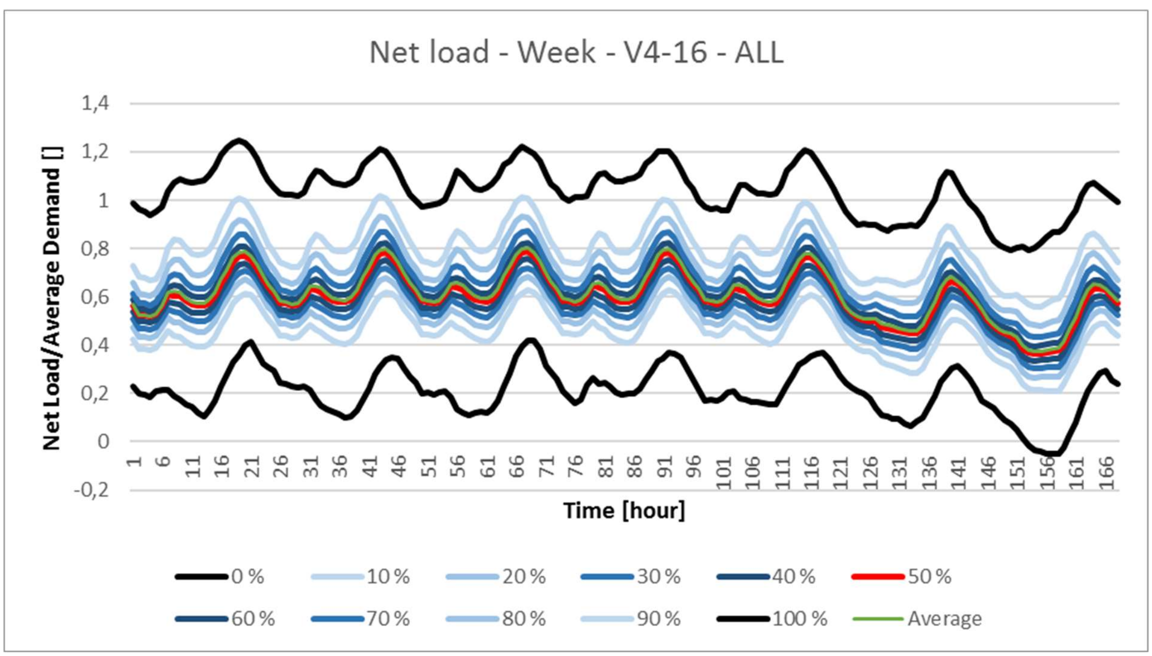


Figure 105



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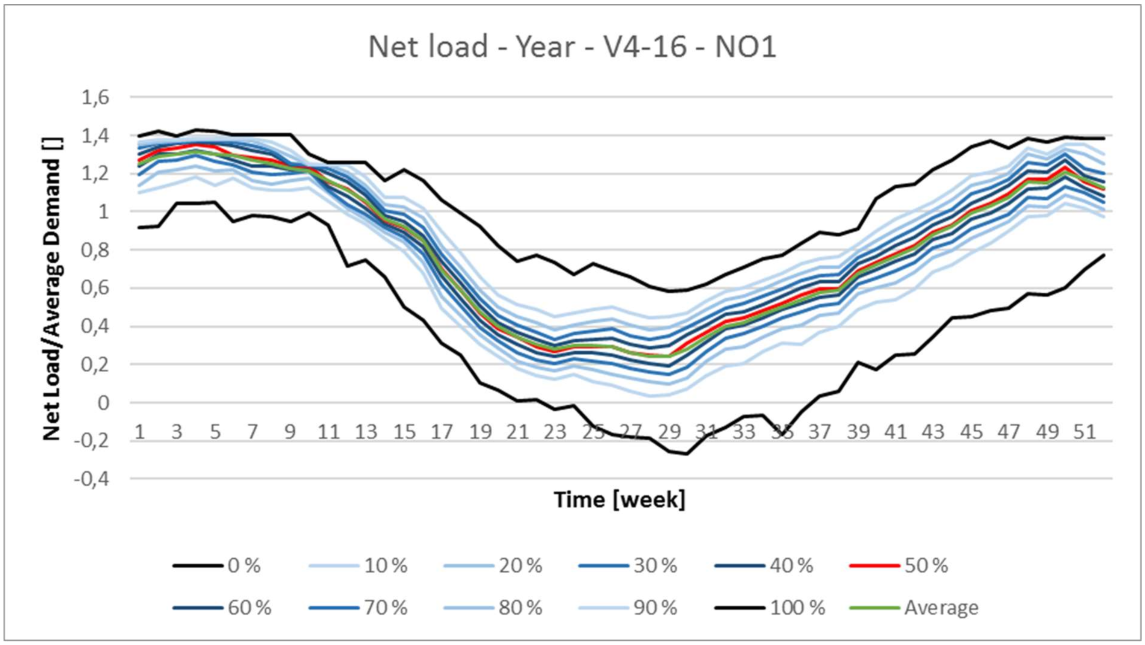

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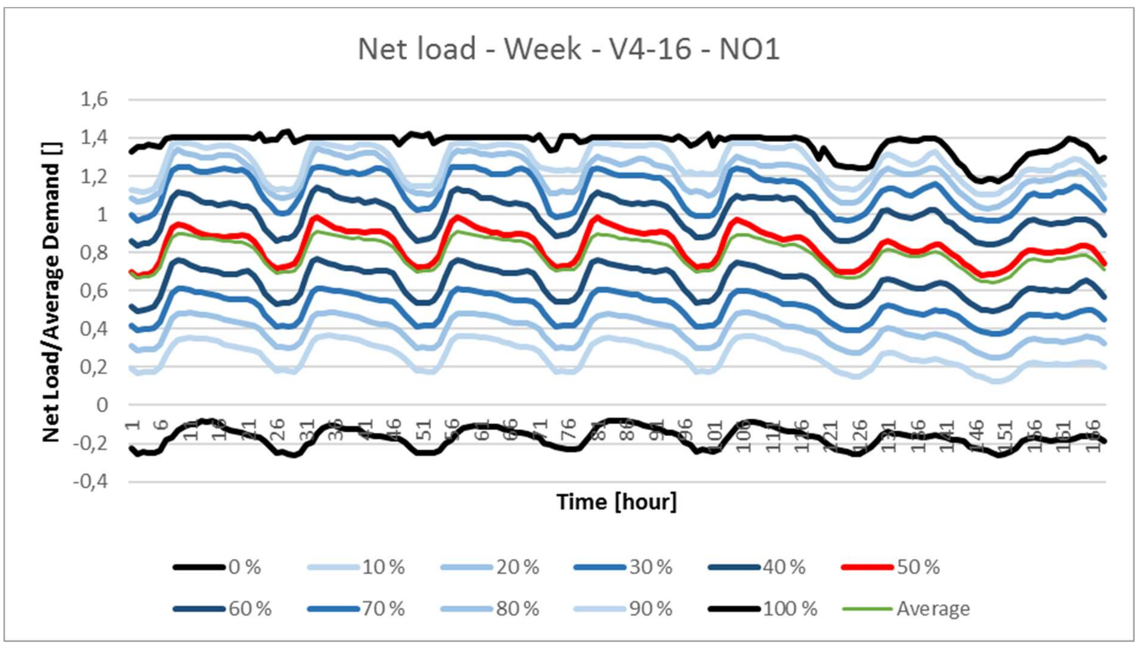

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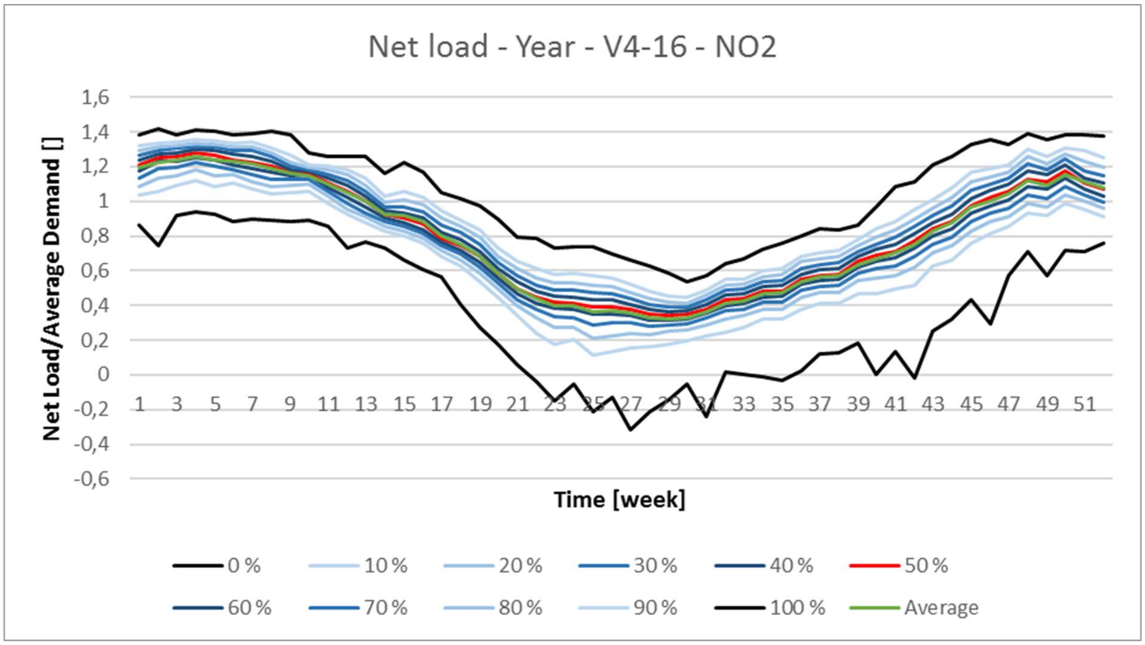

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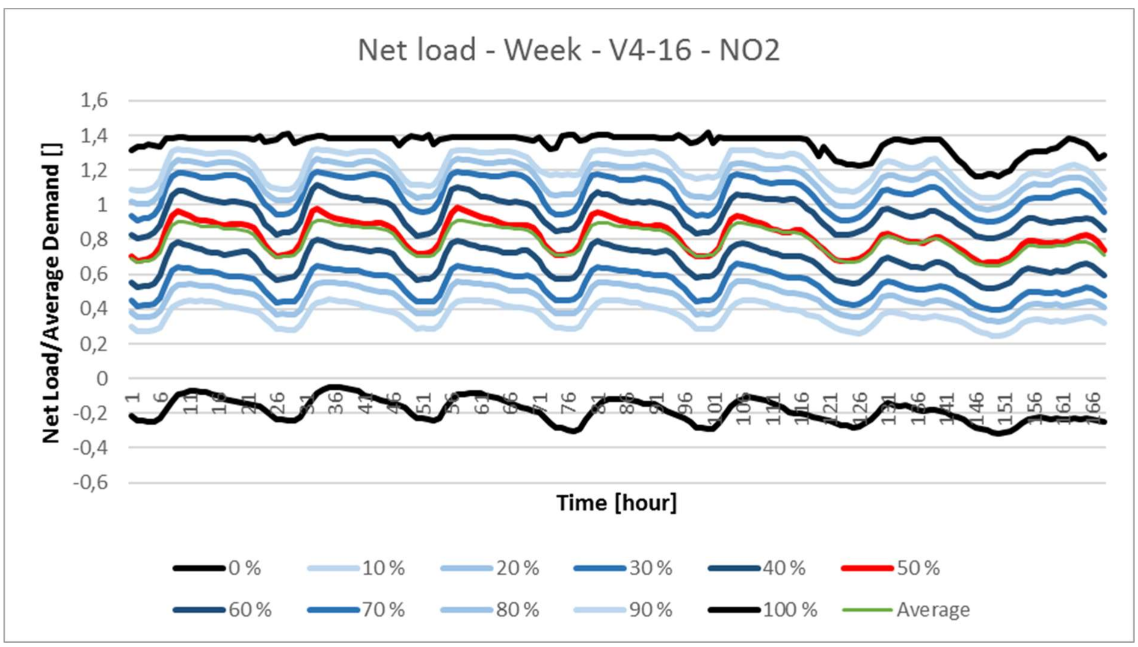

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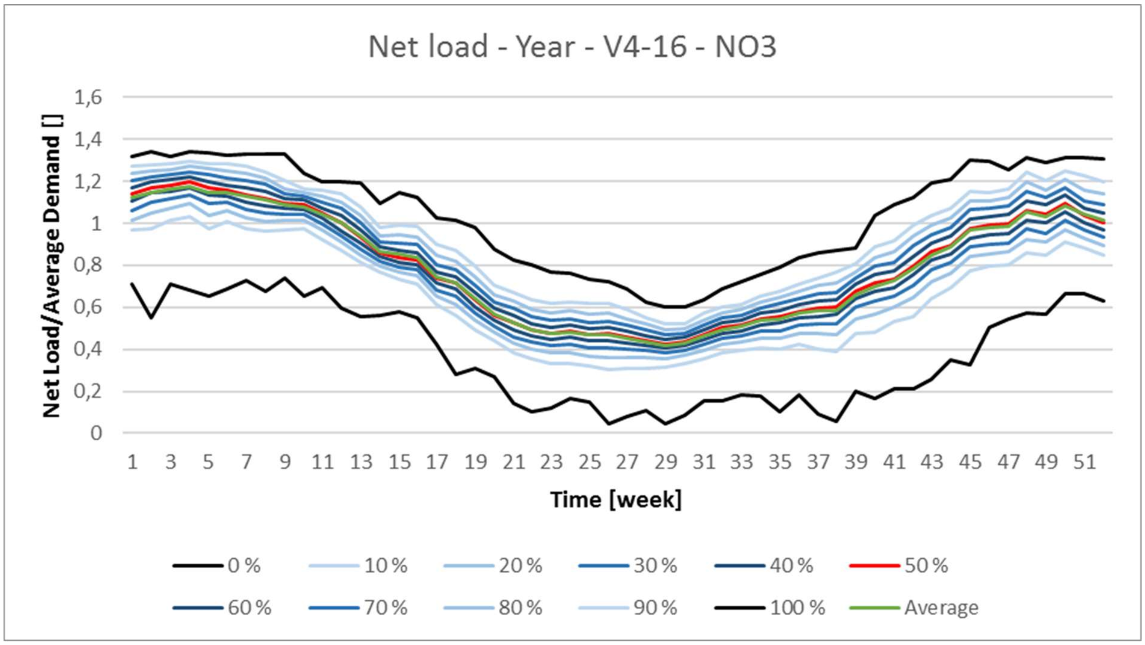

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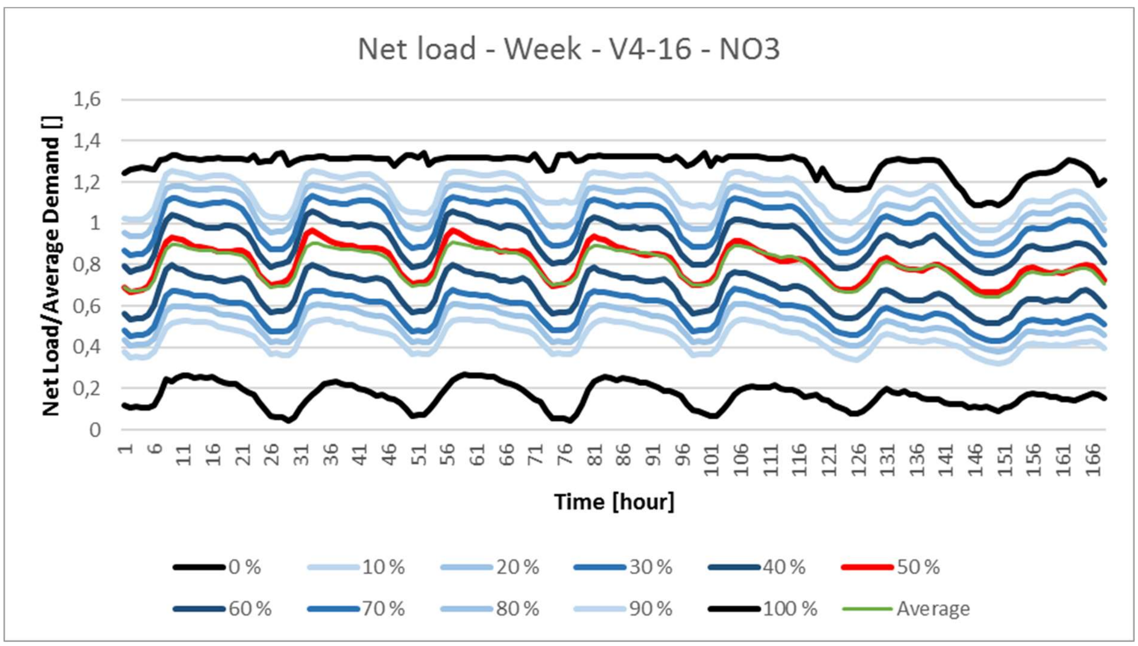

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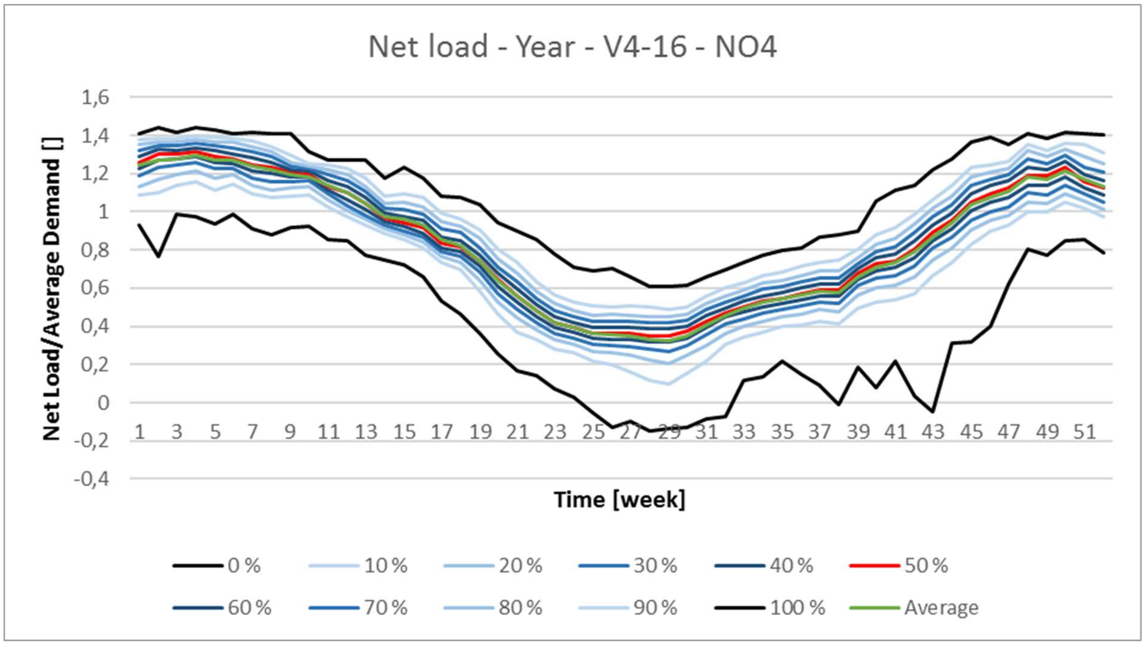

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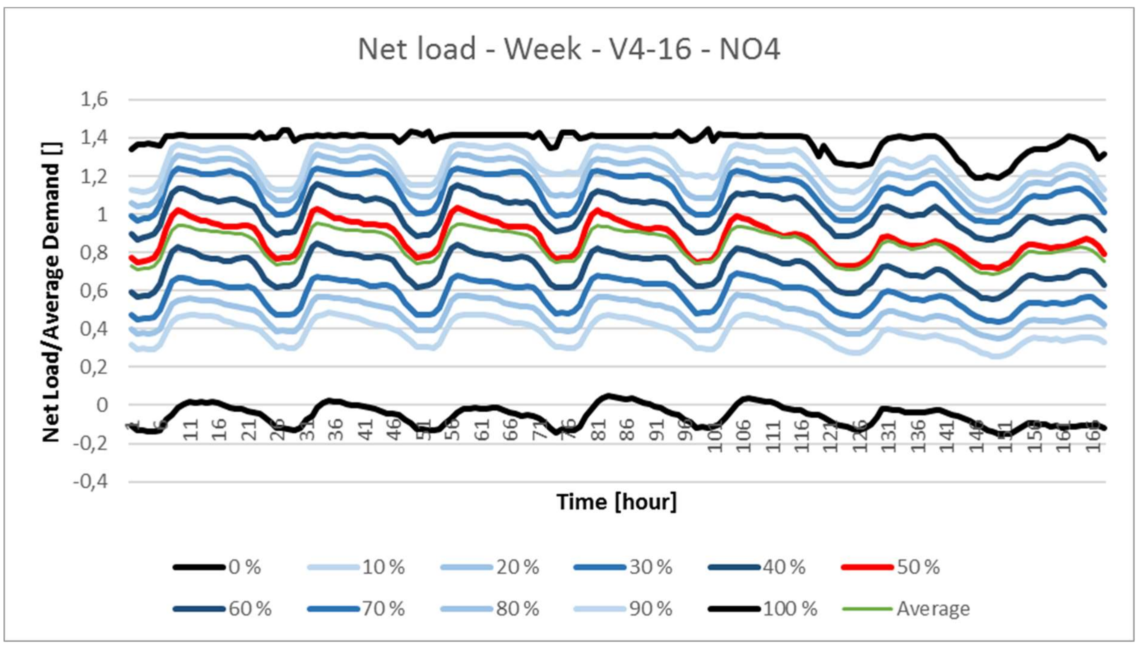

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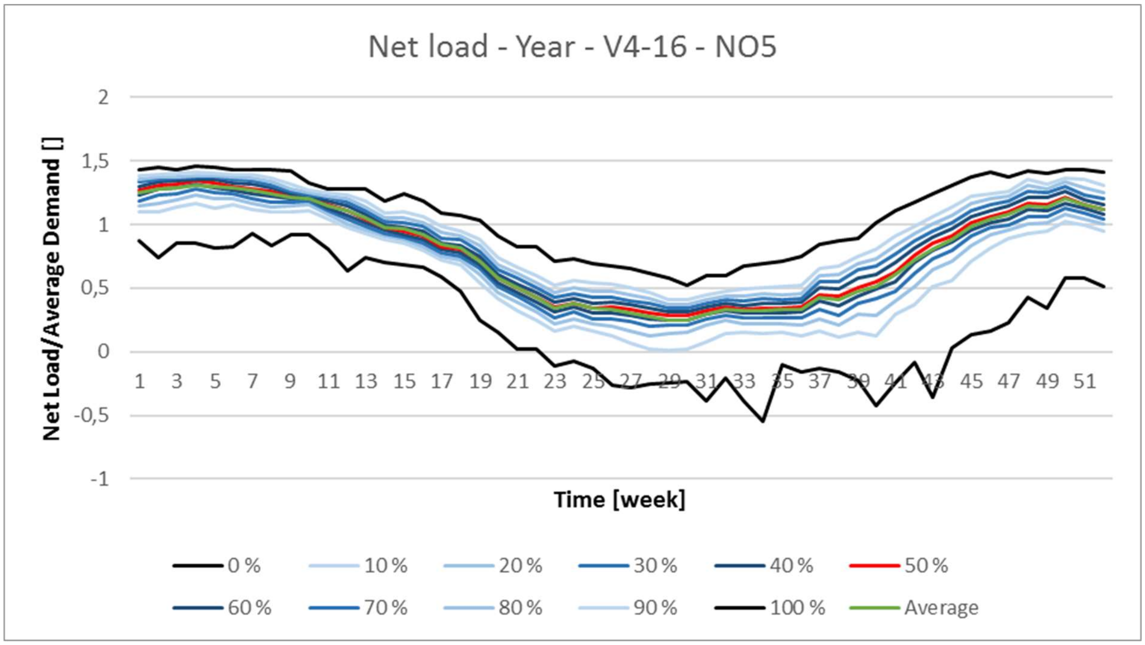

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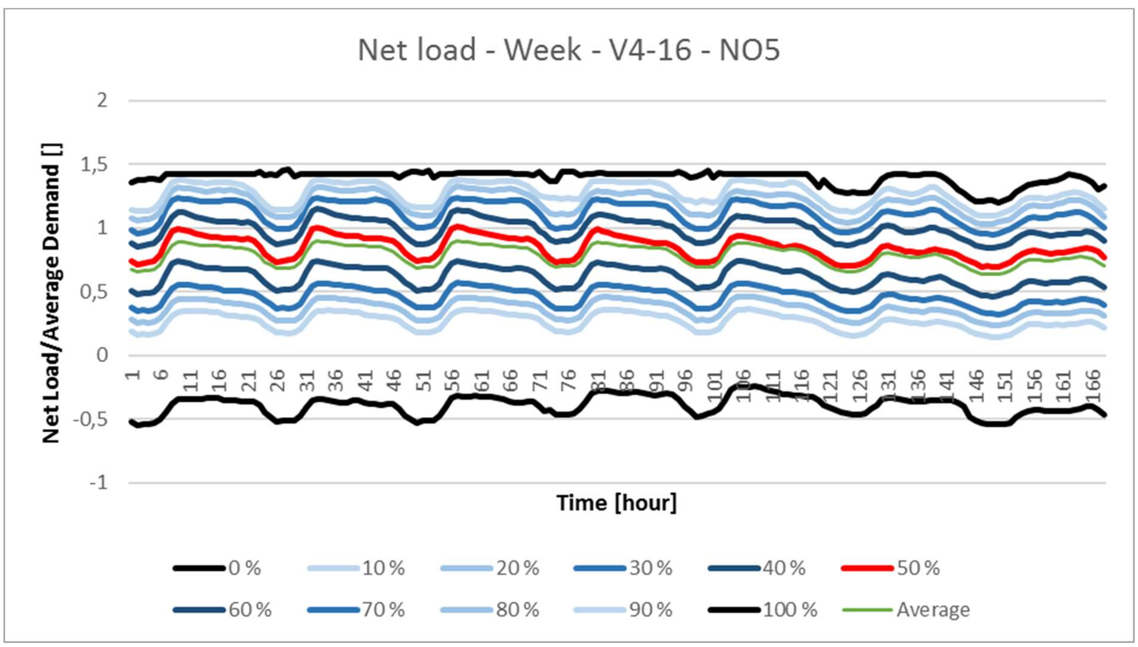

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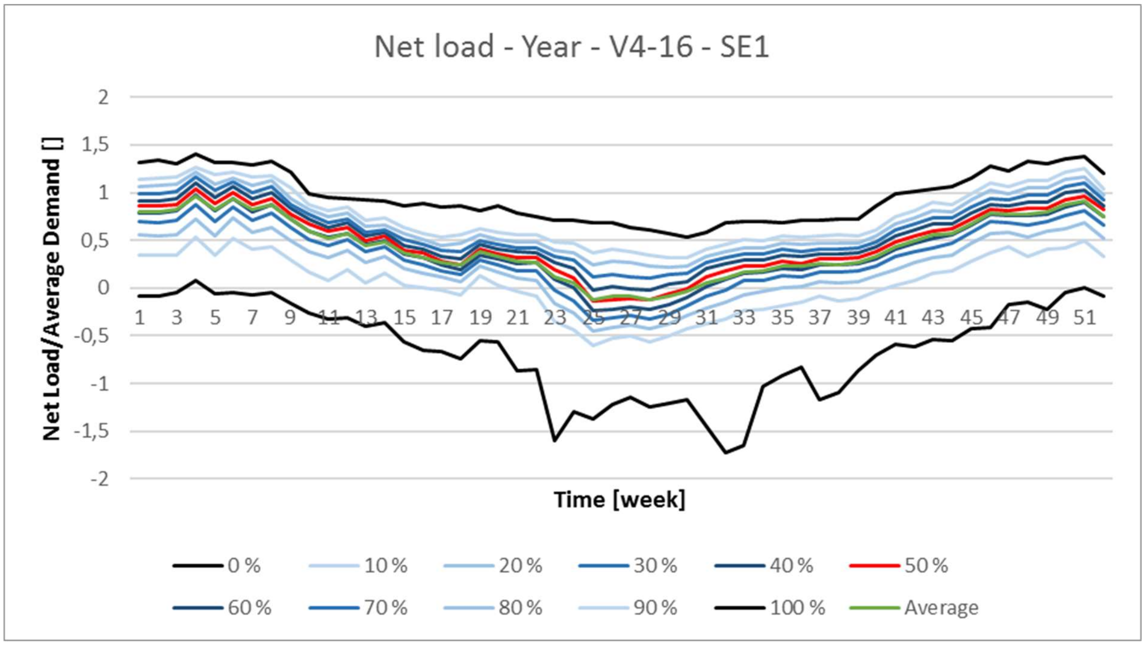

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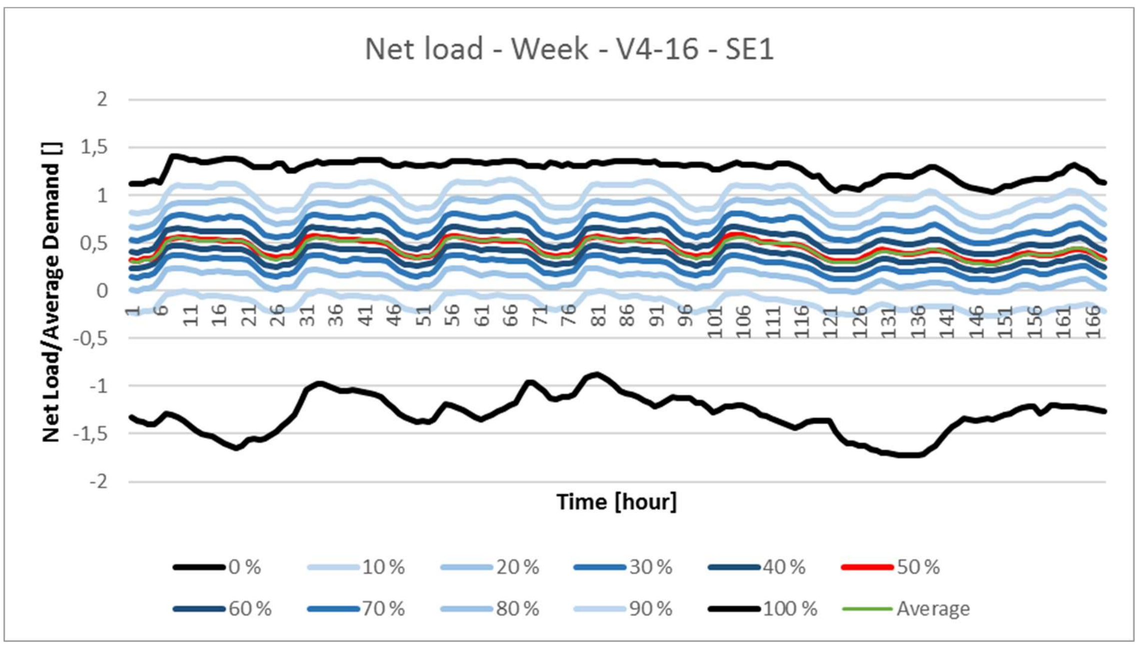

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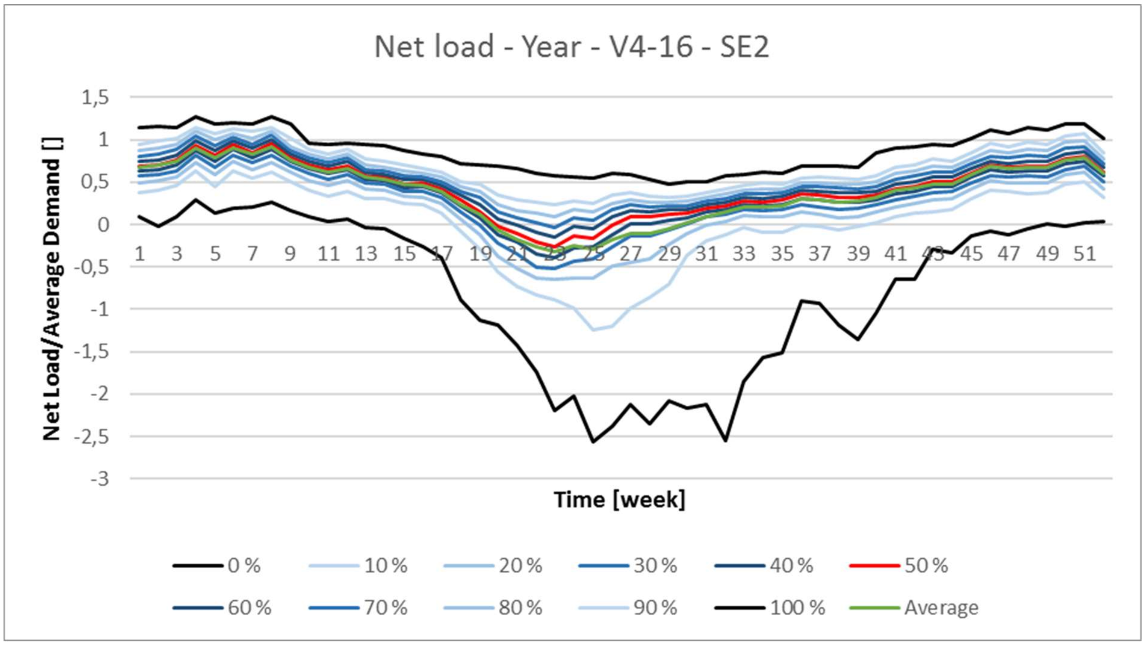

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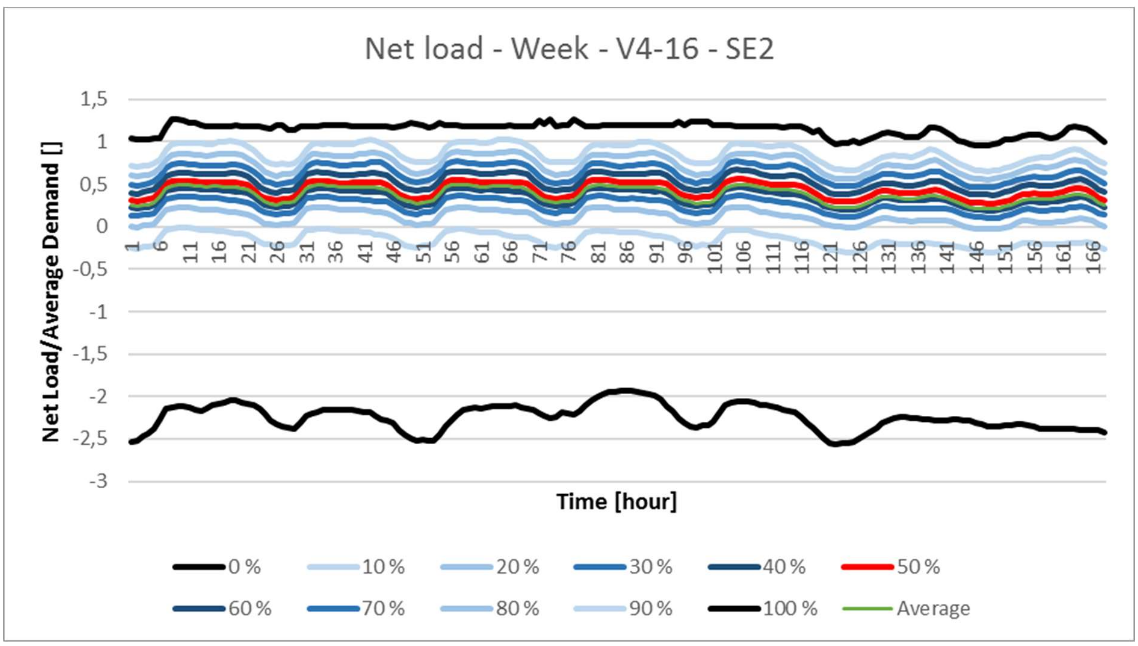

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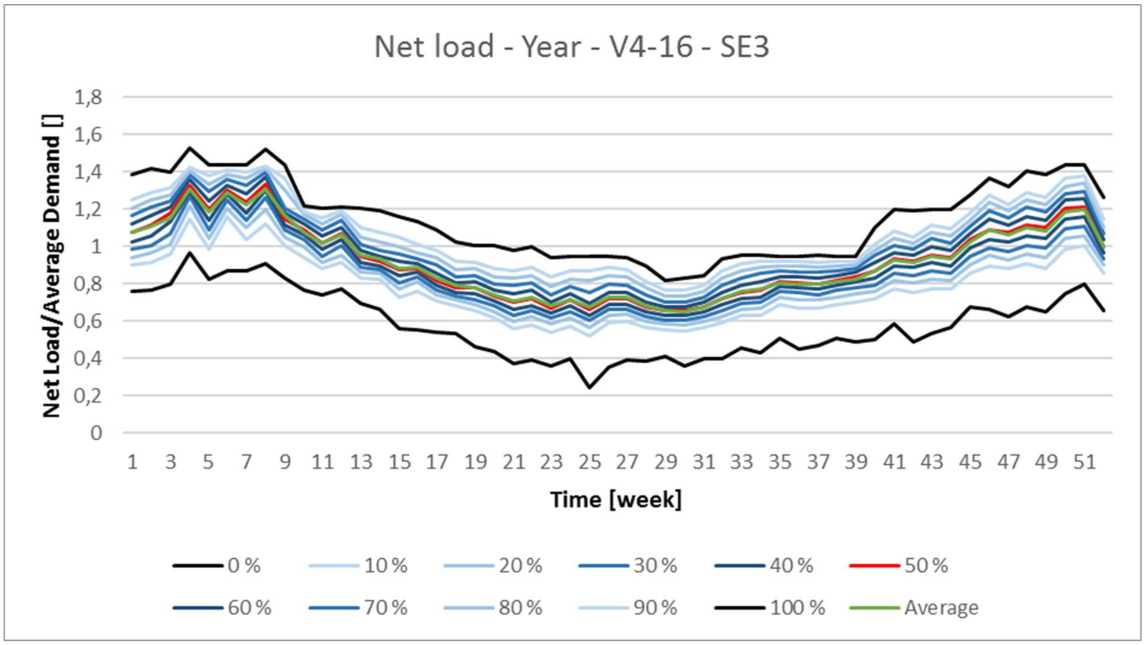

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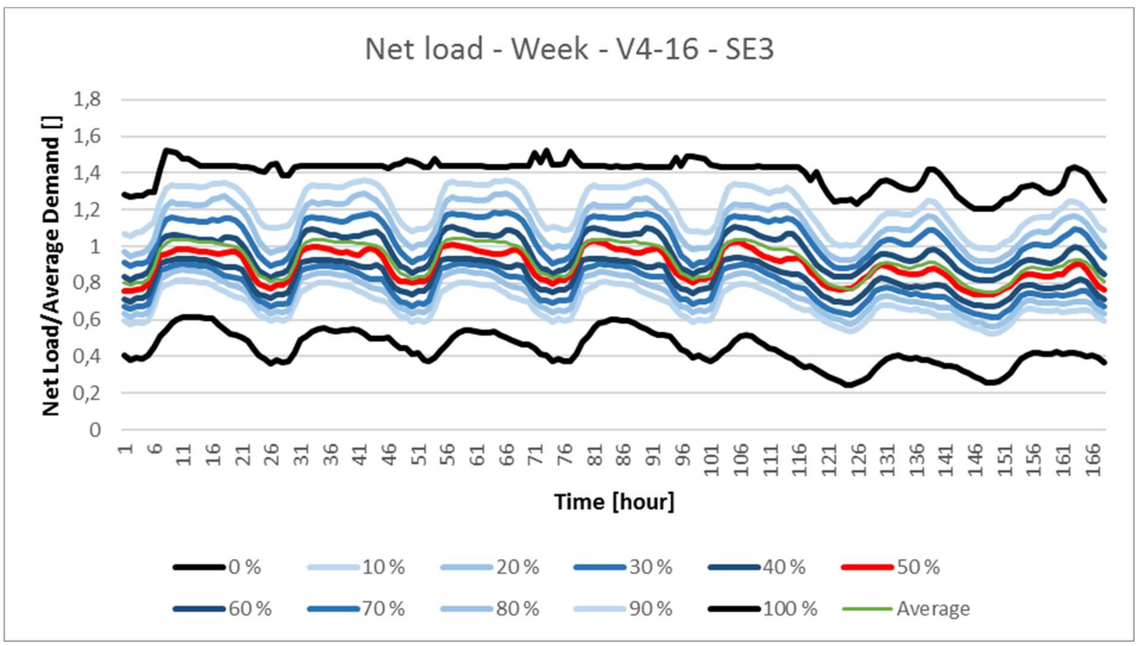

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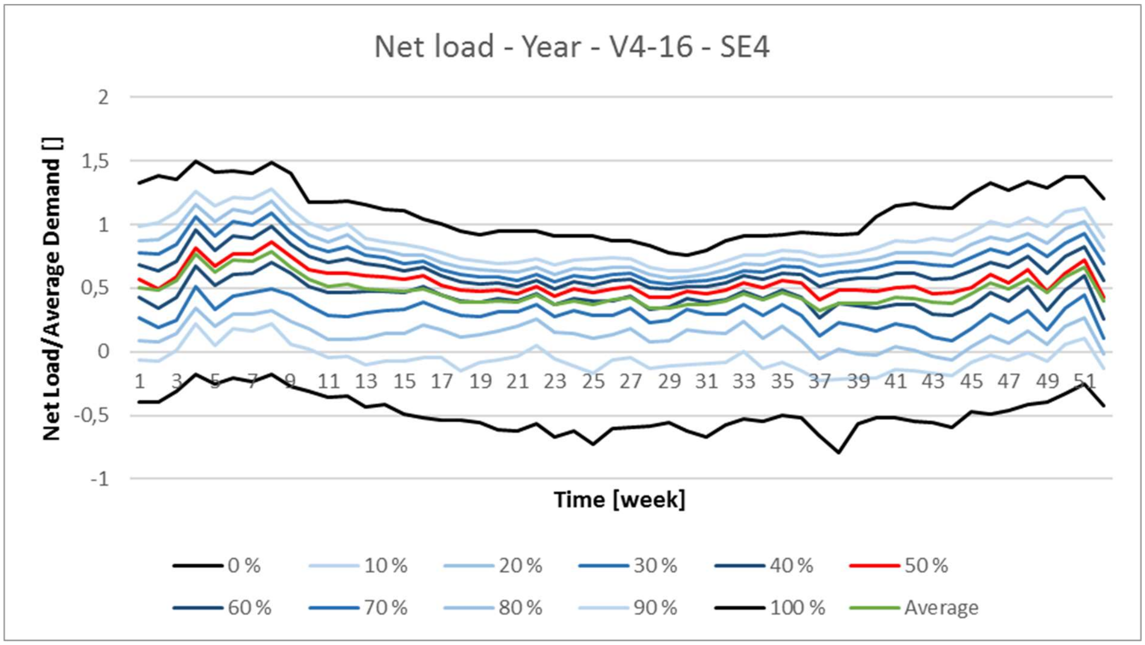

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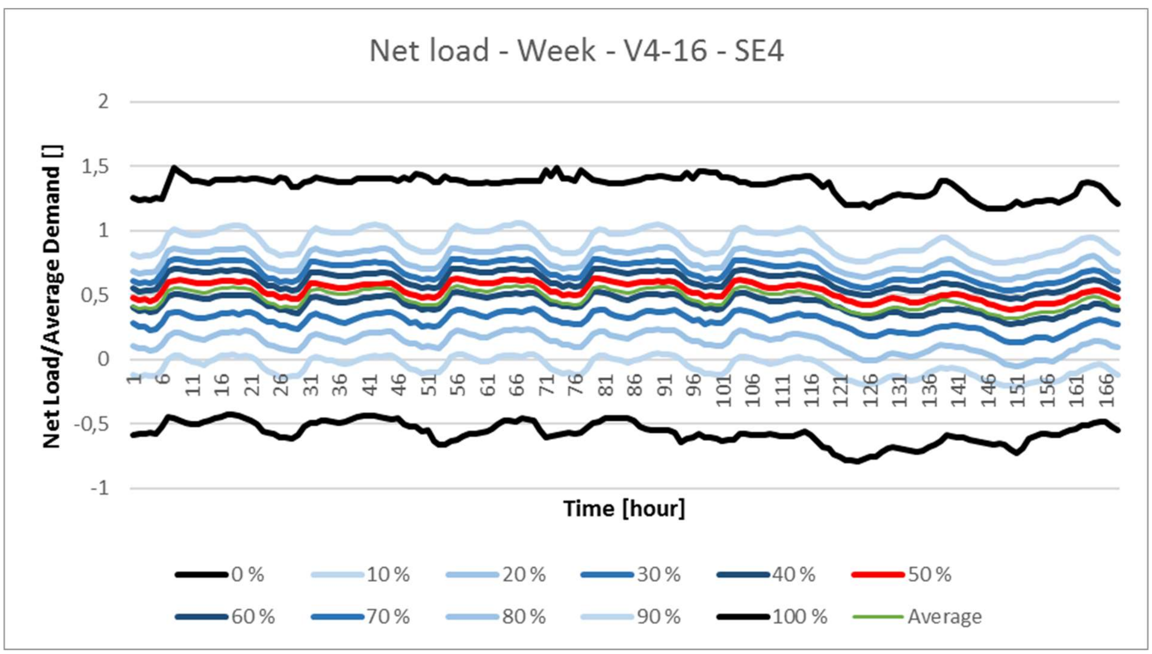

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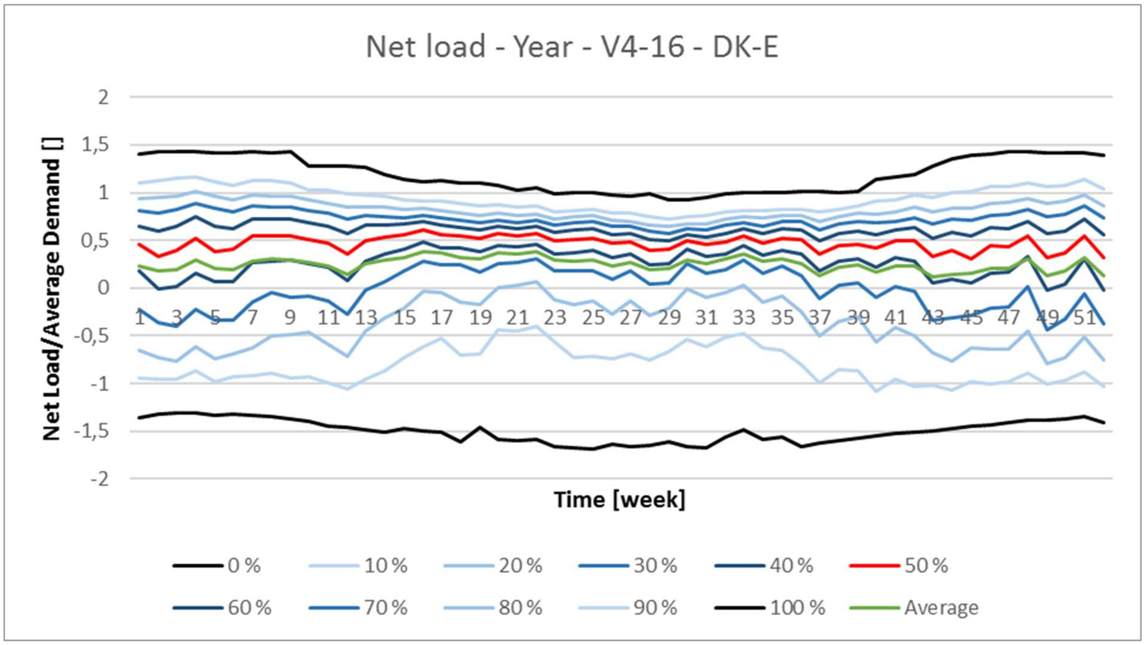

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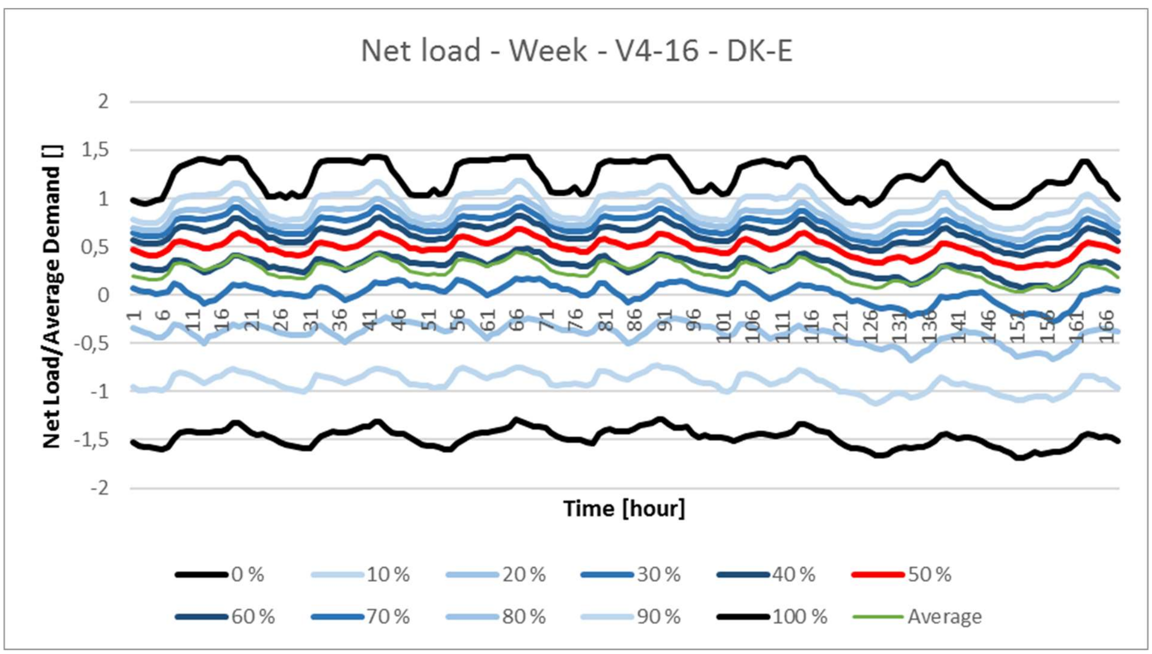

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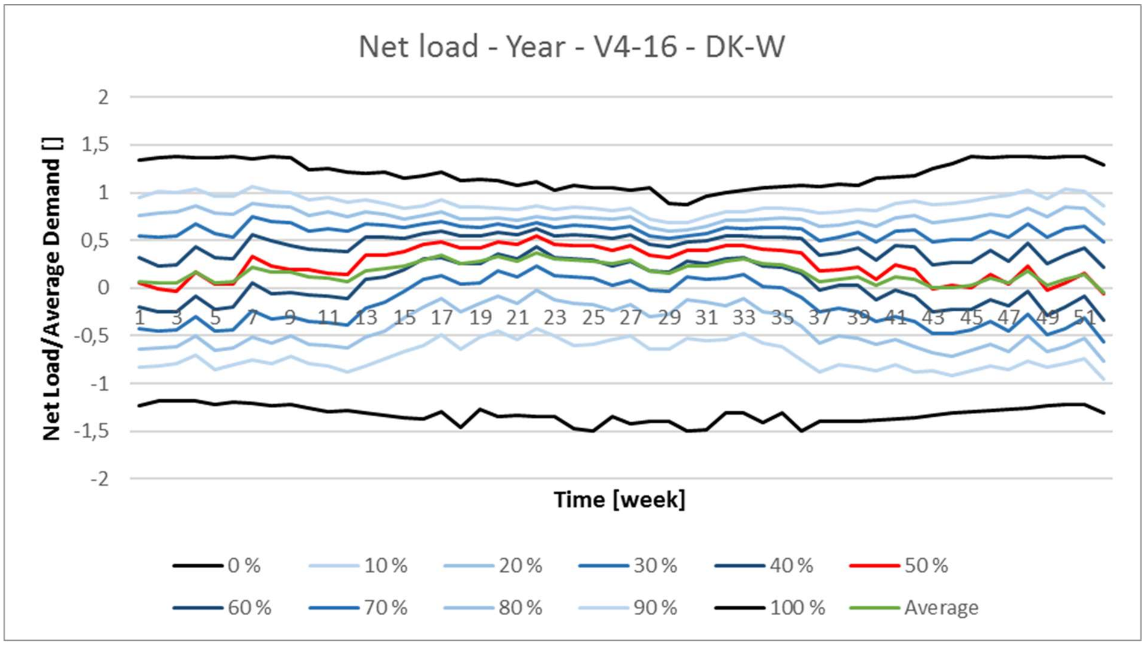

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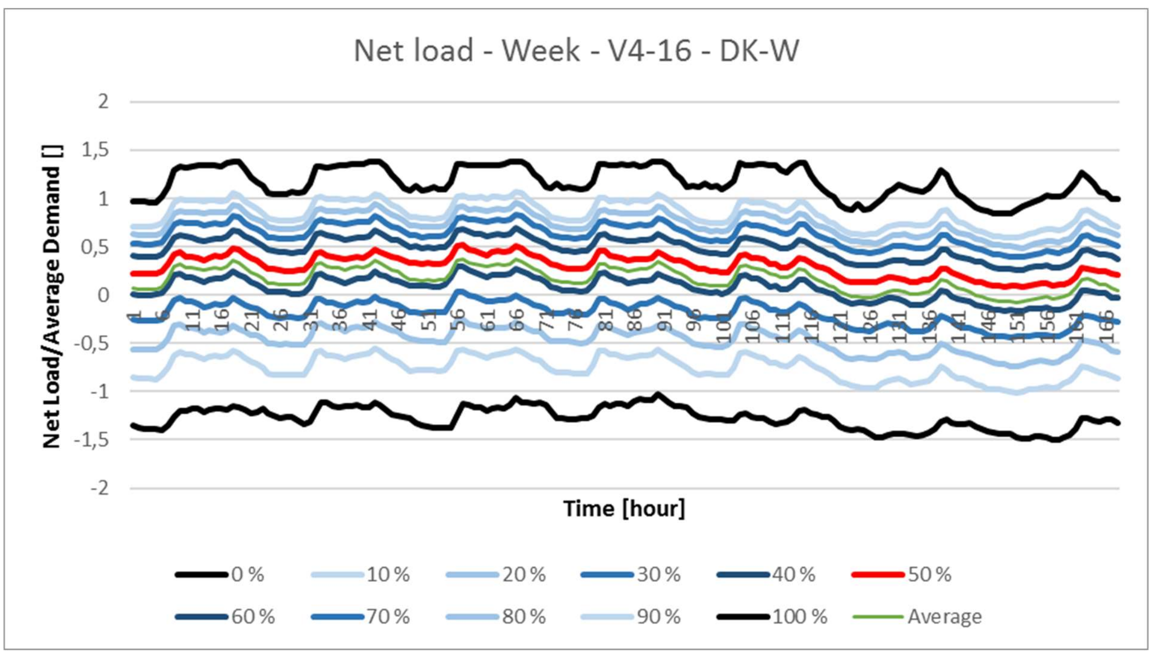

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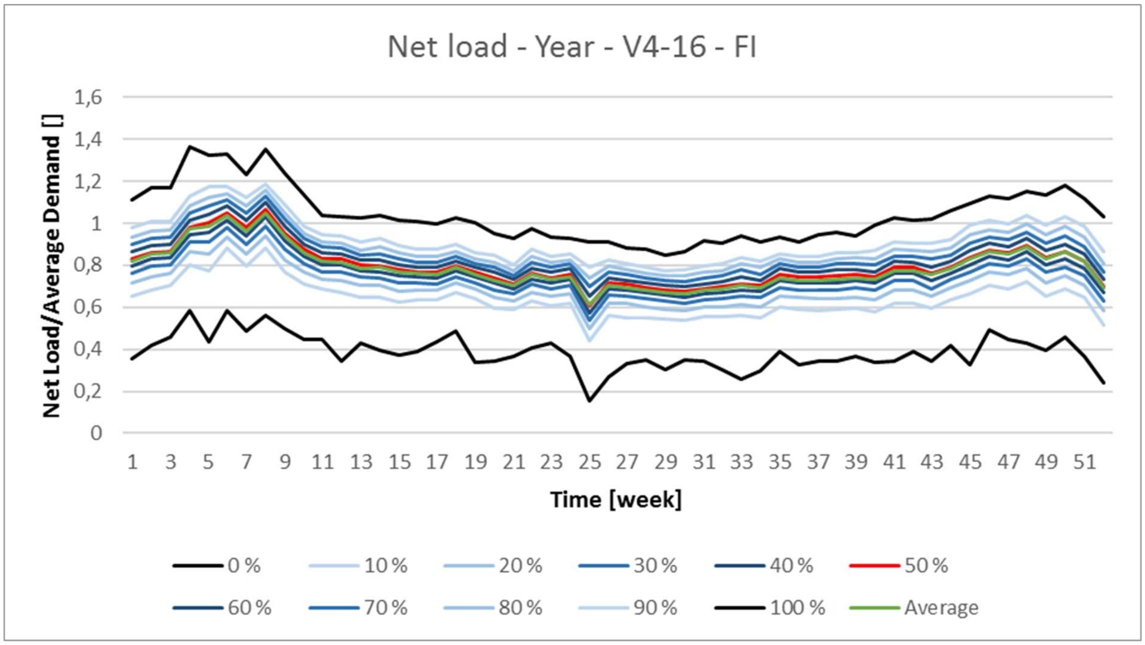

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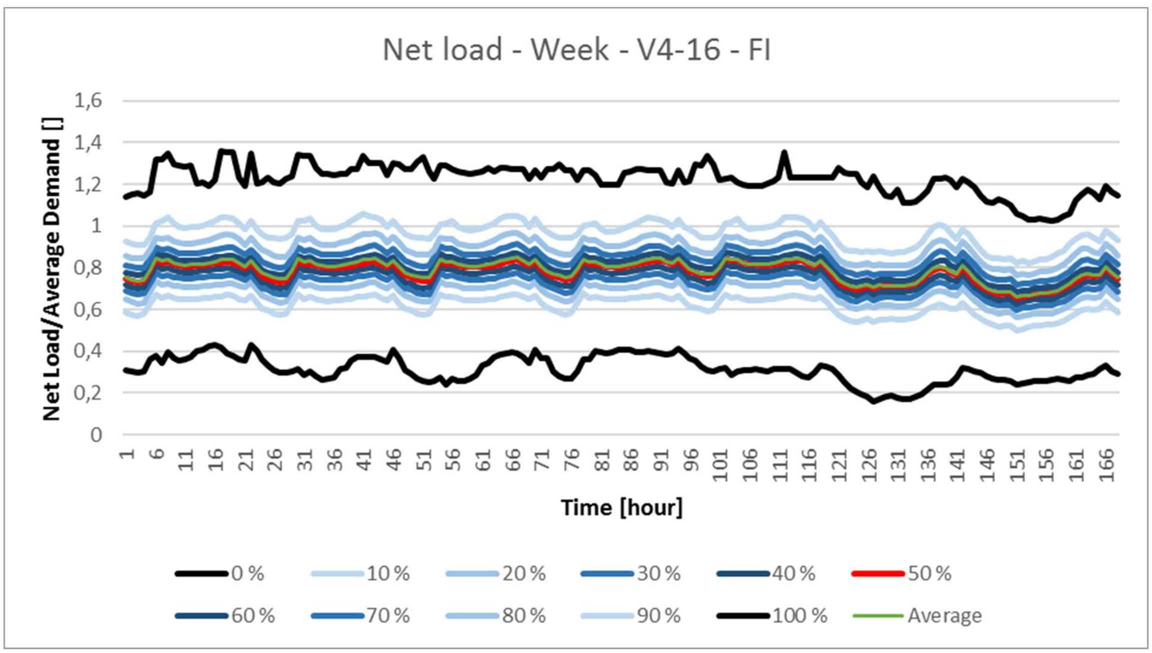

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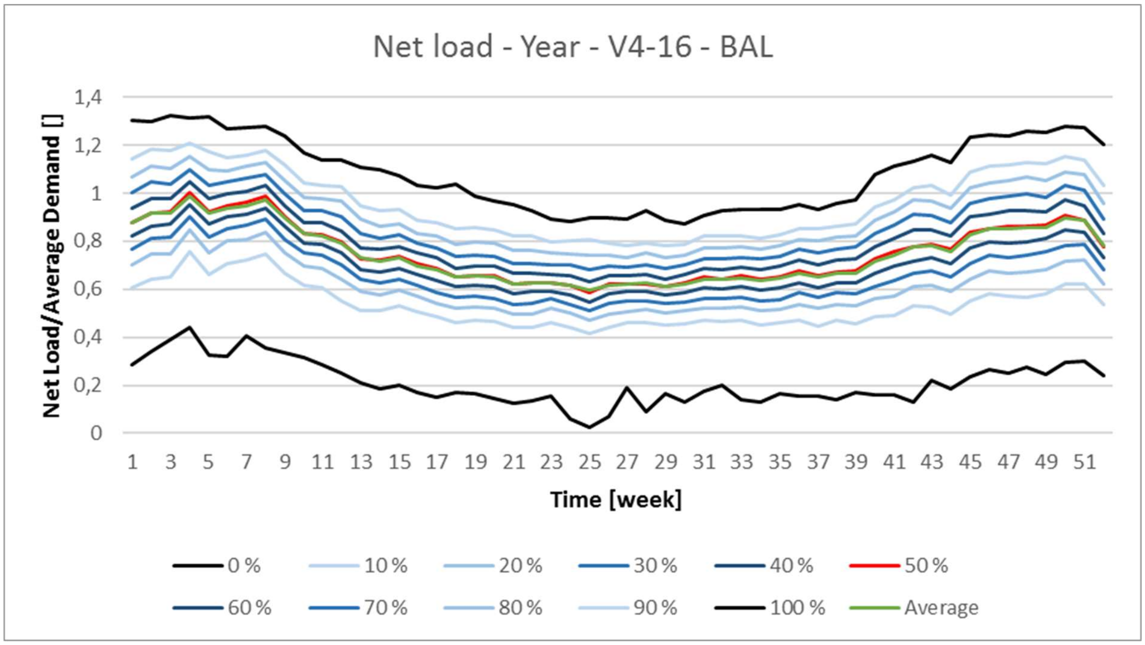
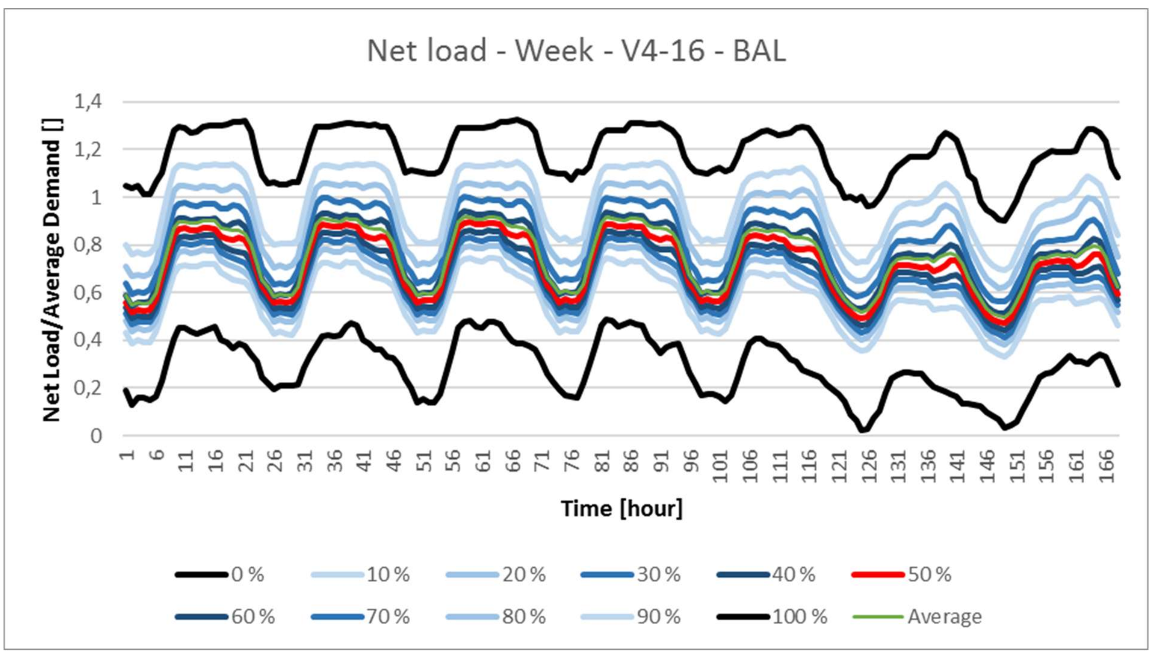


Figure 131



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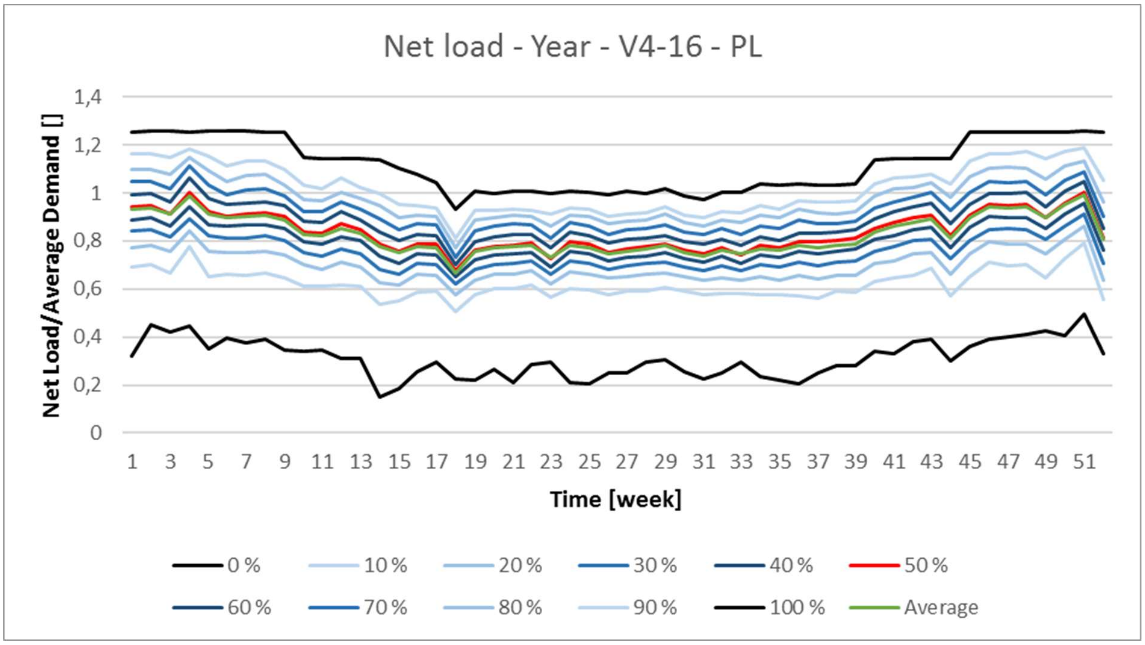

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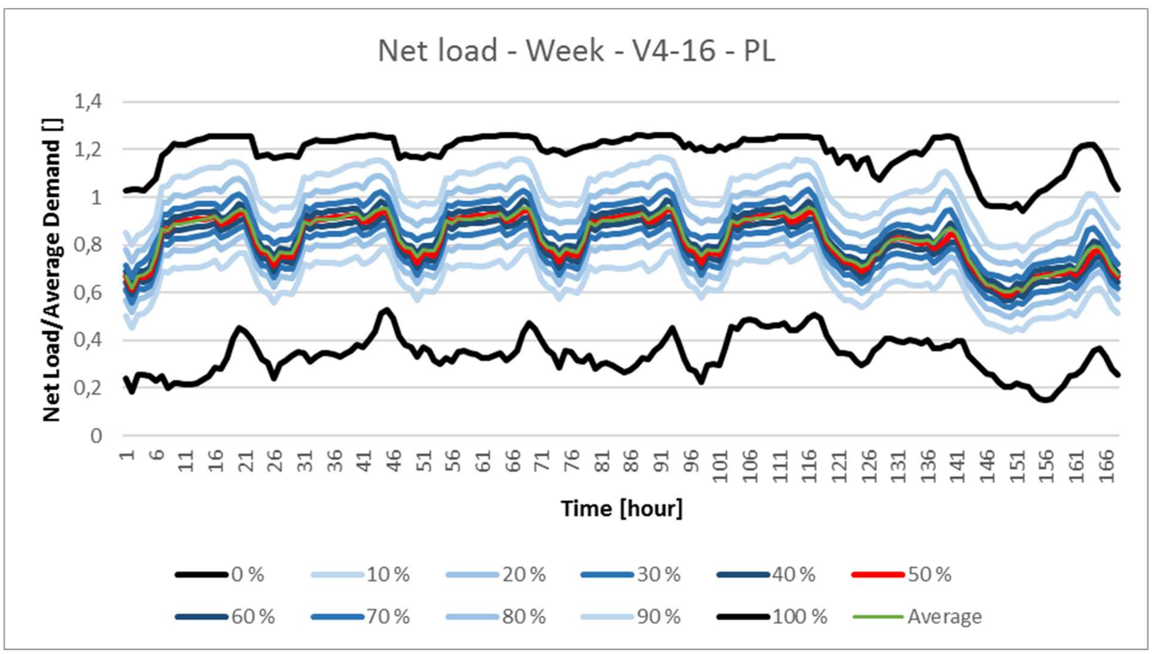

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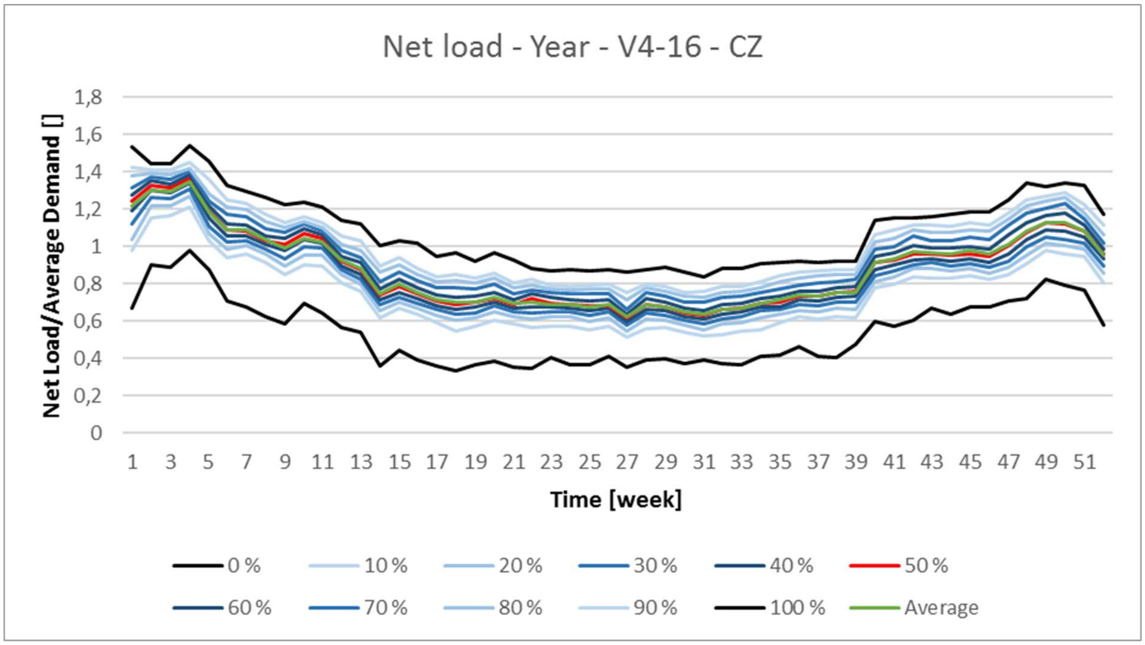

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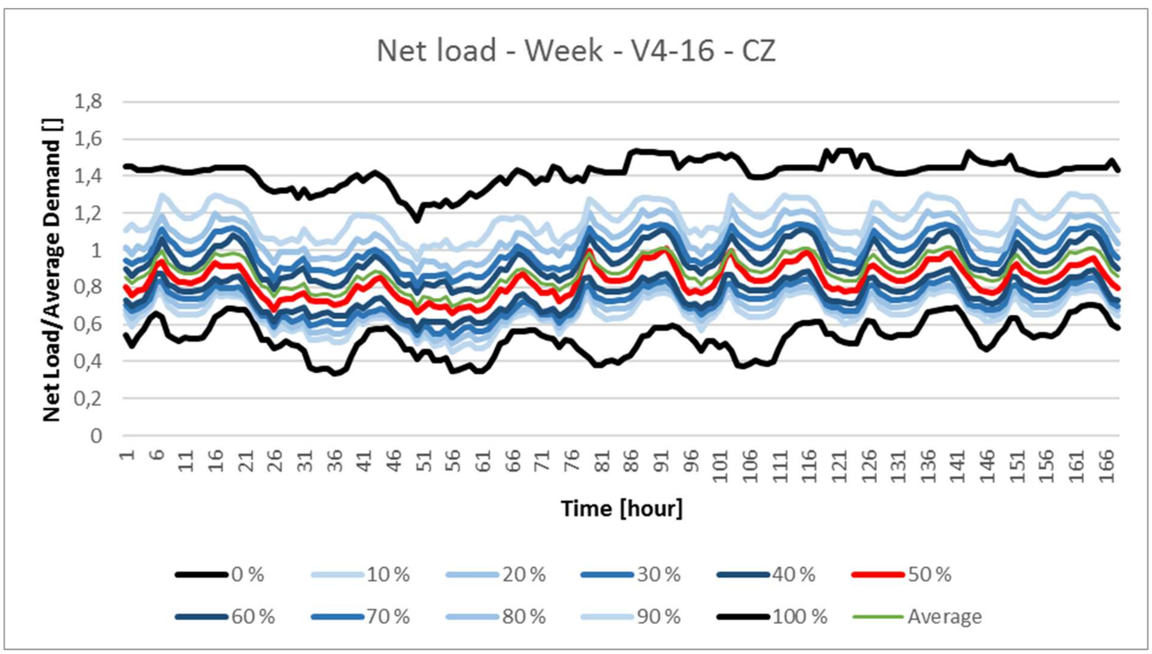

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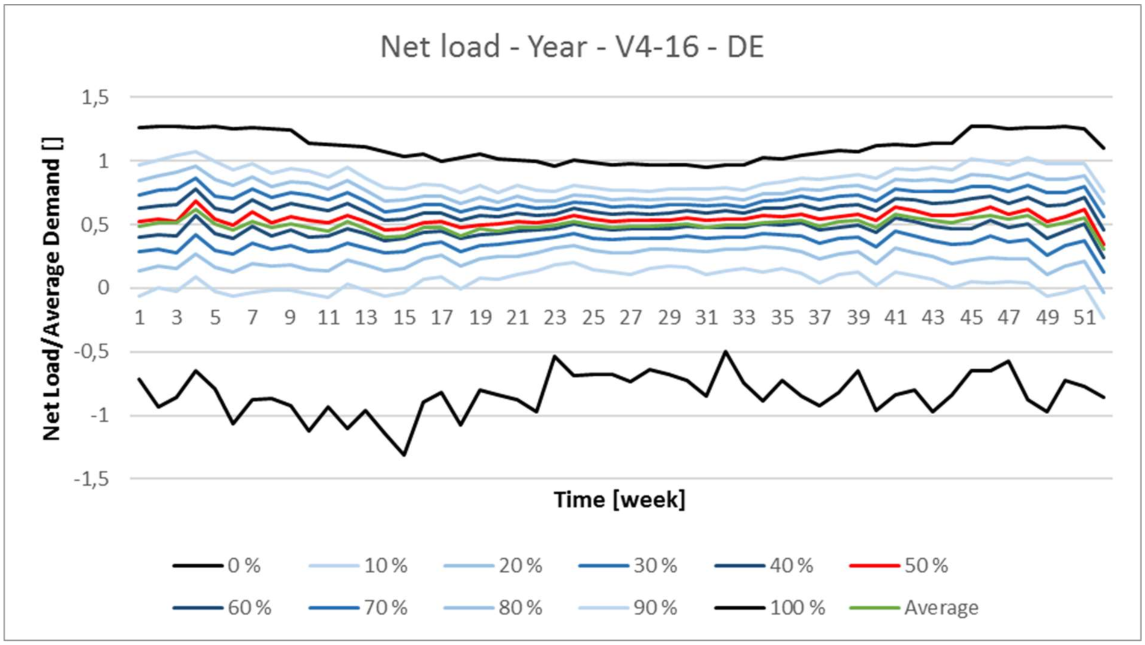

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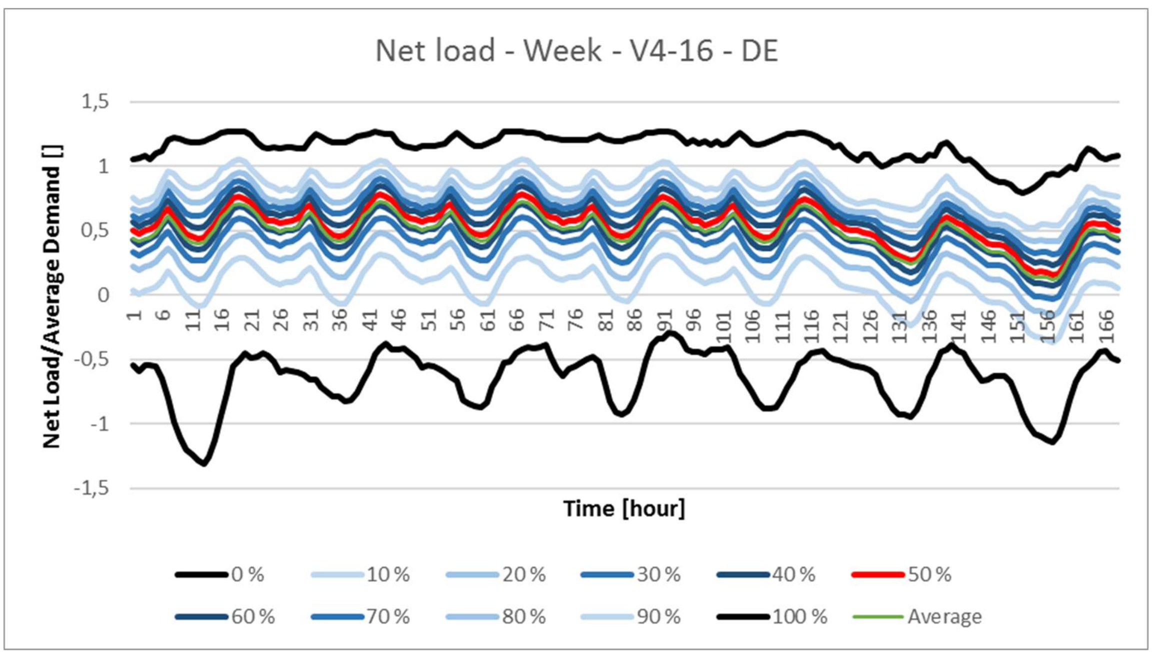

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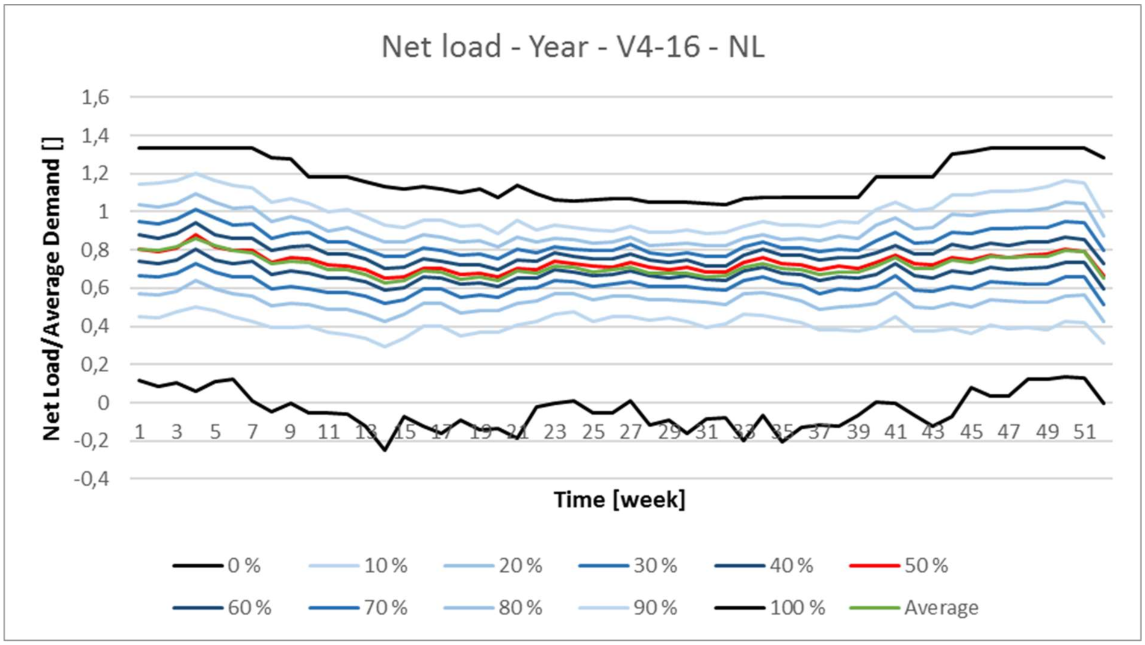

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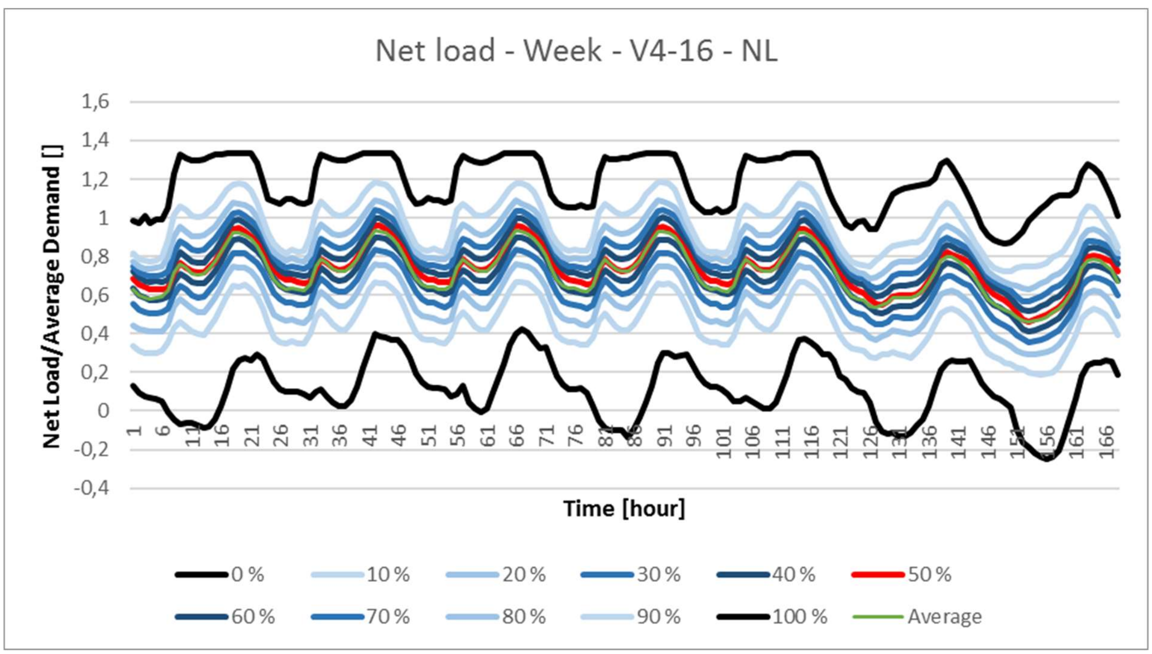

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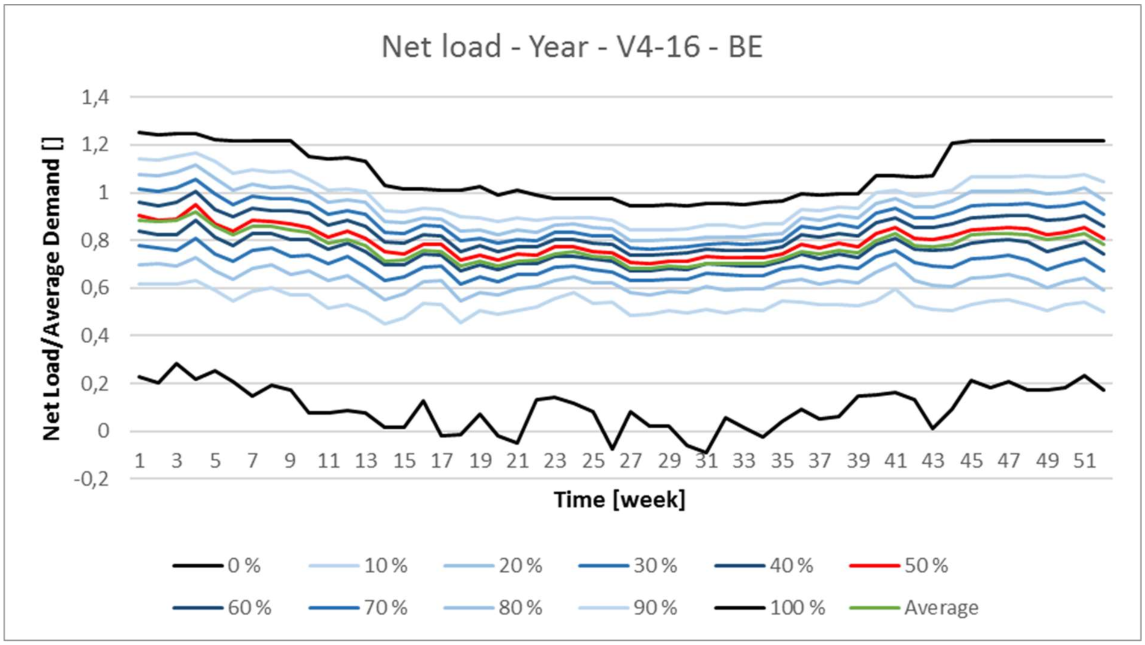

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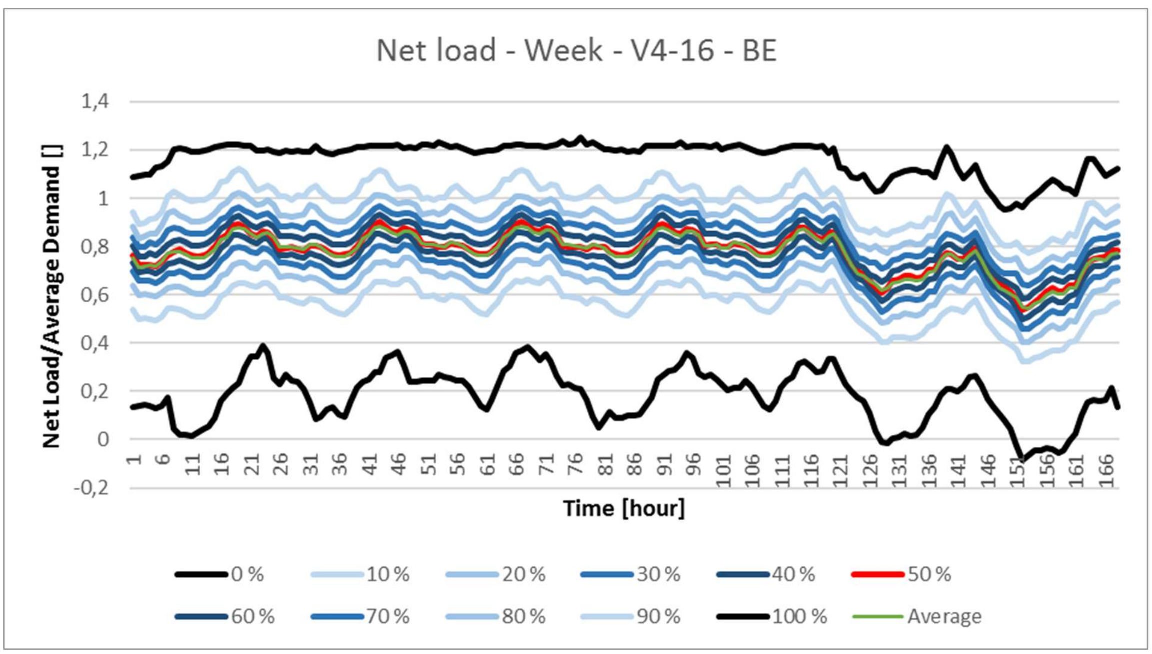

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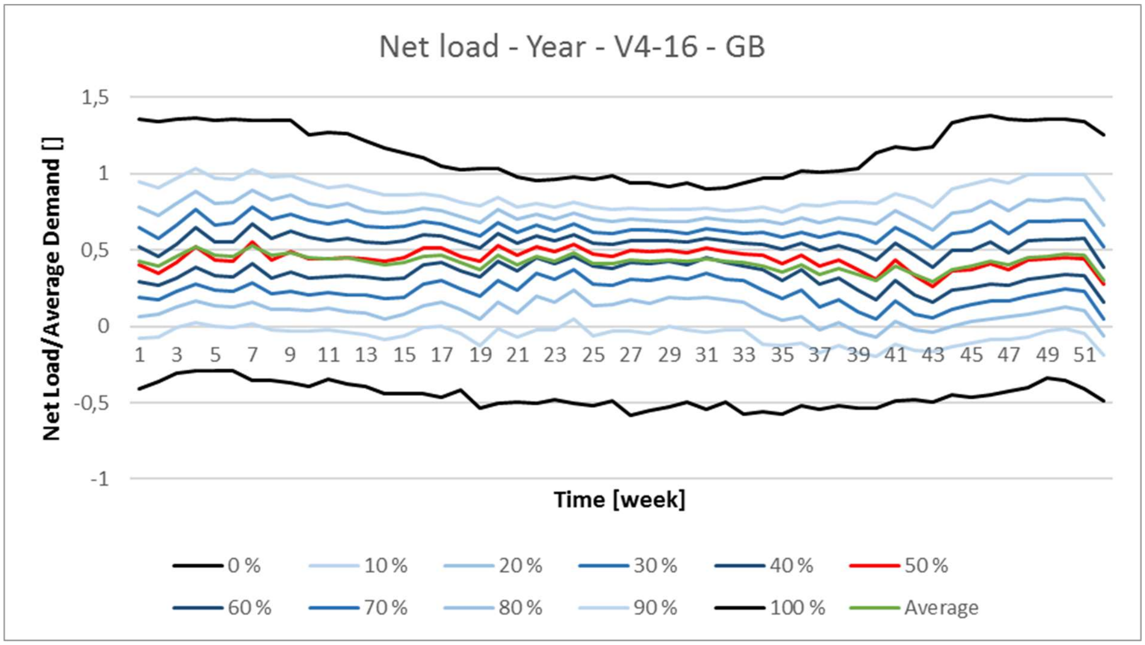

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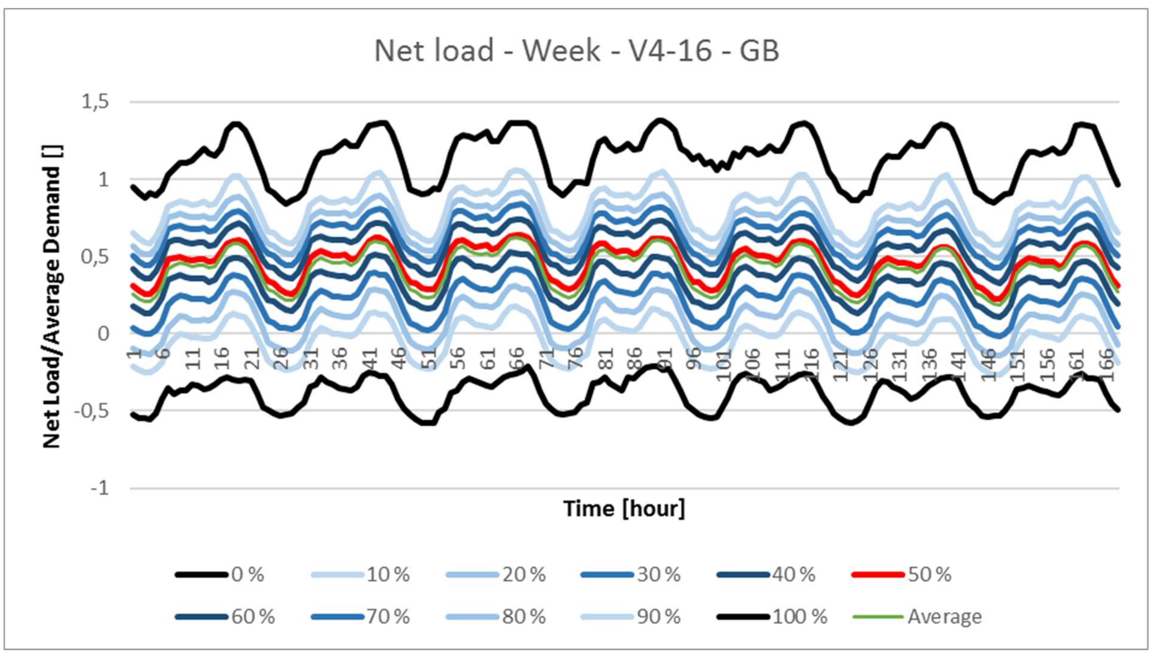

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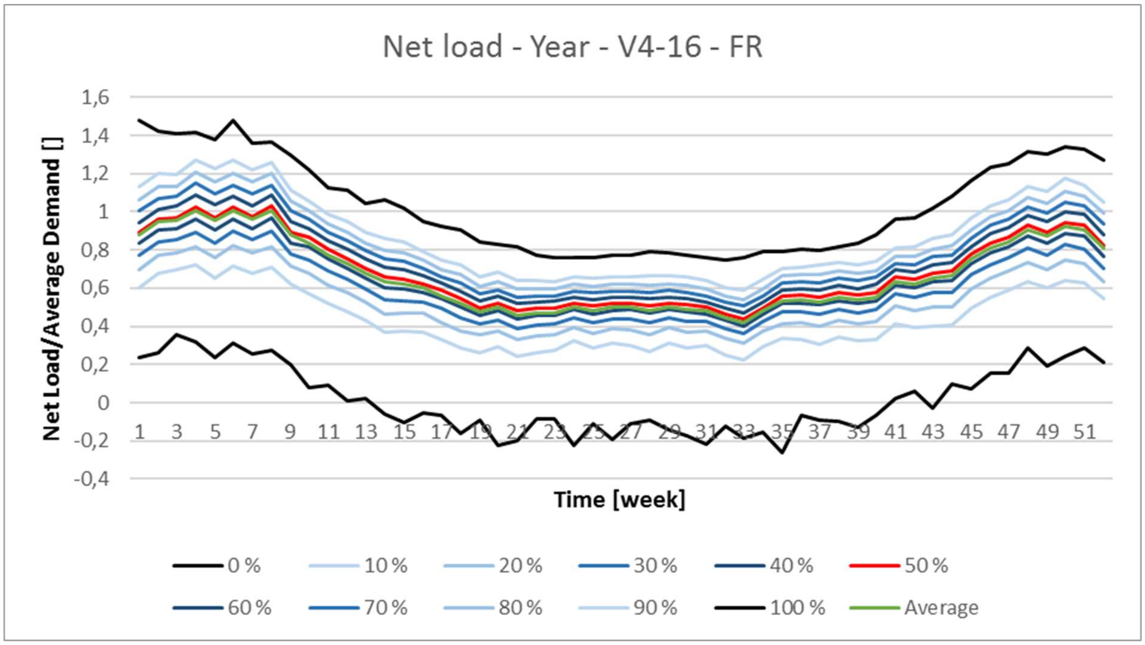

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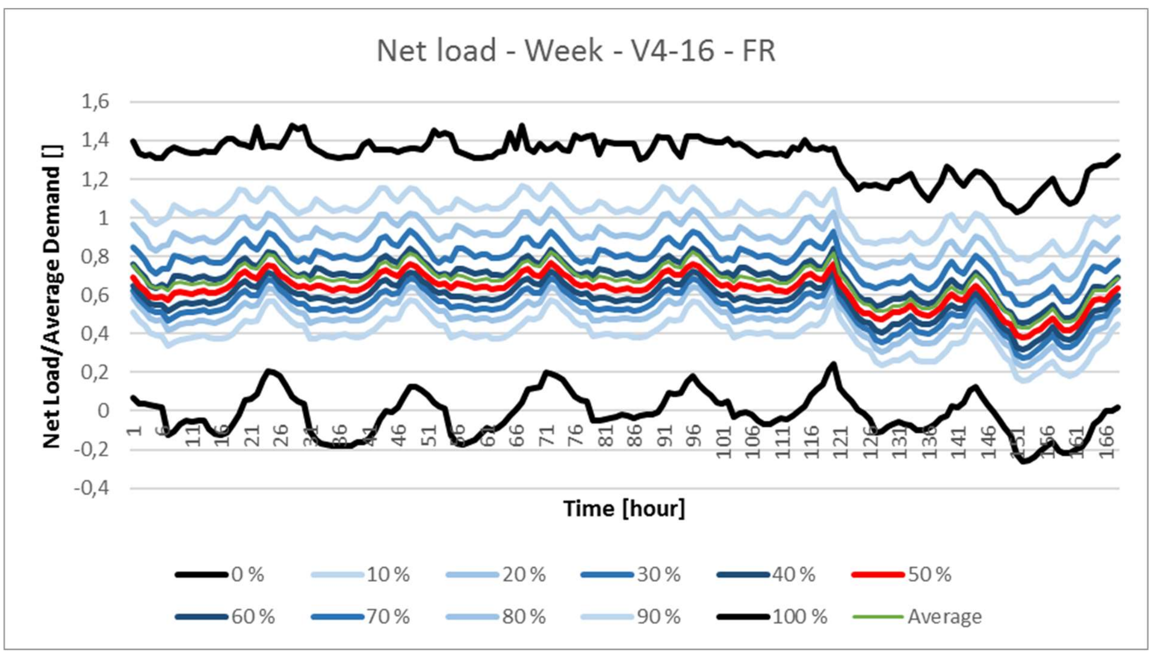

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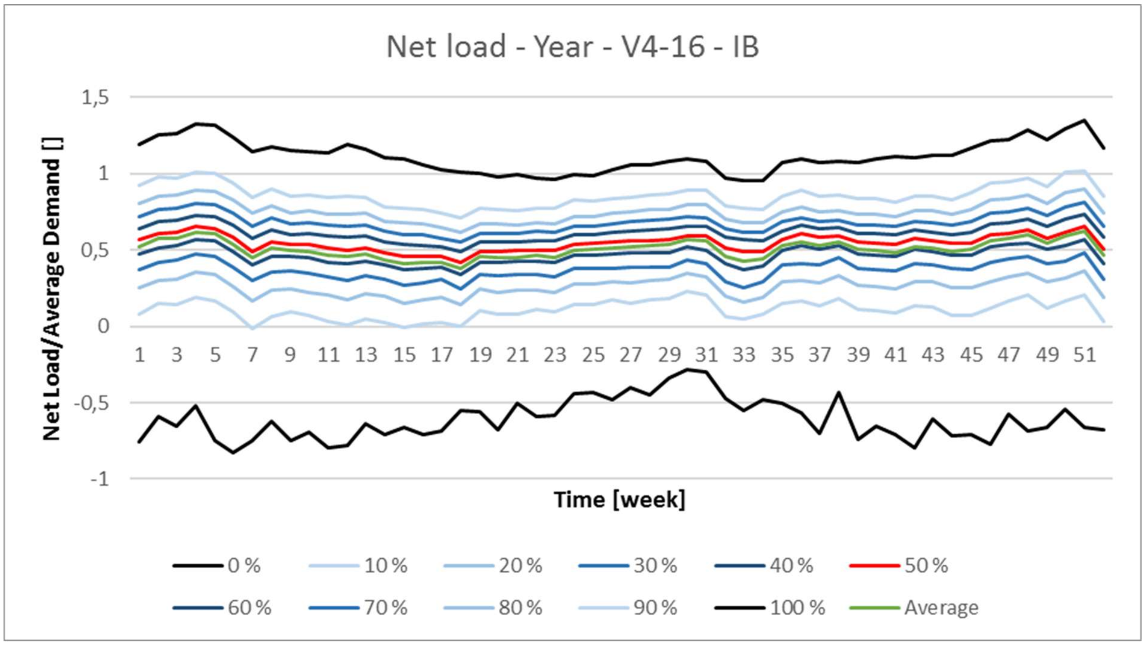

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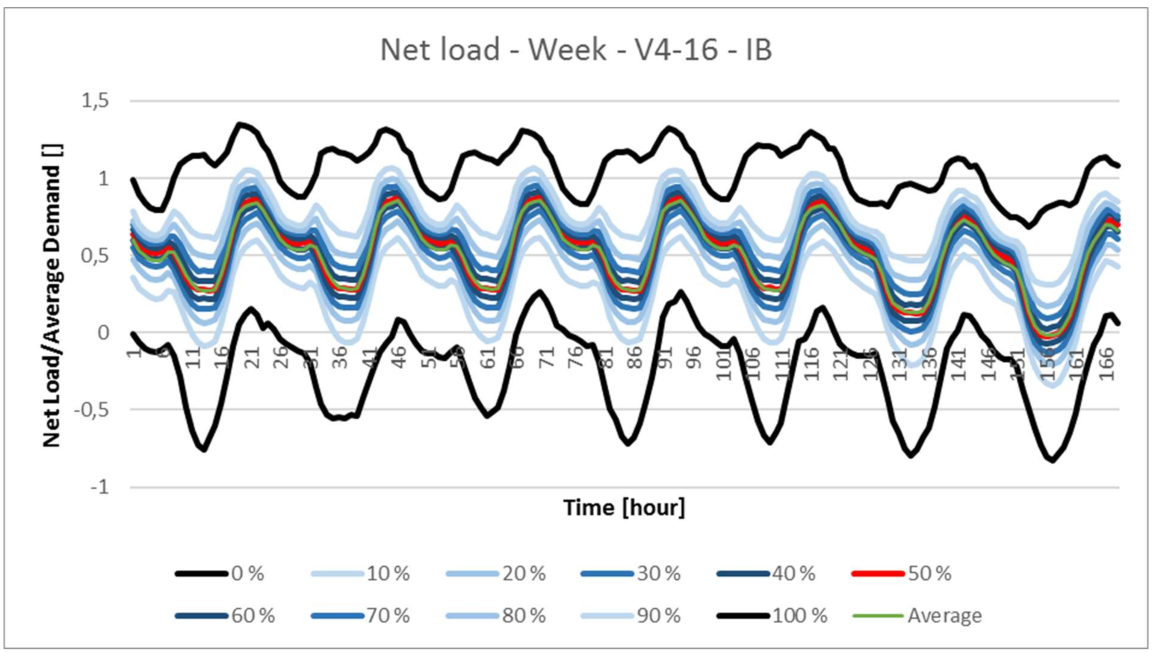

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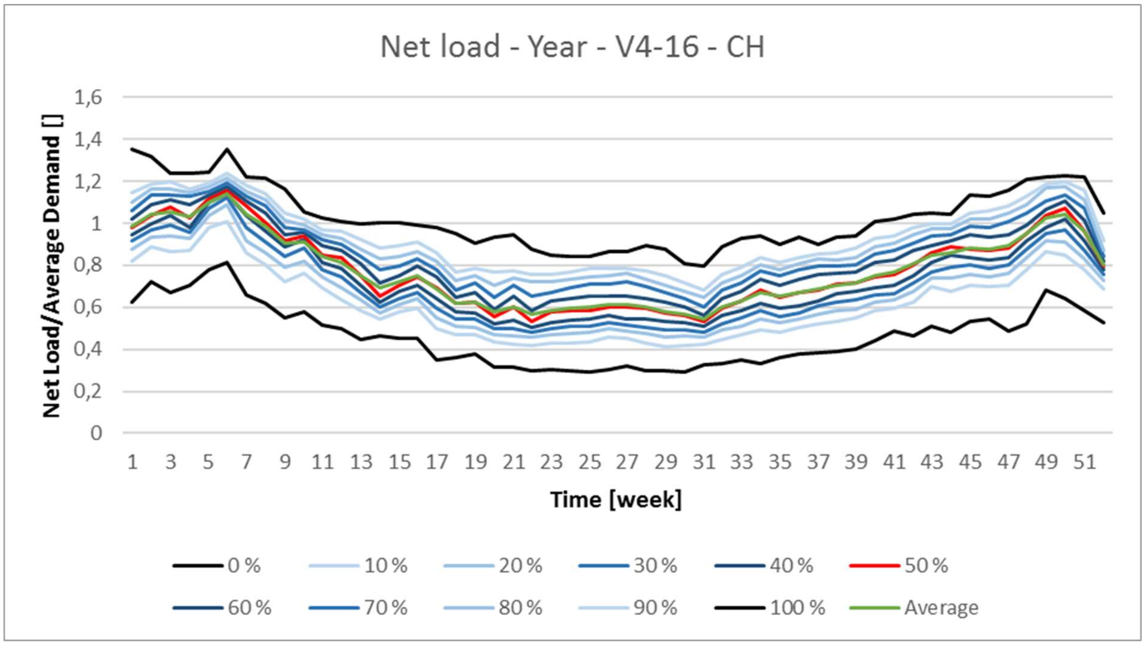

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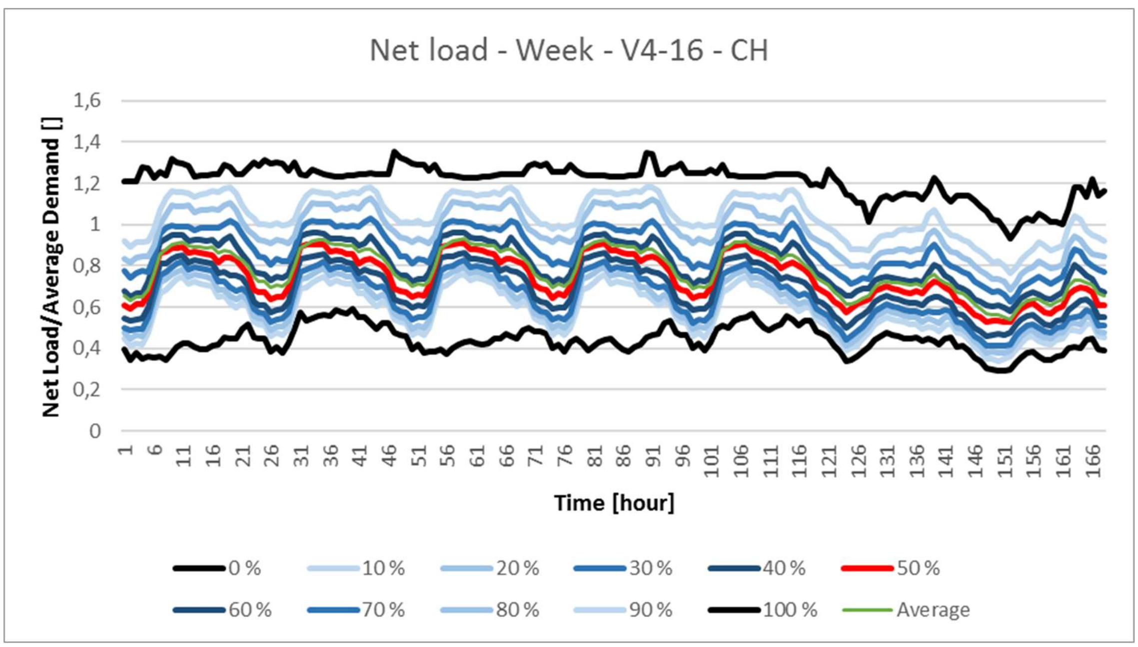

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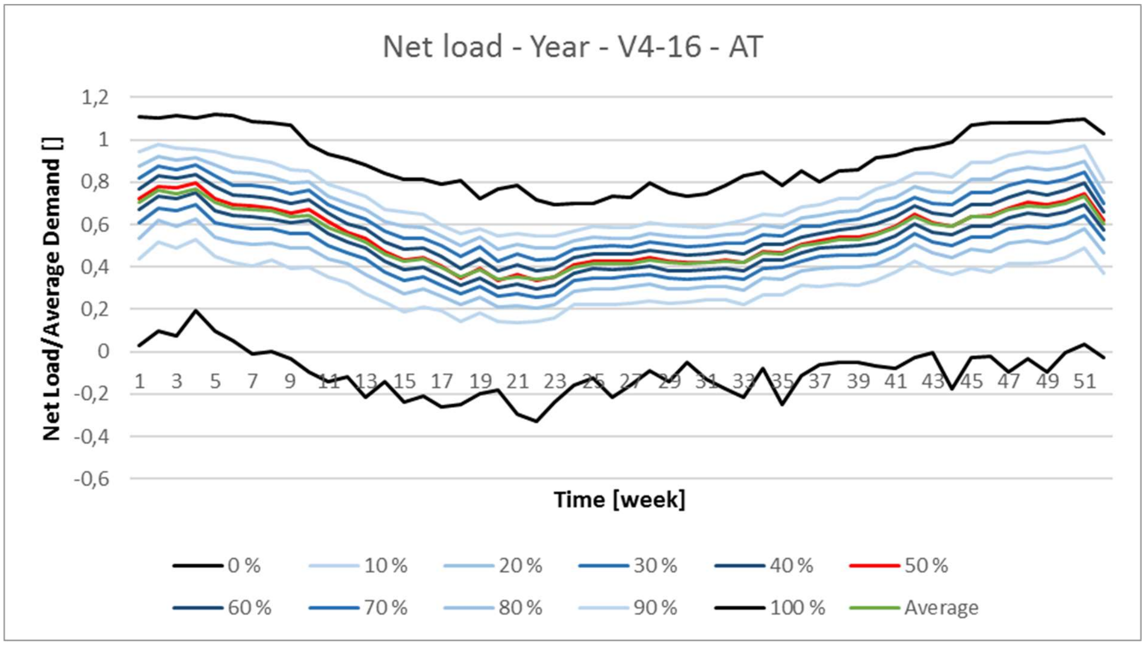

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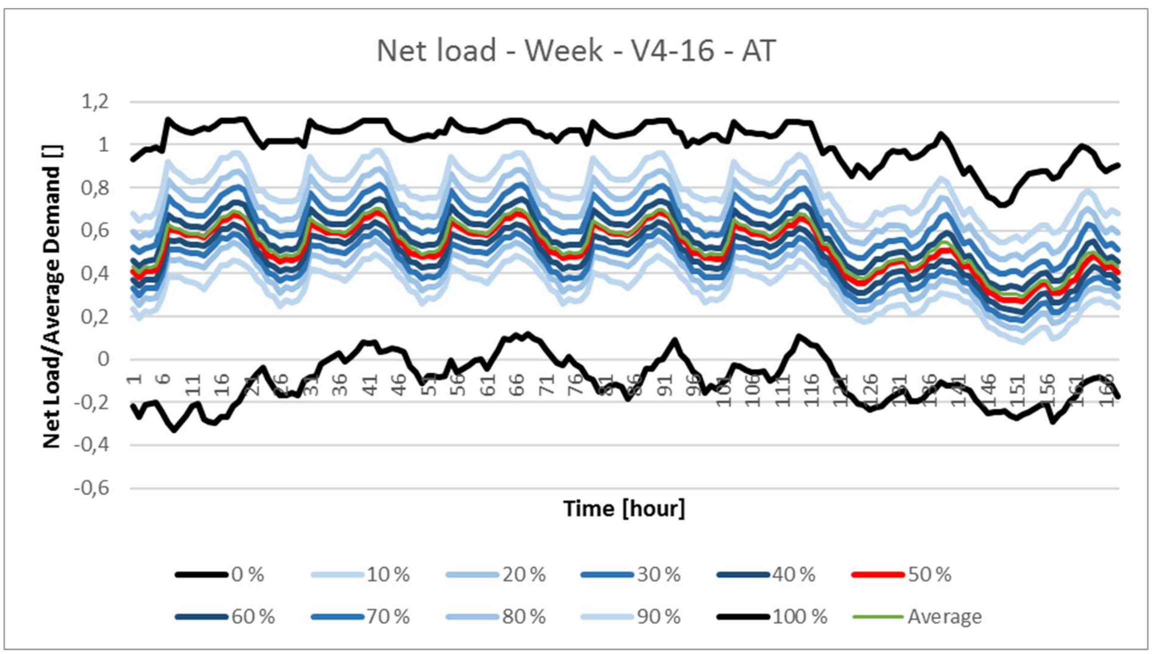

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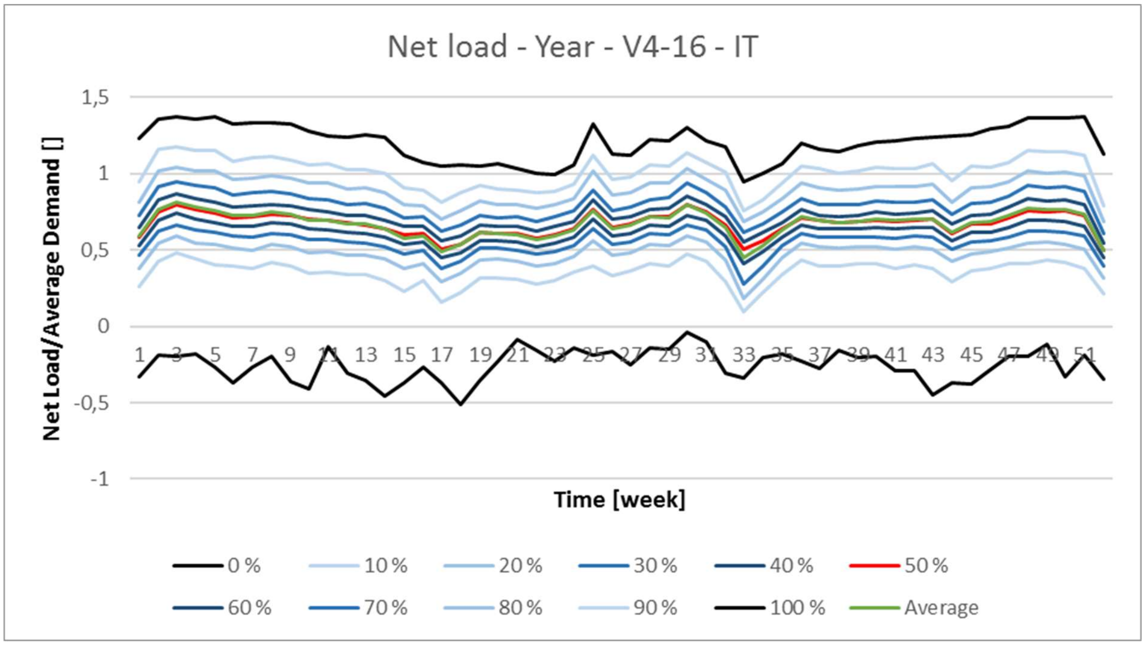

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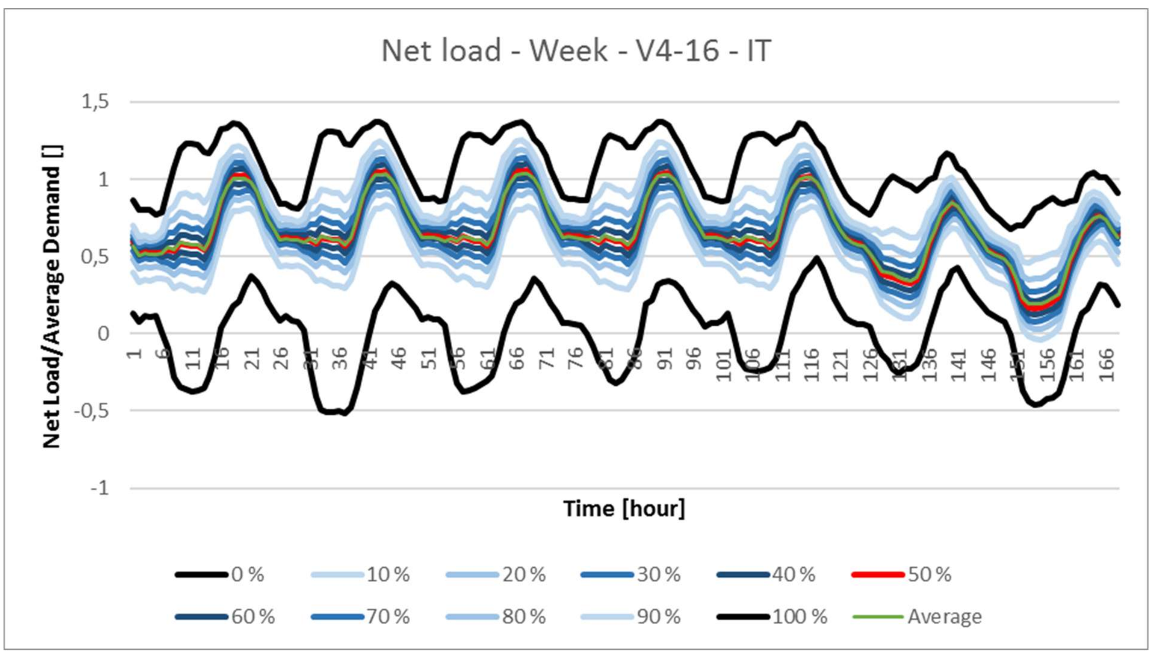

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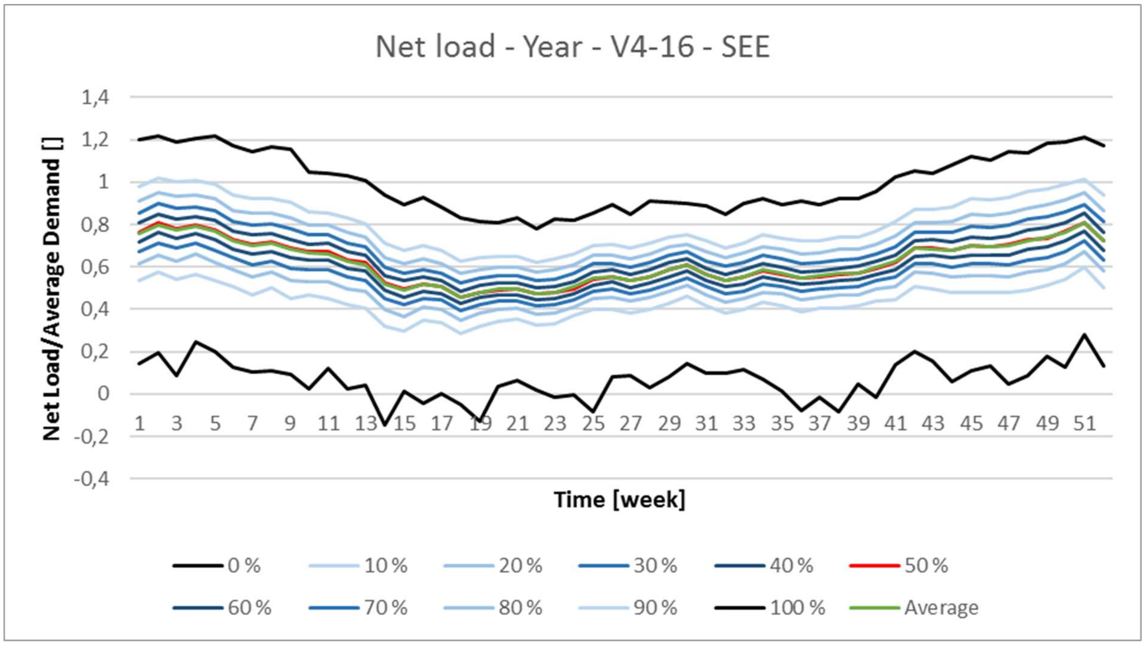

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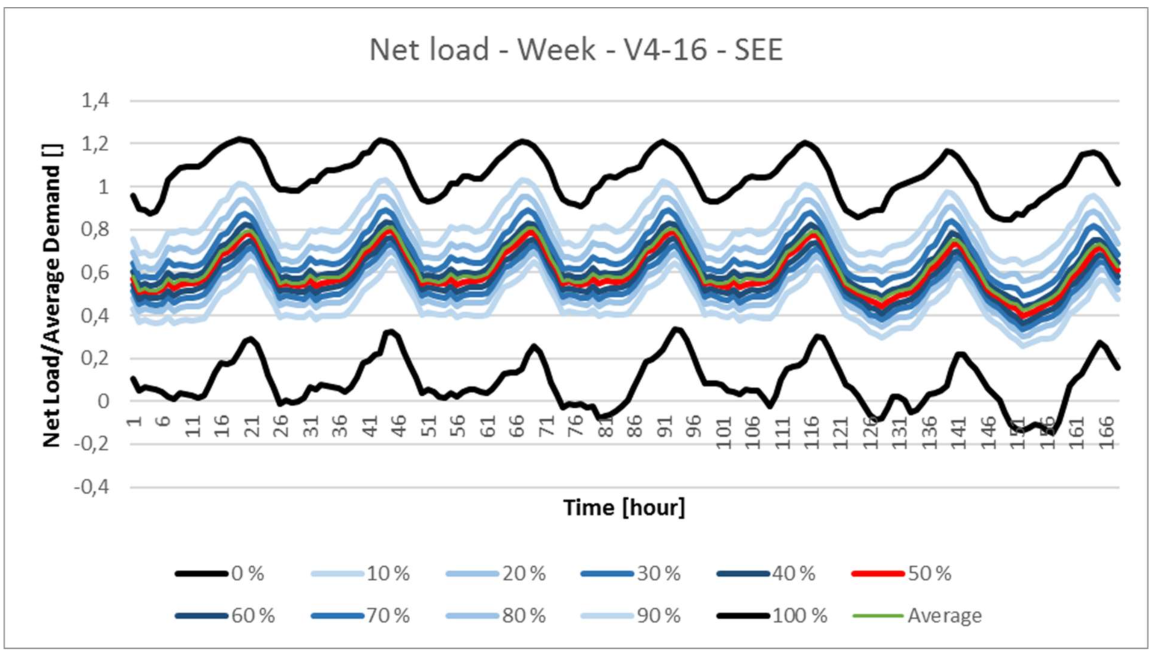
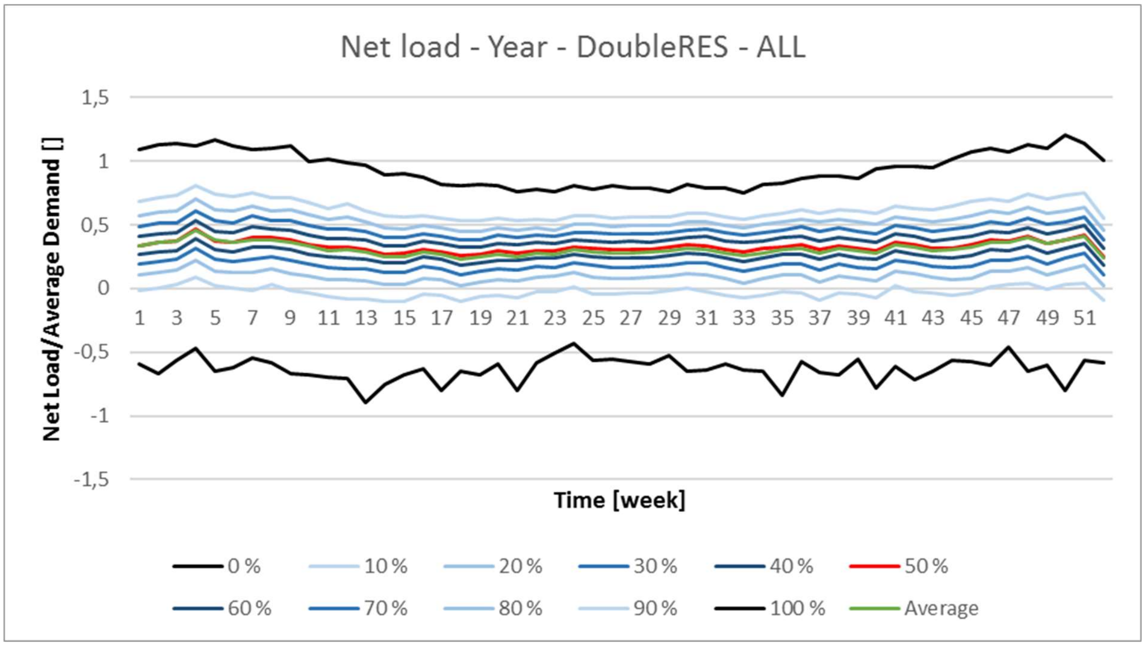


Figure 156

8.7.2 Net load – DoubleRES



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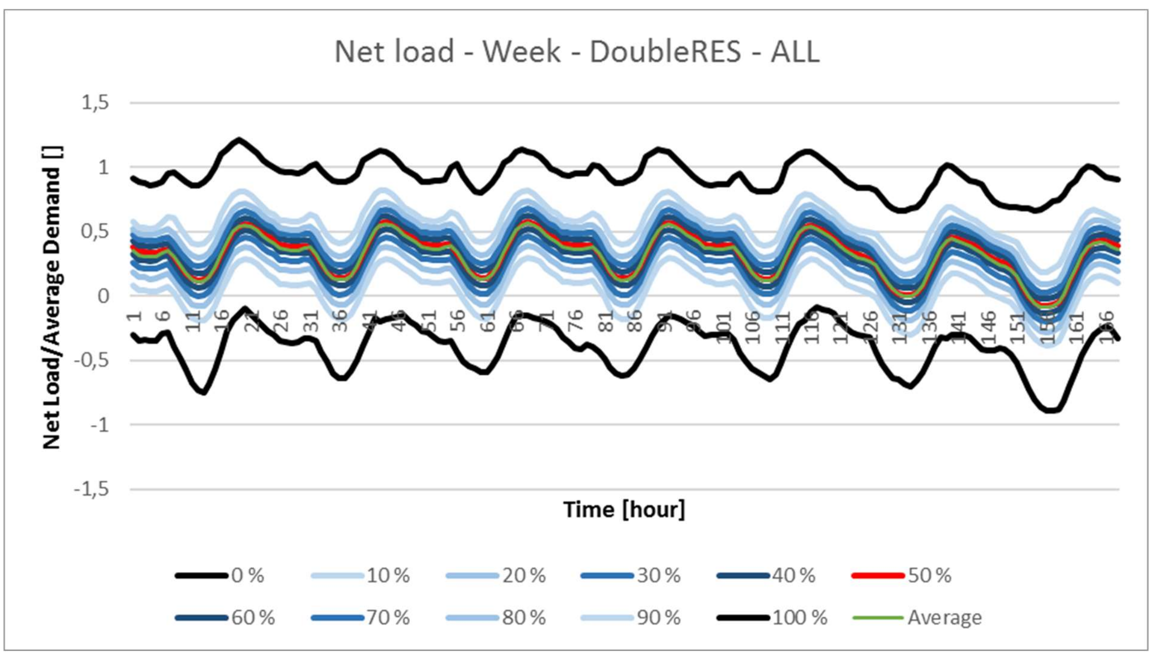

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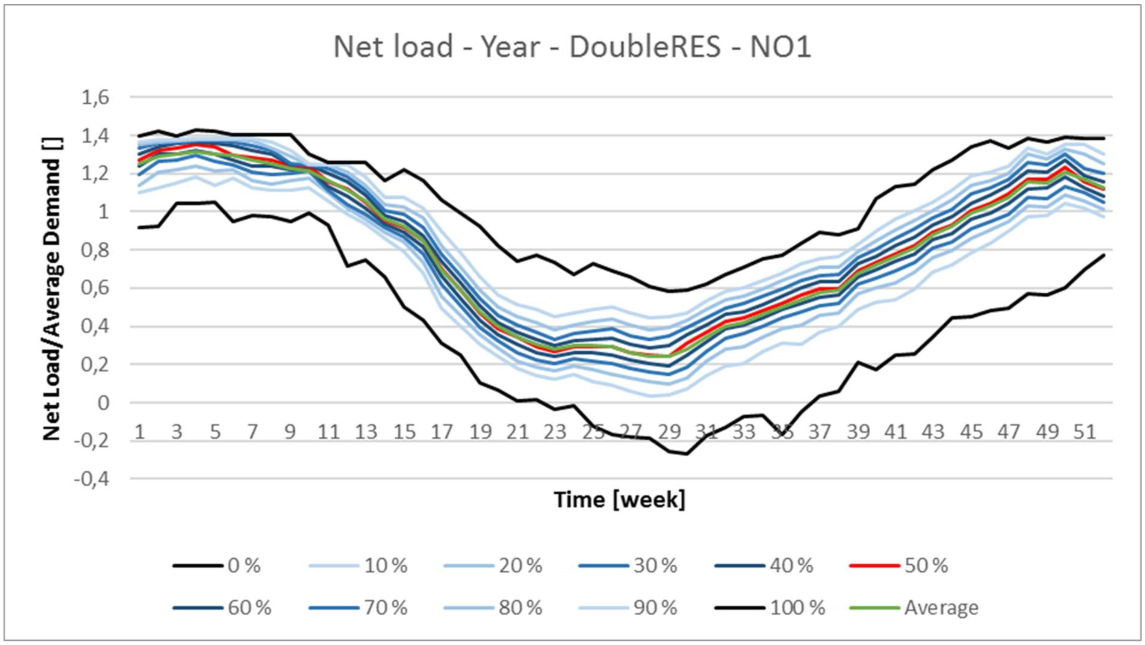

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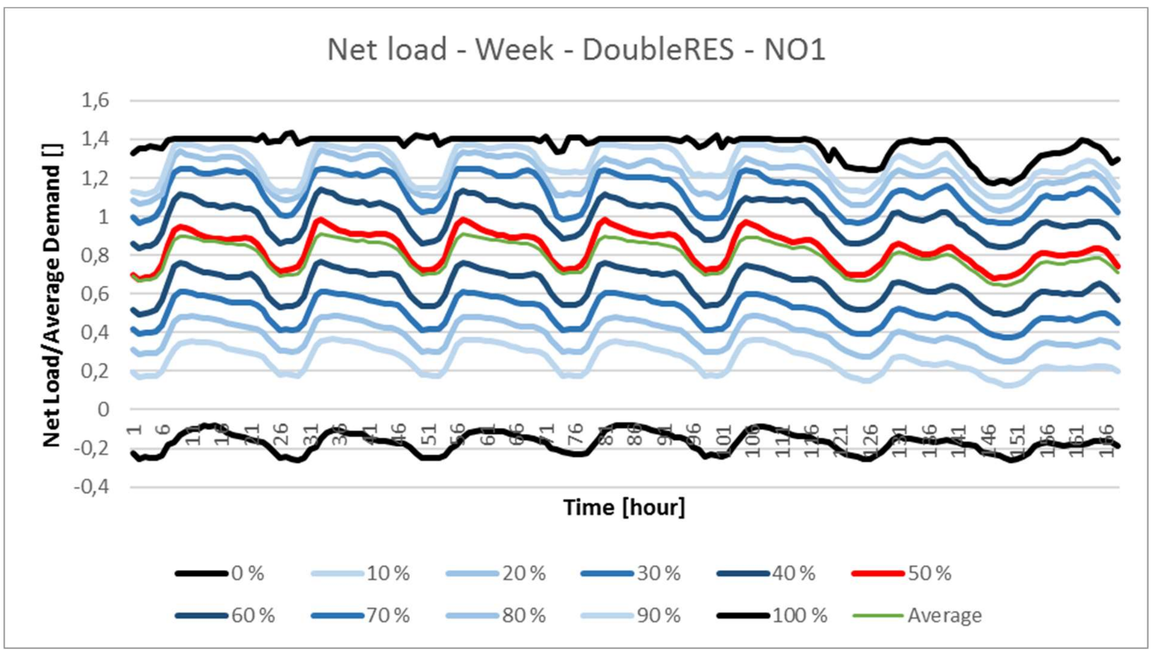

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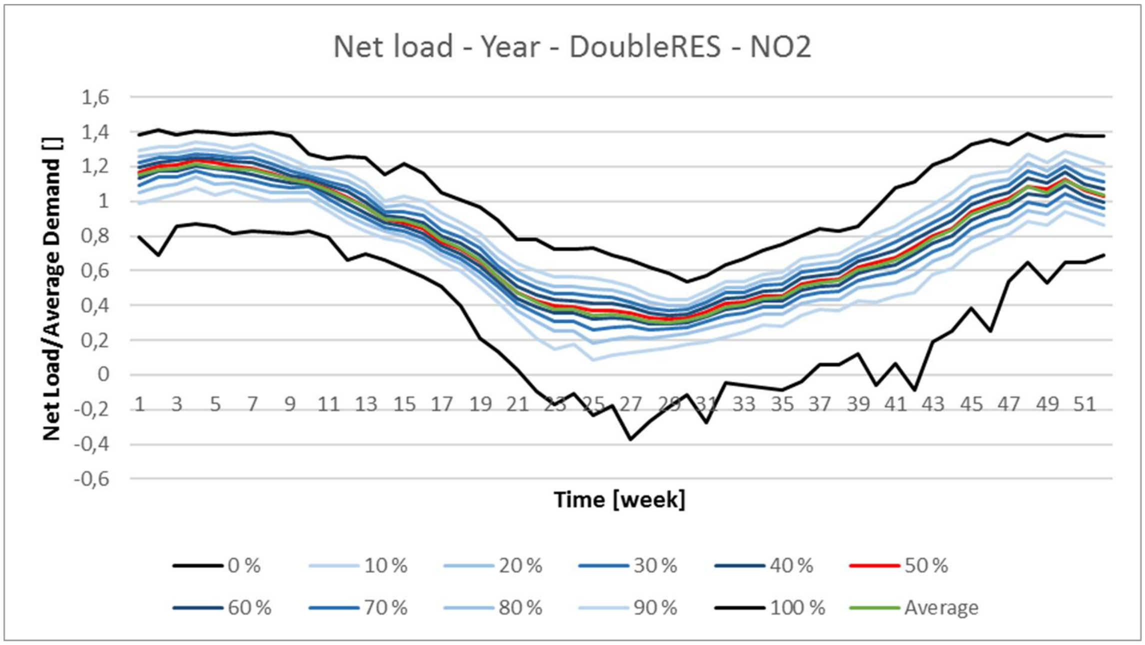

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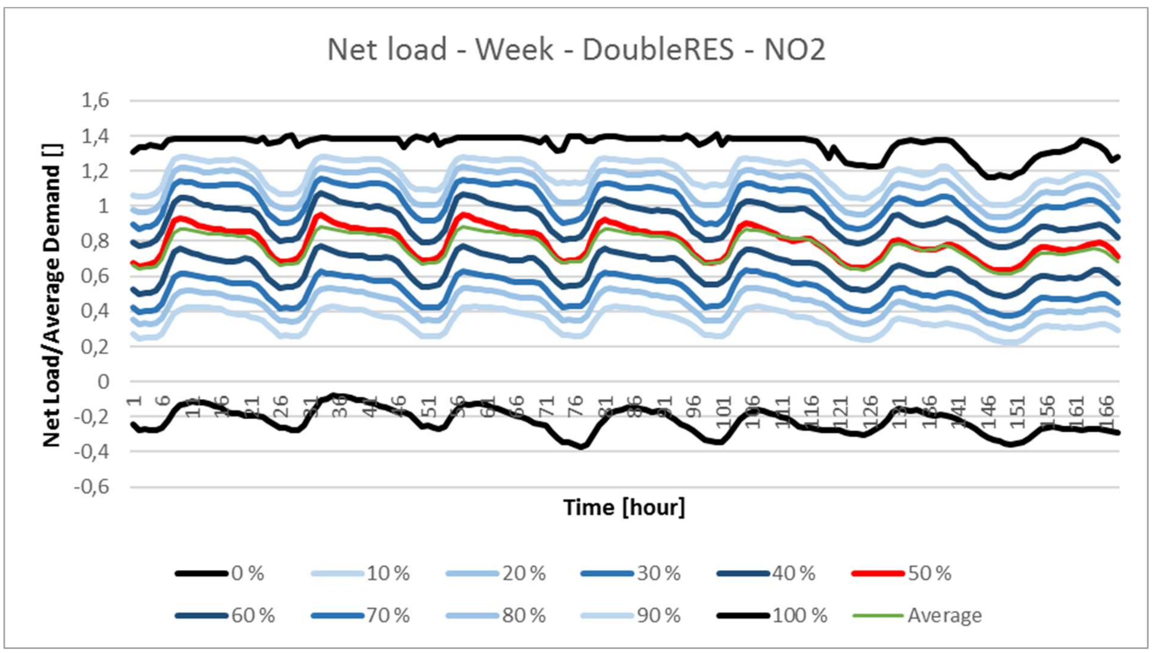

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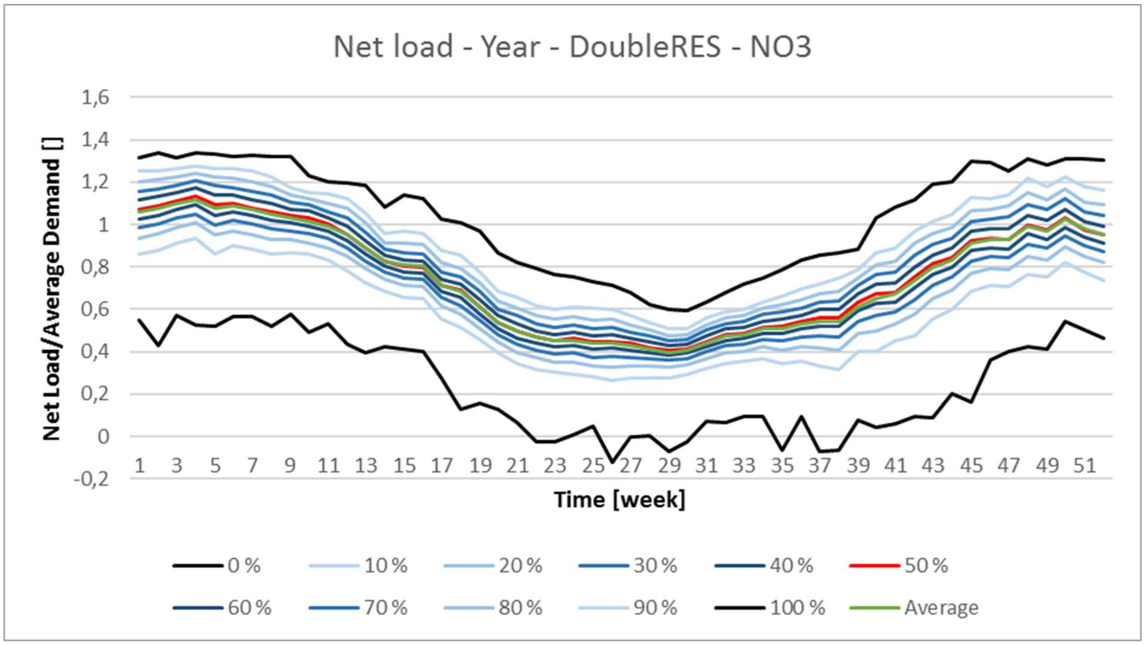

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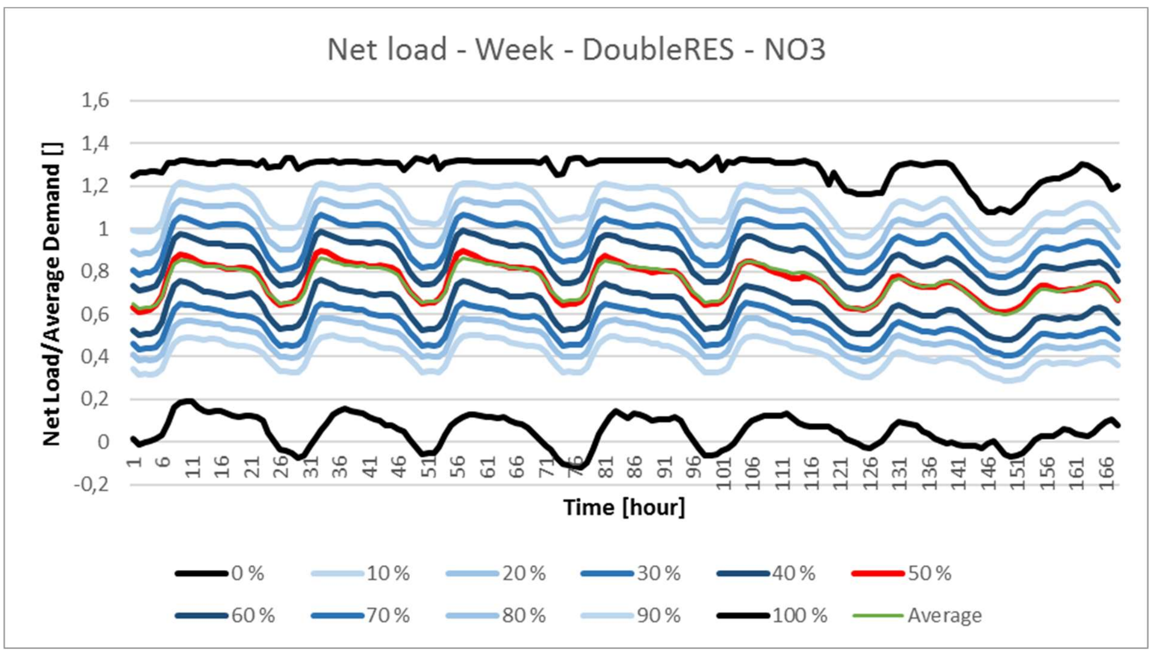

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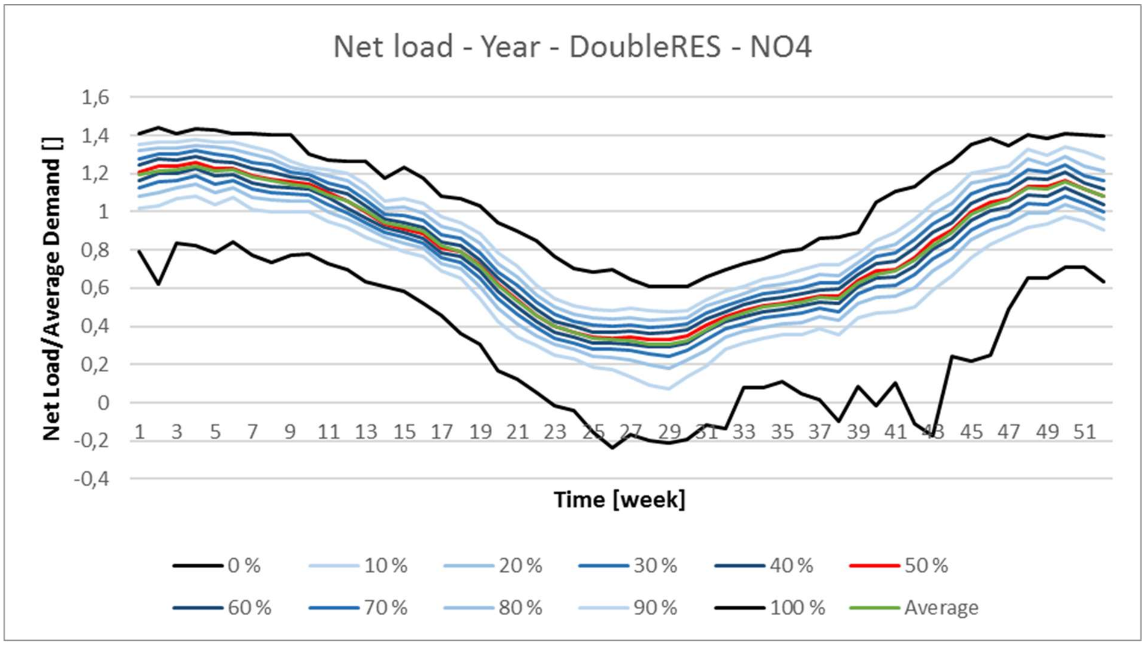

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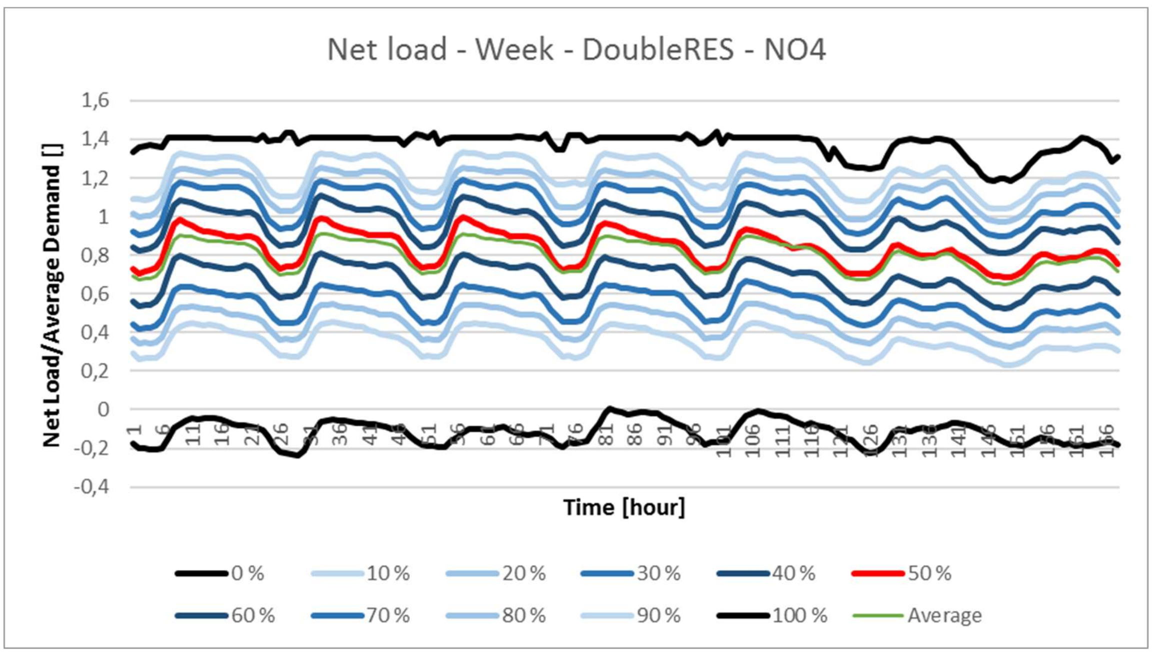

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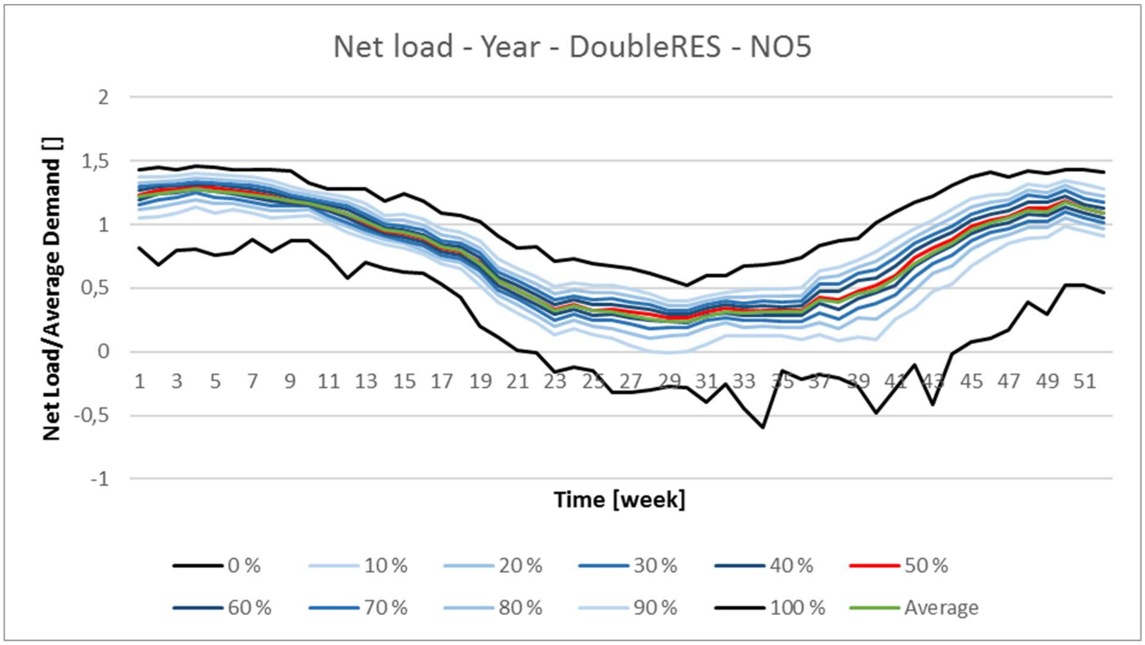

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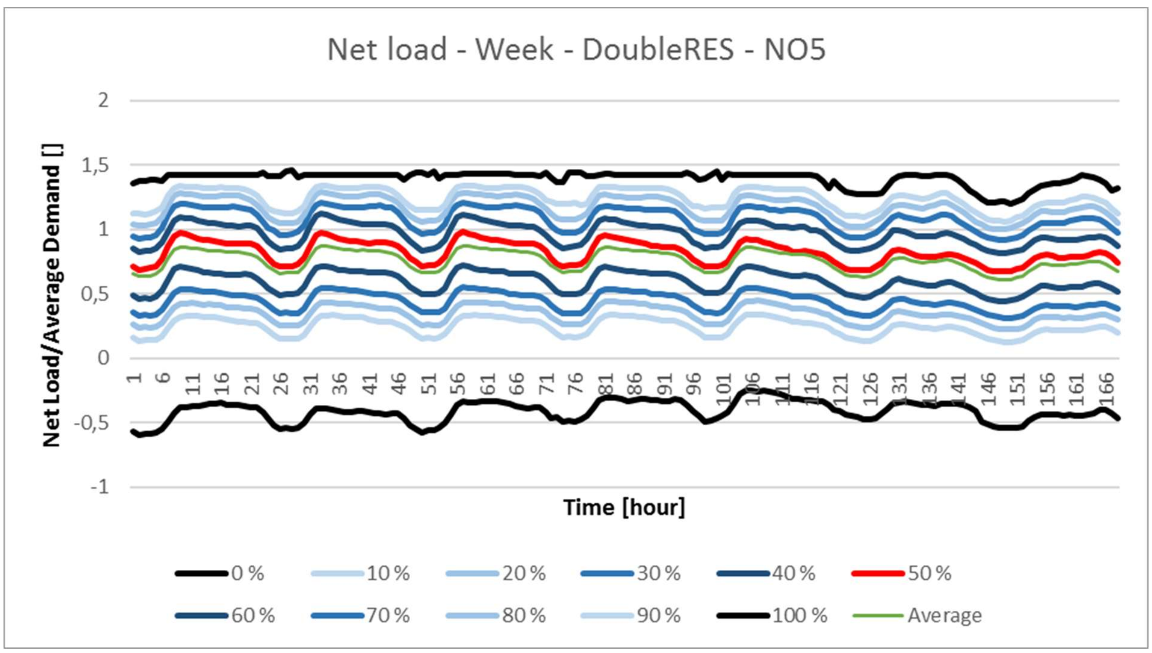

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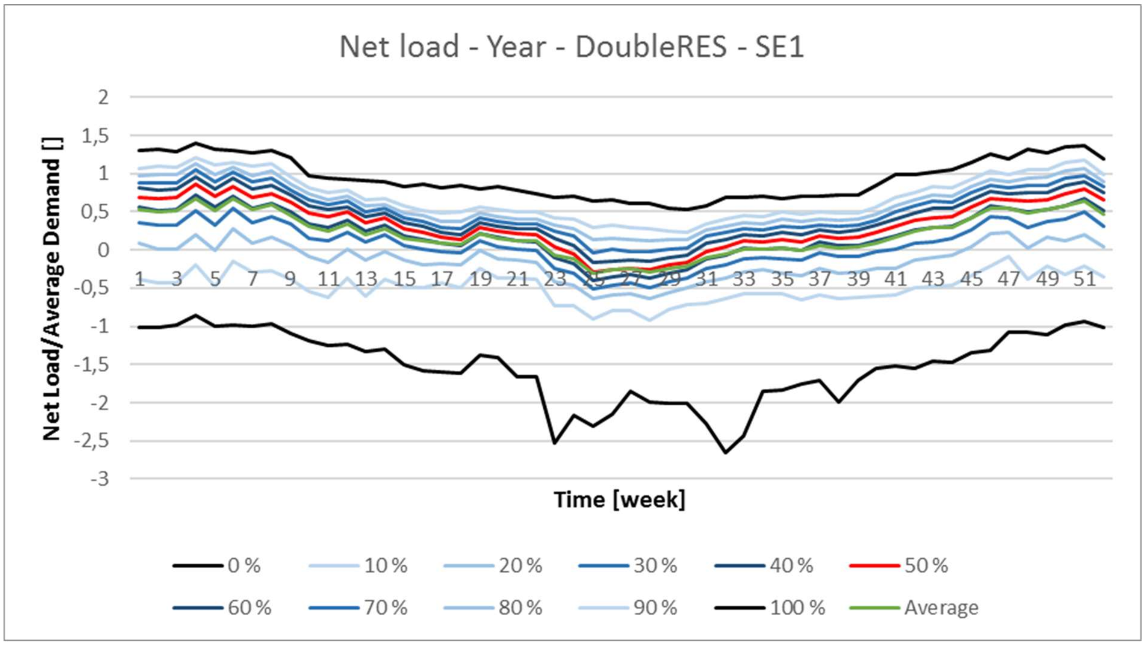

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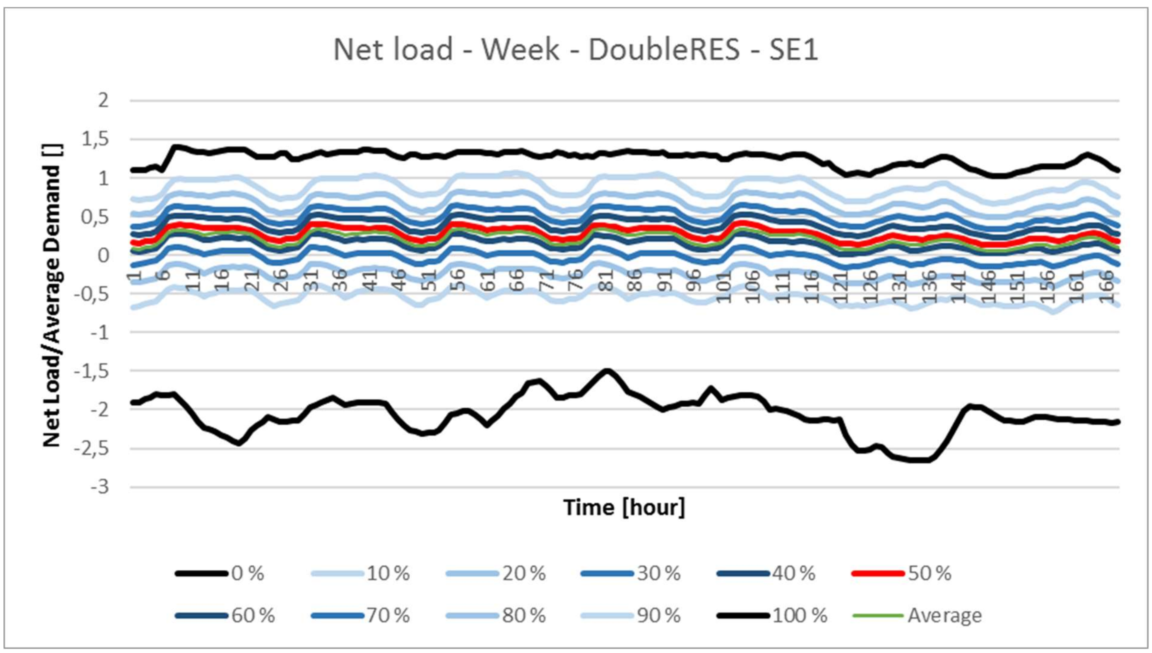

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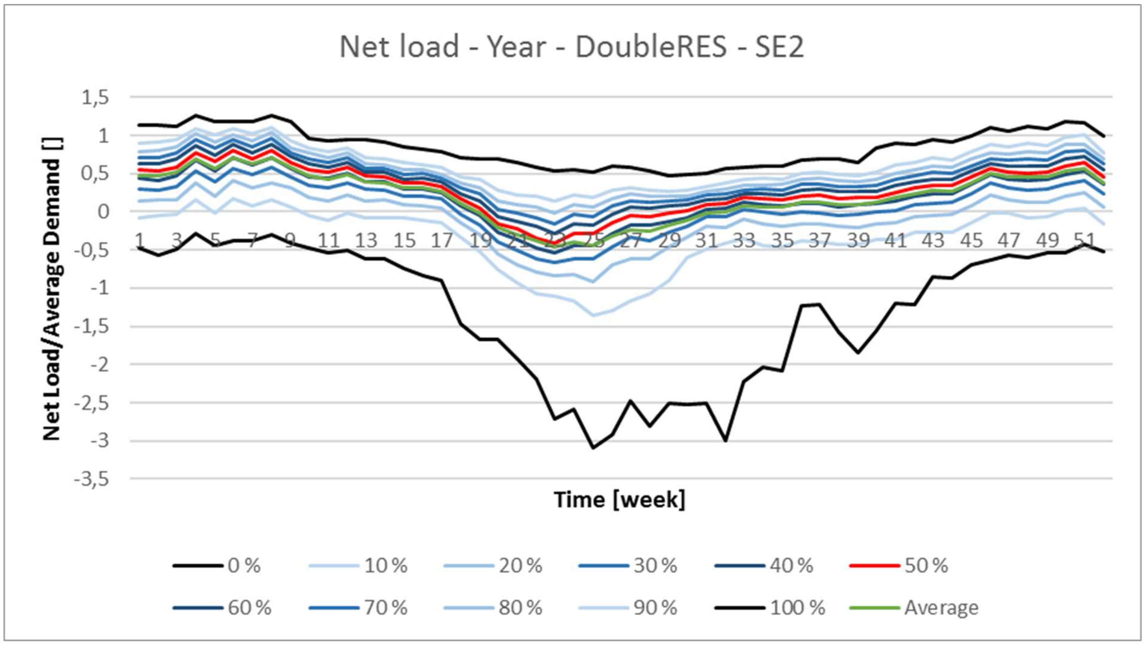

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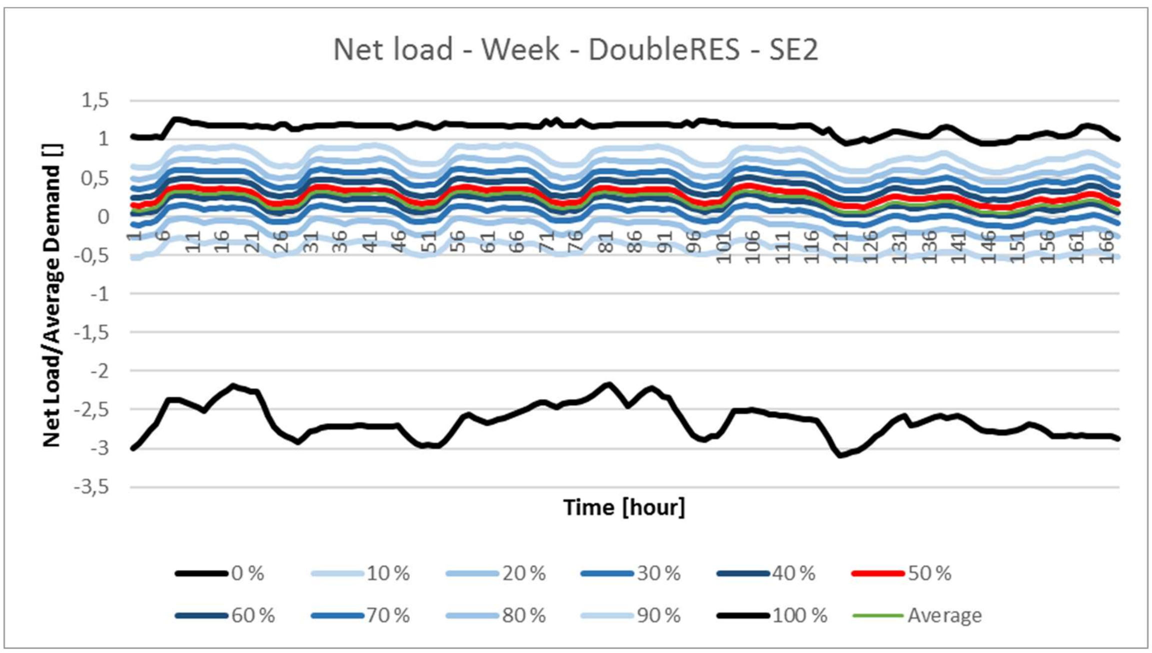

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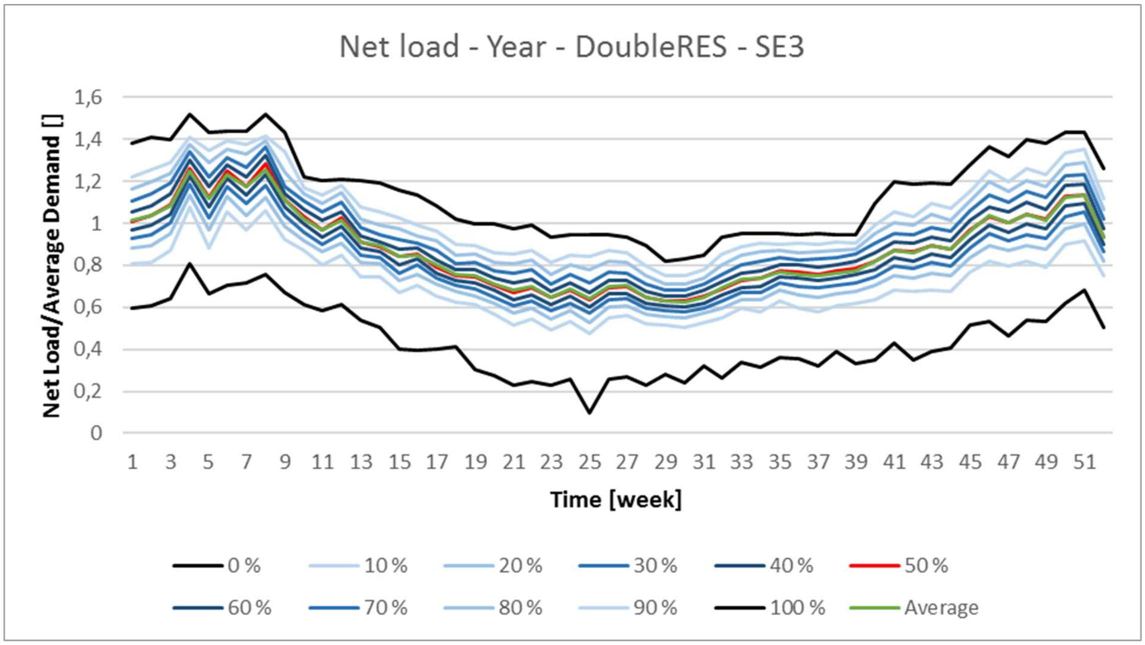

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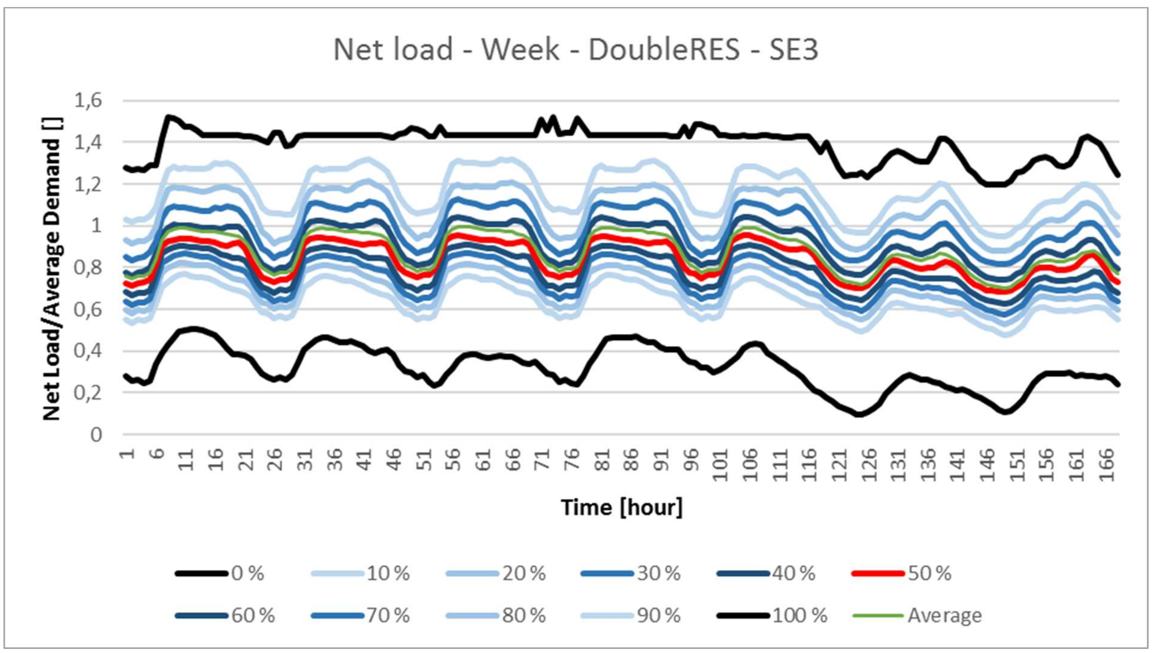

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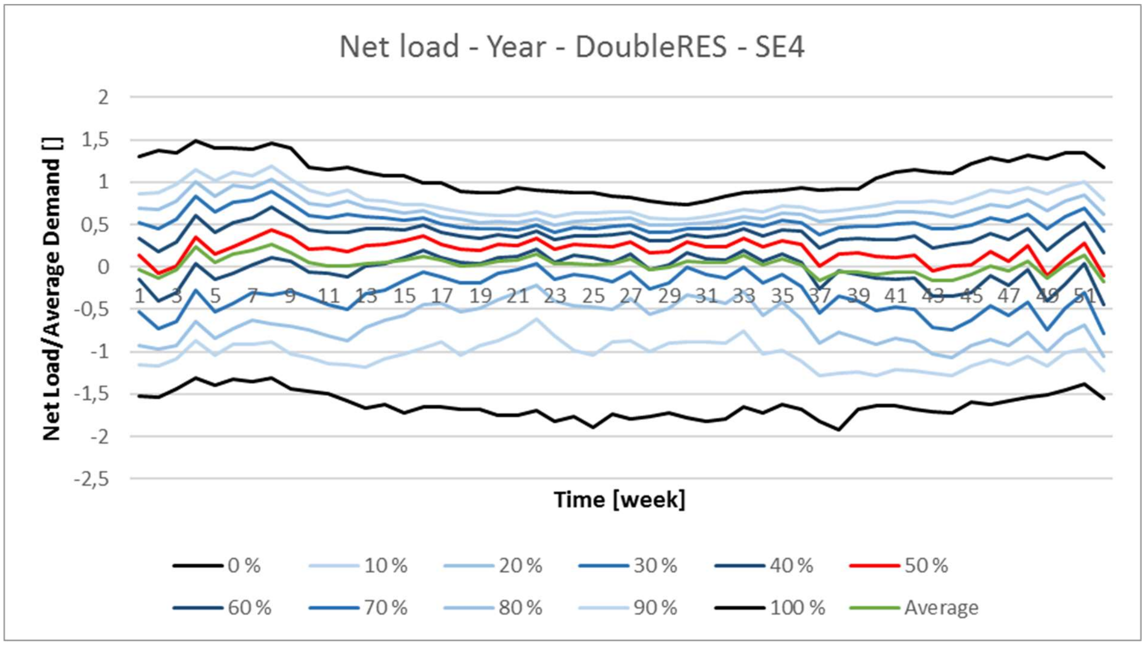


Figure 175

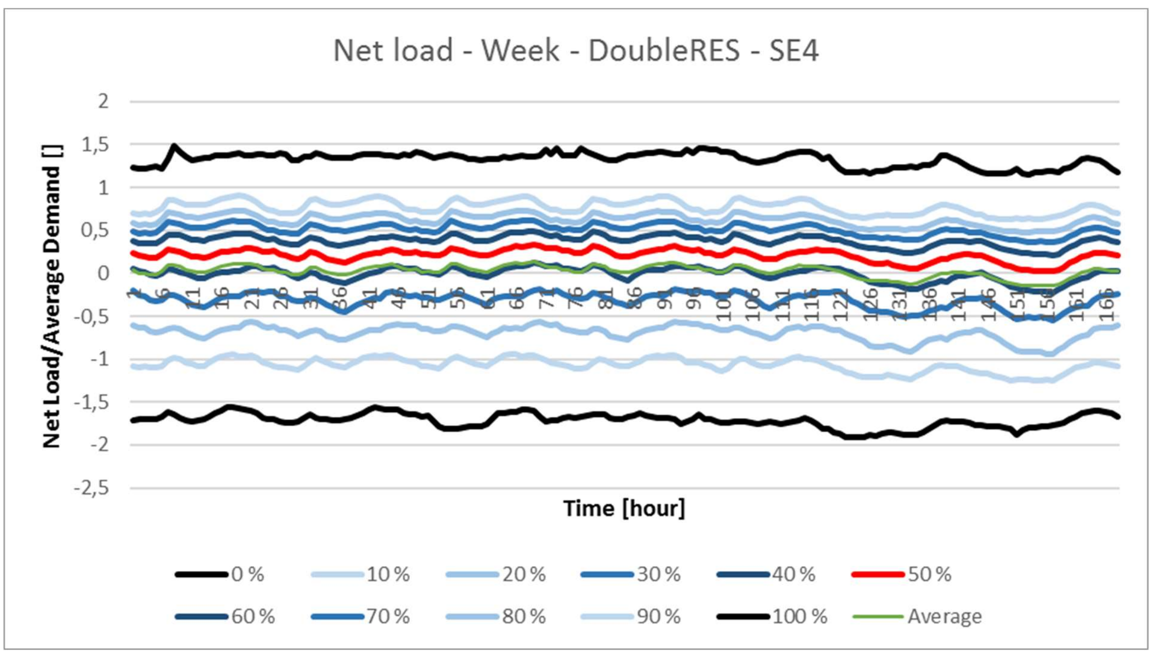
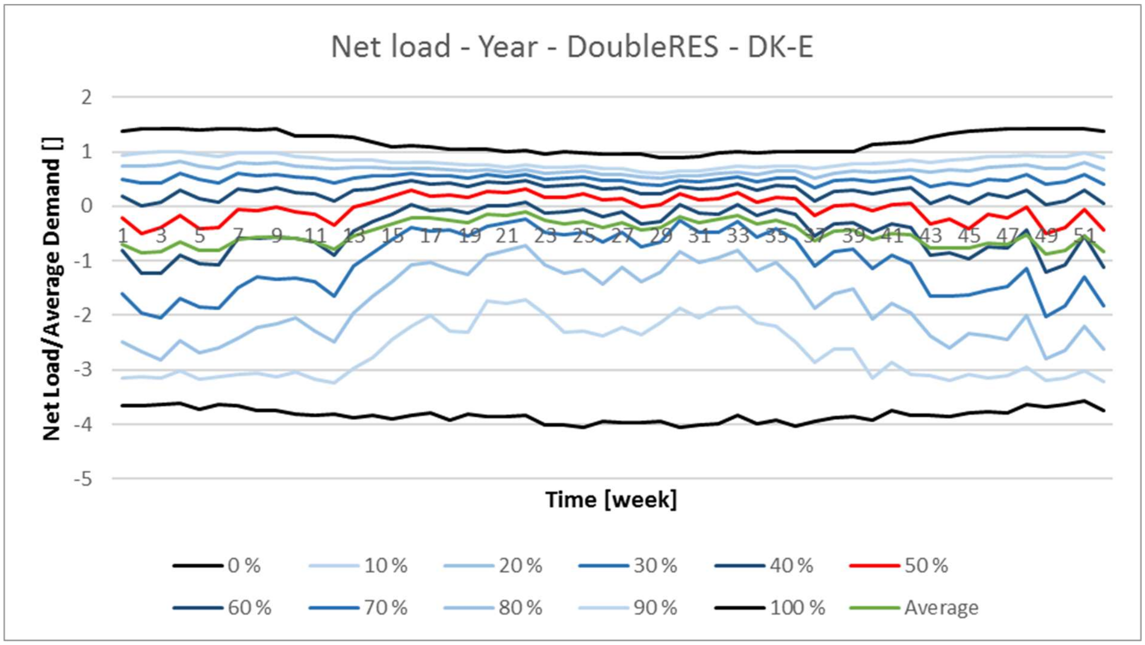


Figure 176



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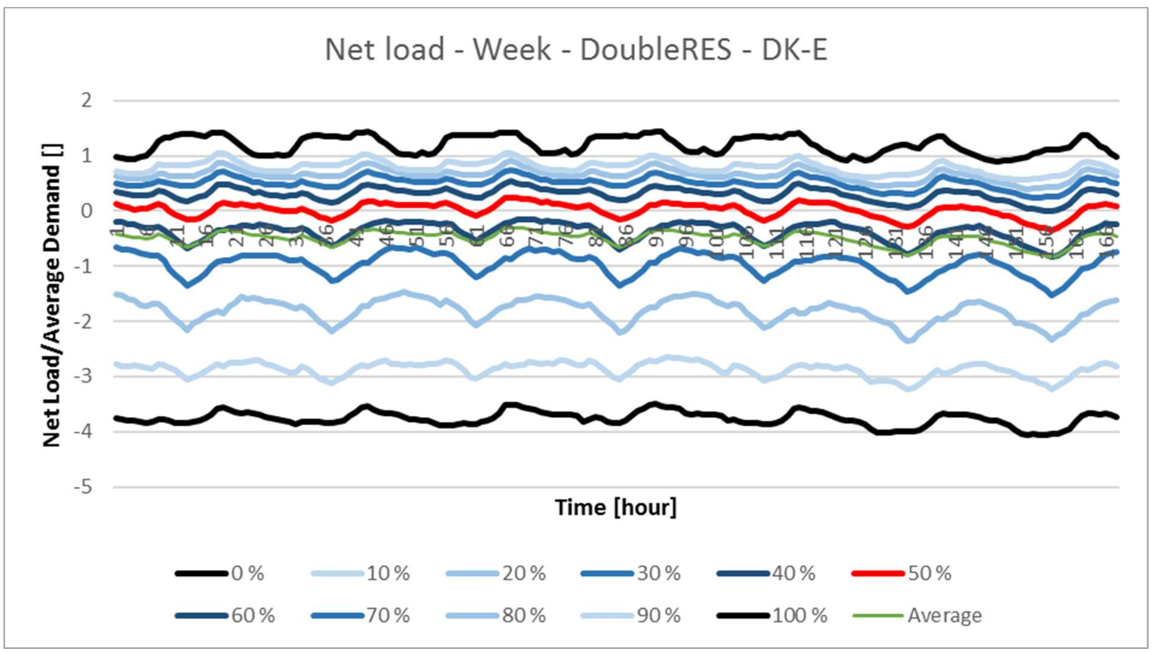

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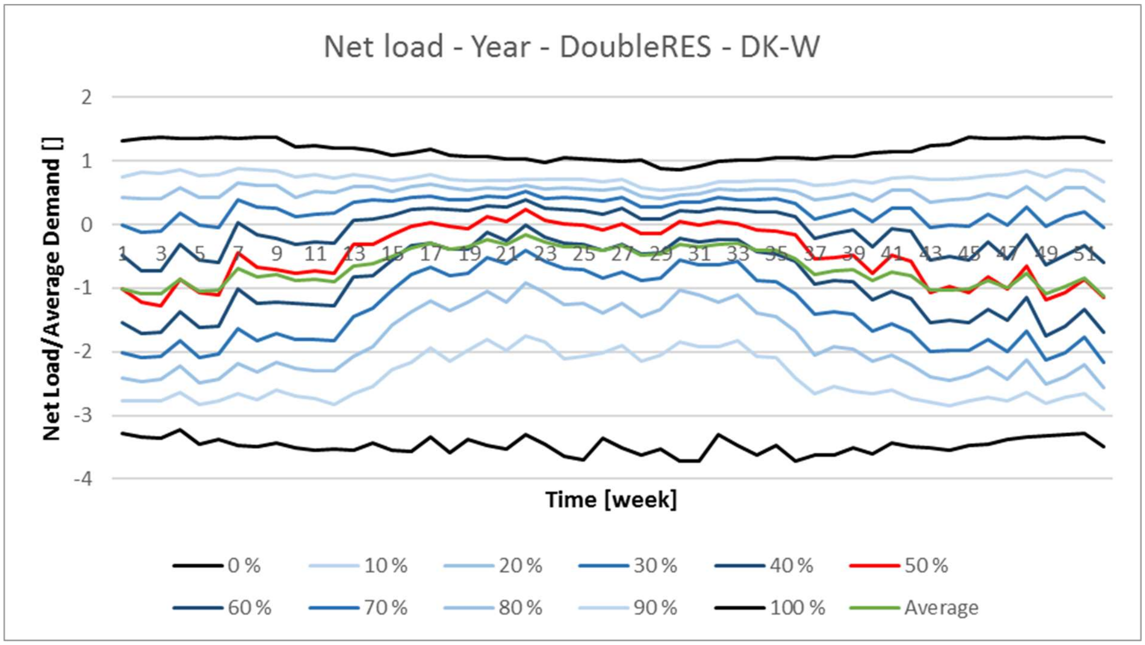

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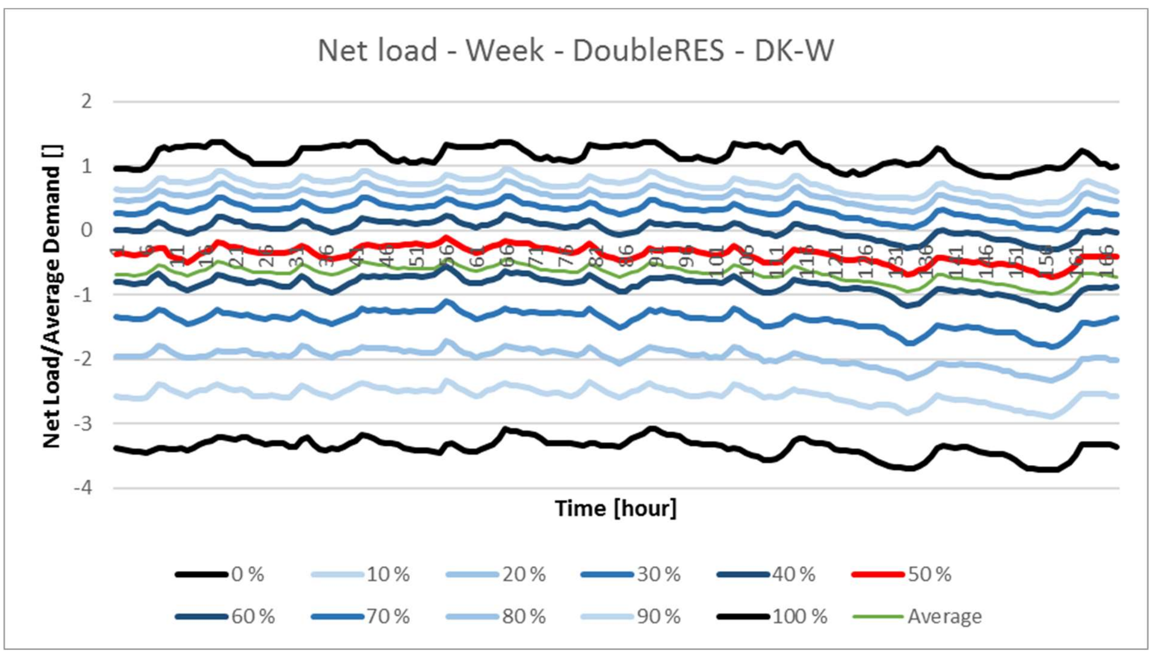
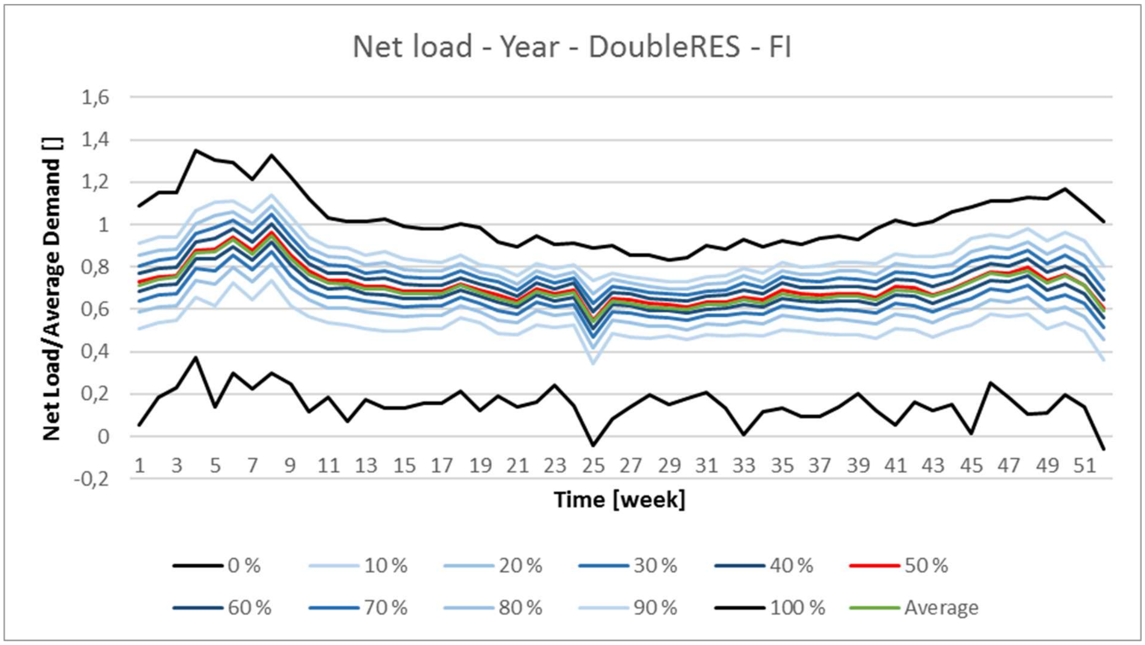


Figure 180



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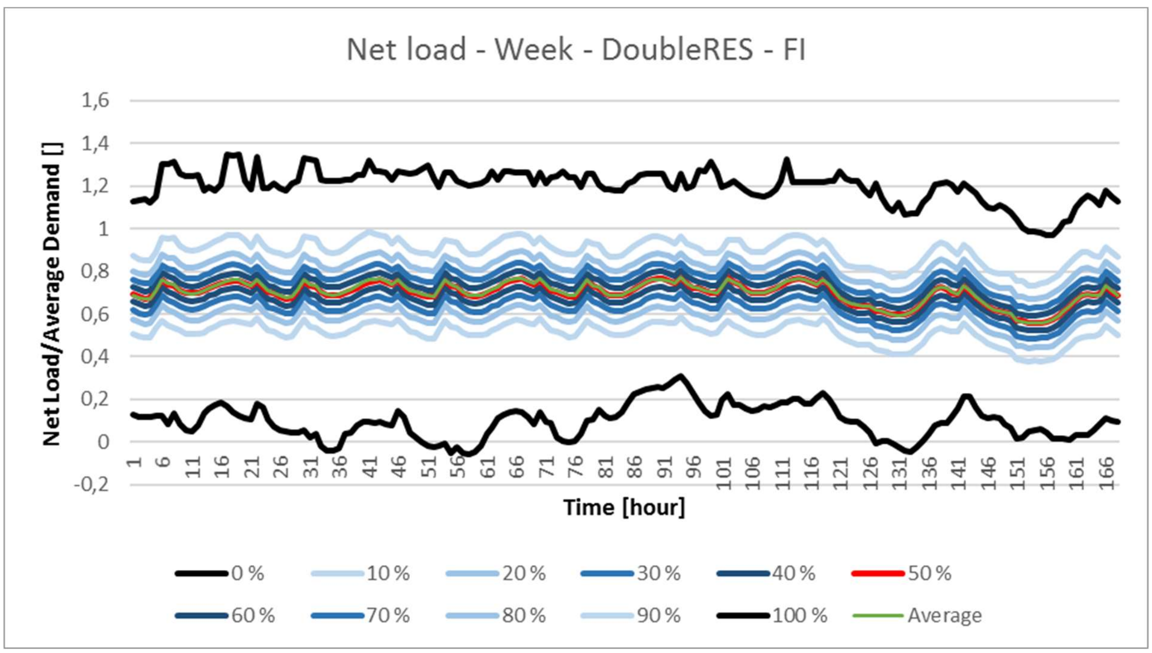

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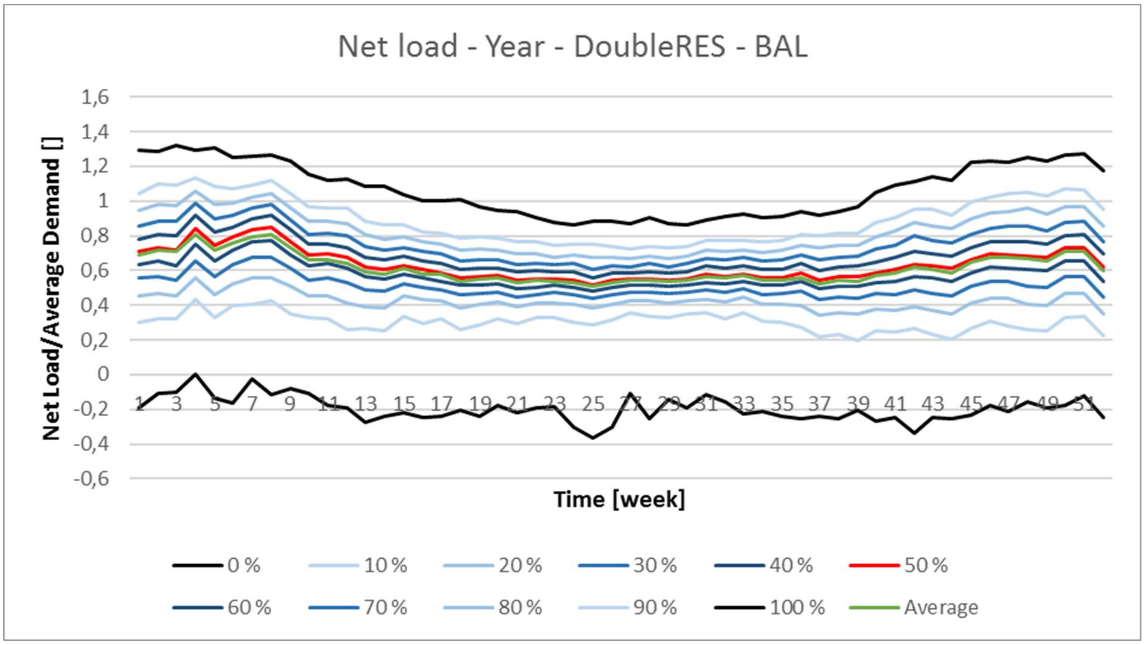

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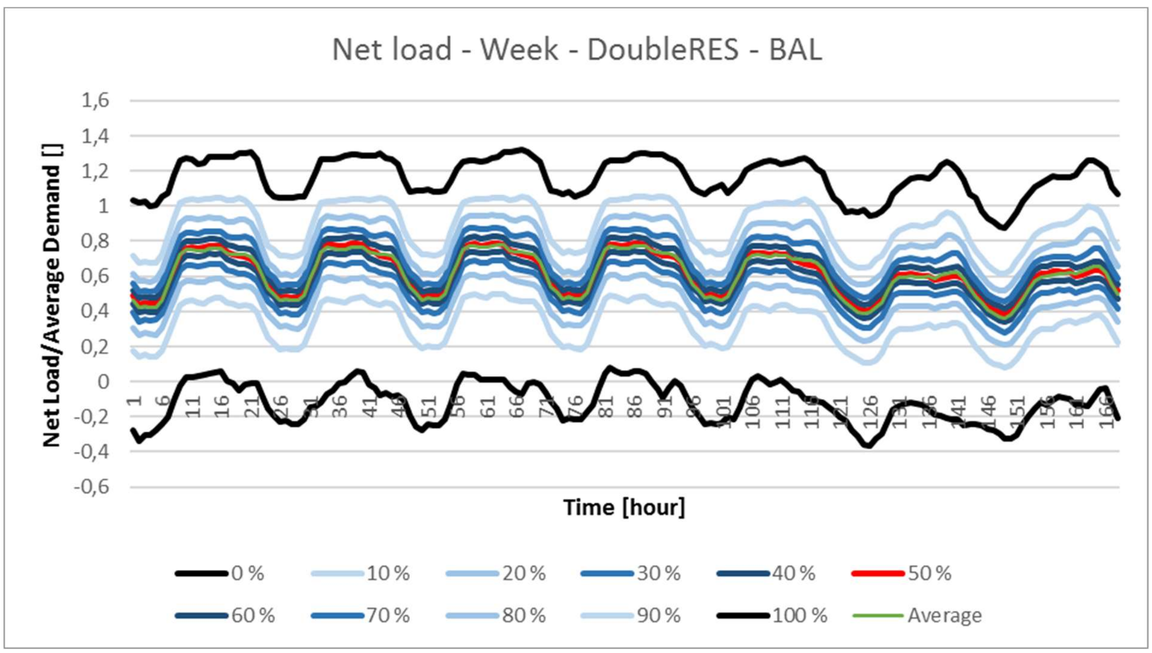

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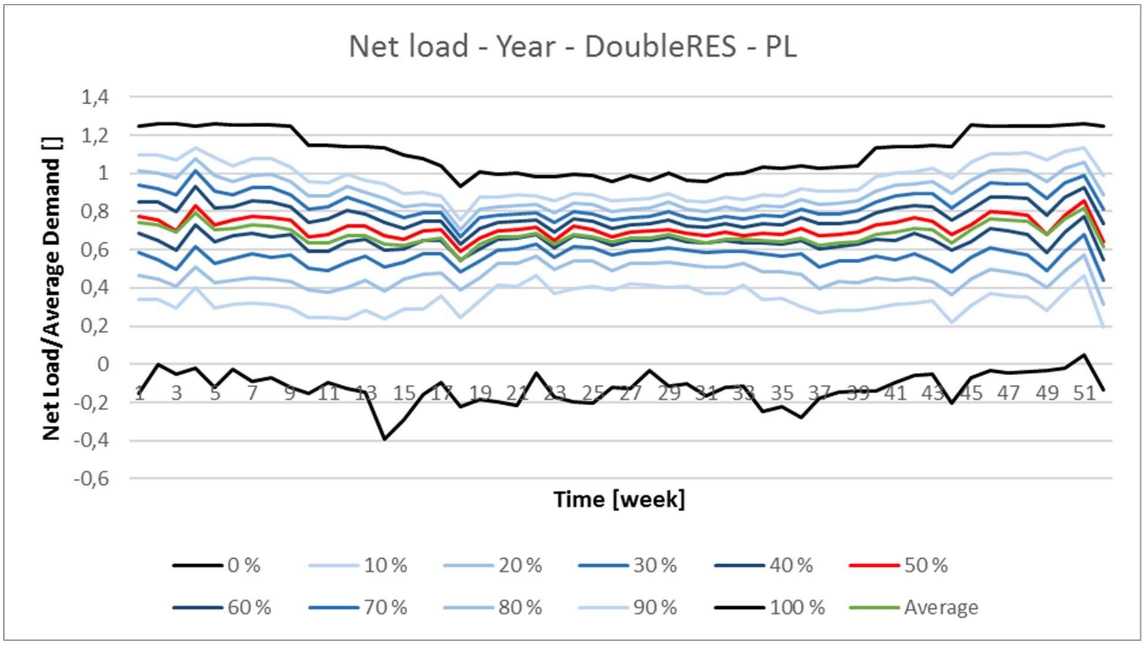

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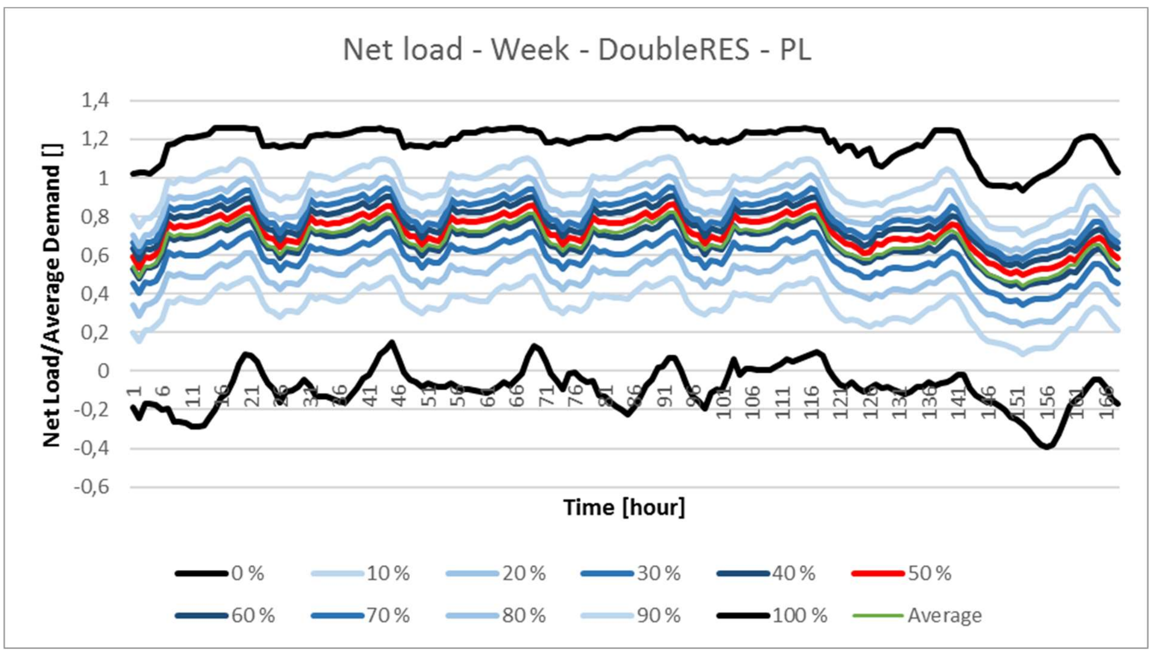

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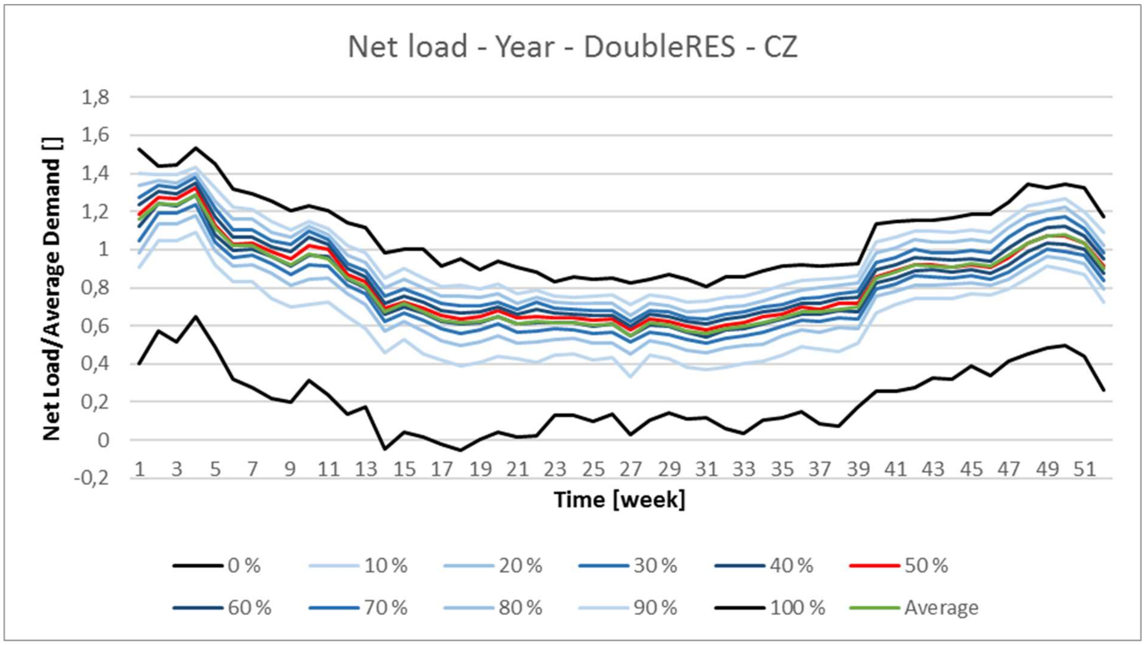

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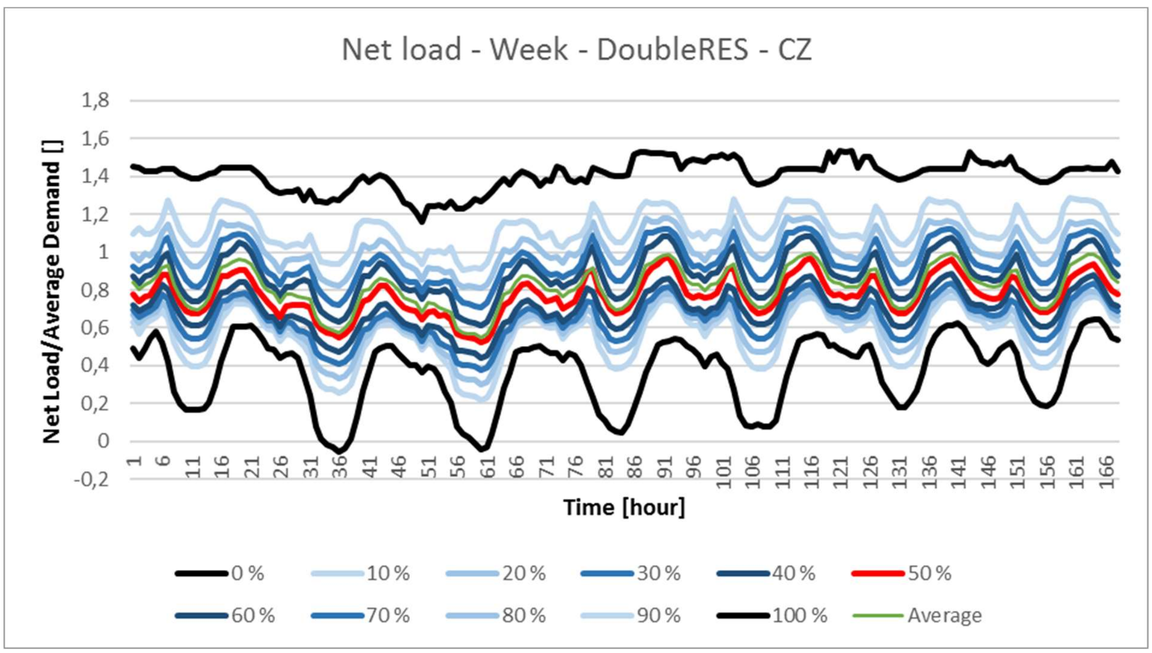

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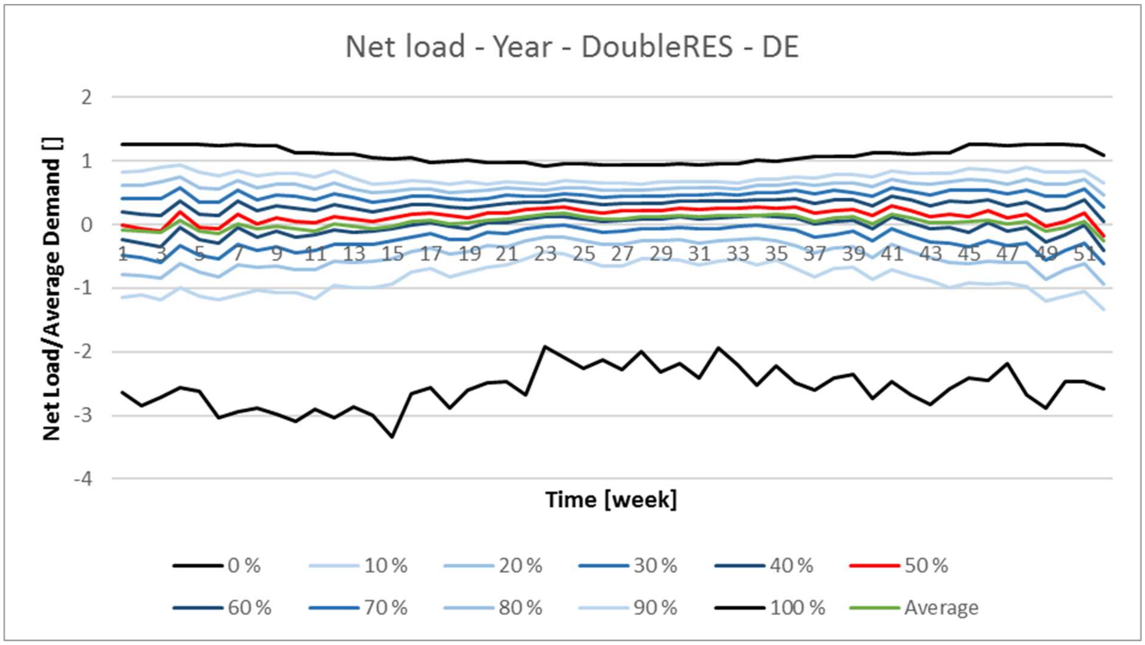

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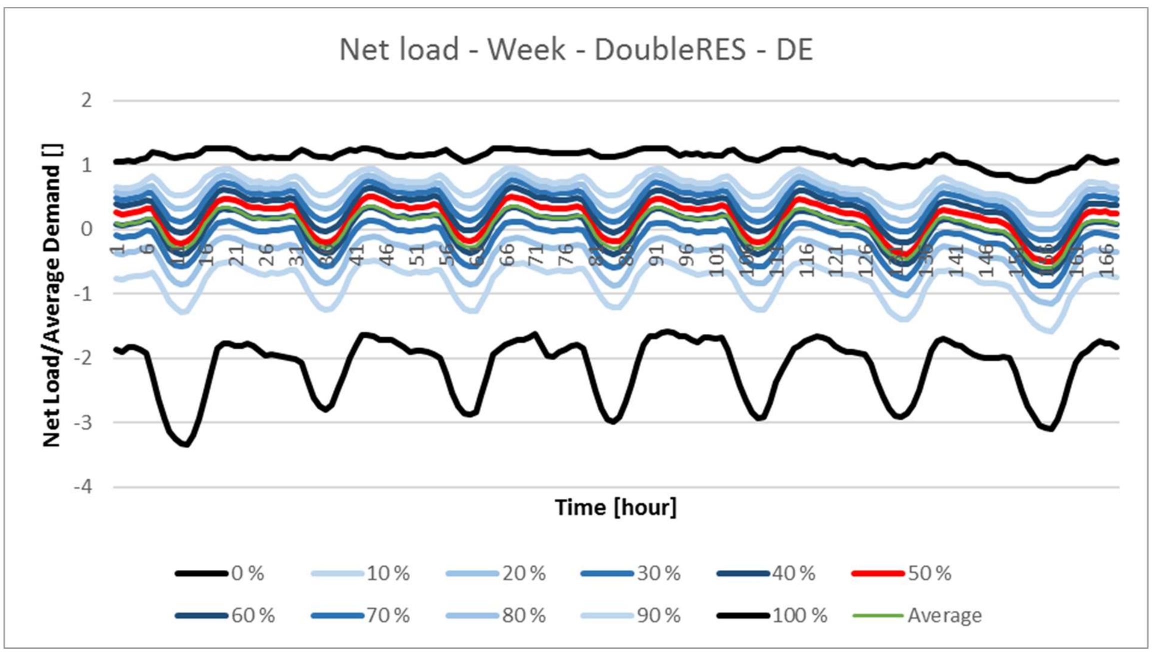

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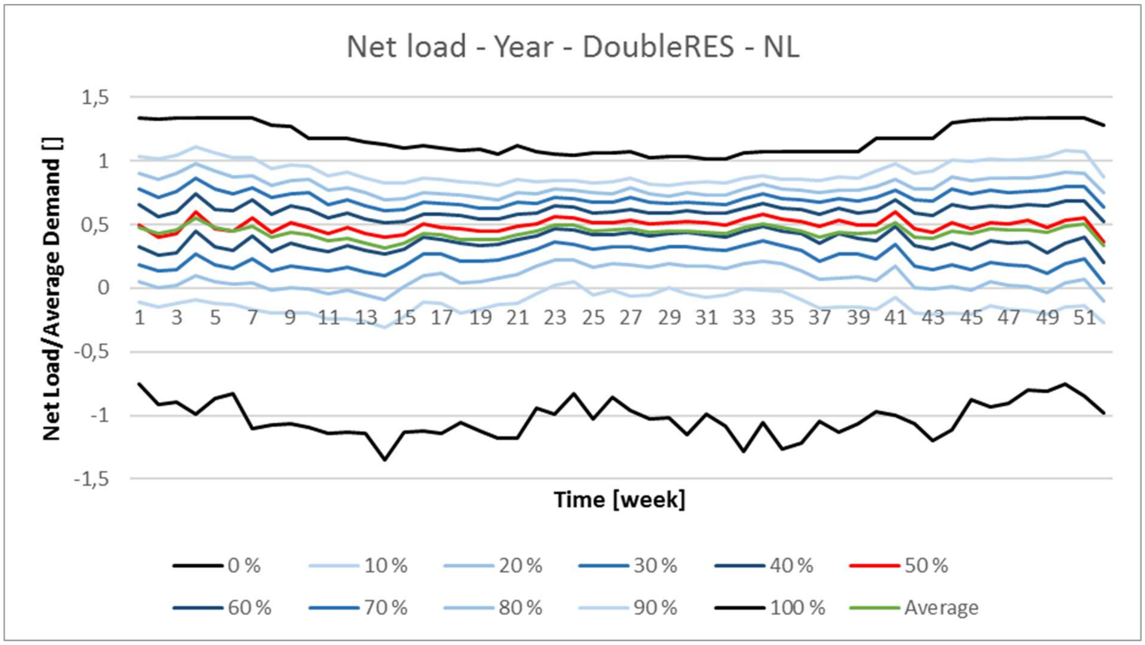

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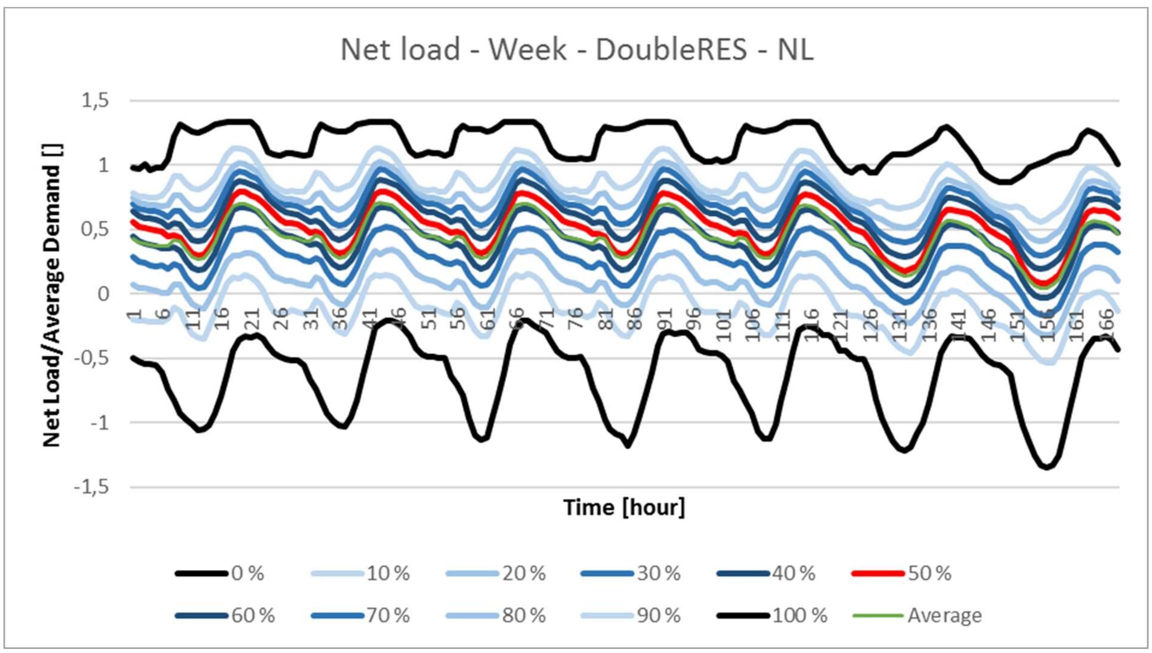

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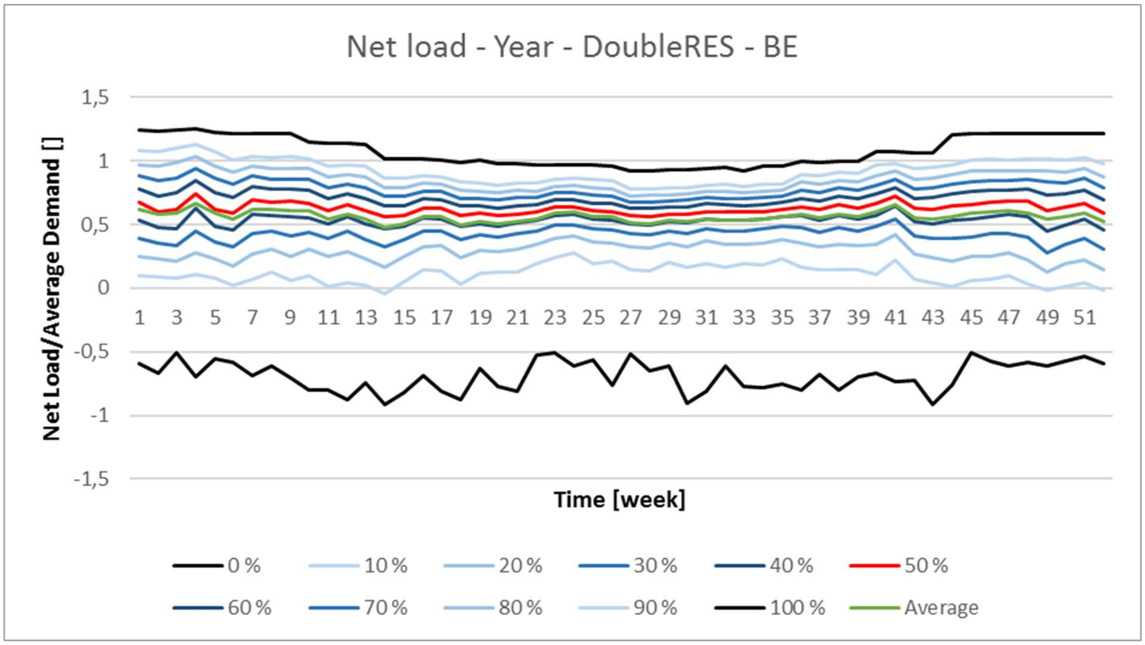

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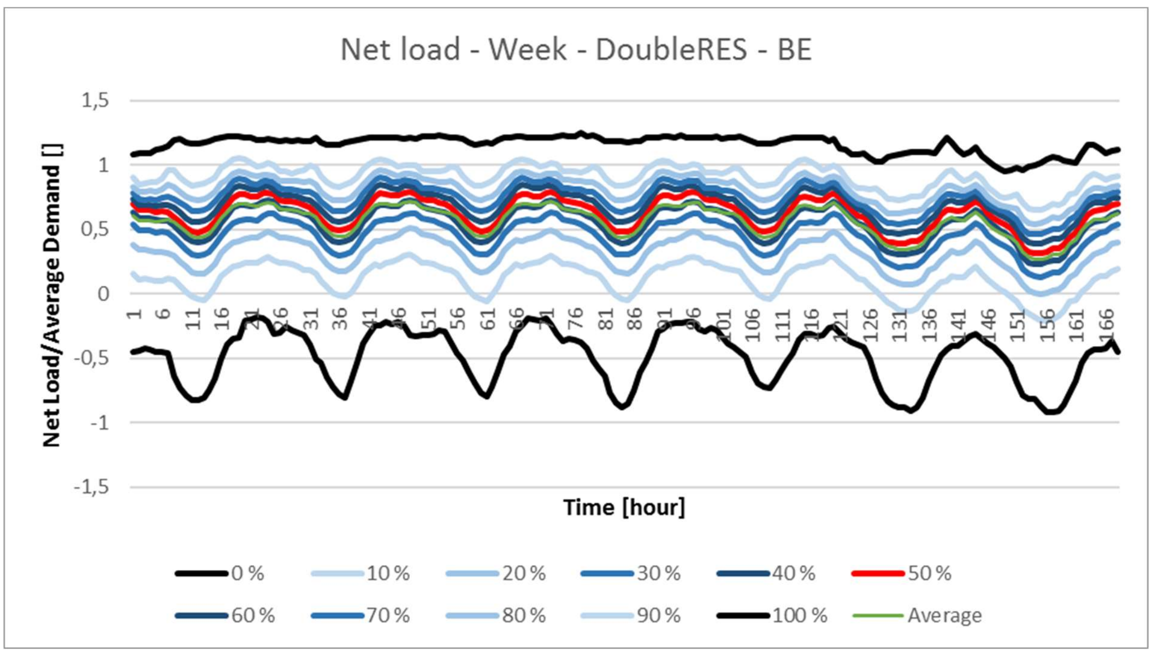

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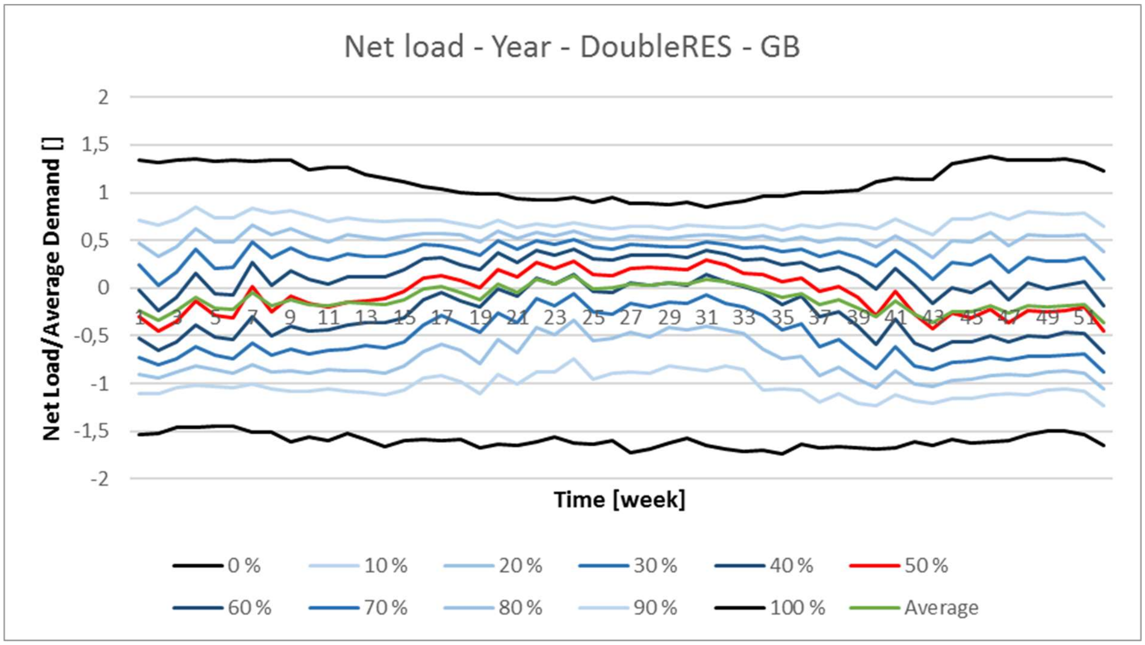

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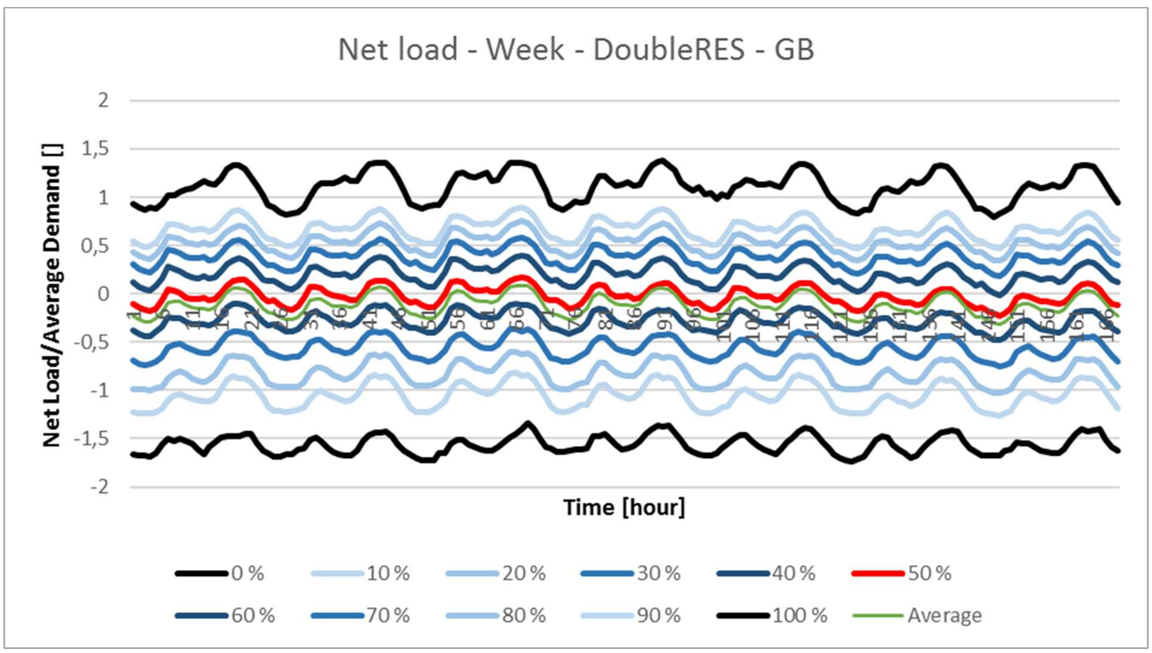

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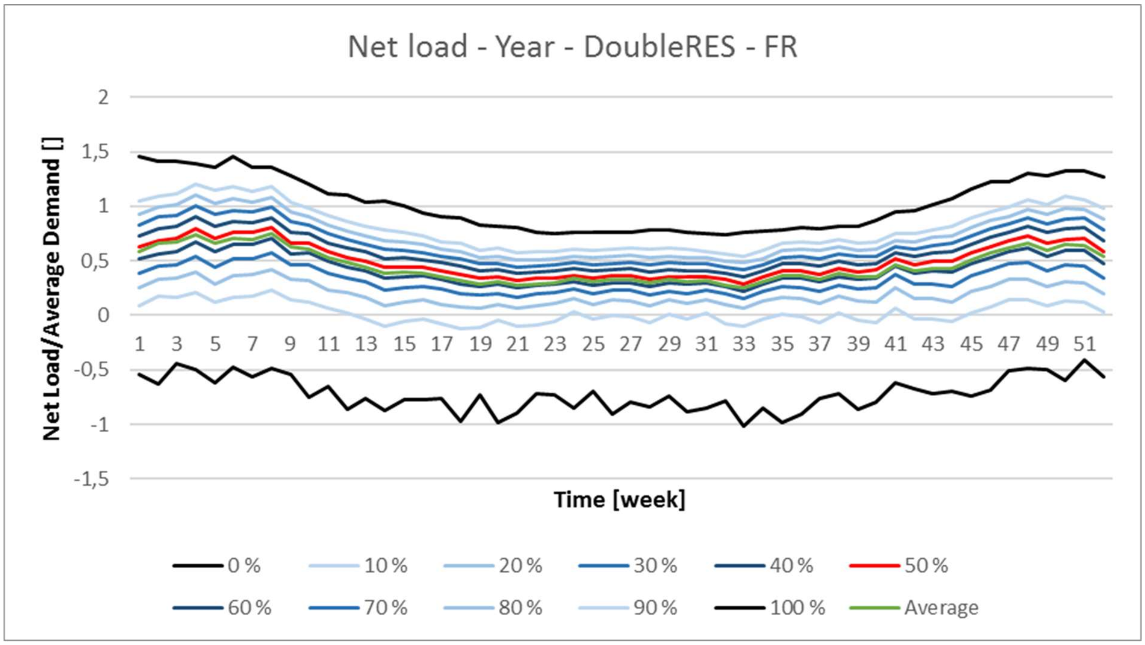

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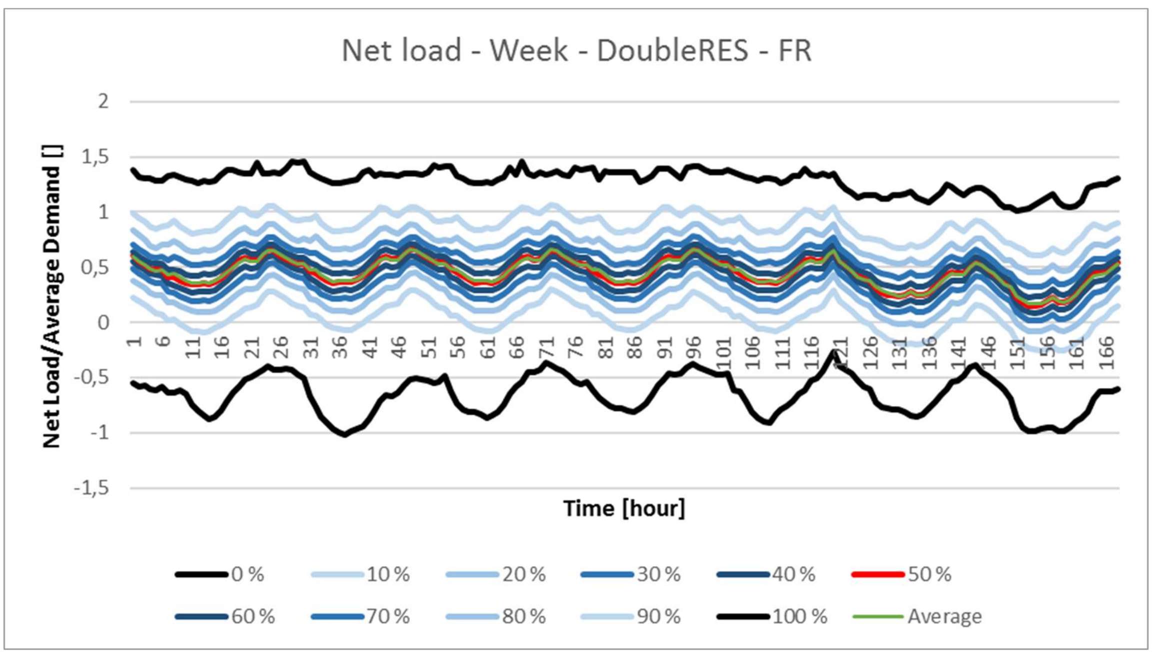

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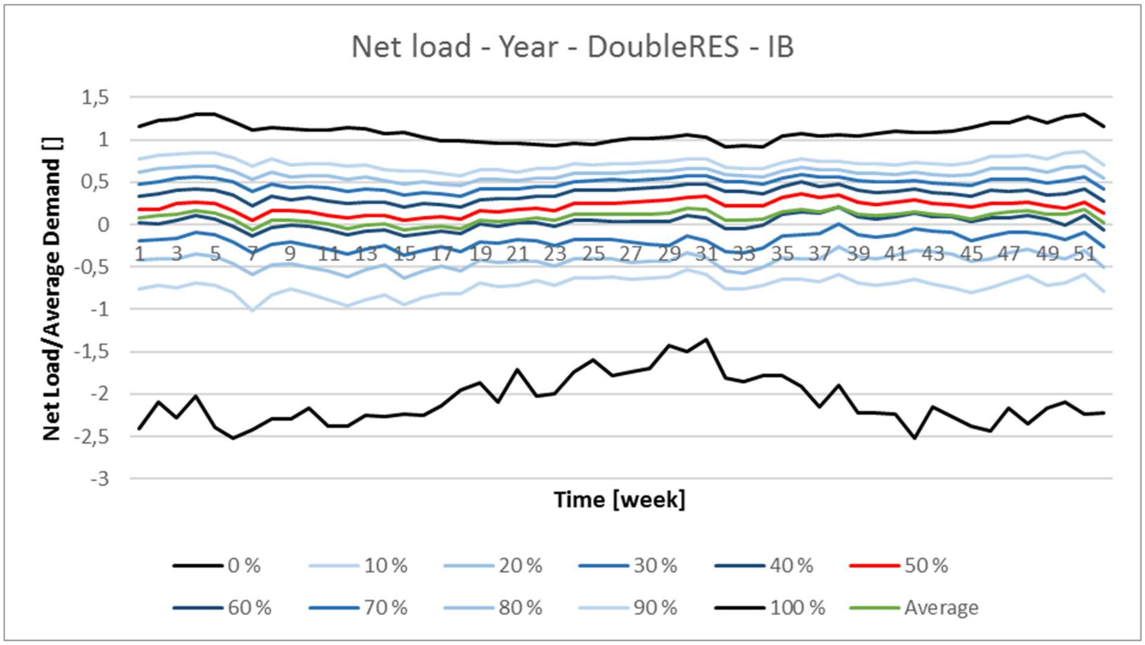

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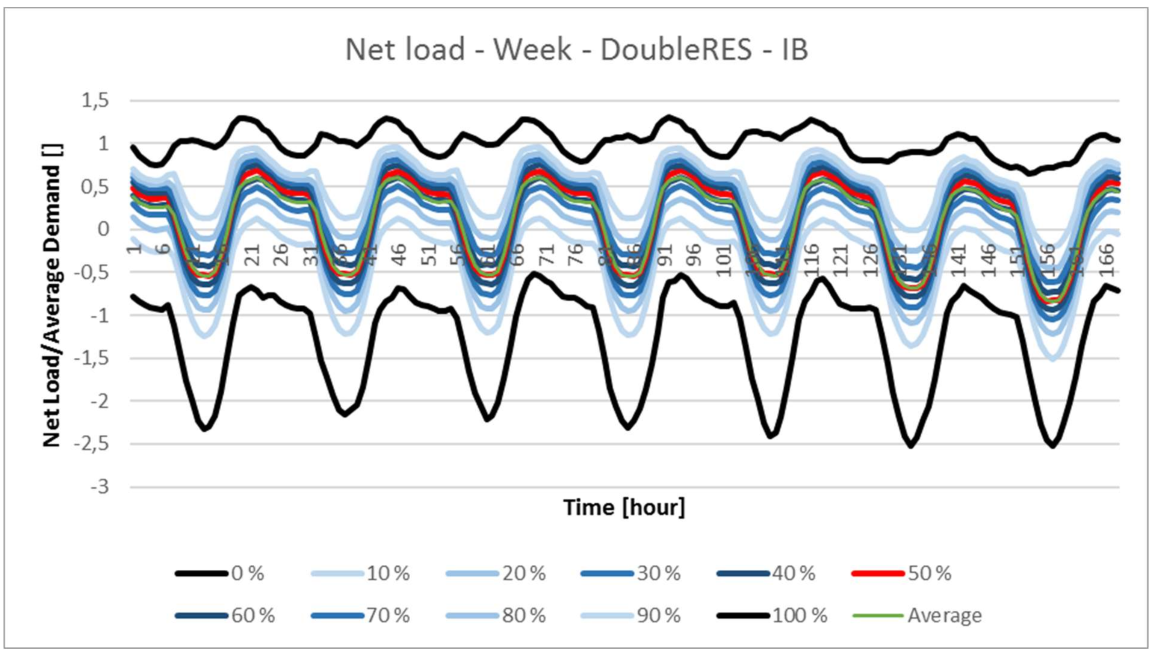

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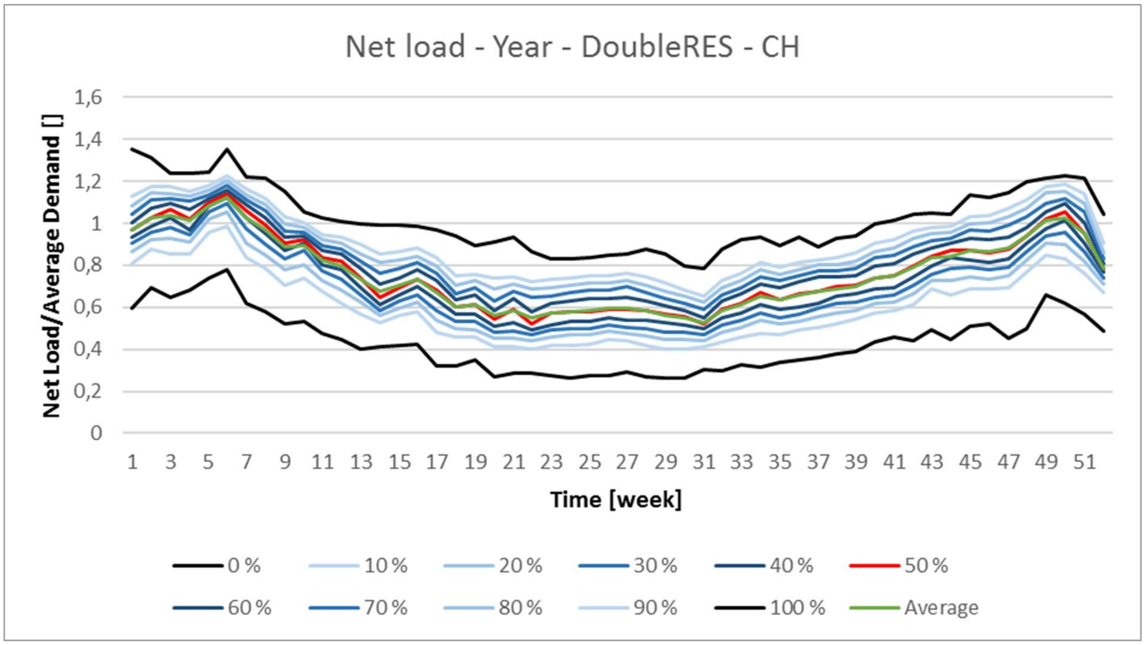

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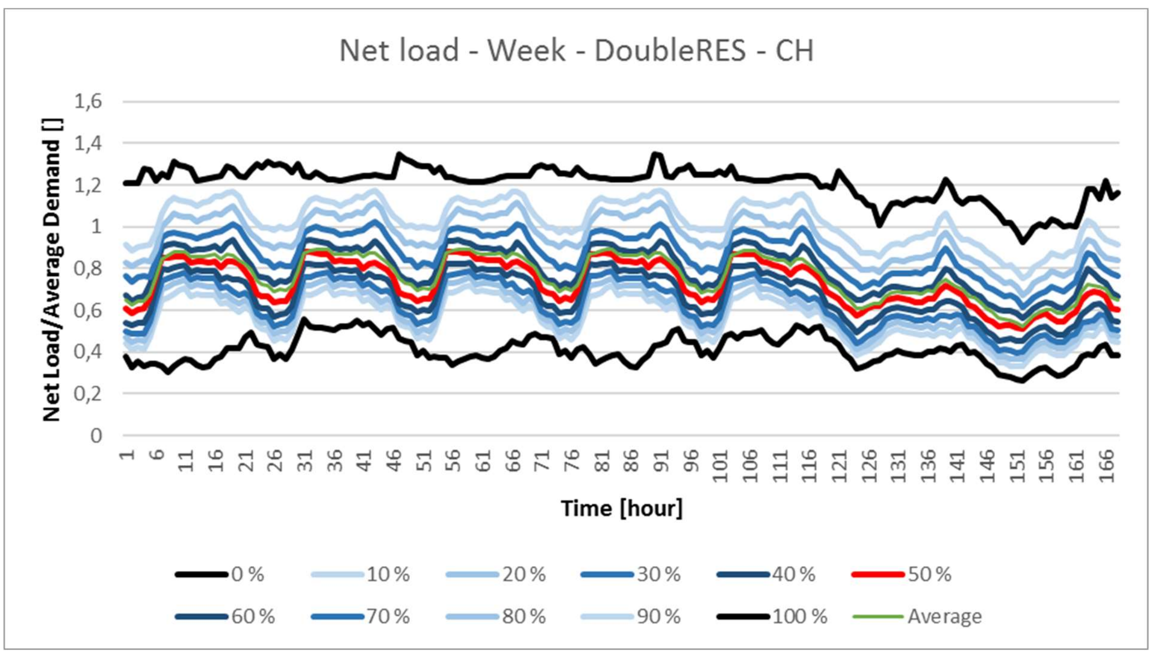

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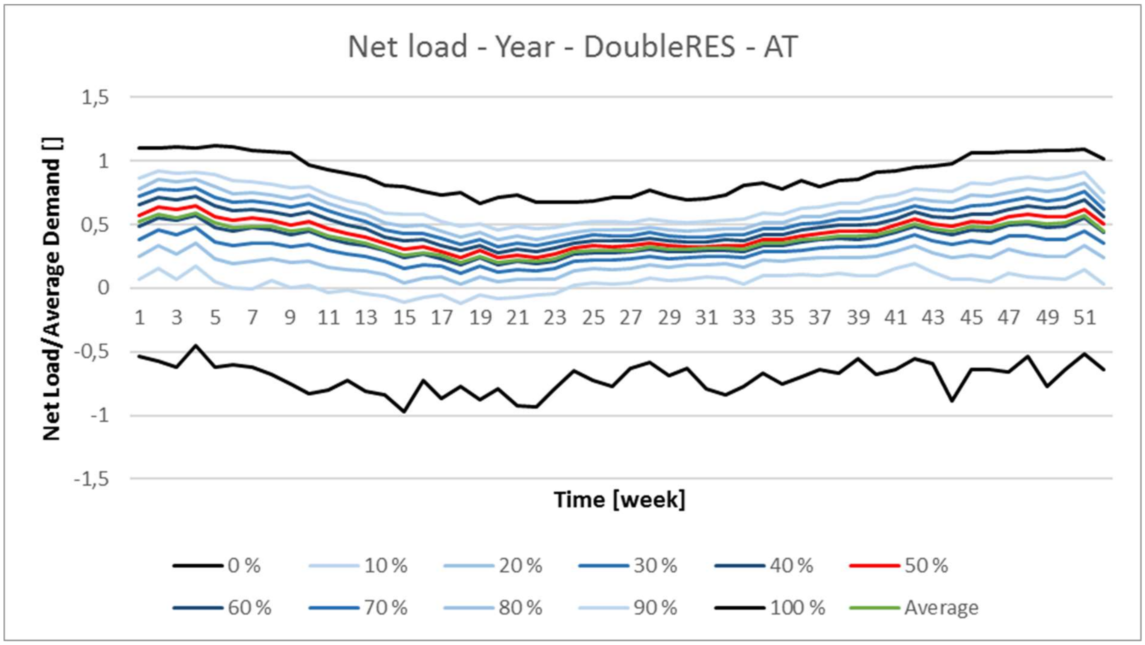

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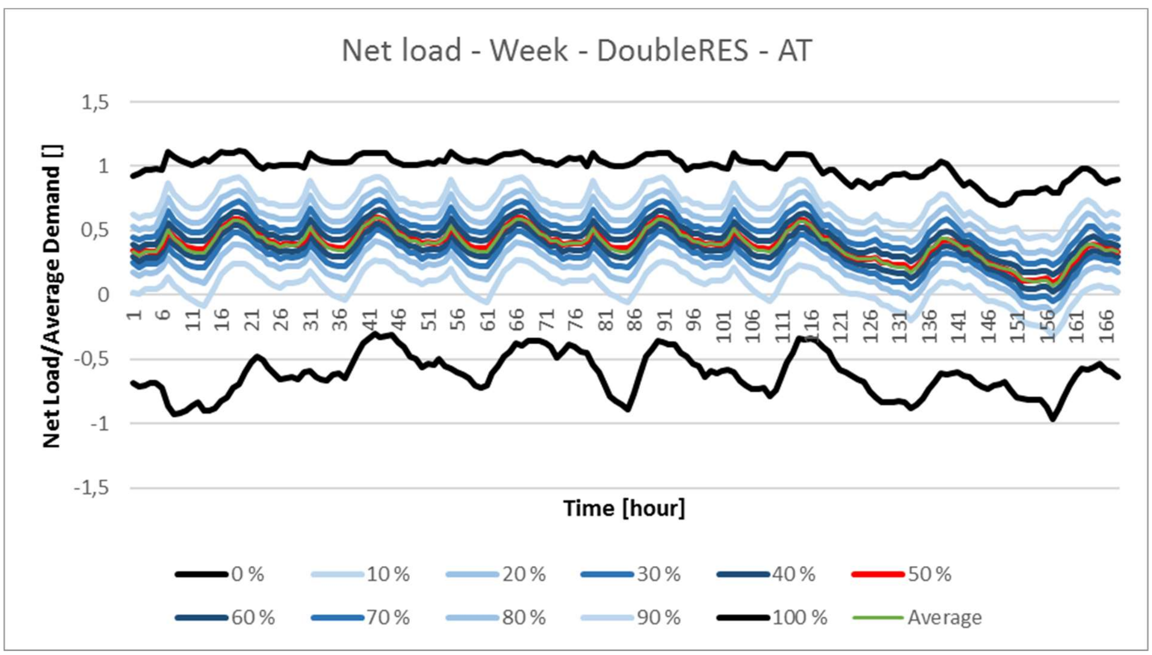

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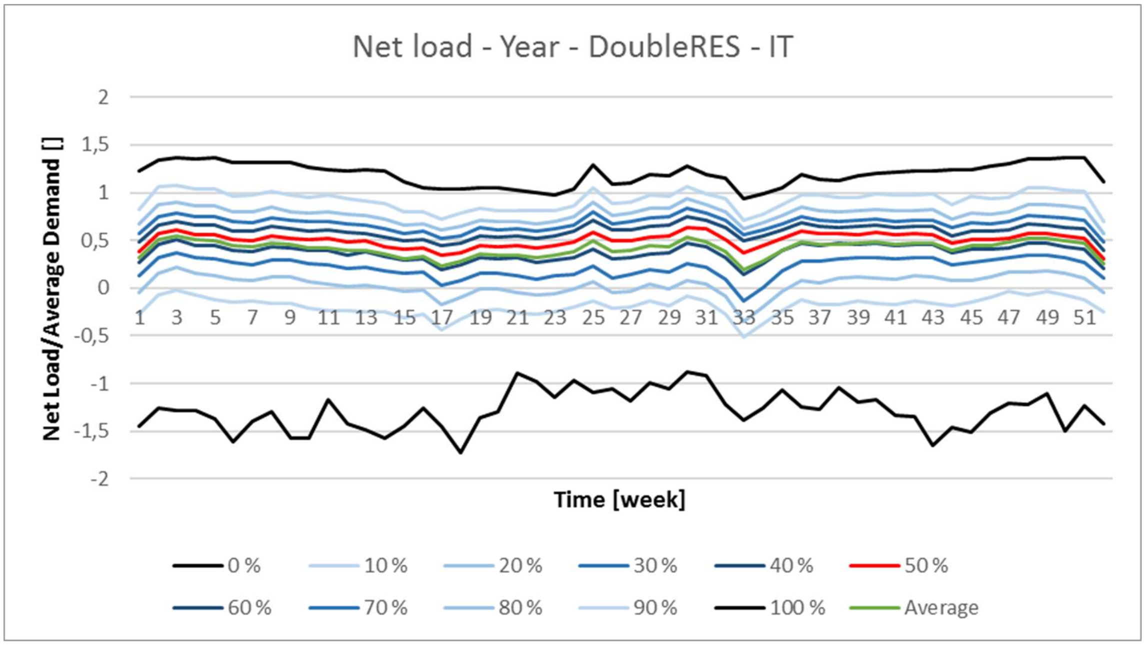


Figure 205

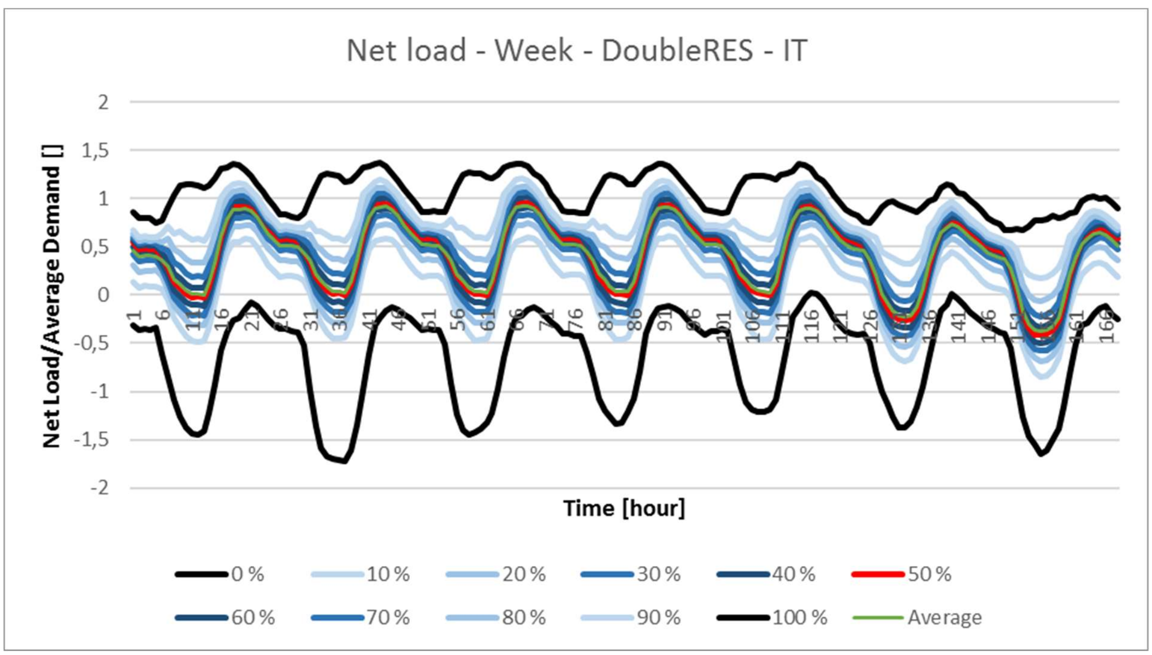
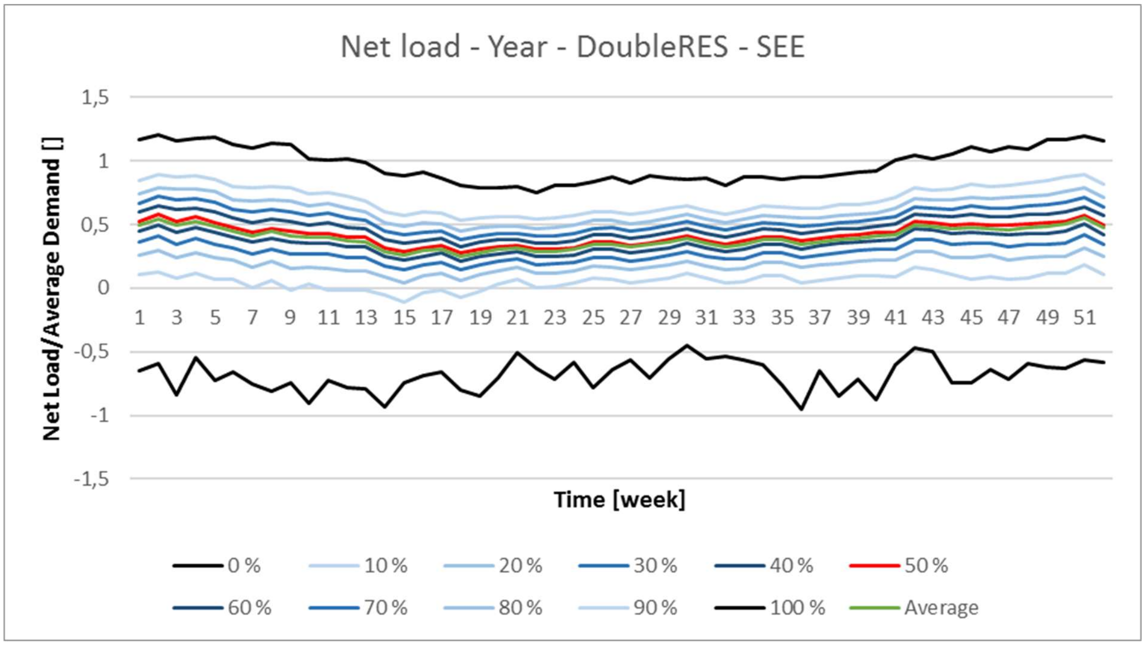


Figure 206



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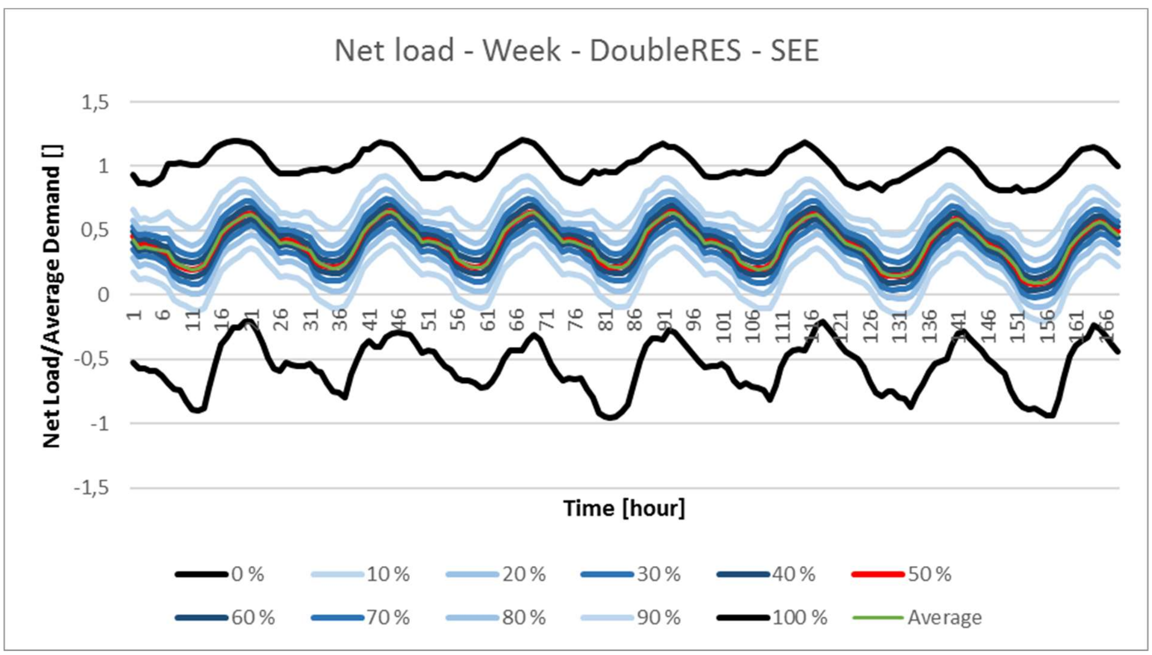


Figure 208

8.7.3 Power price – V4-16

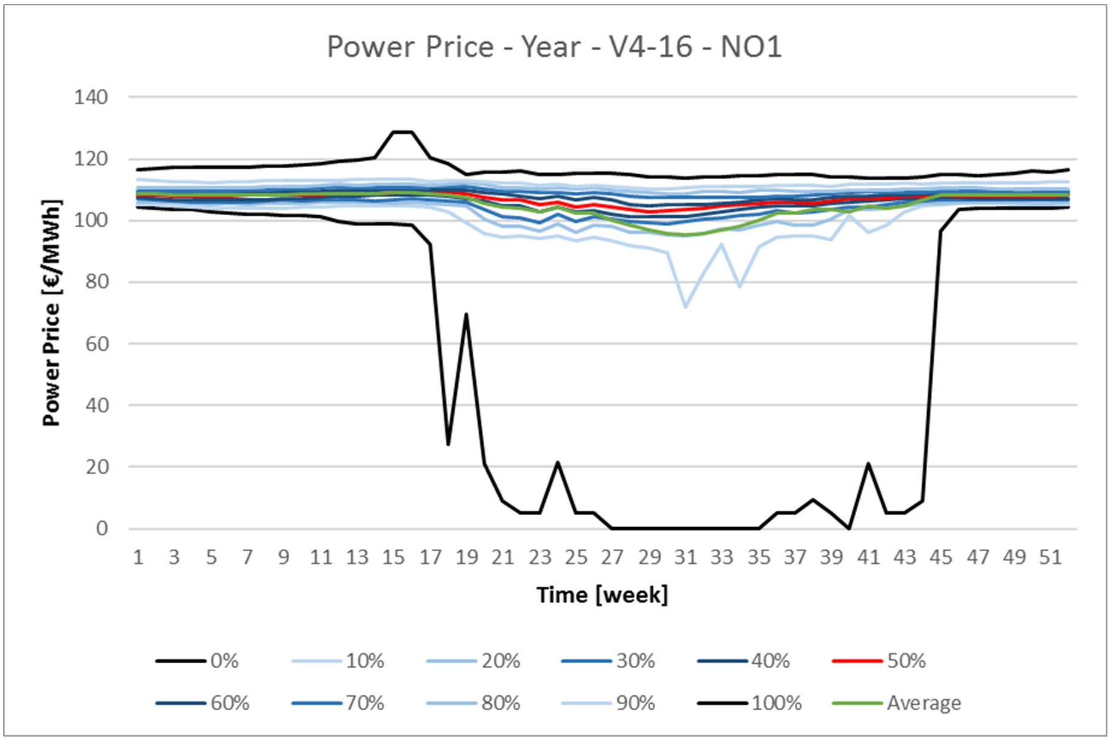


Figure 209

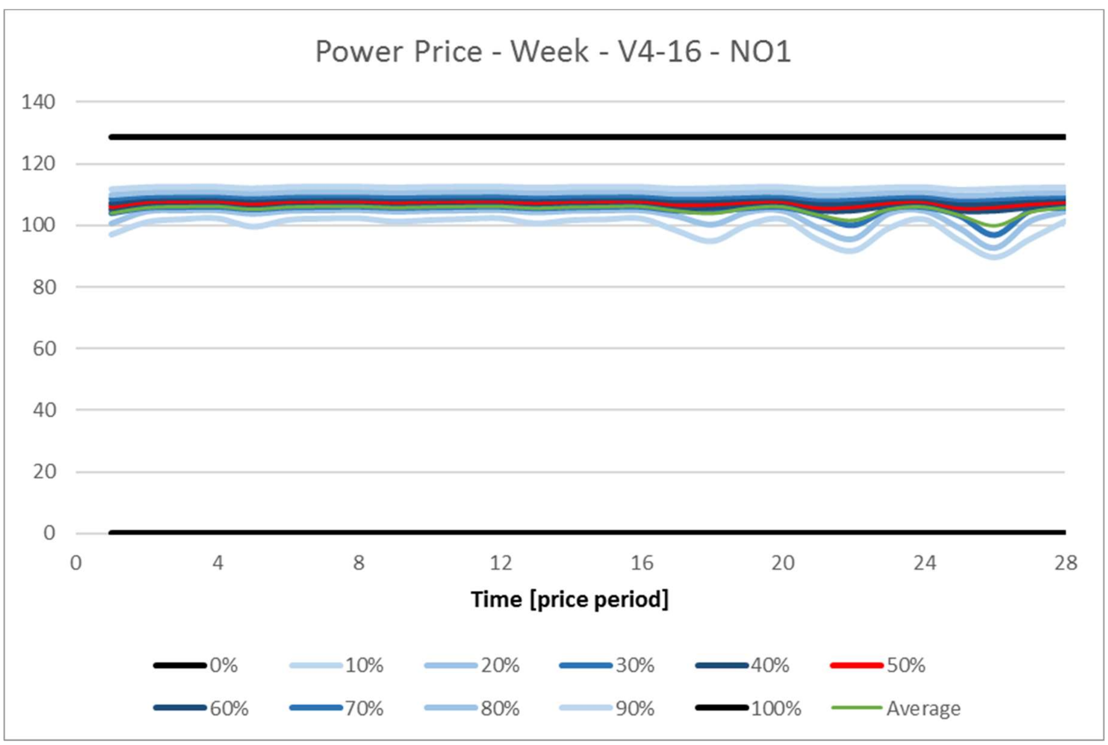


Figure 210

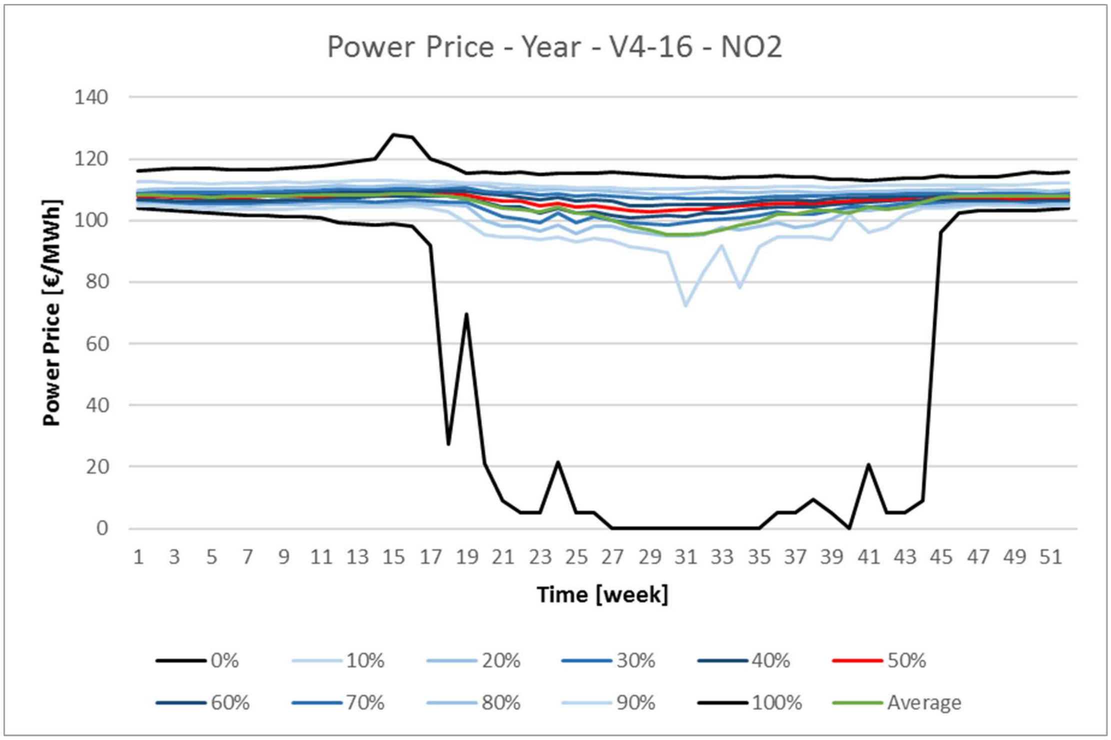
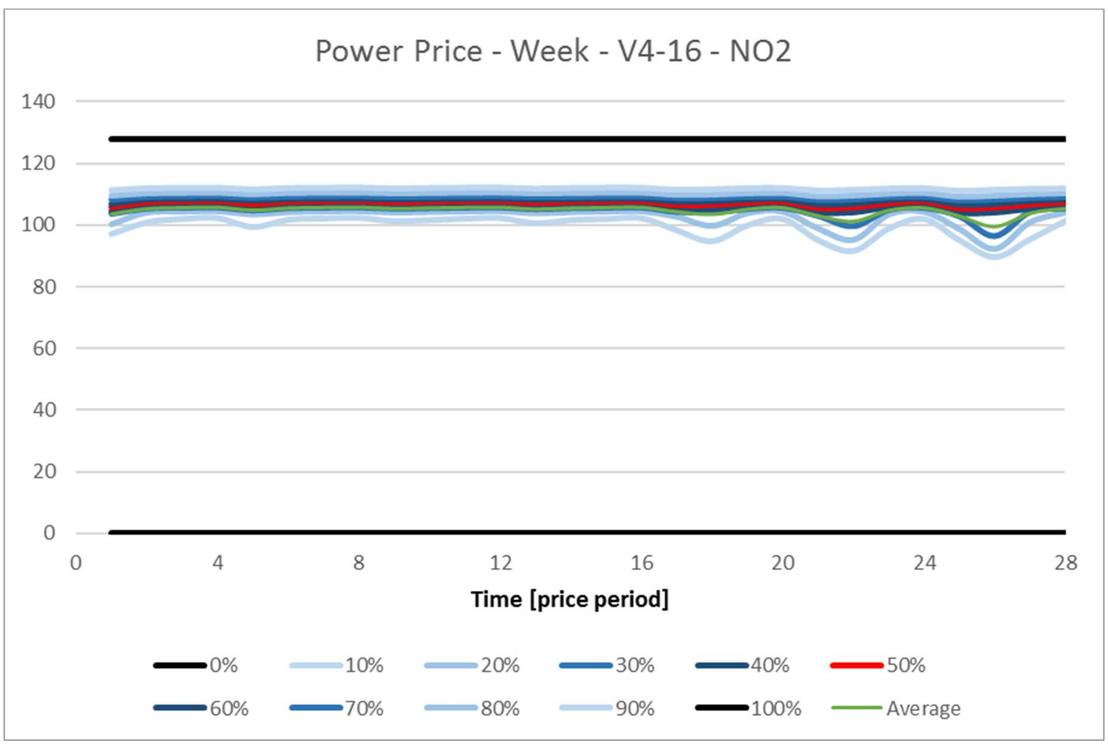


Figure 211



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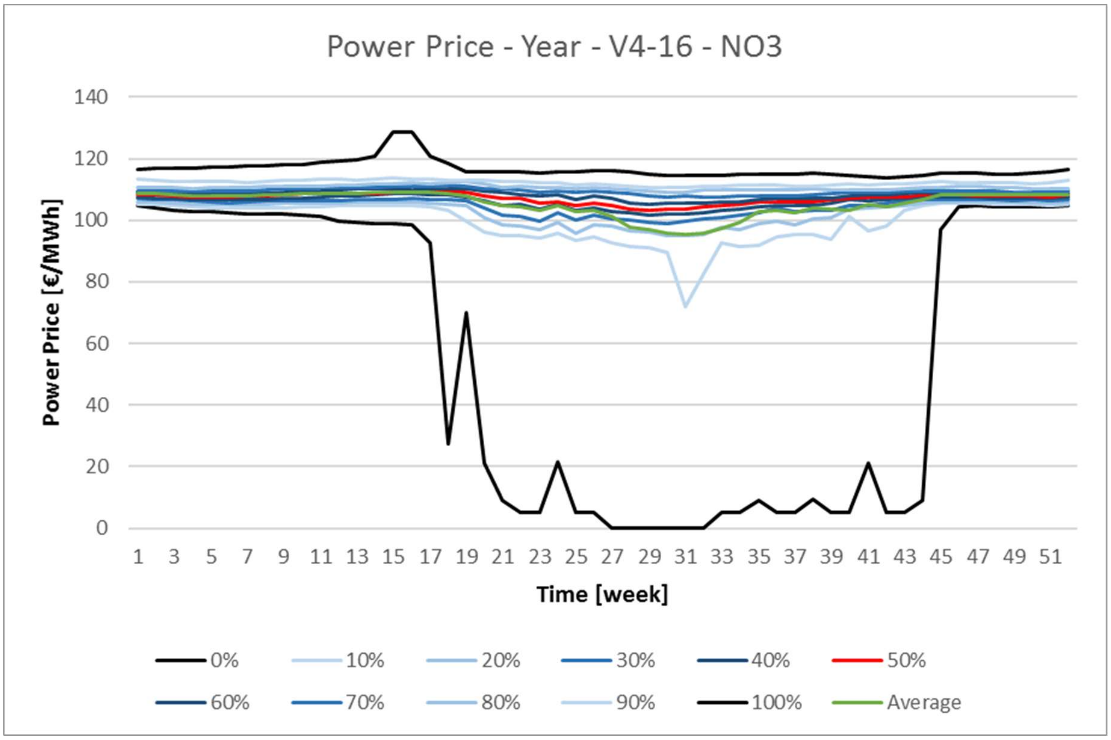


Figure 213

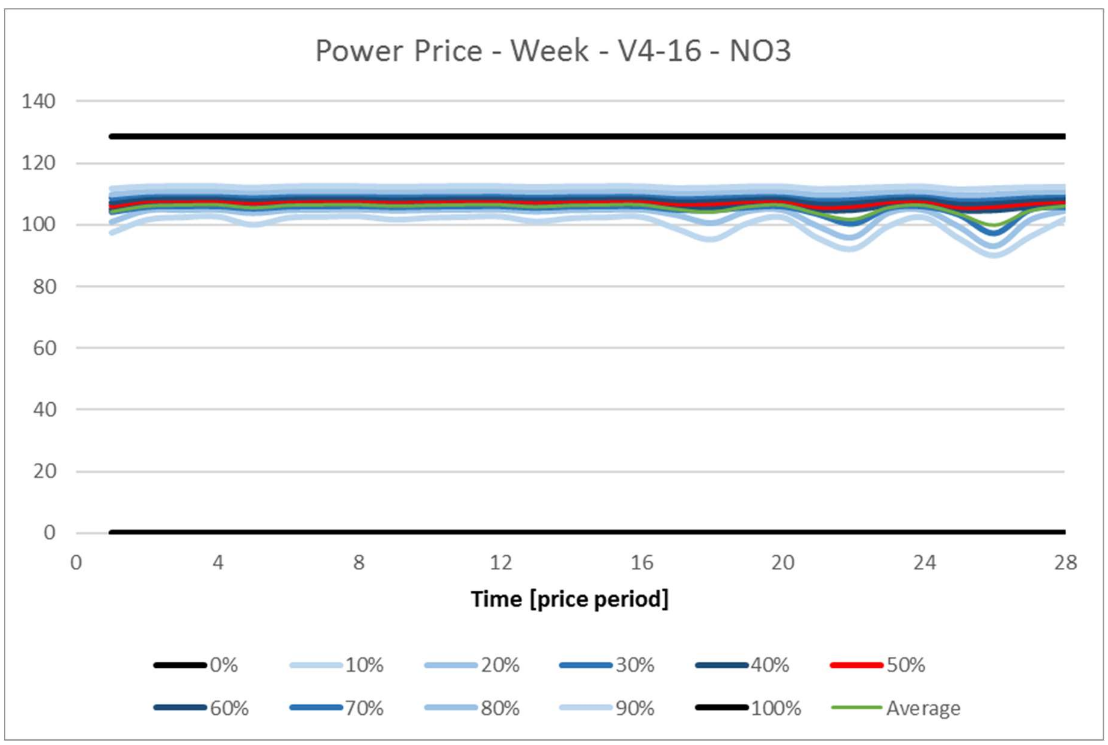
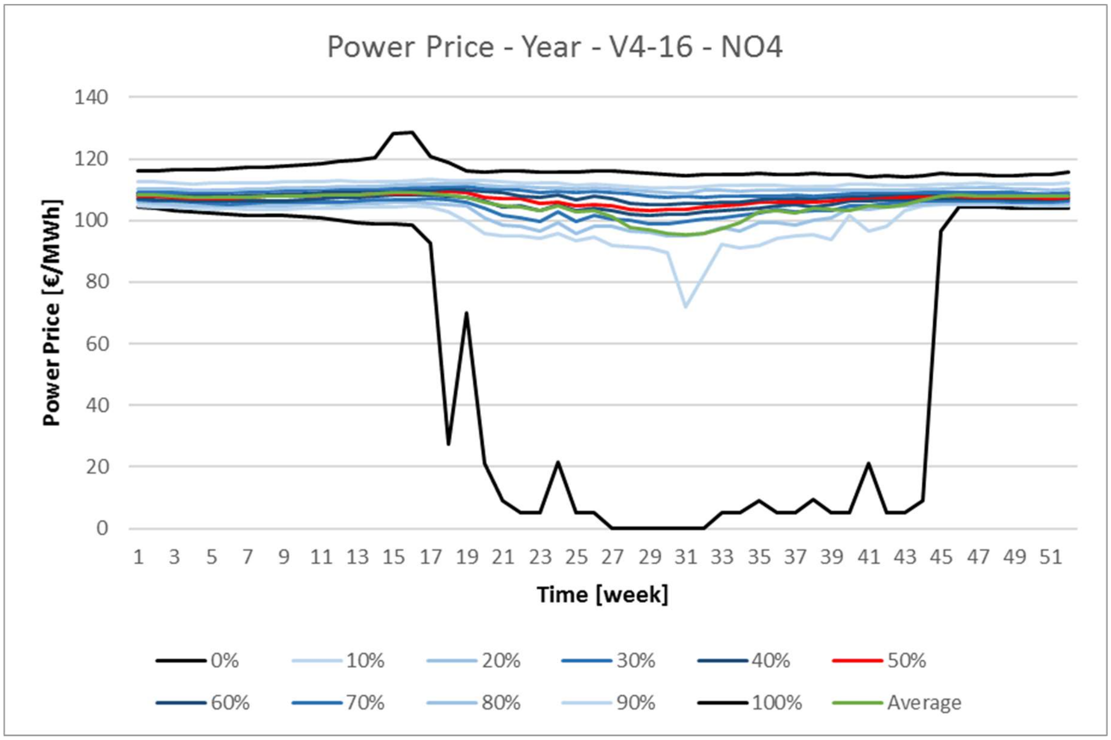


Figure 214



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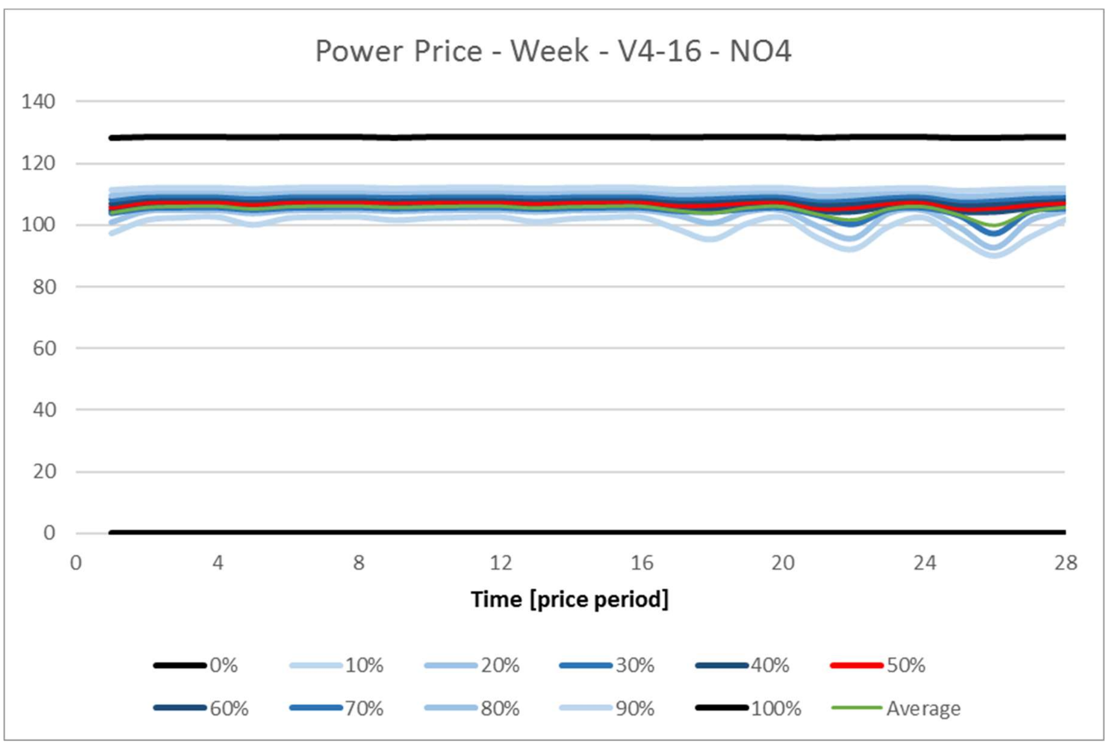

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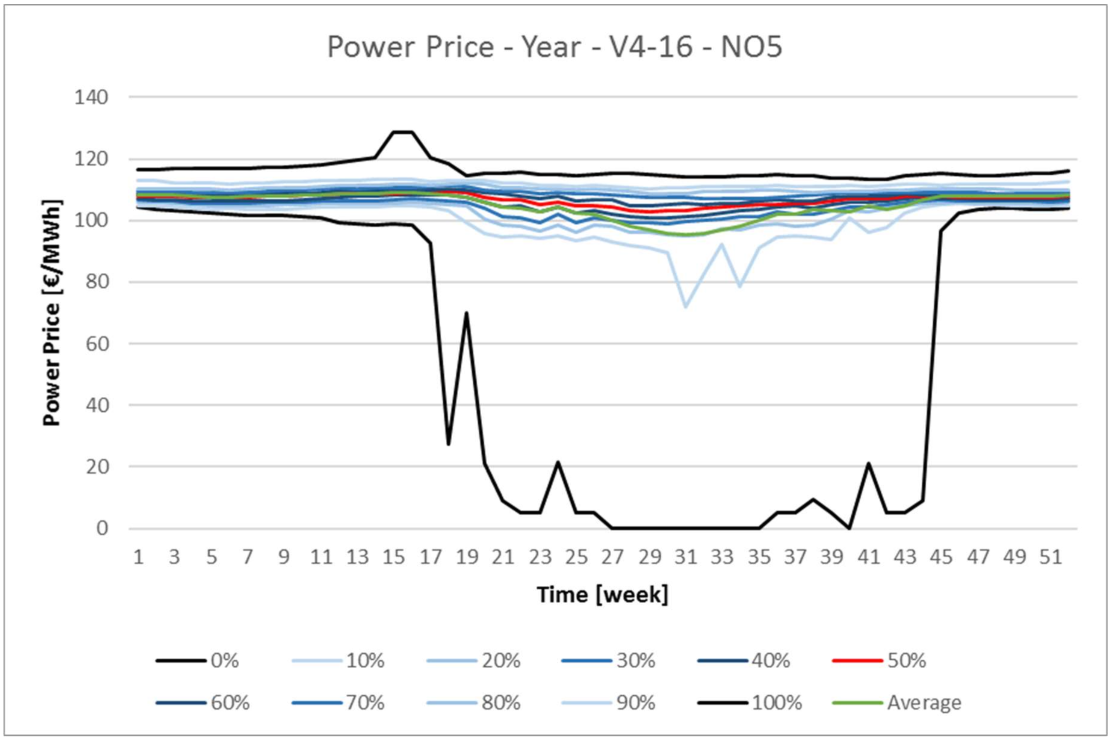
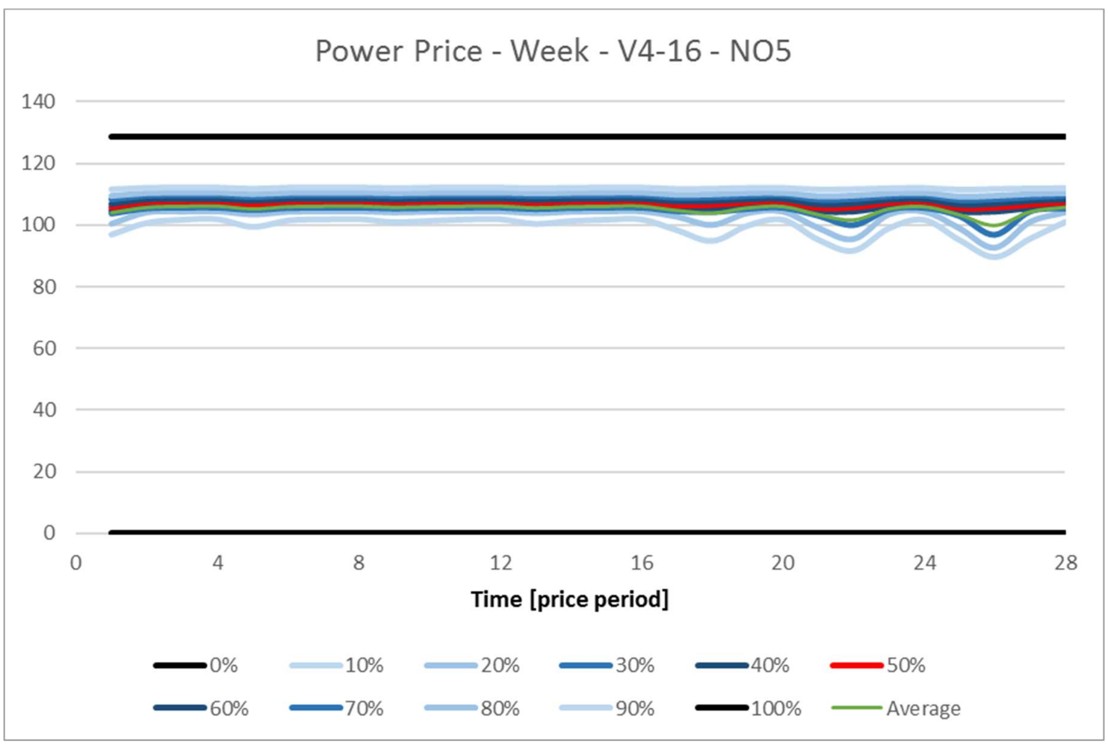


Figure 217



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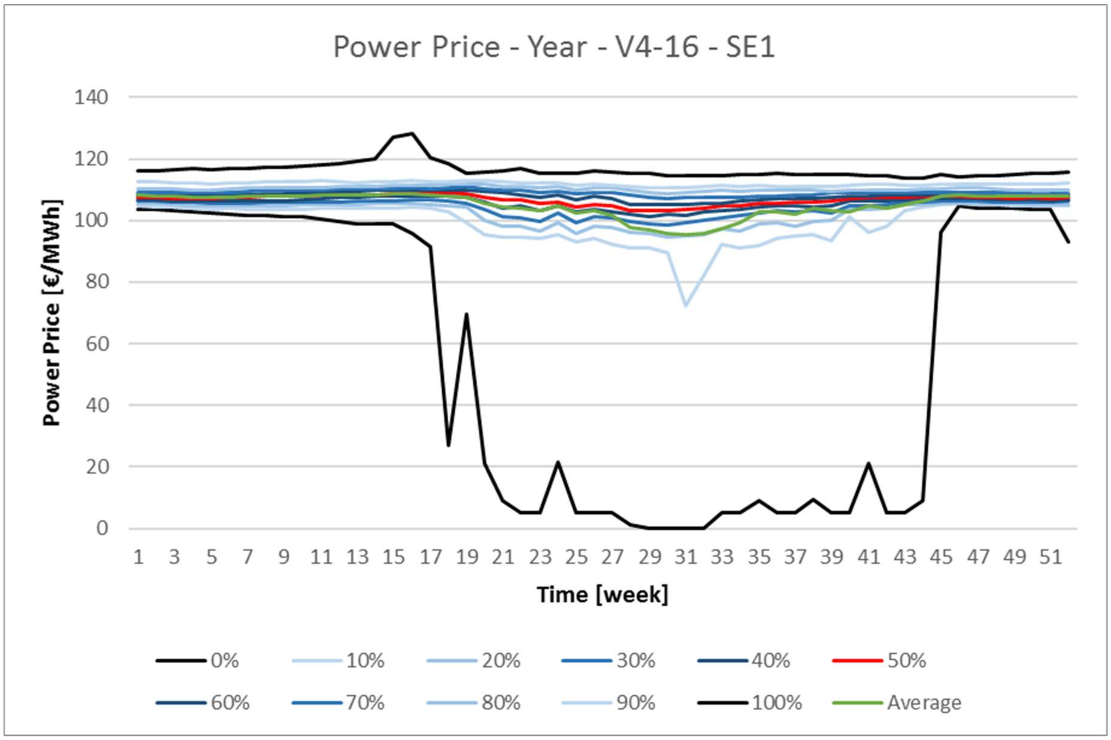

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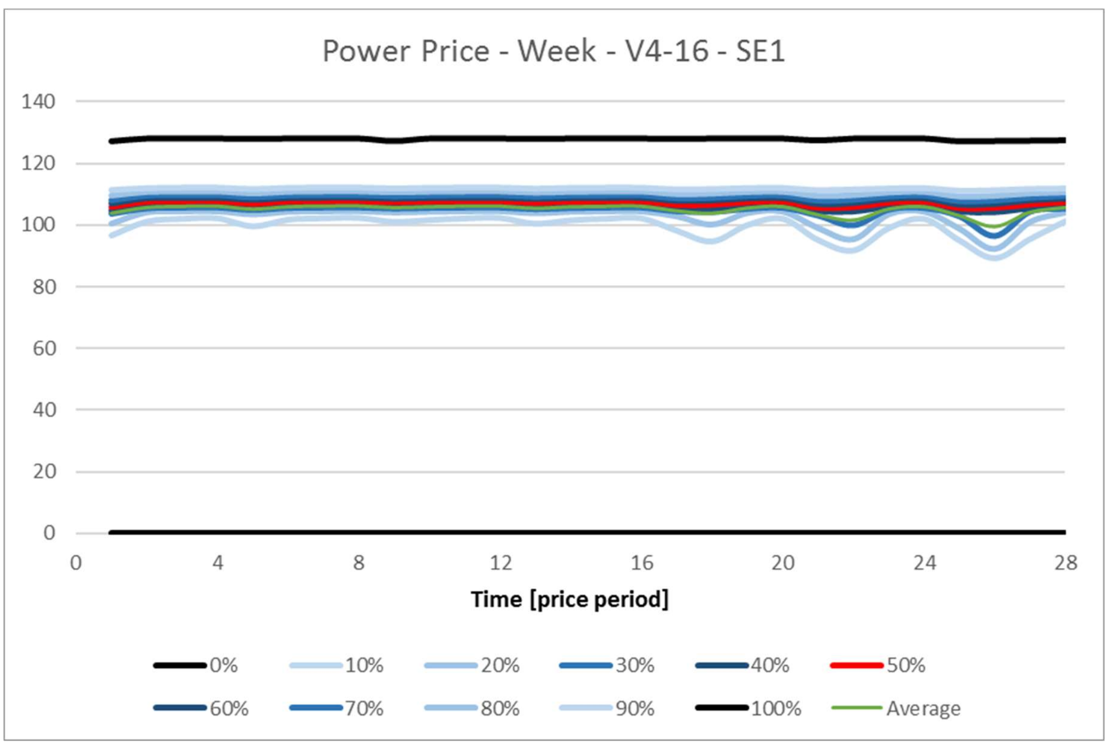

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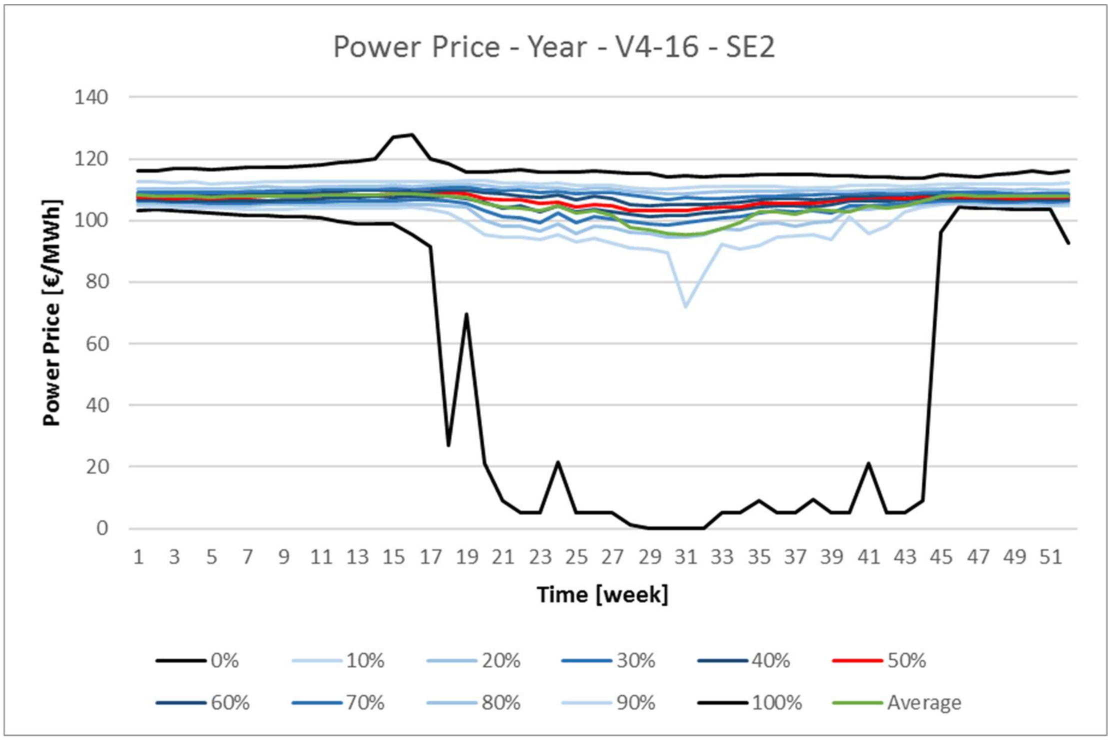

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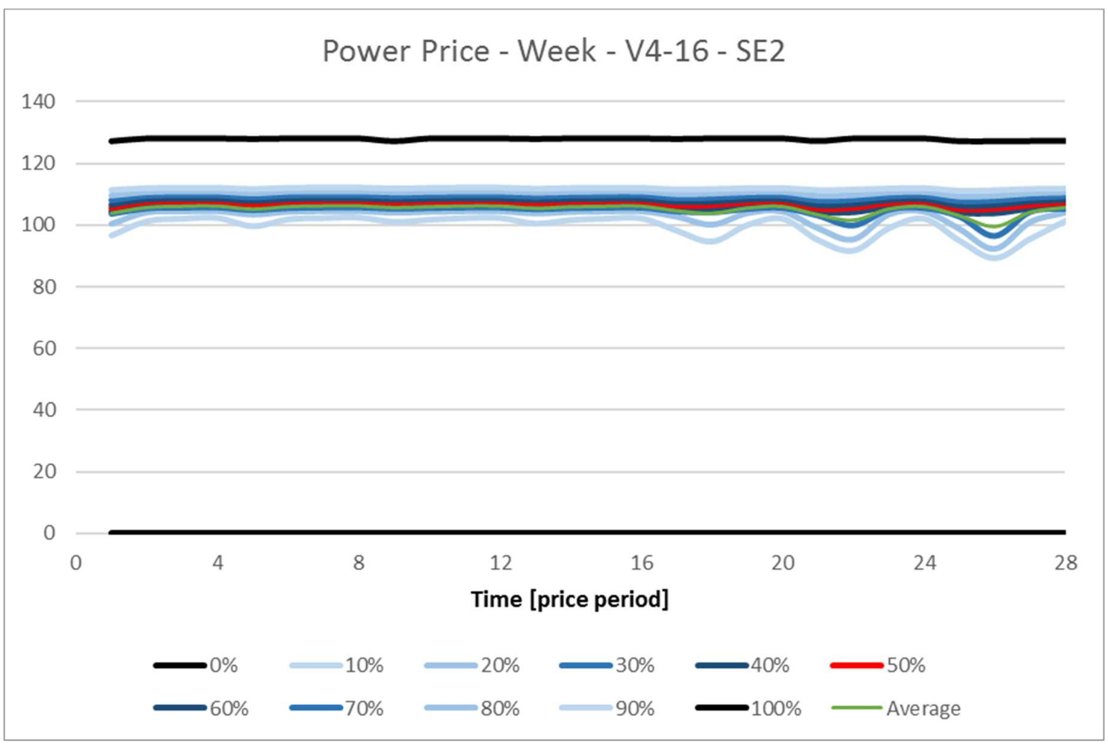

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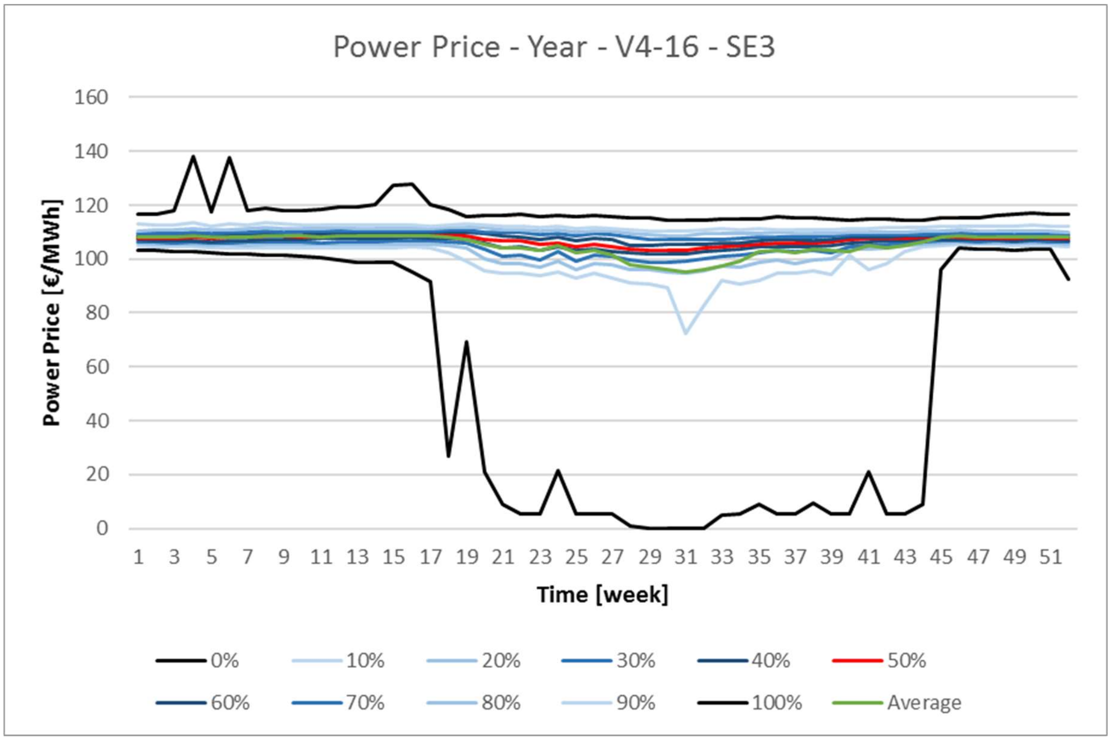

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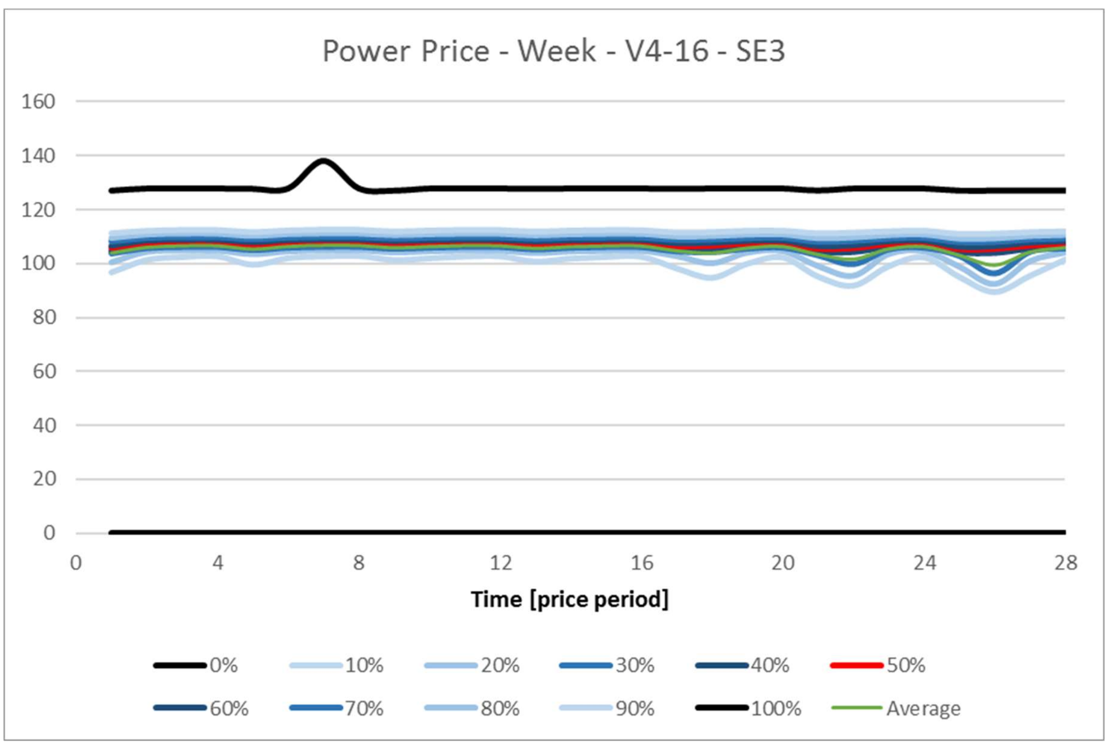

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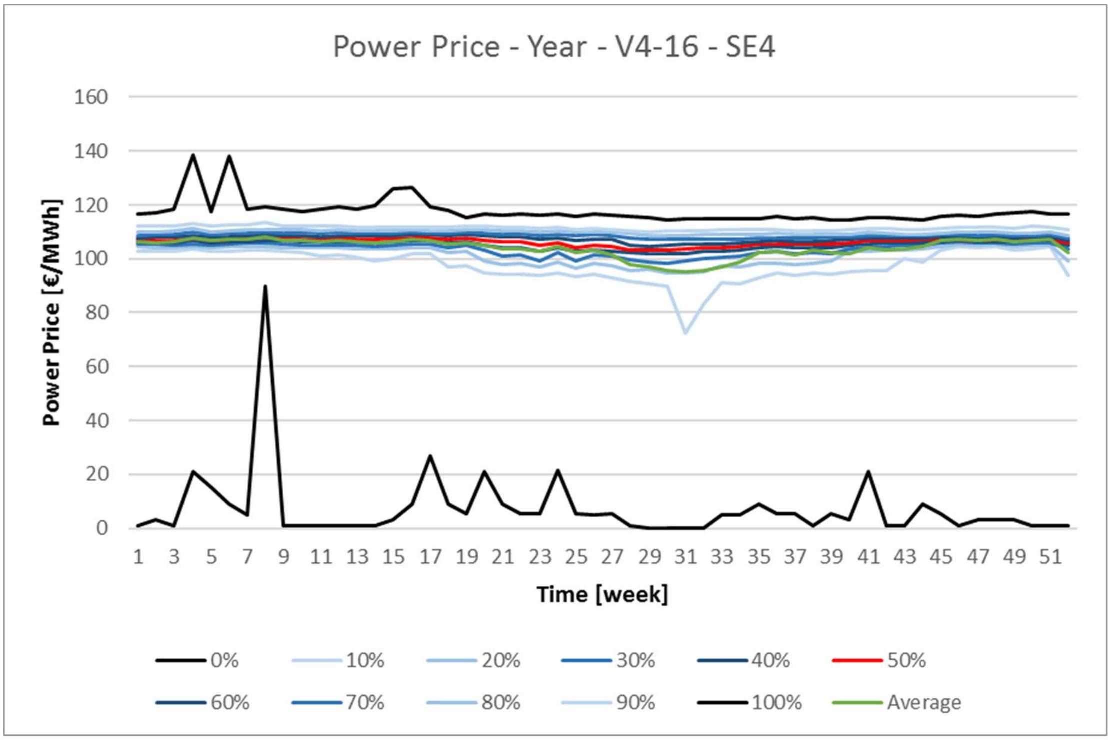

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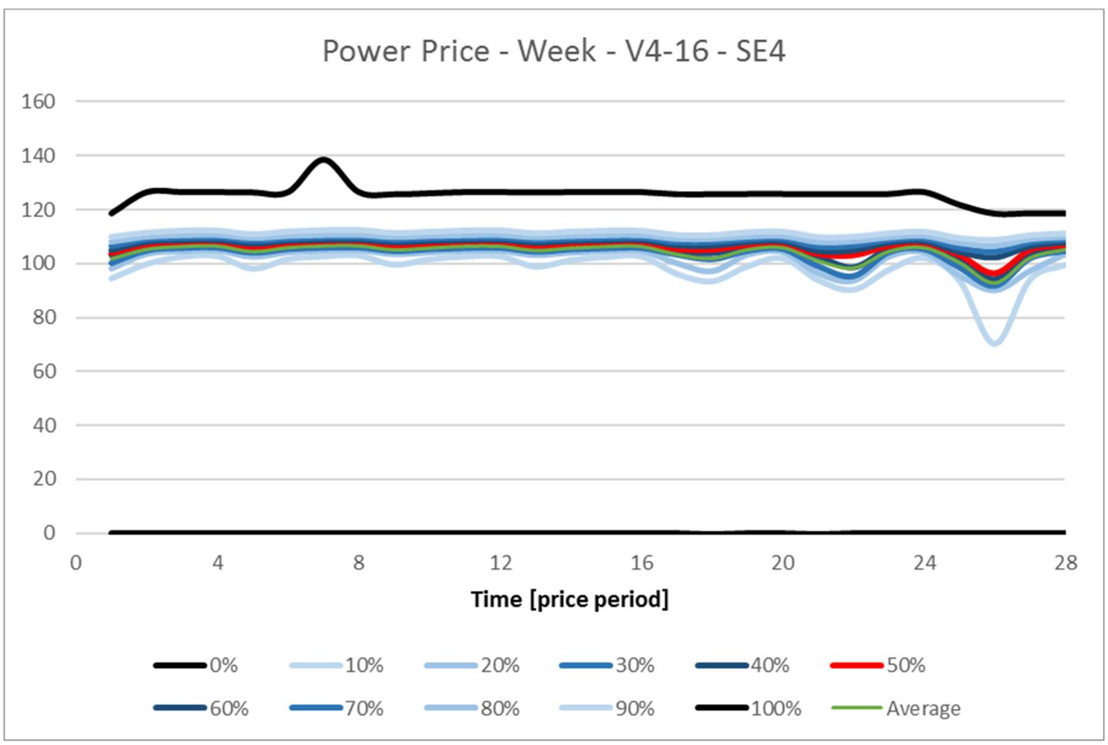

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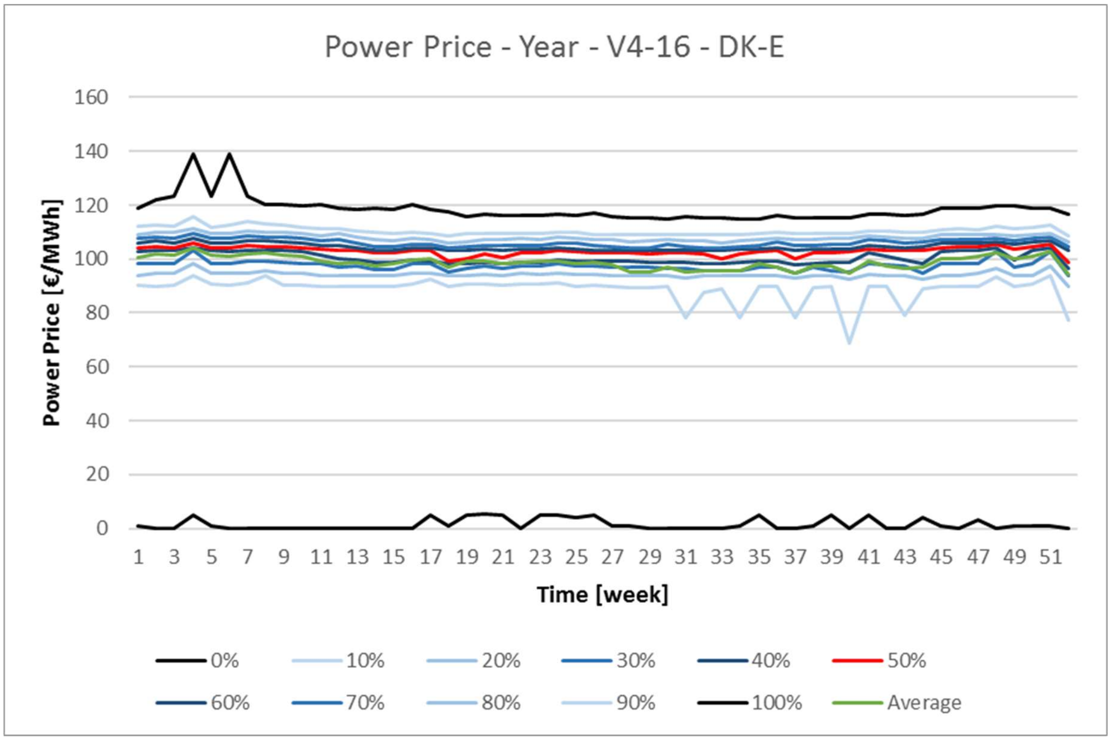

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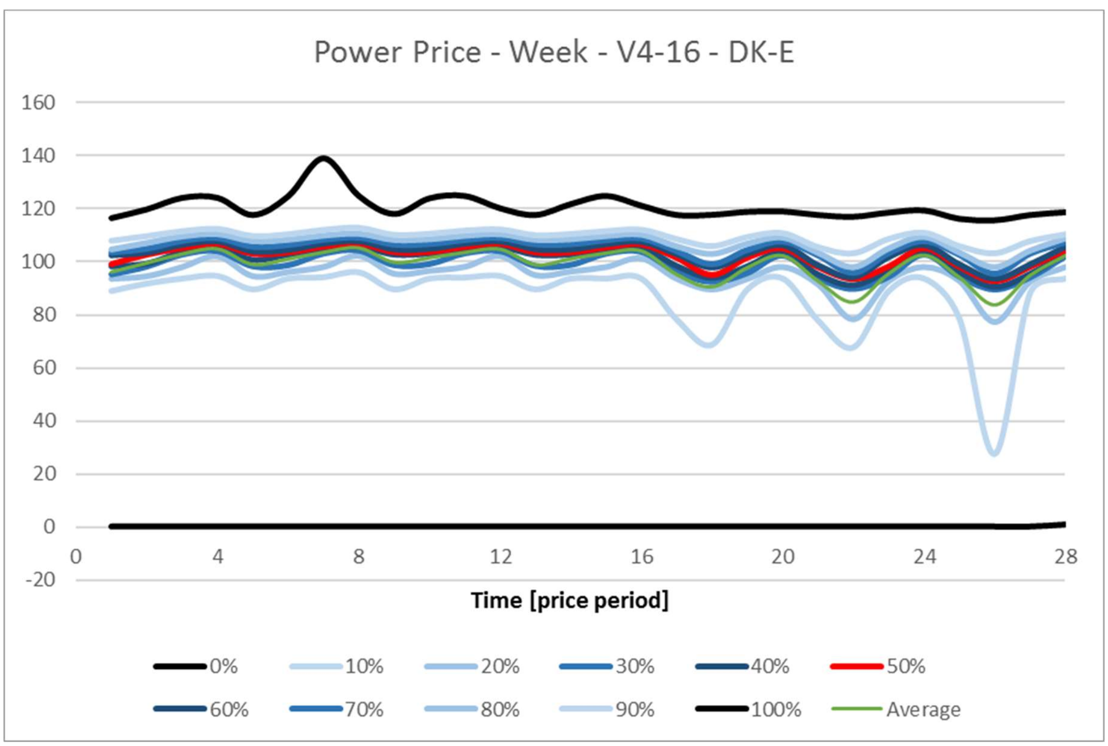

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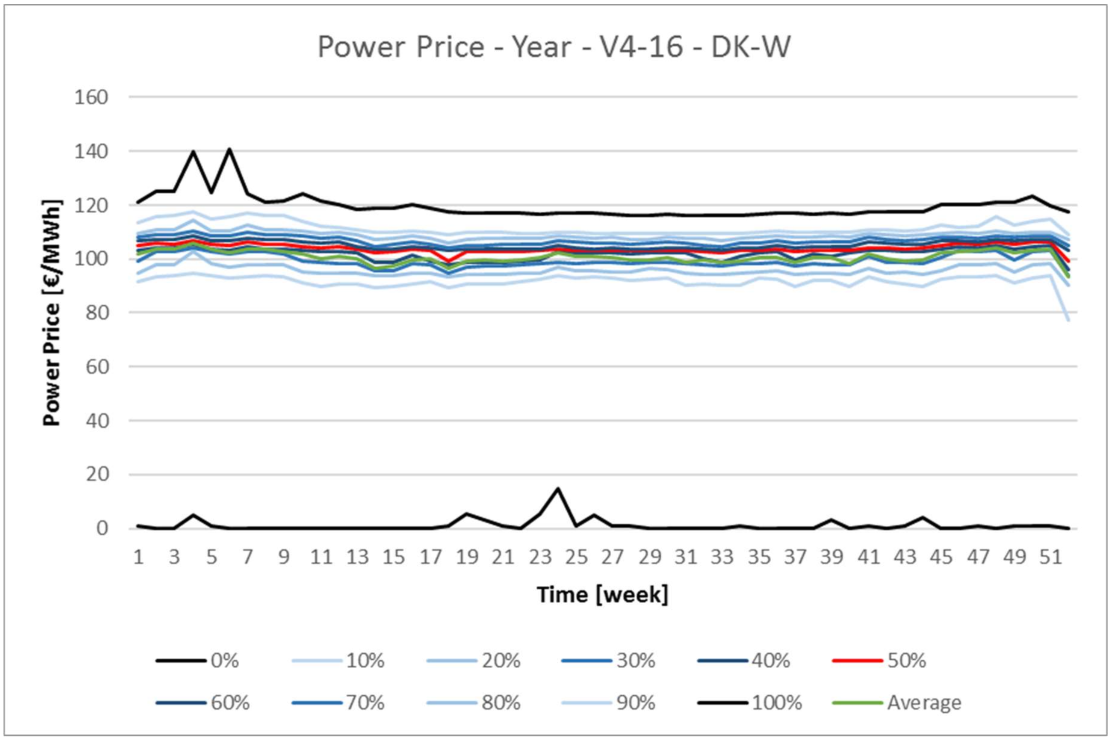

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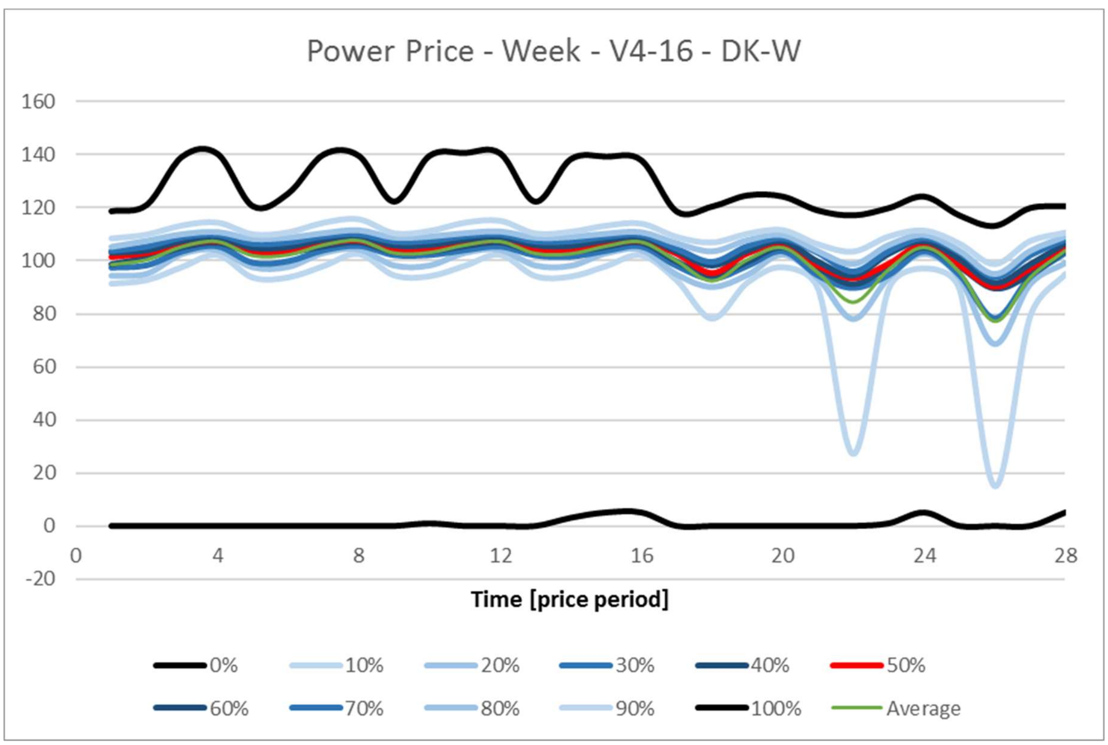

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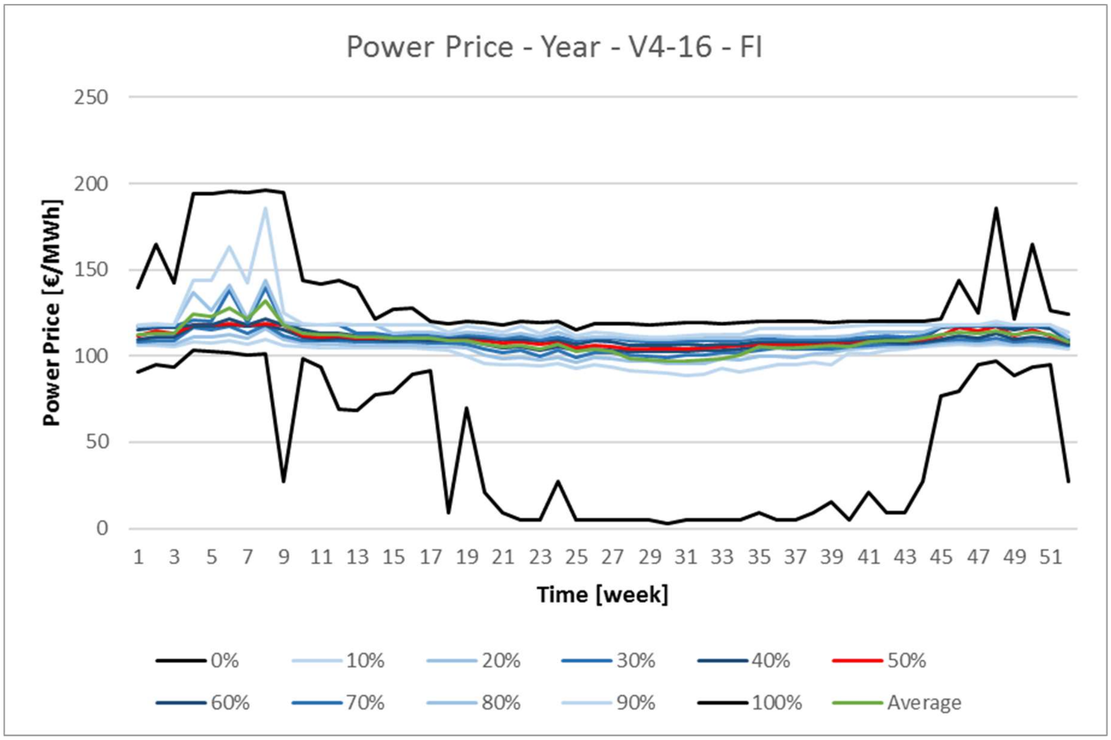

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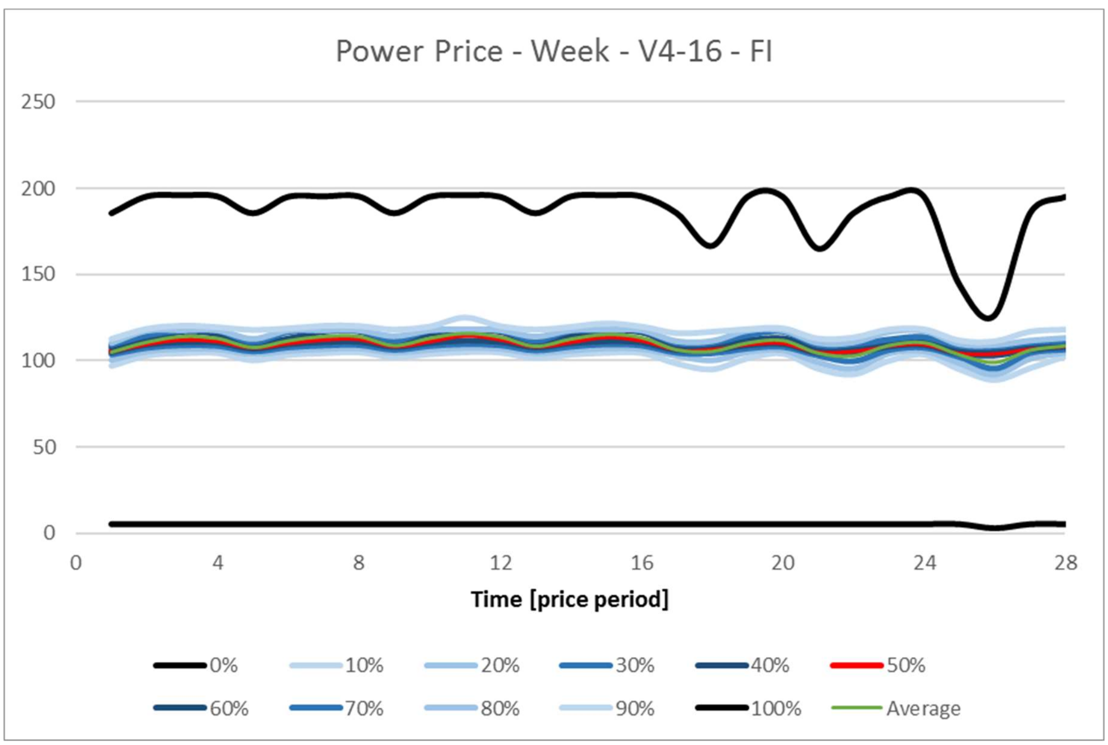

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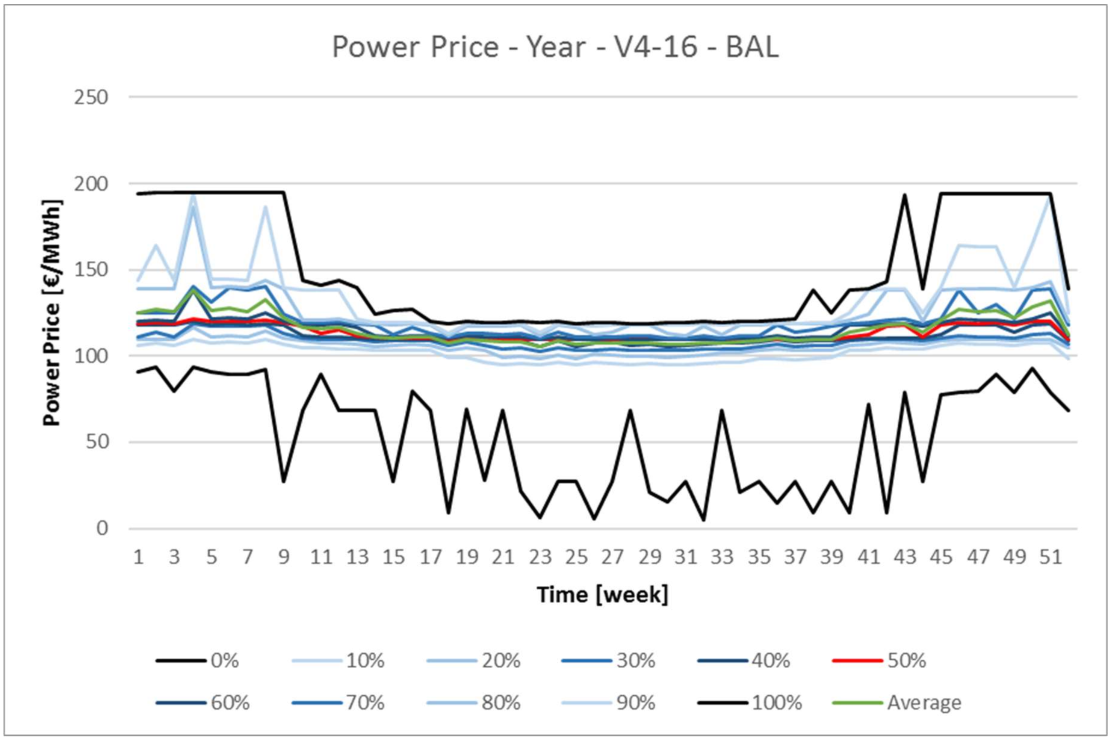

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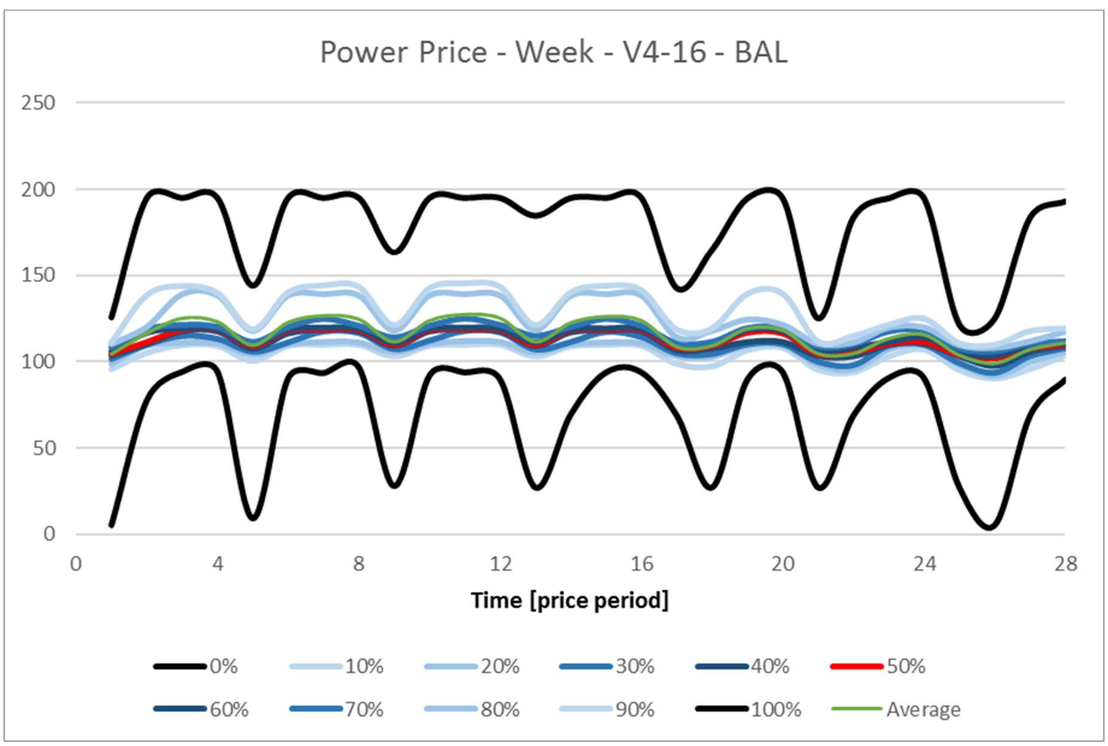

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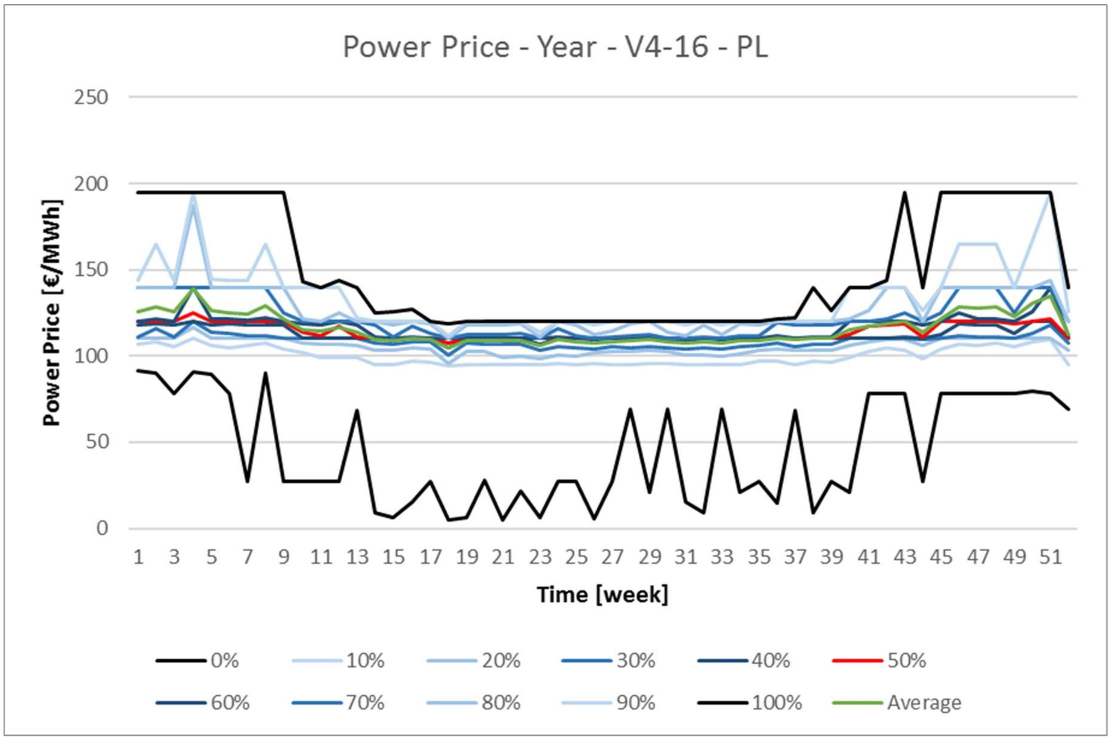

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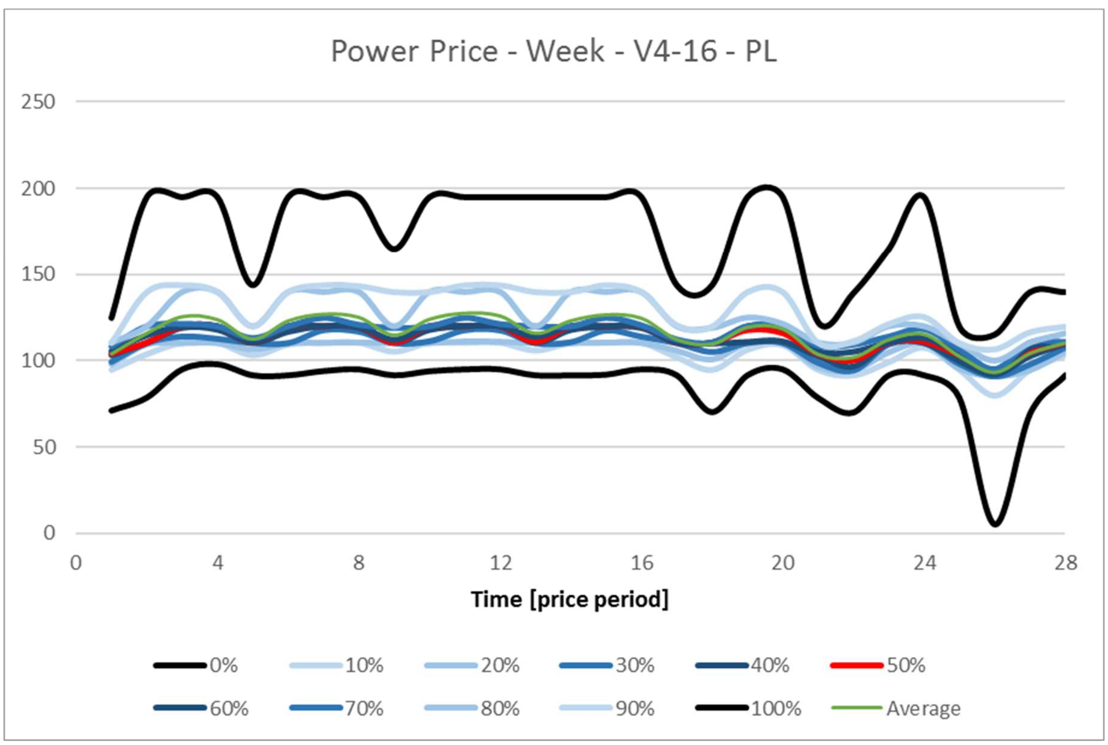

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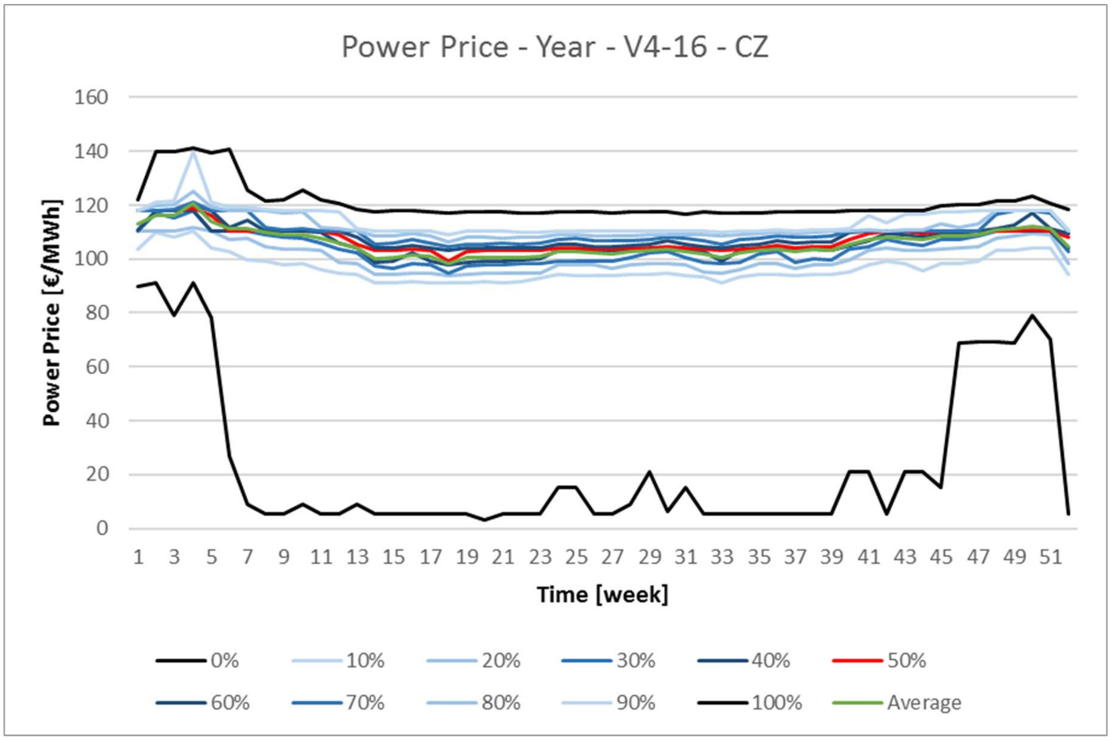

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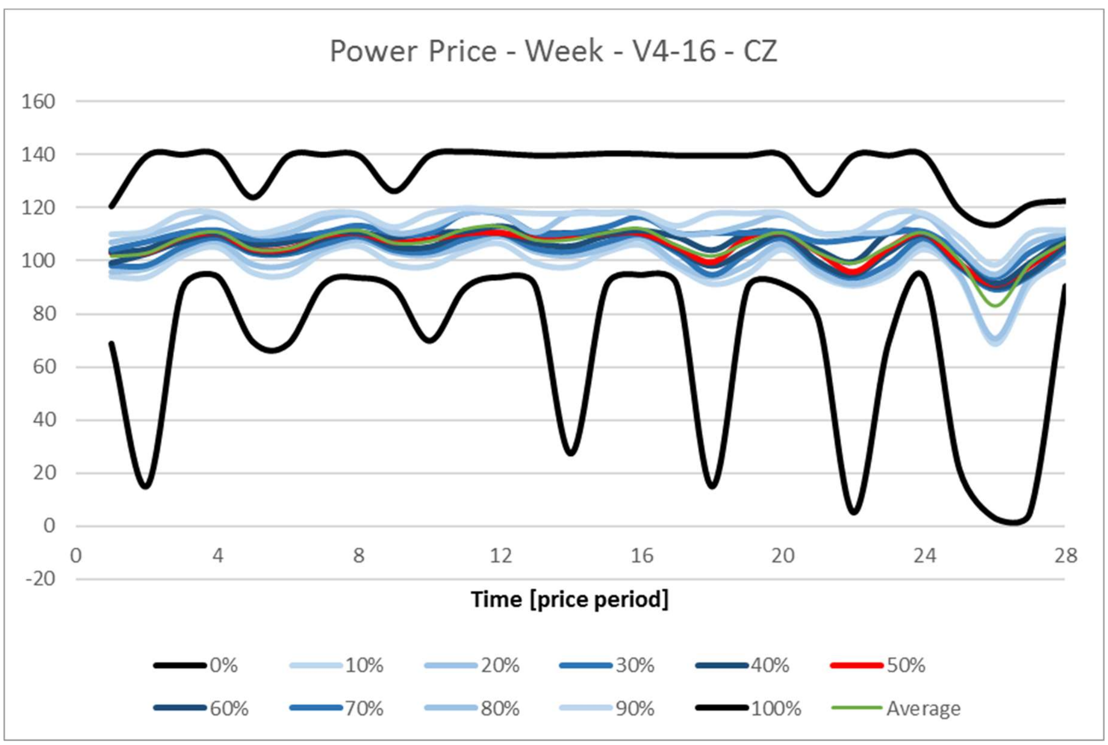

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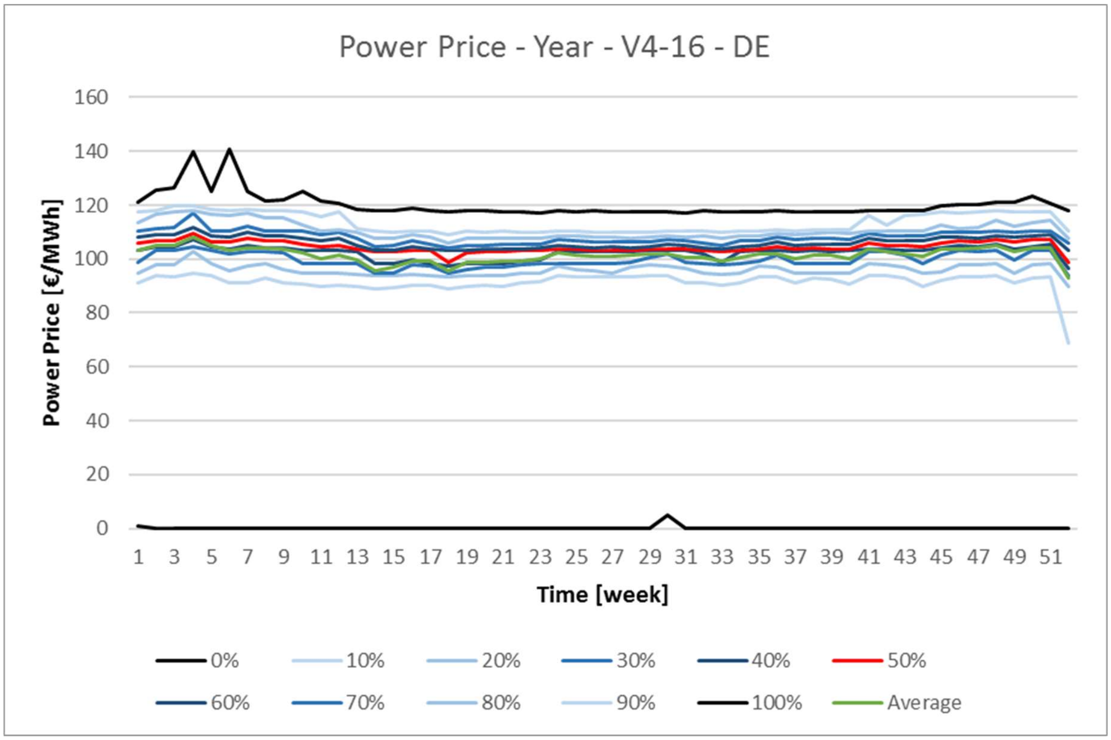

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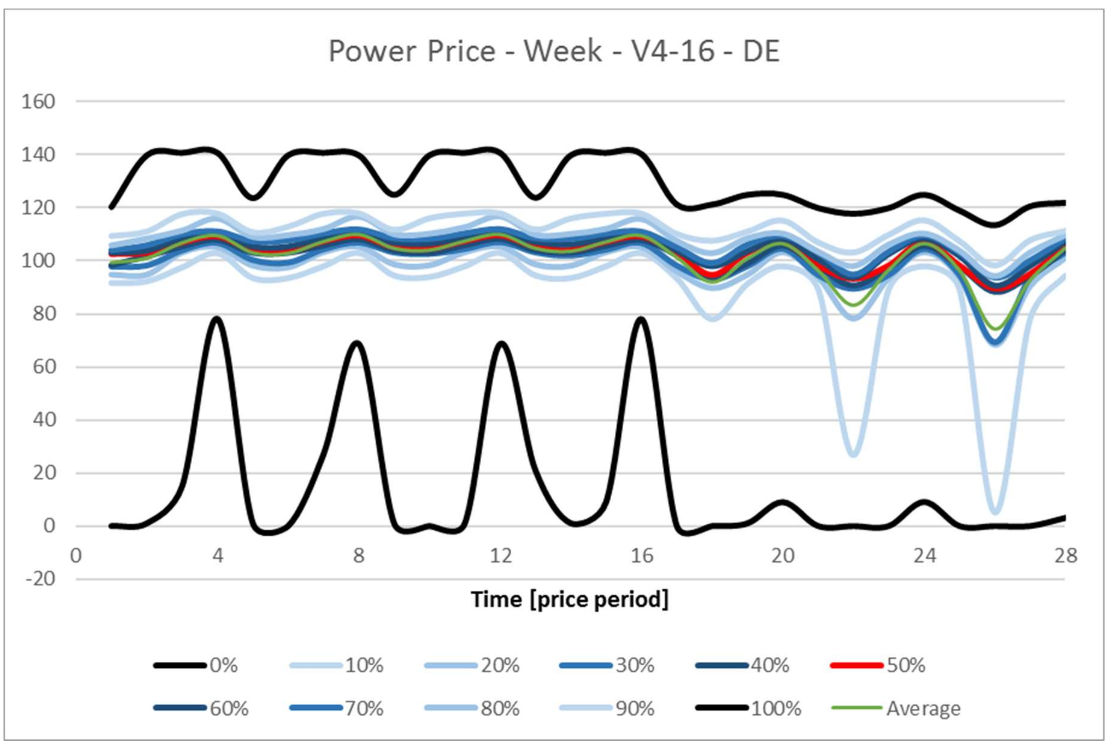

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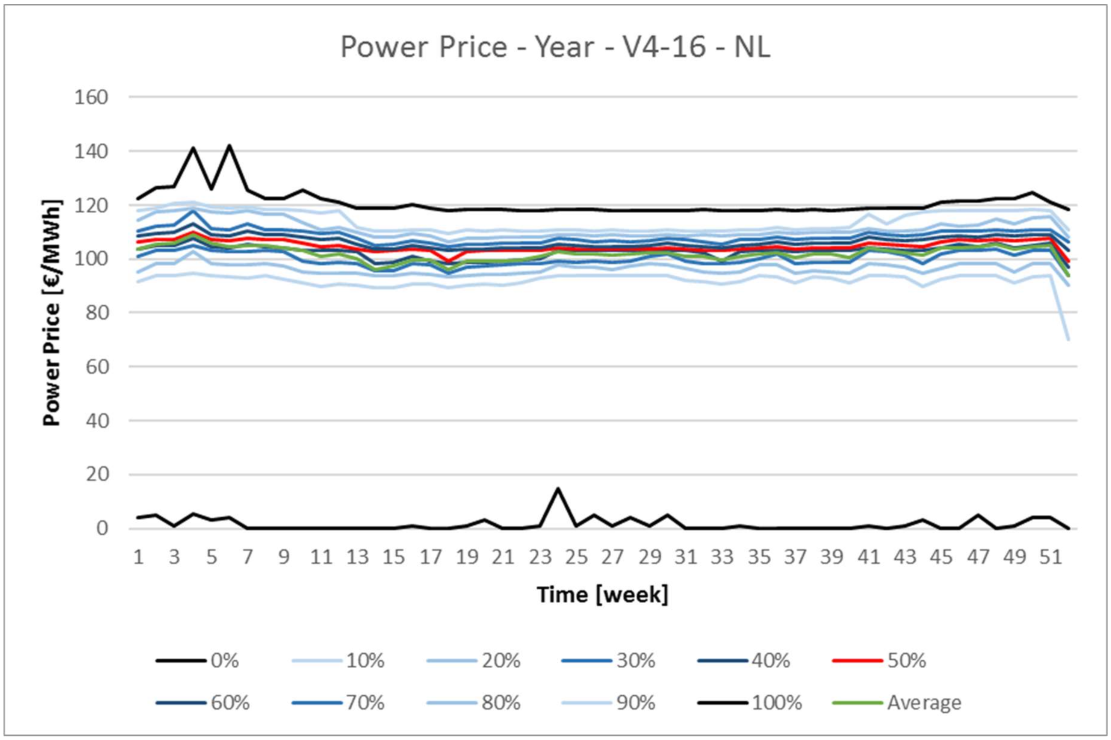

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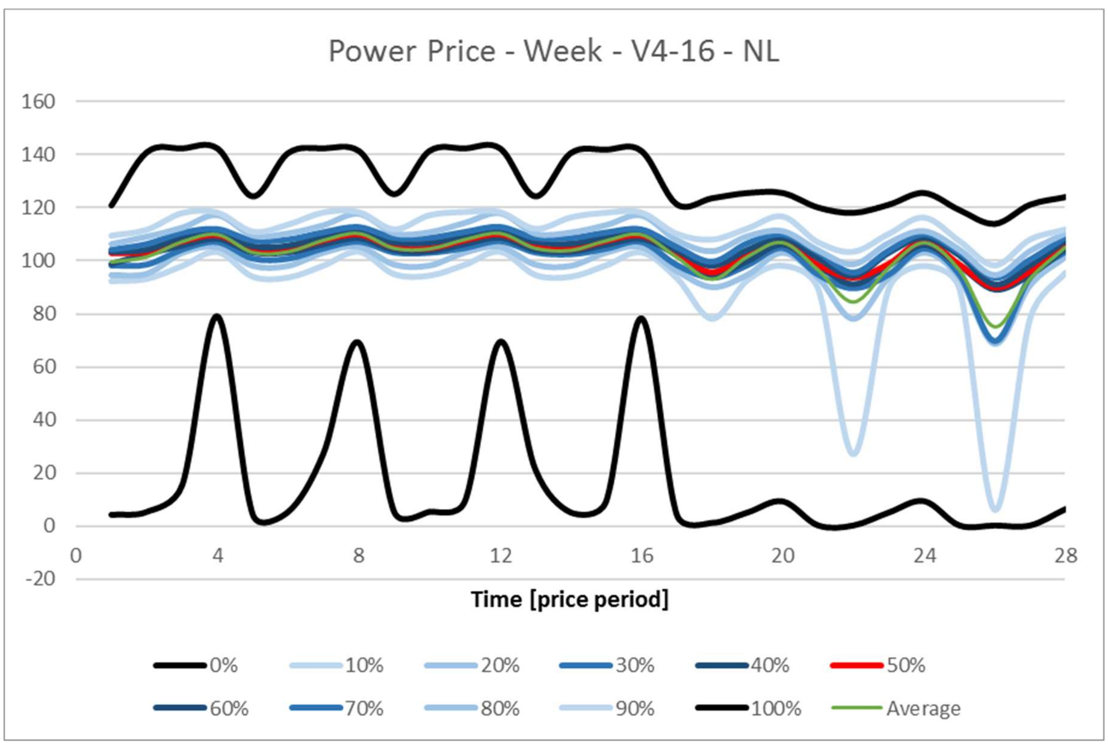

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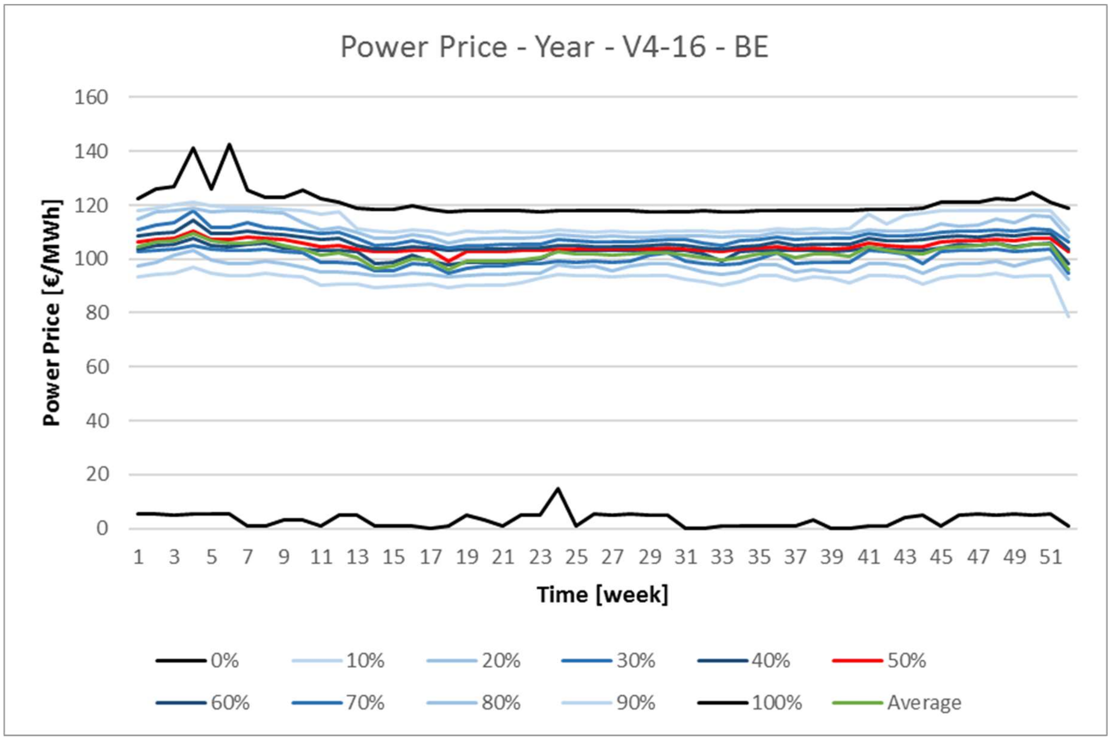

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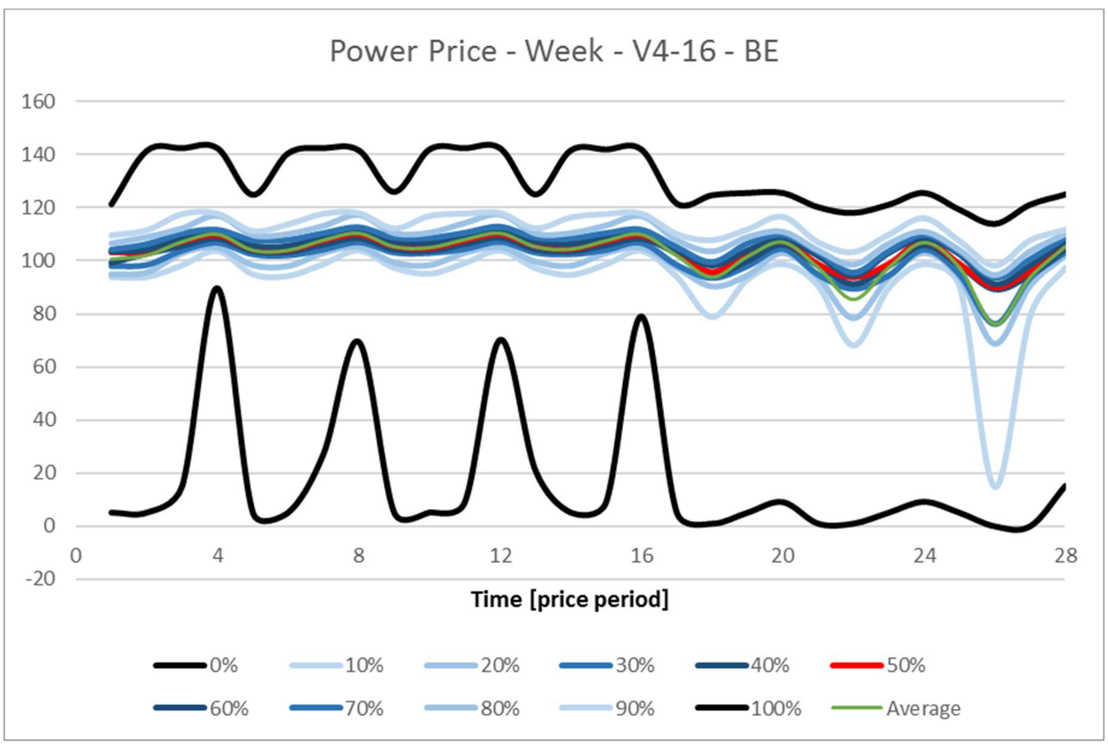

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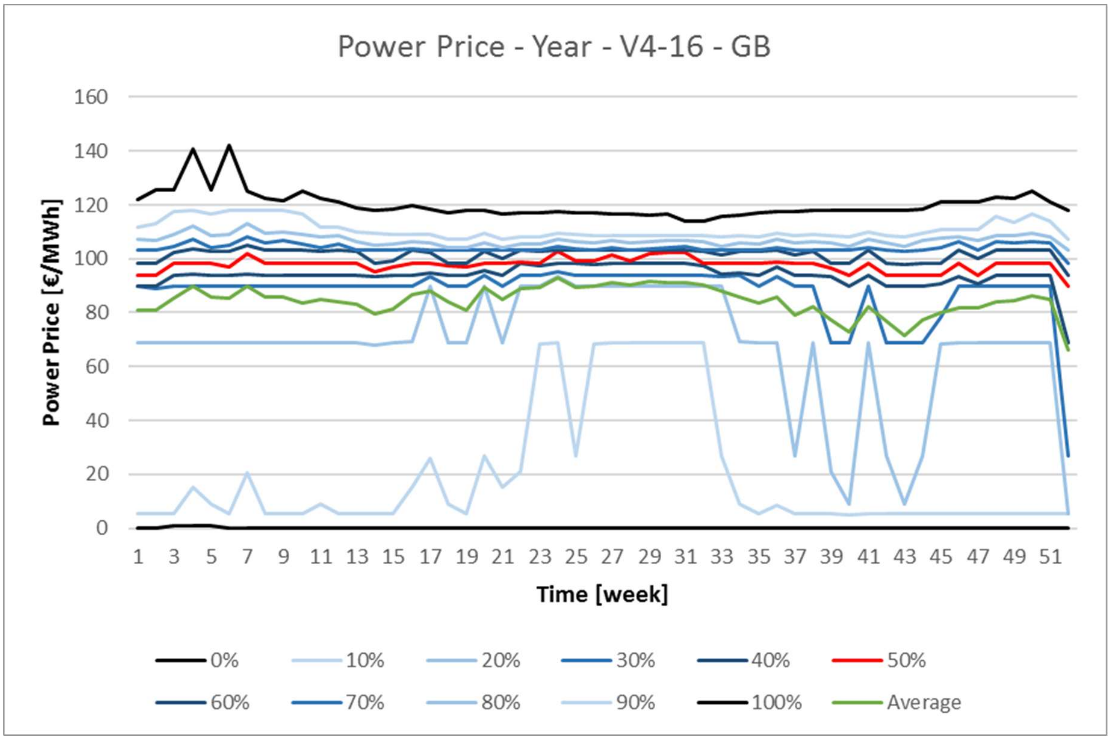

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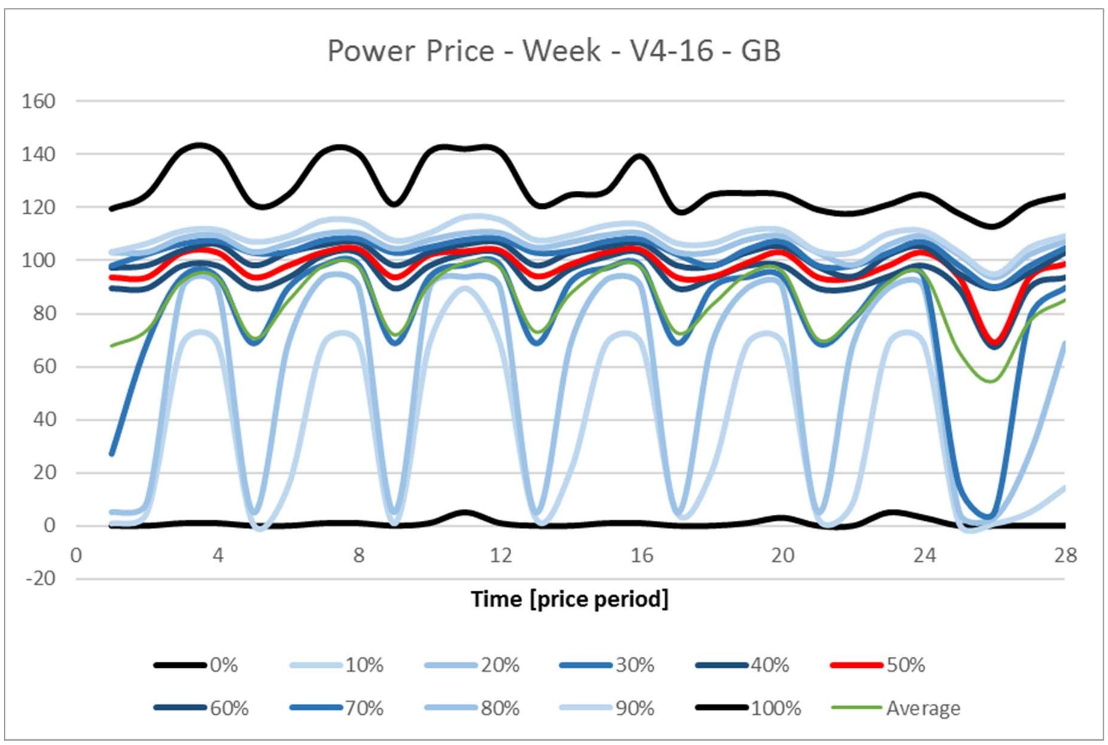

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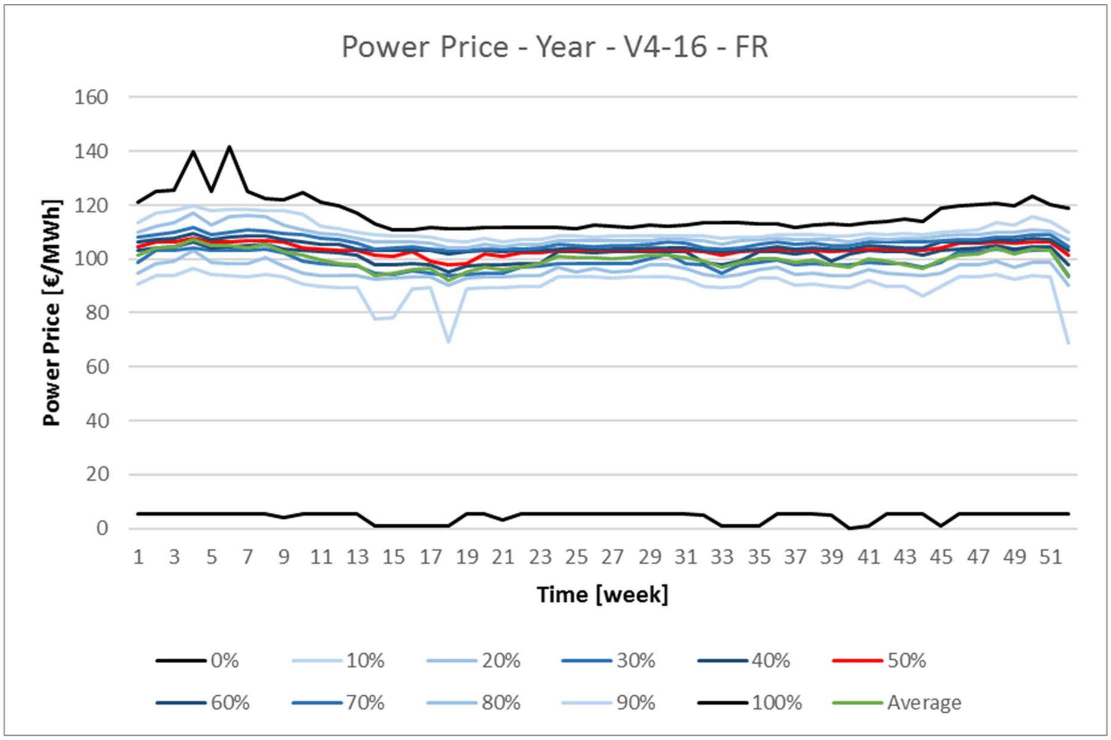

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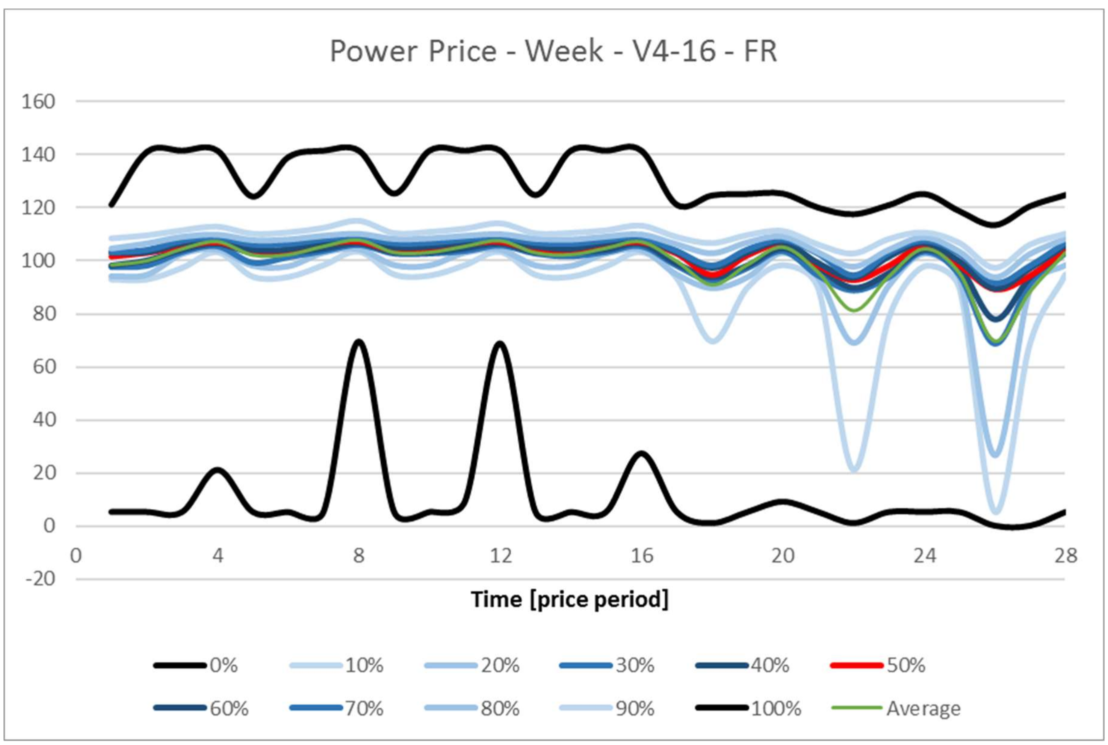

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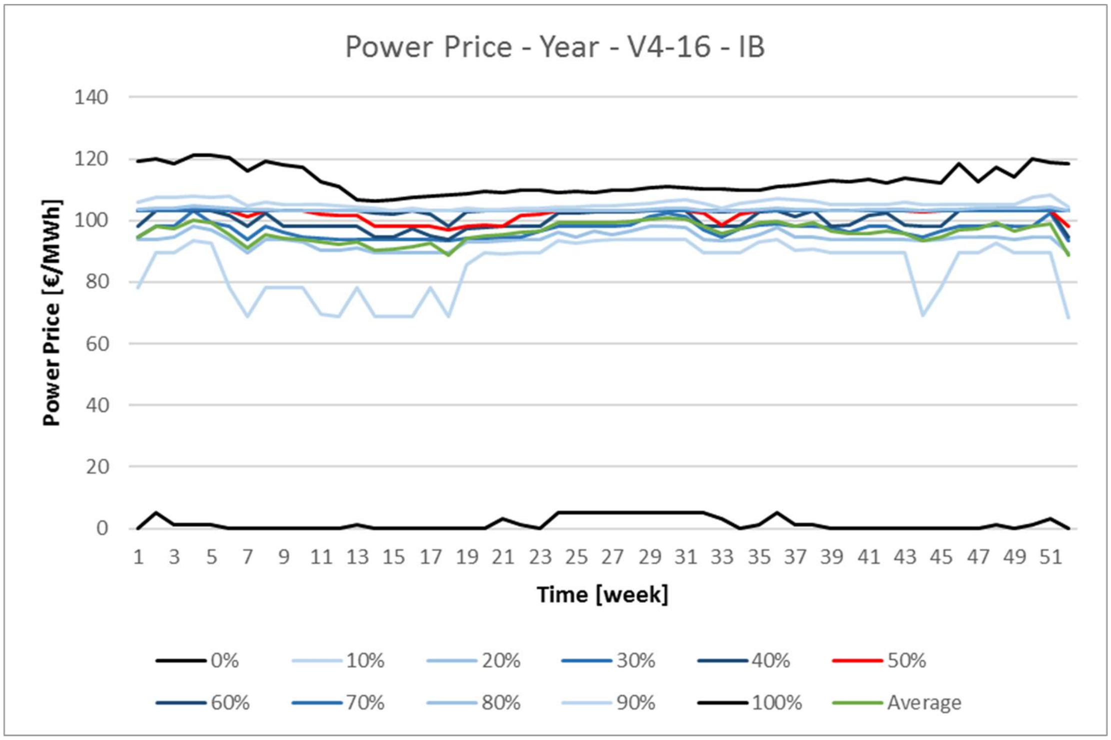

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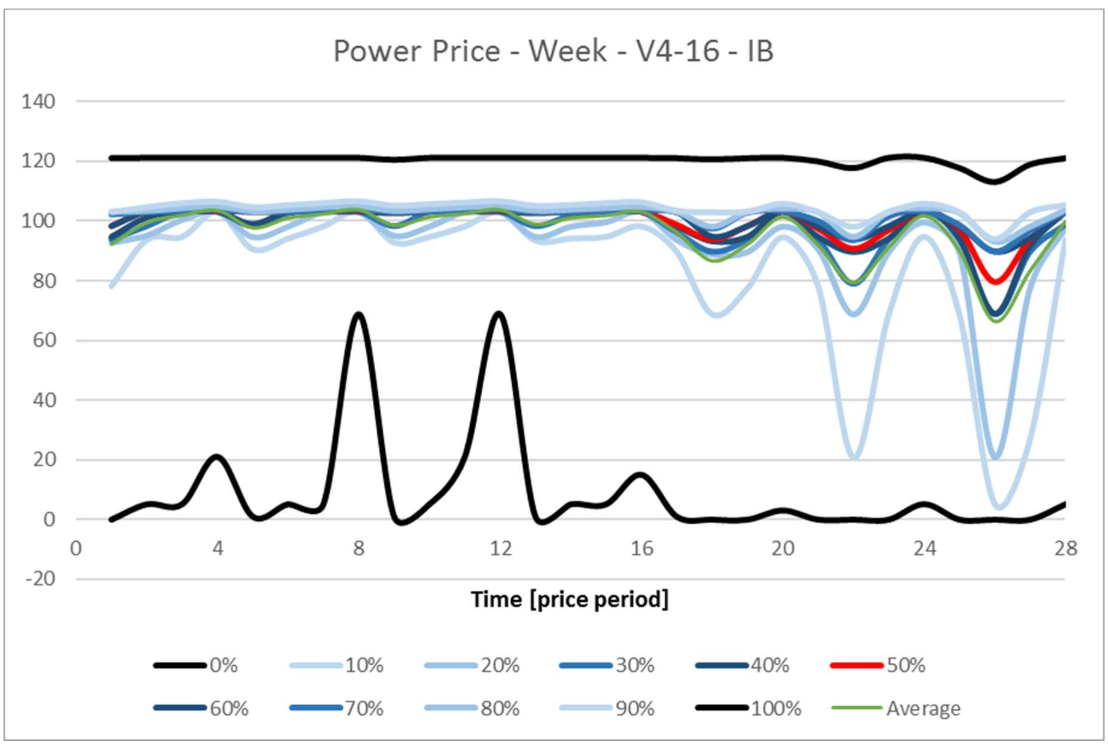

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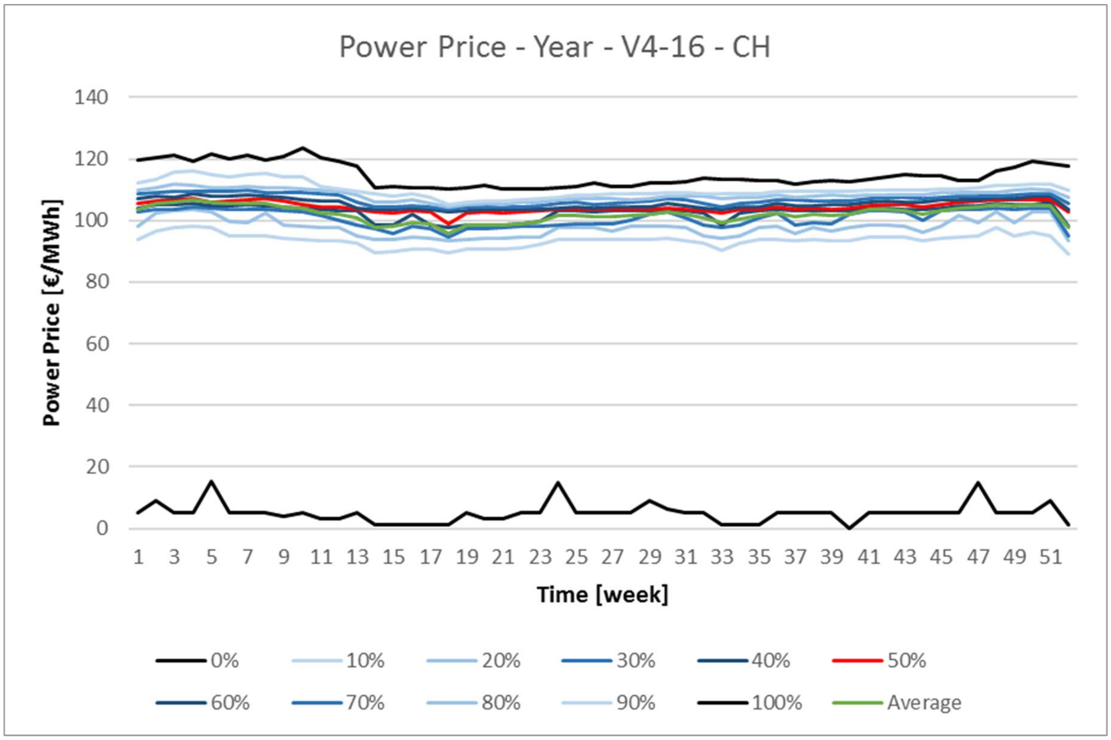

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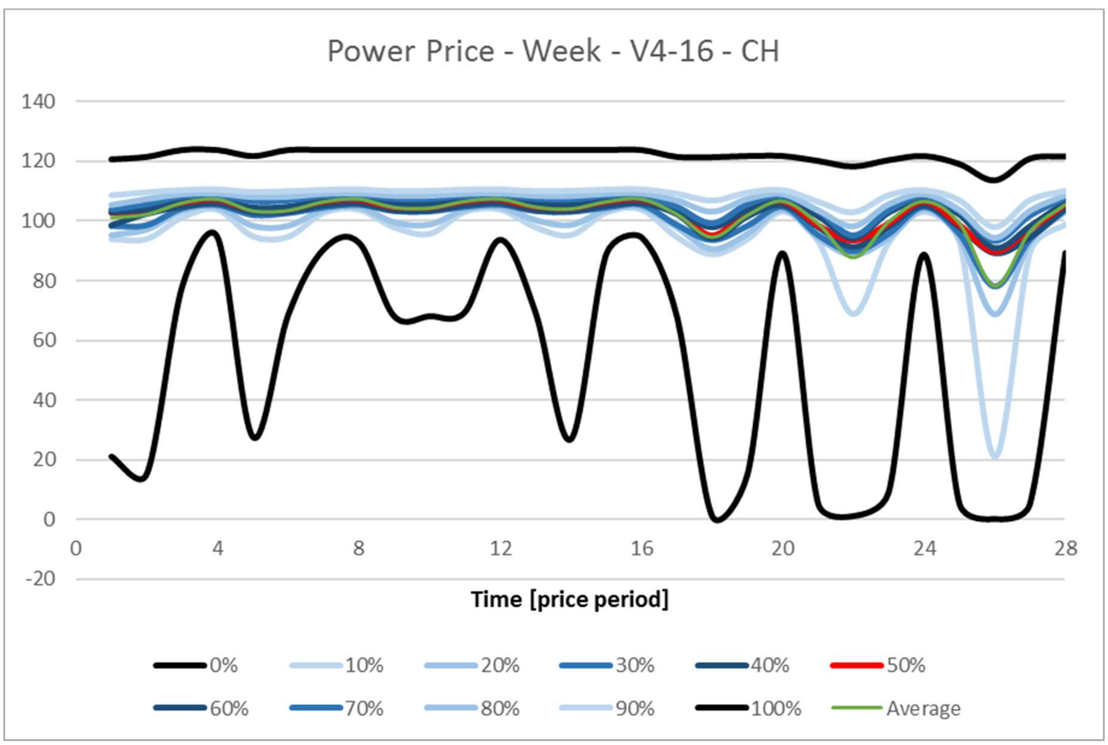

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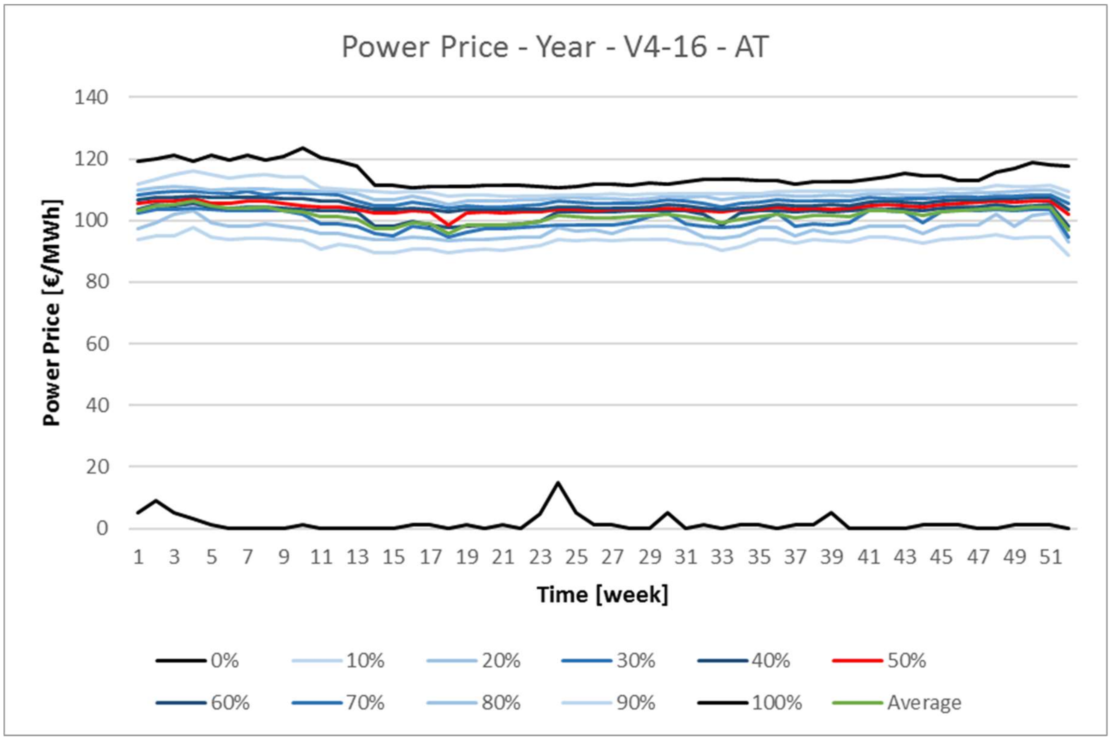

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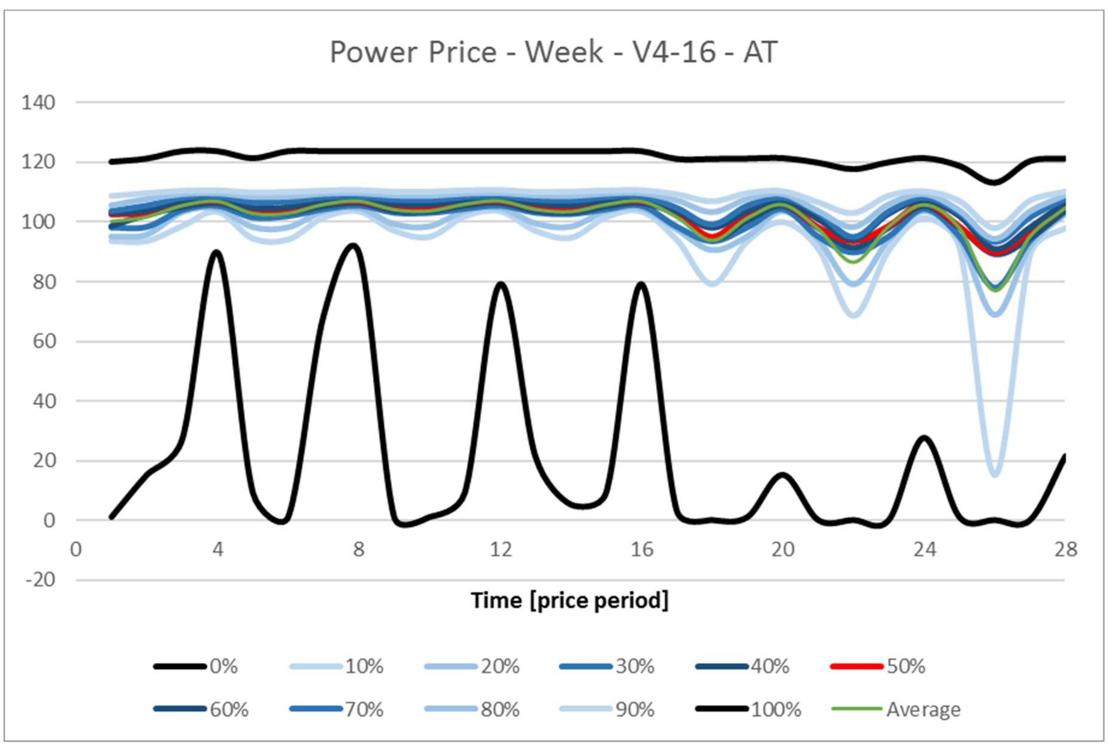
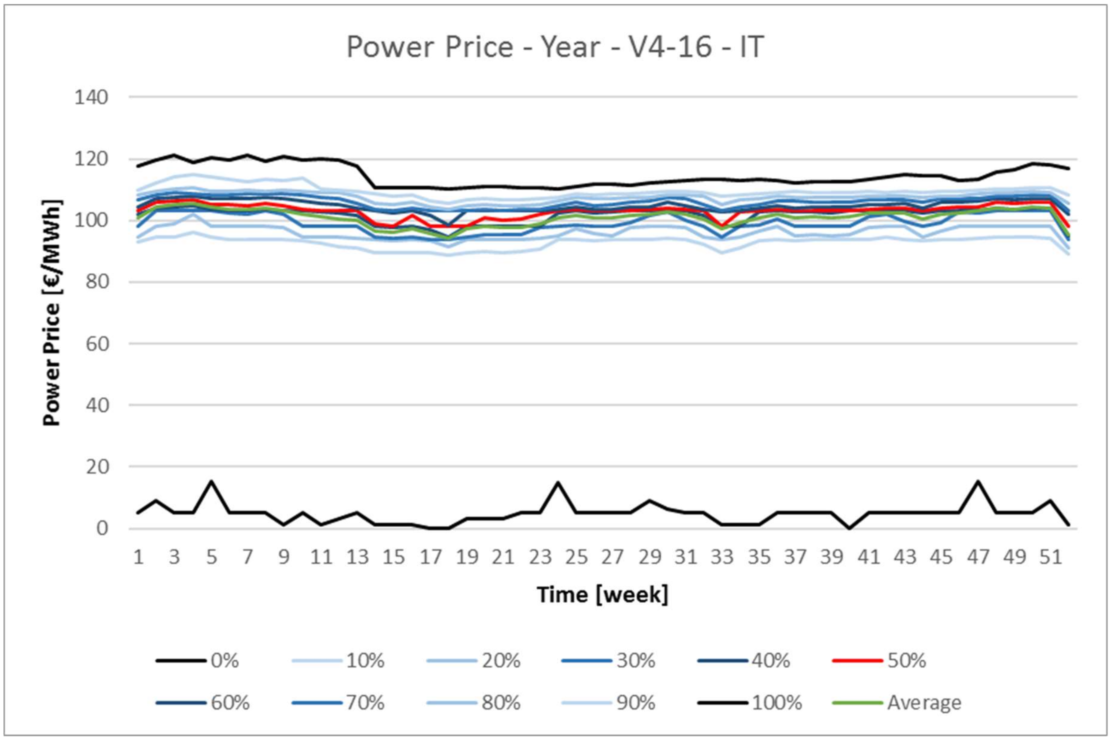


Figure 254



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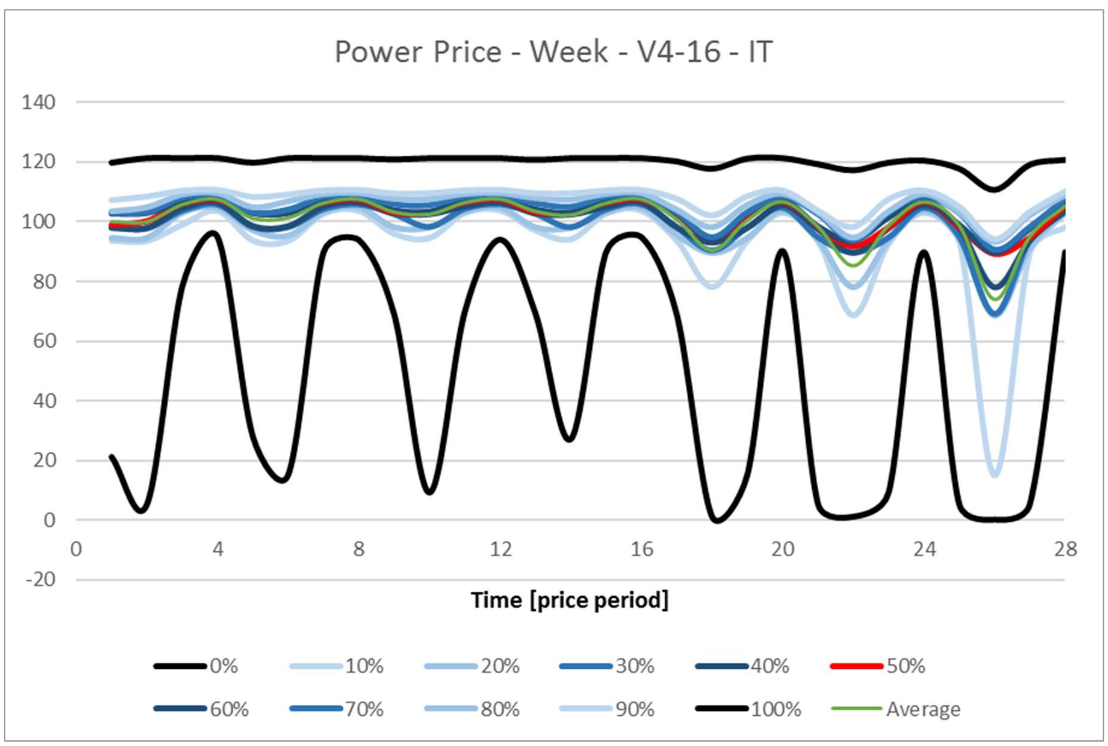


Figure 256

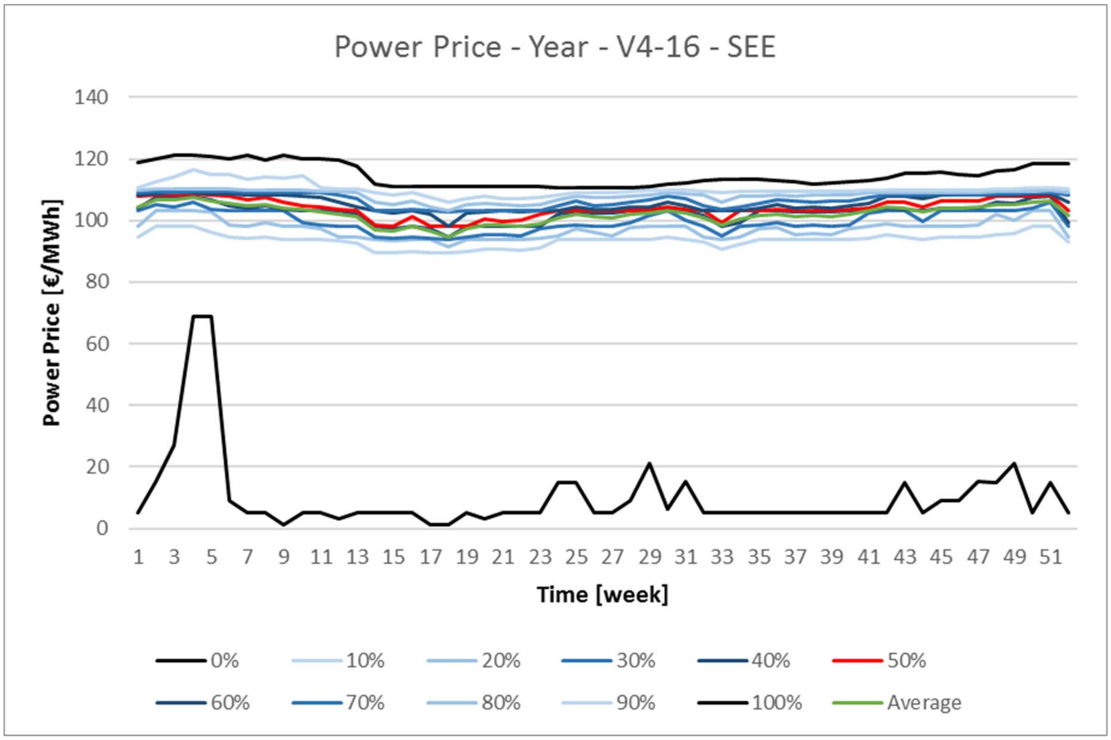


Figure 257

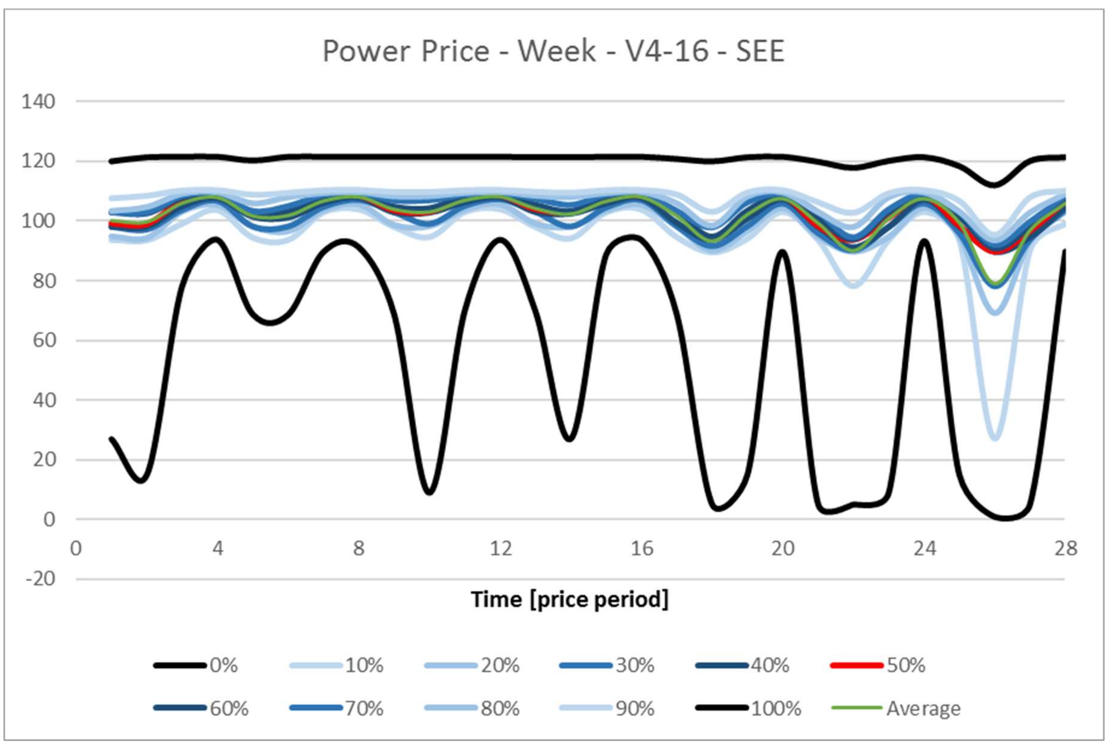


Figure 258

8.7.4 Power price – DoubleRES

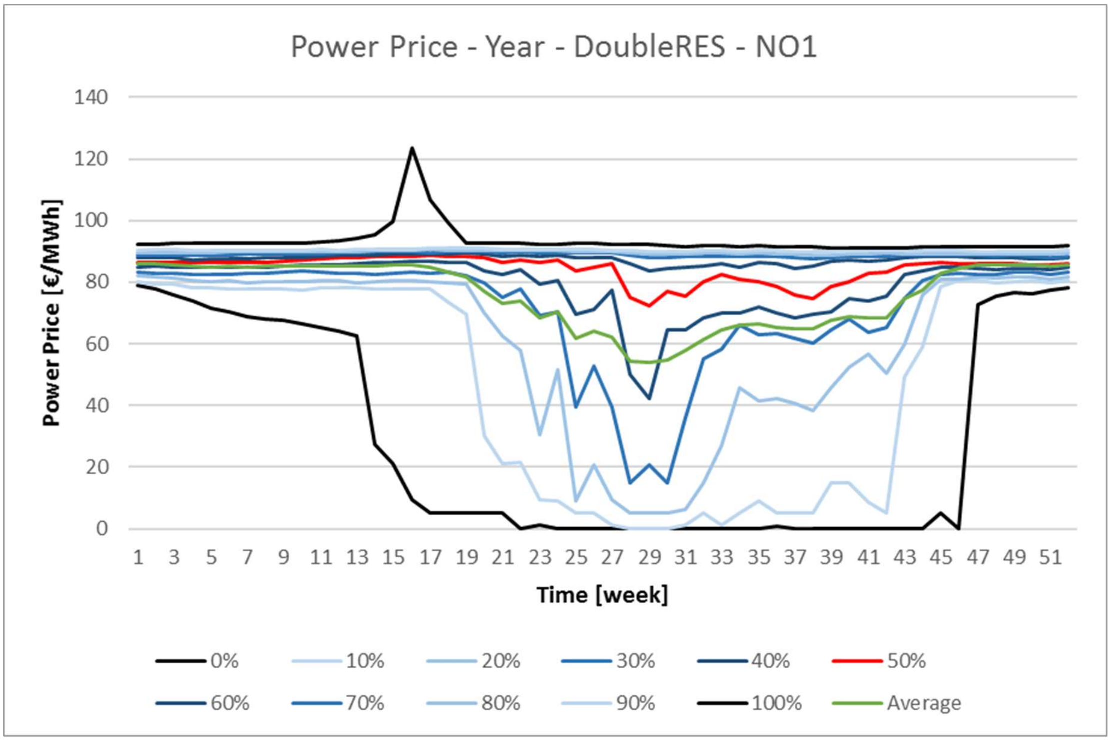


Figure 259

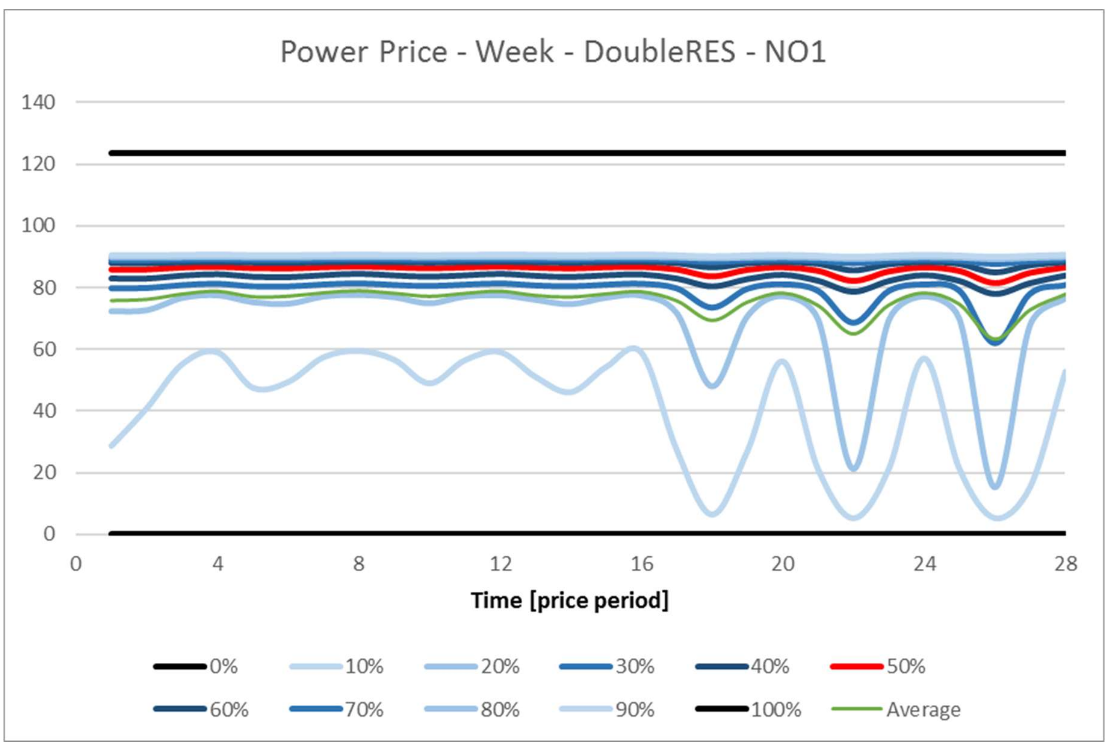


Figure 260

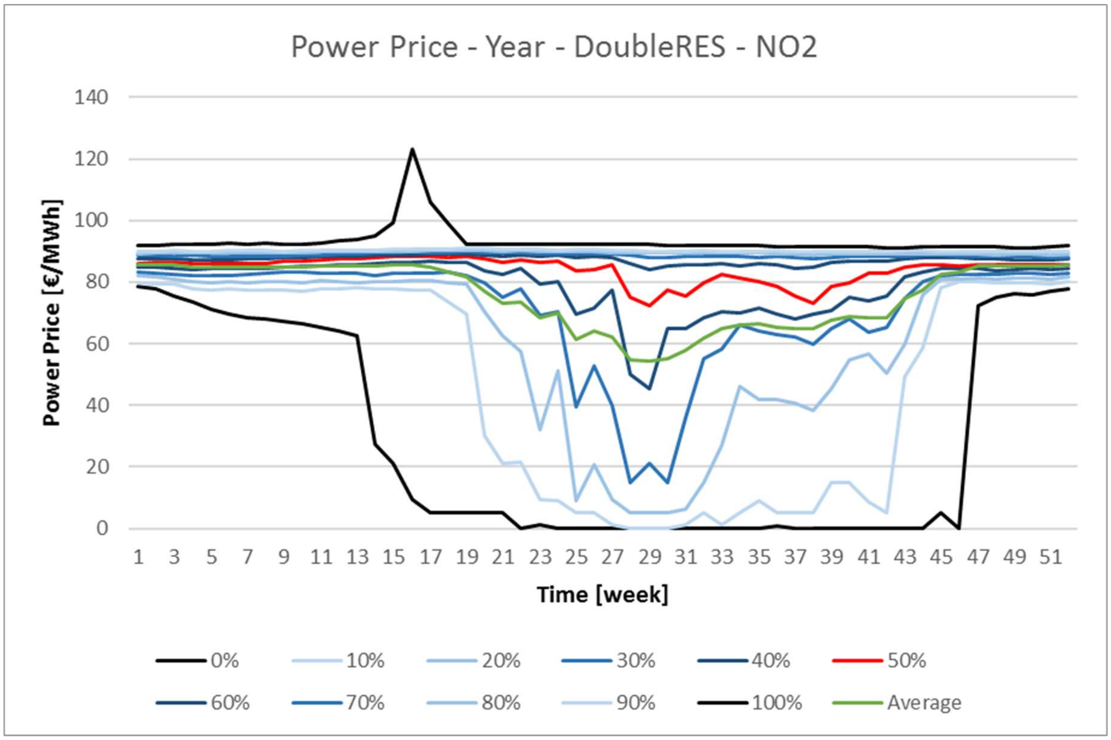


Figure 261

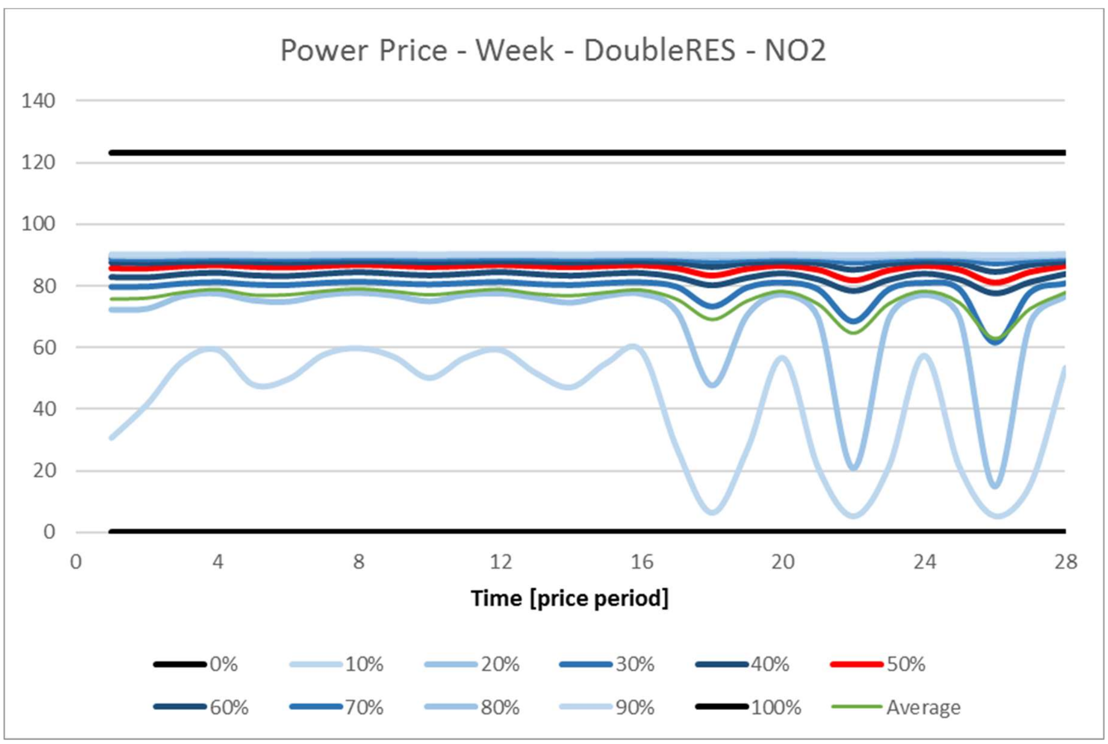


Figure 262

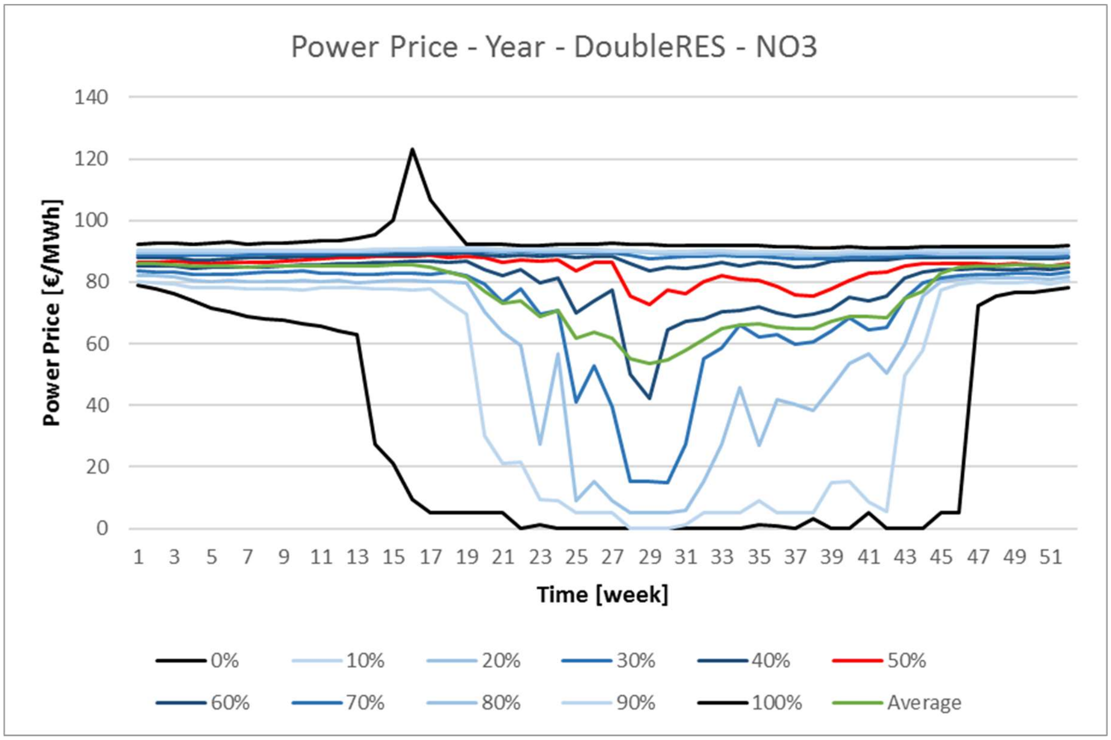


Figure 263

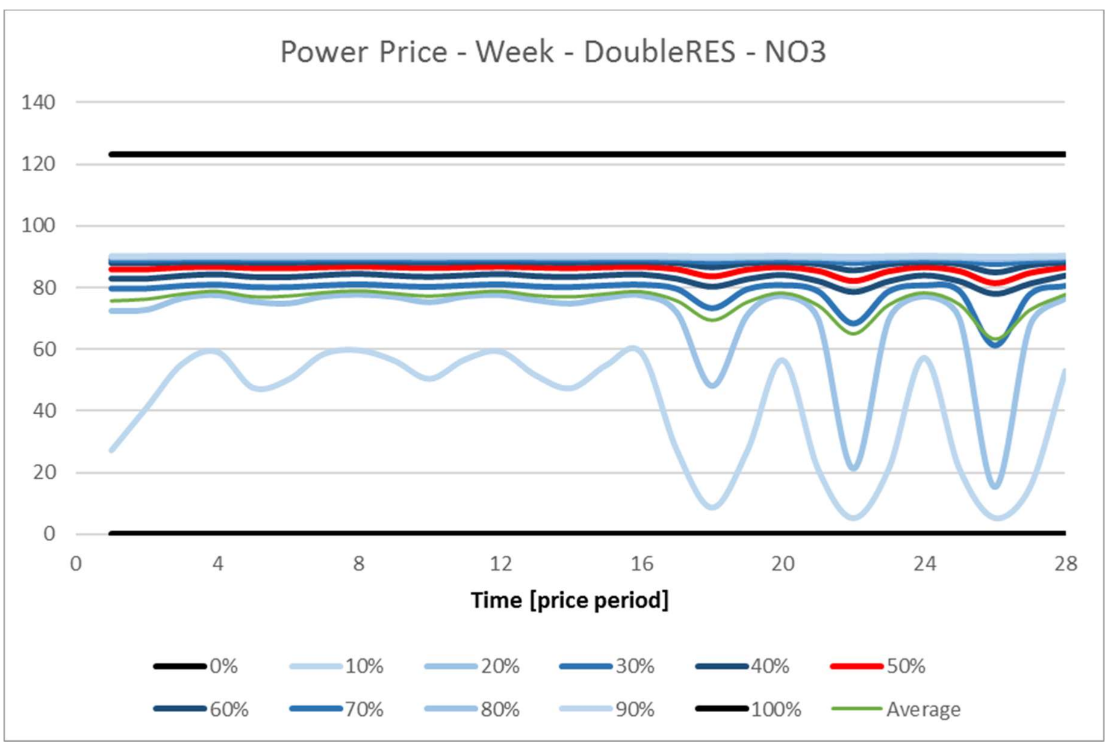


Figure 264

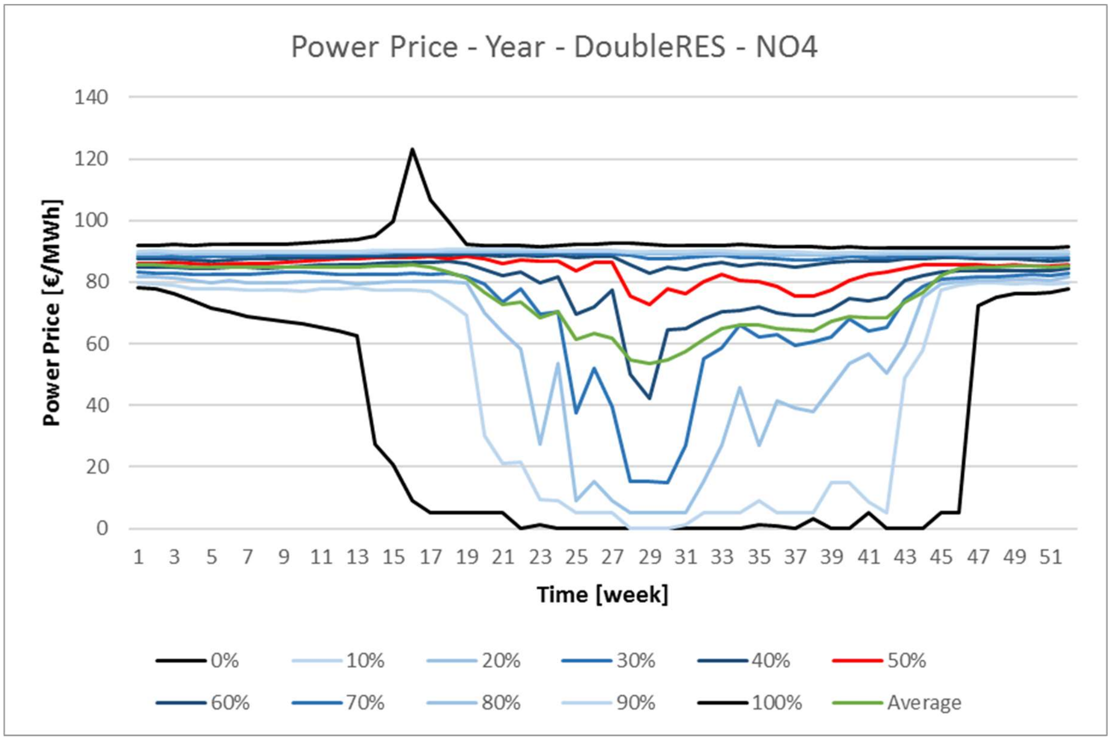


Figure 265

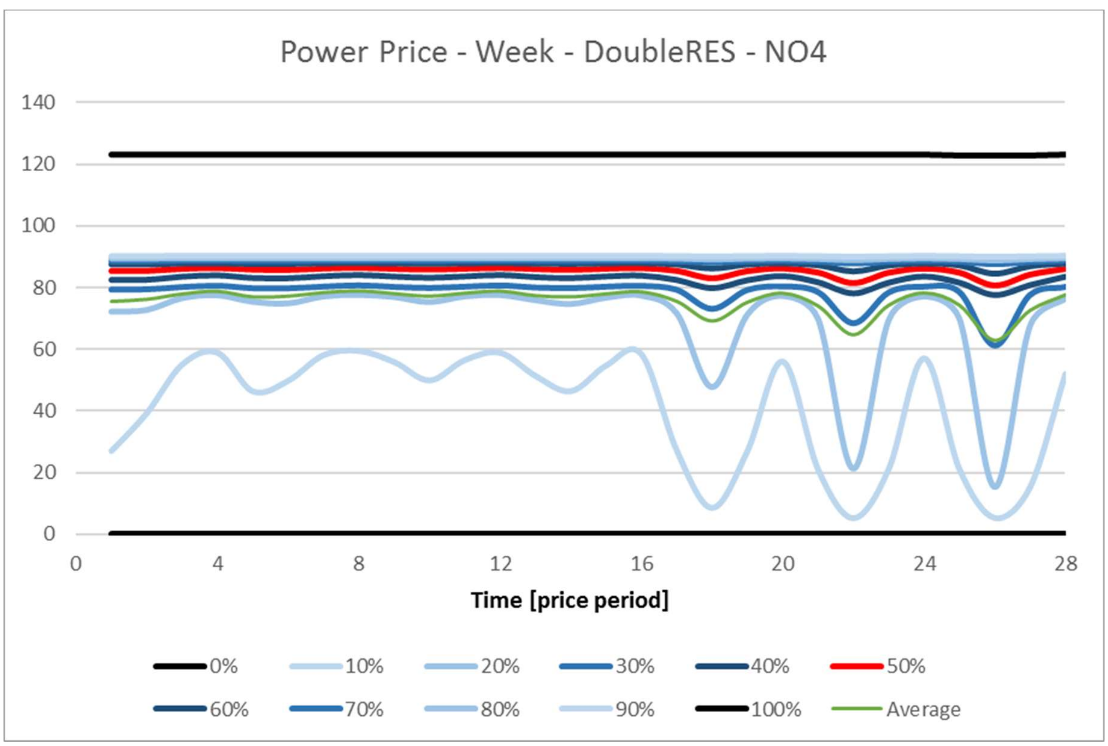


Figure 266

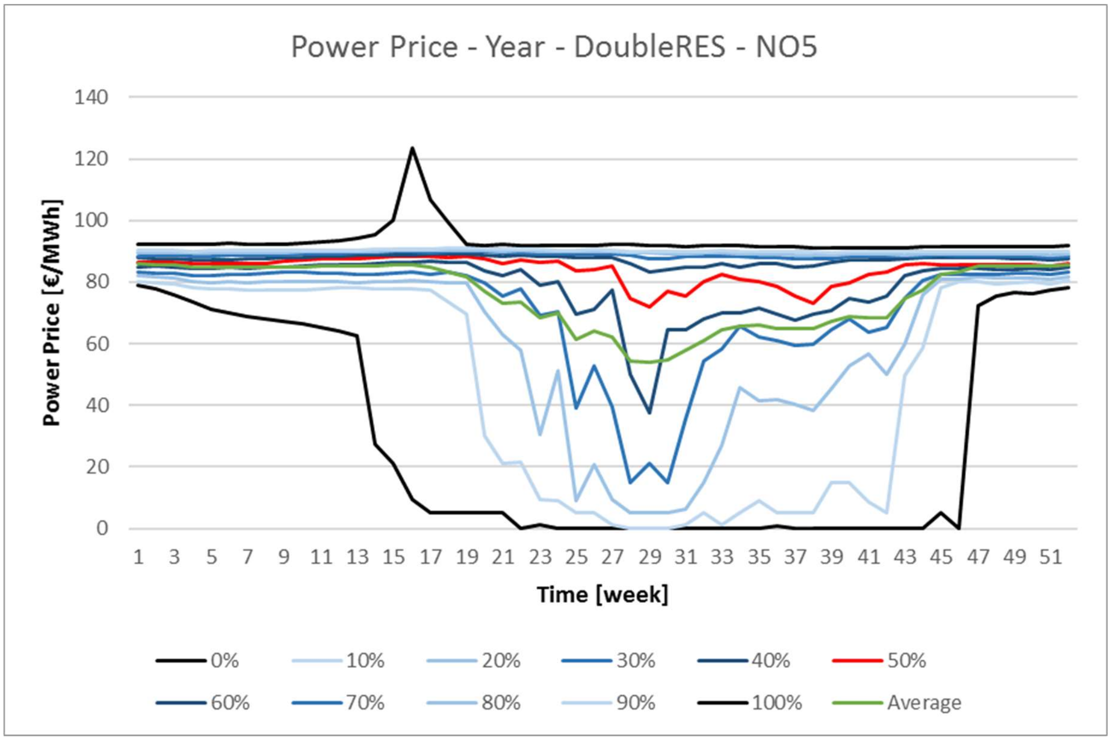


Figure 267

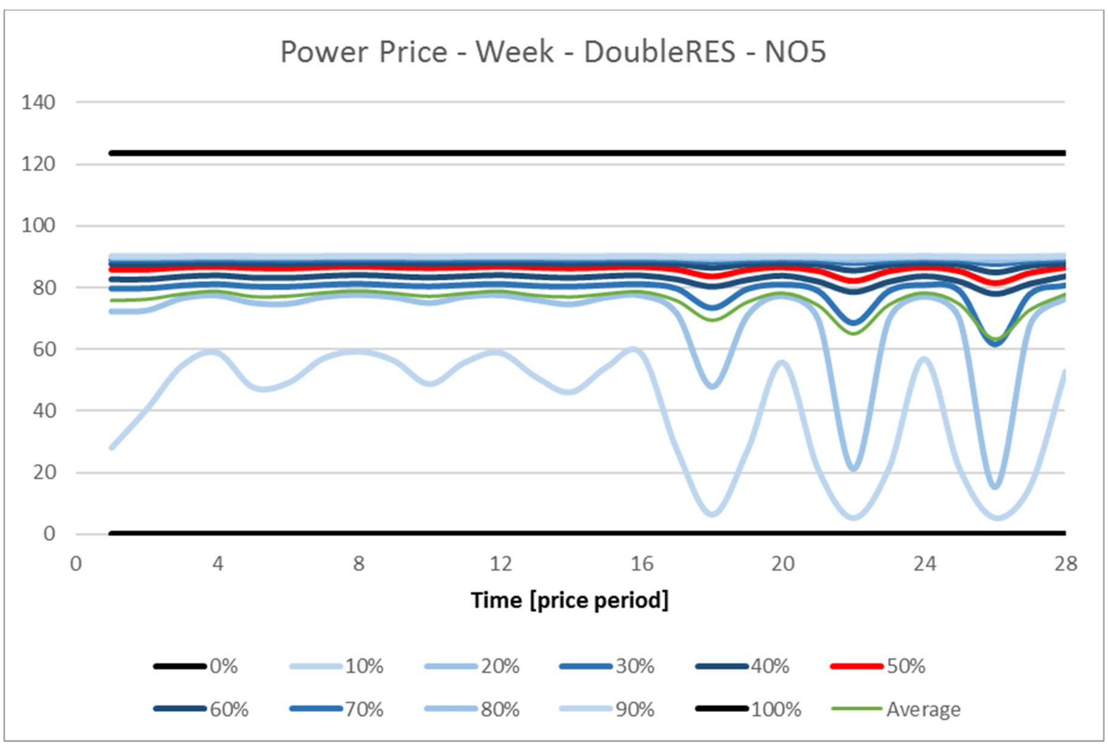


Figure 268

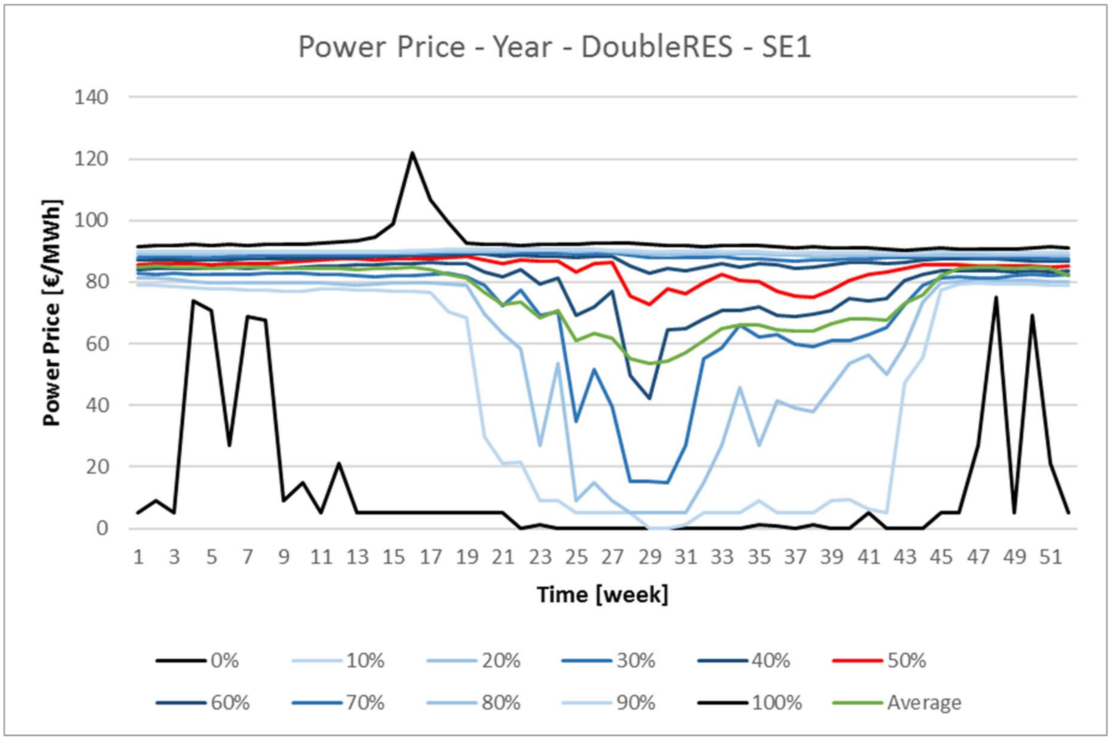


Figure 269

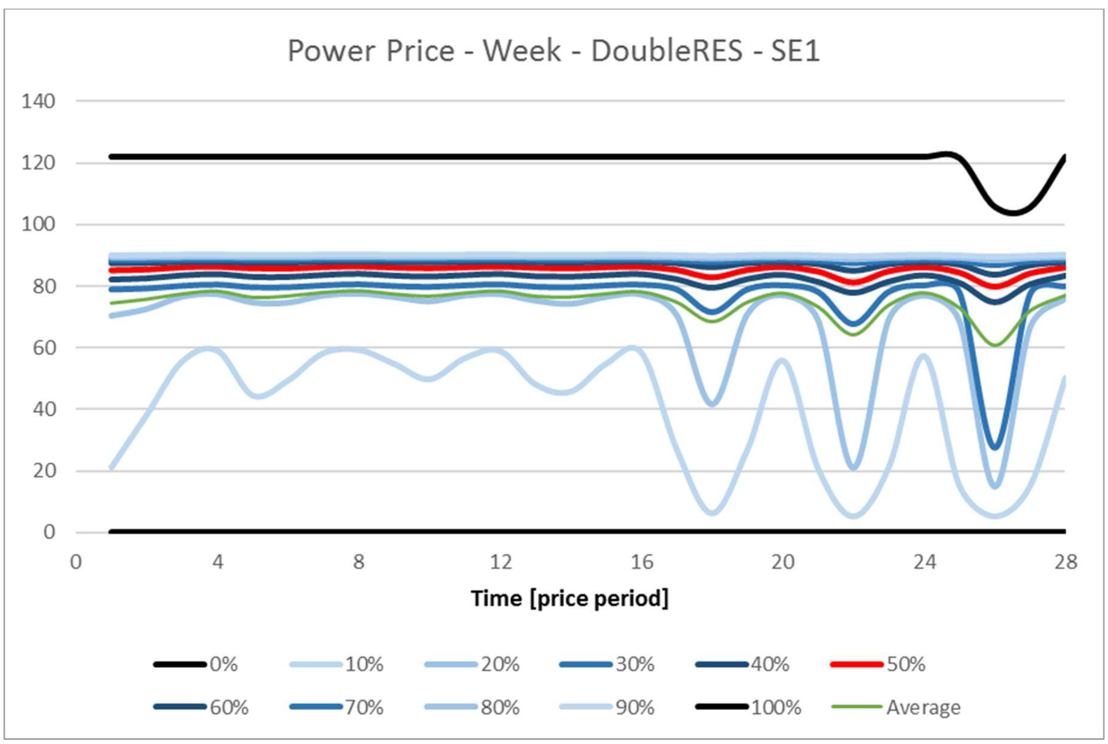


Figure 270

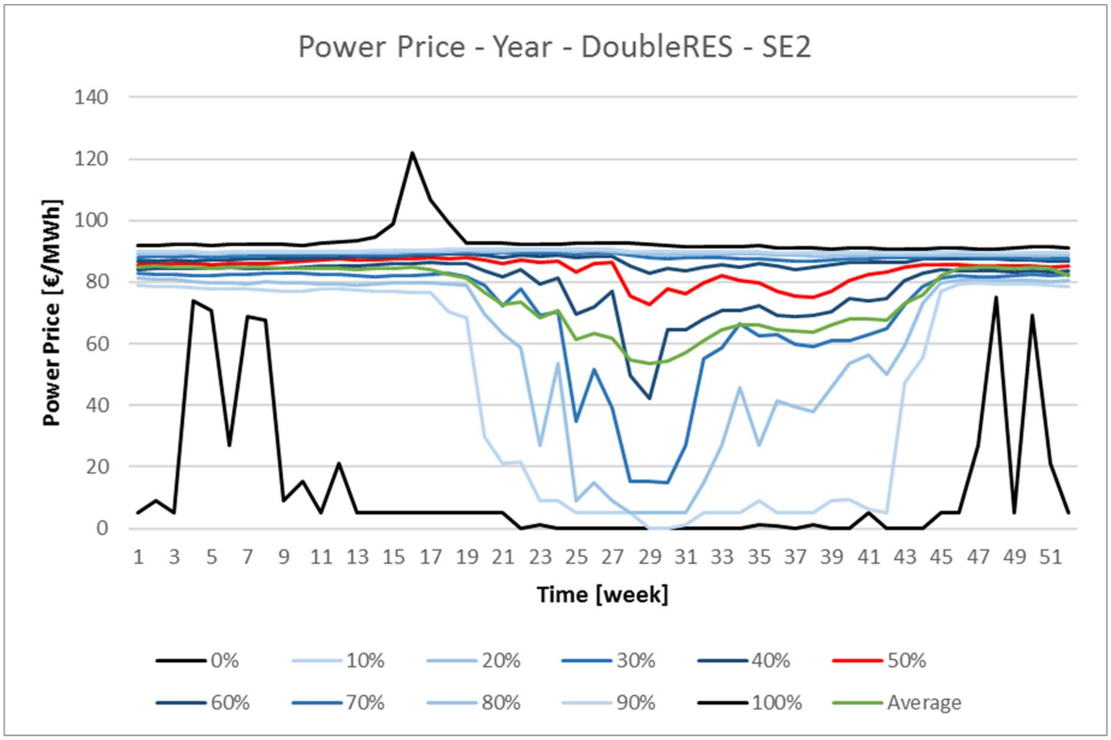


Figure 271

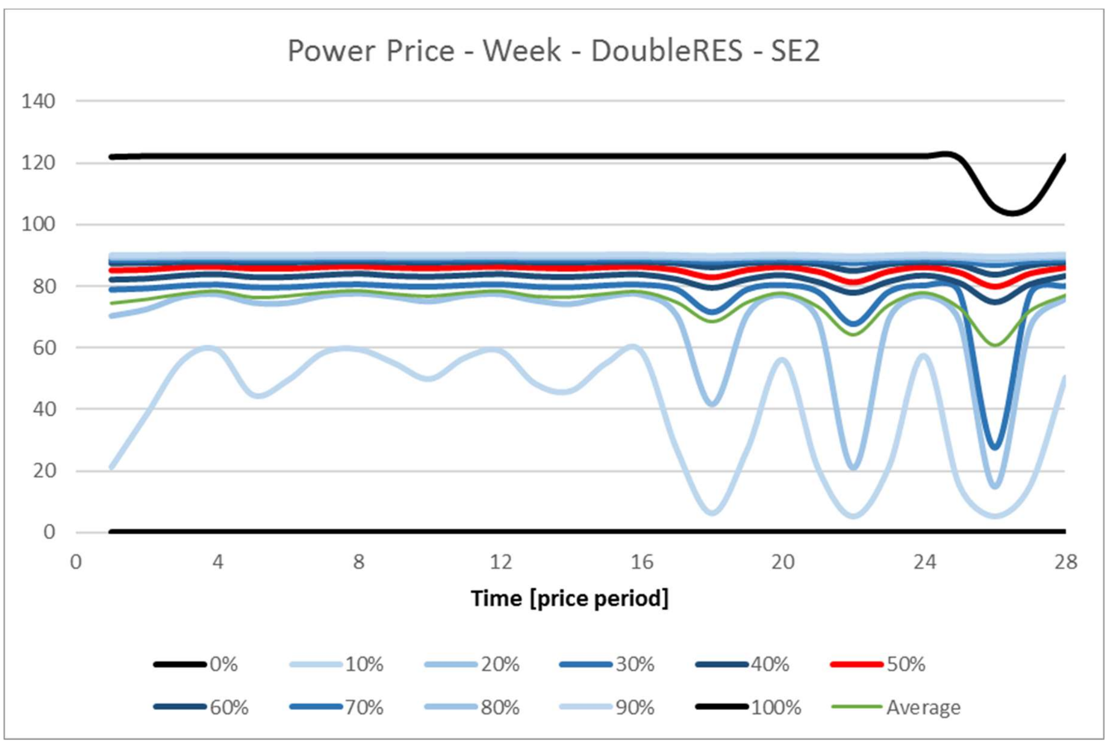


Figure 272

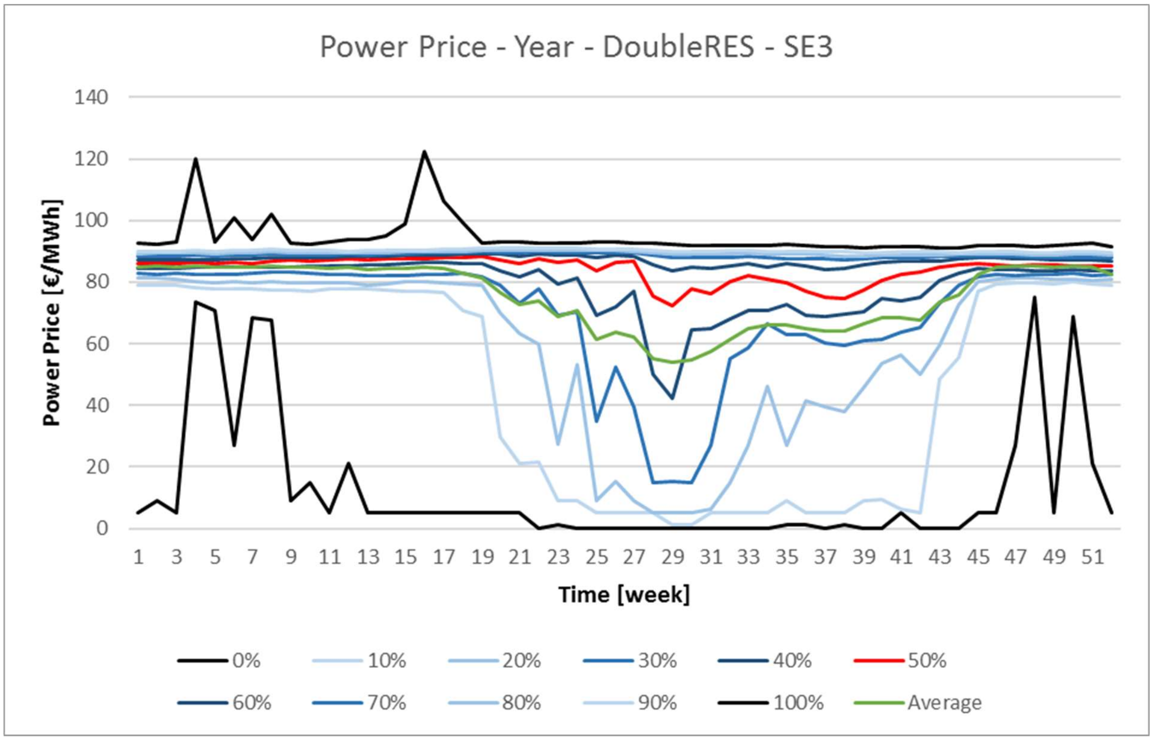


Figure 273

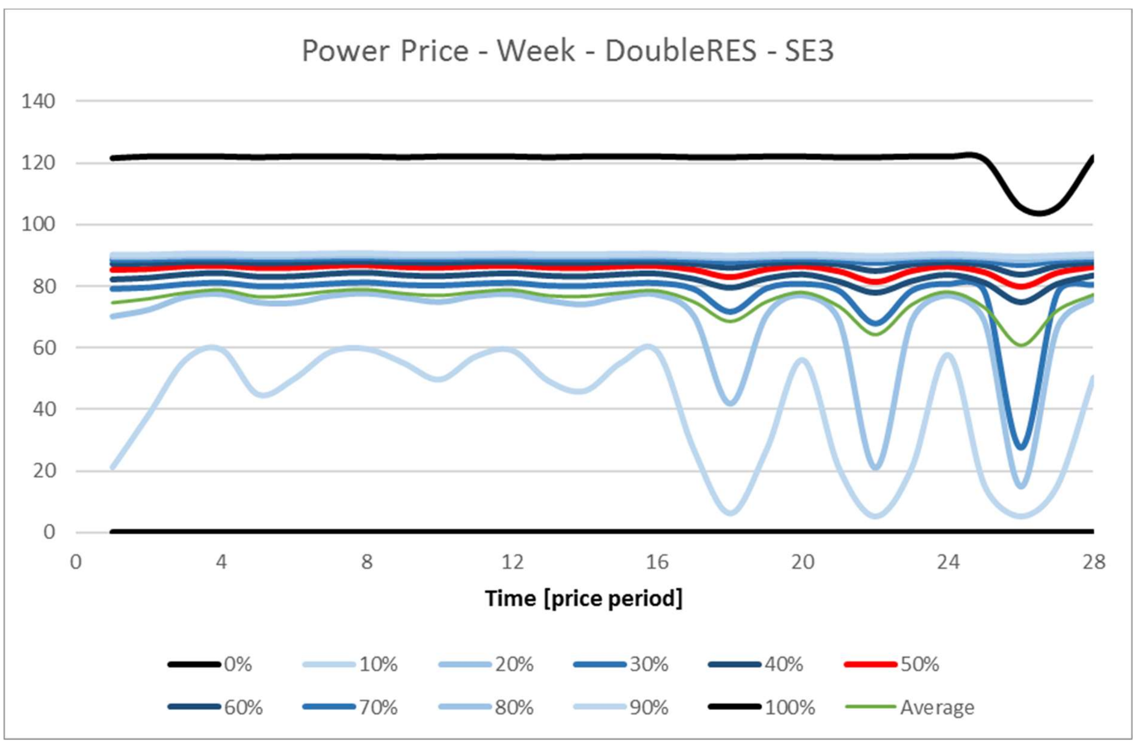


Figure 274

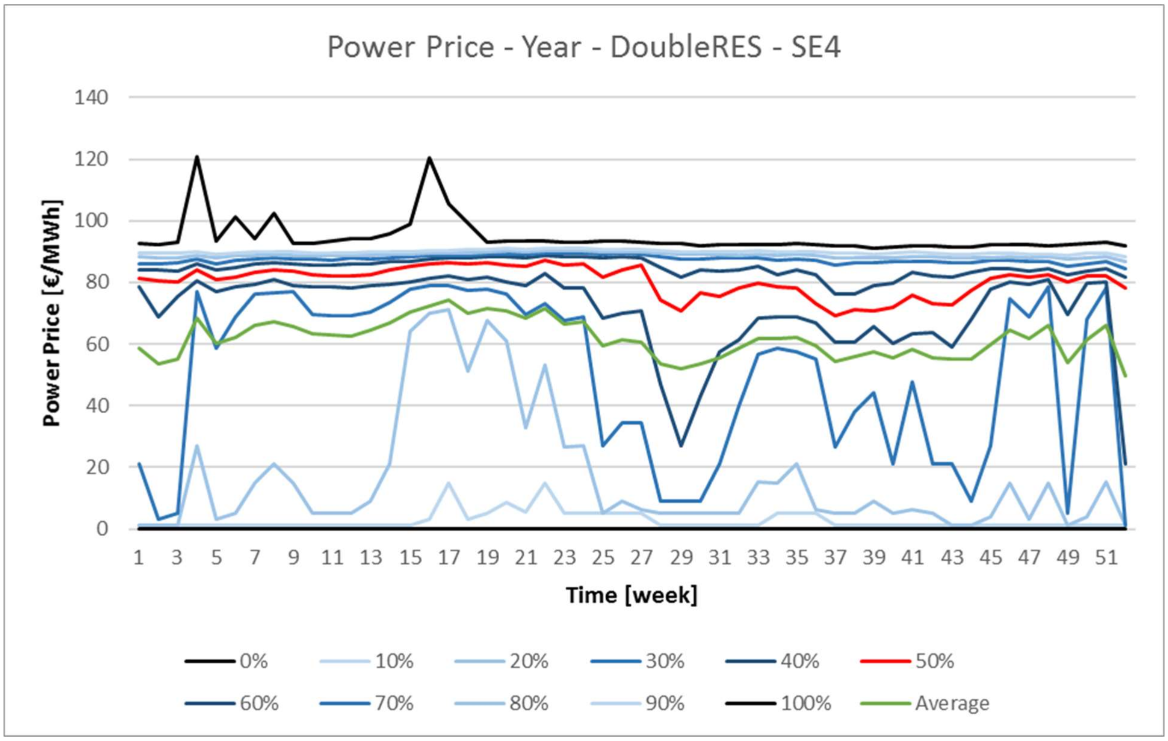


Figure 275

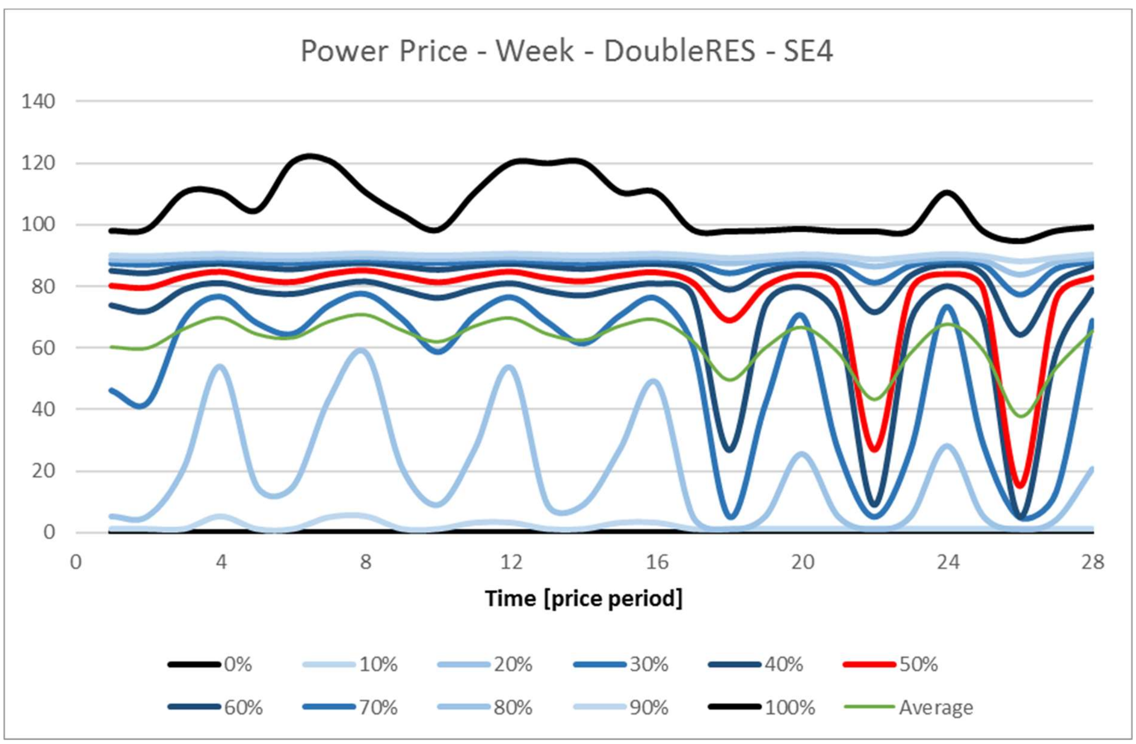


Figure 276

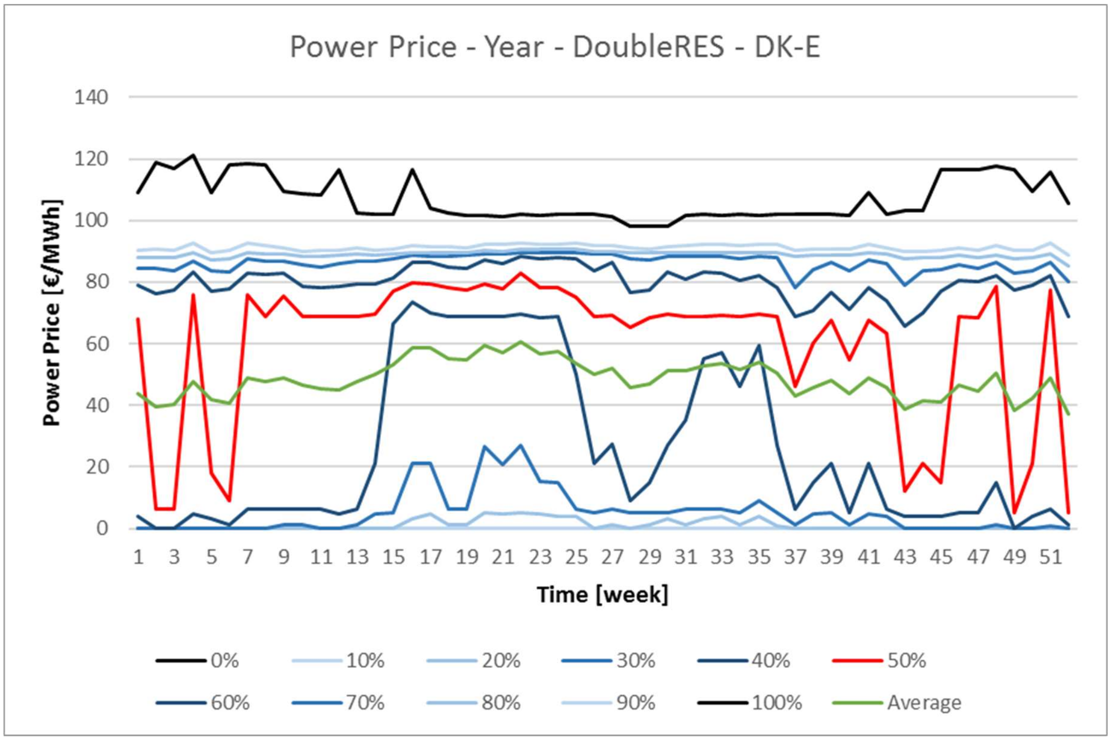


Figure 277

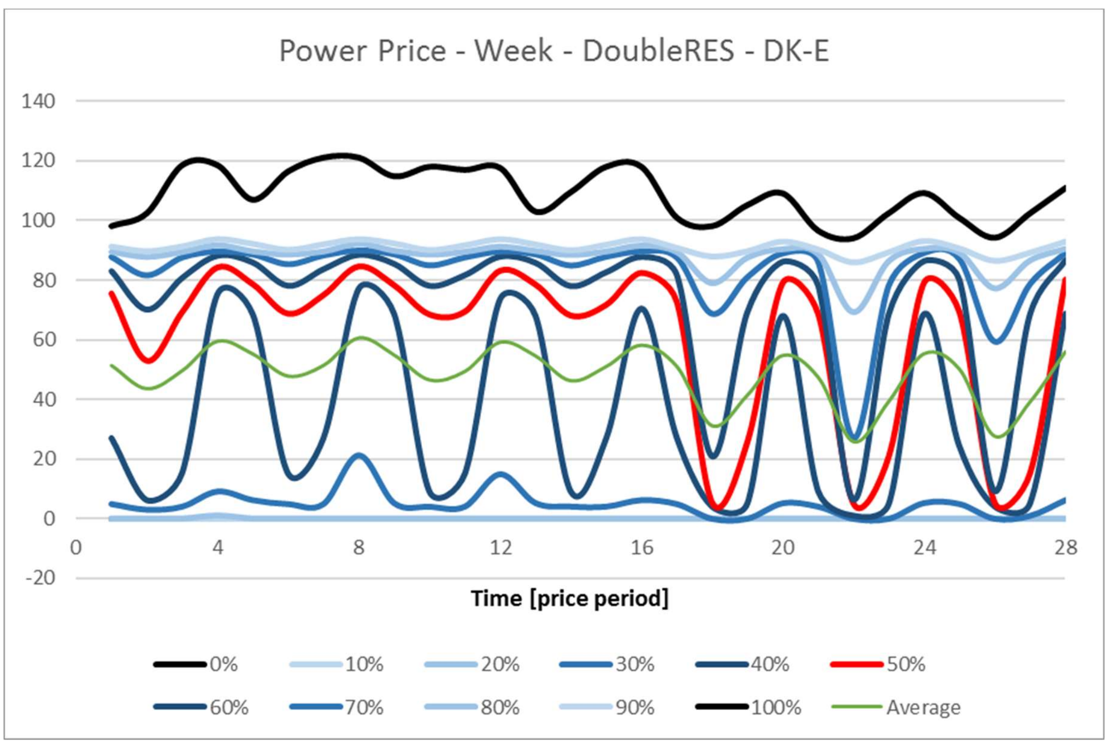


Figure 278

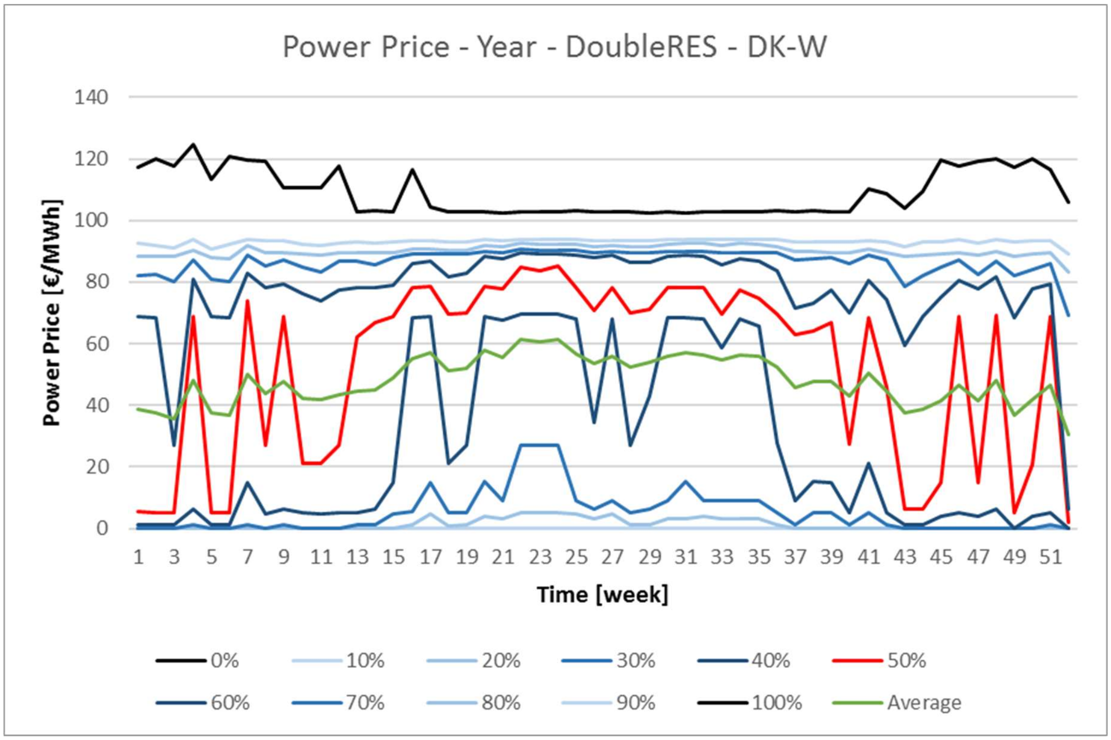
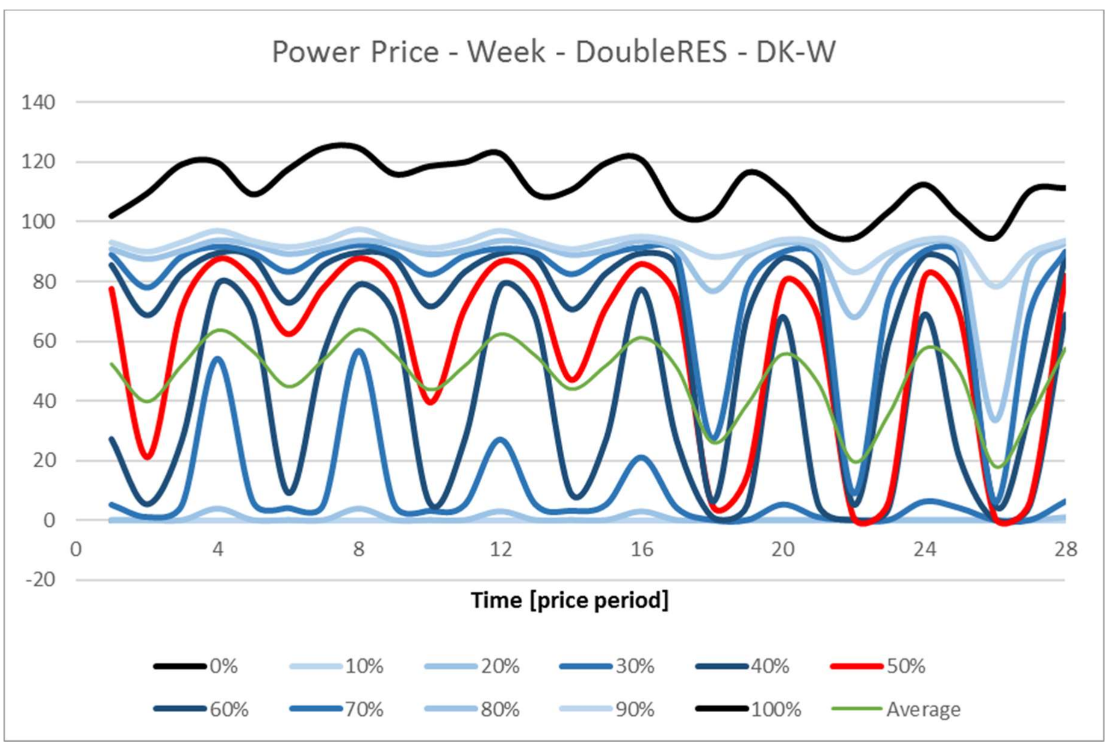


Figure 279



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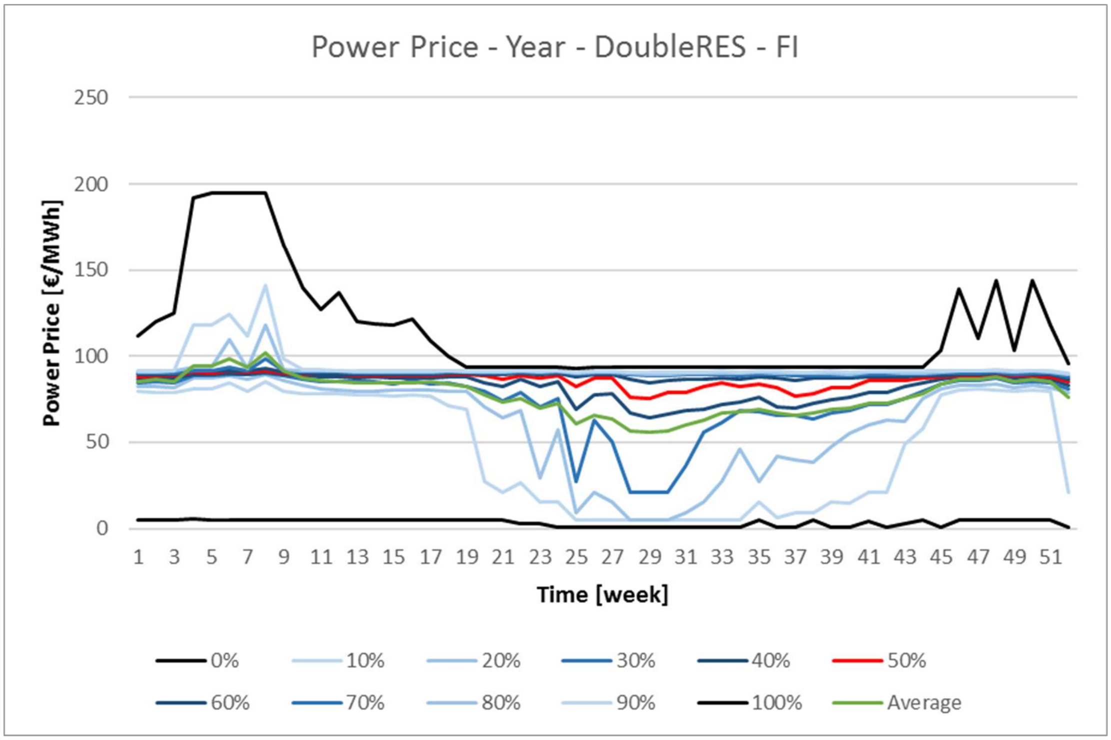

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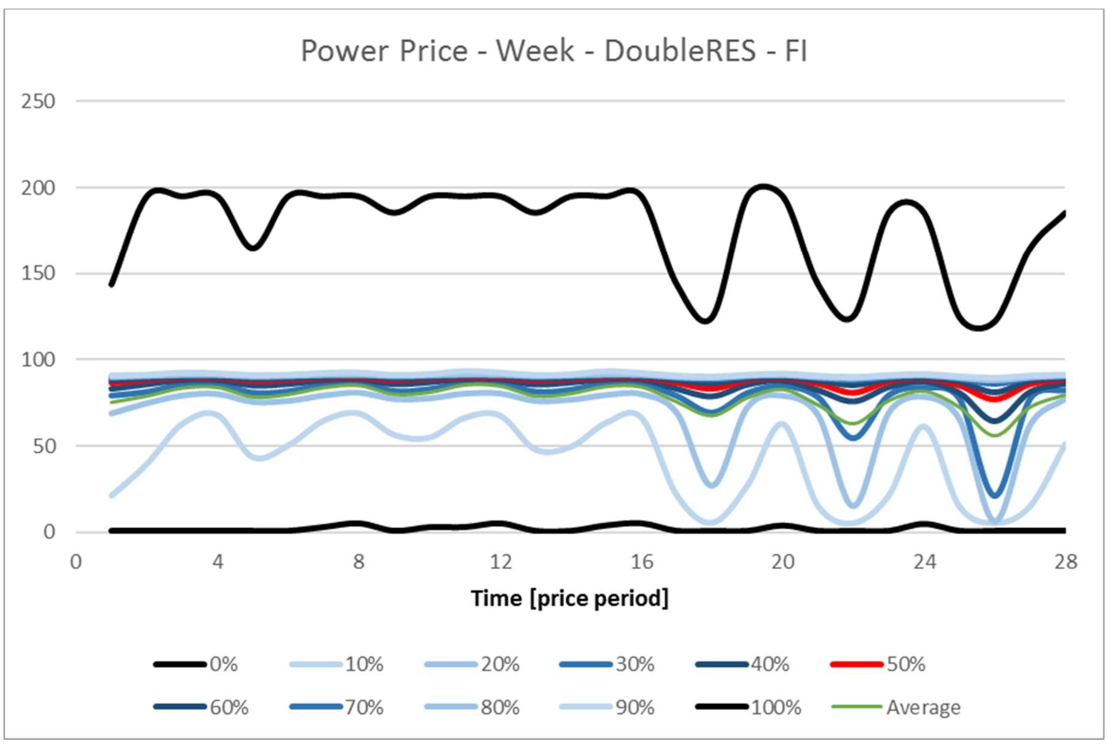

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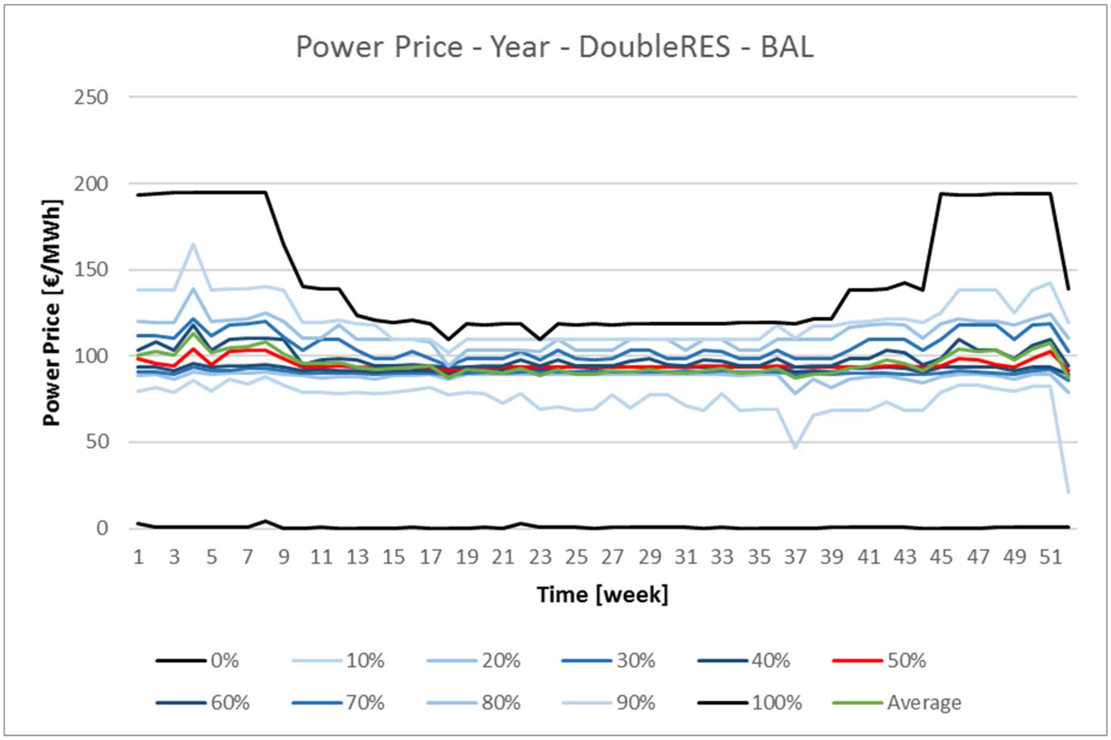

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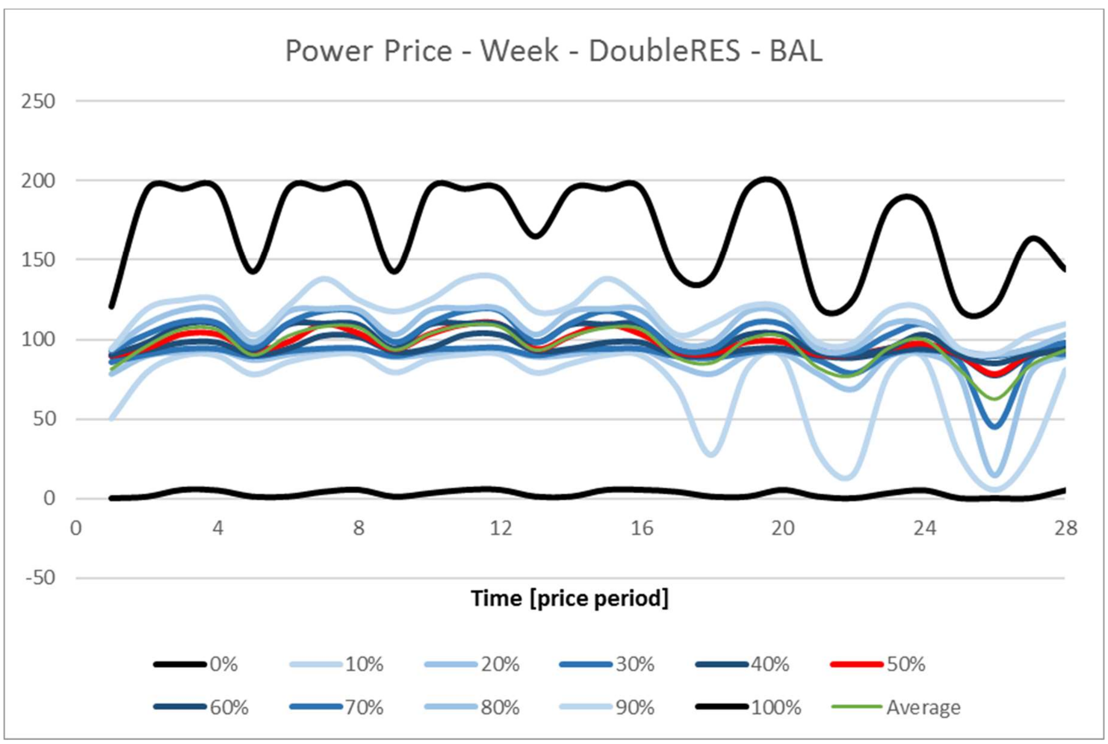

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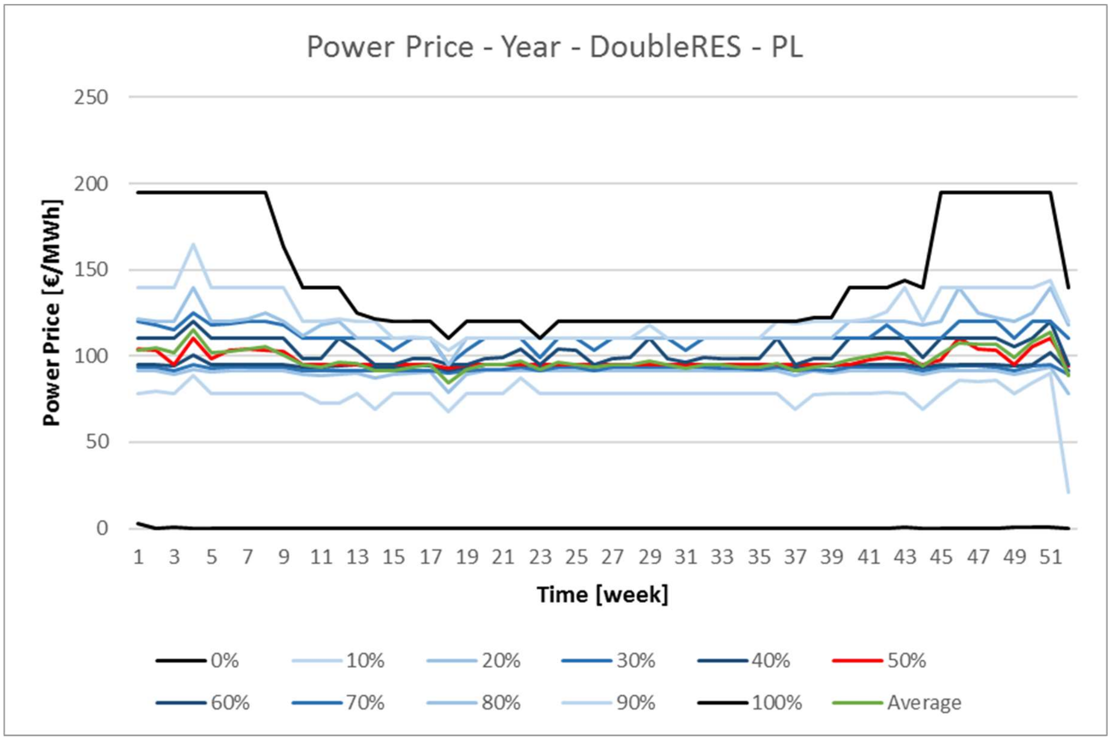

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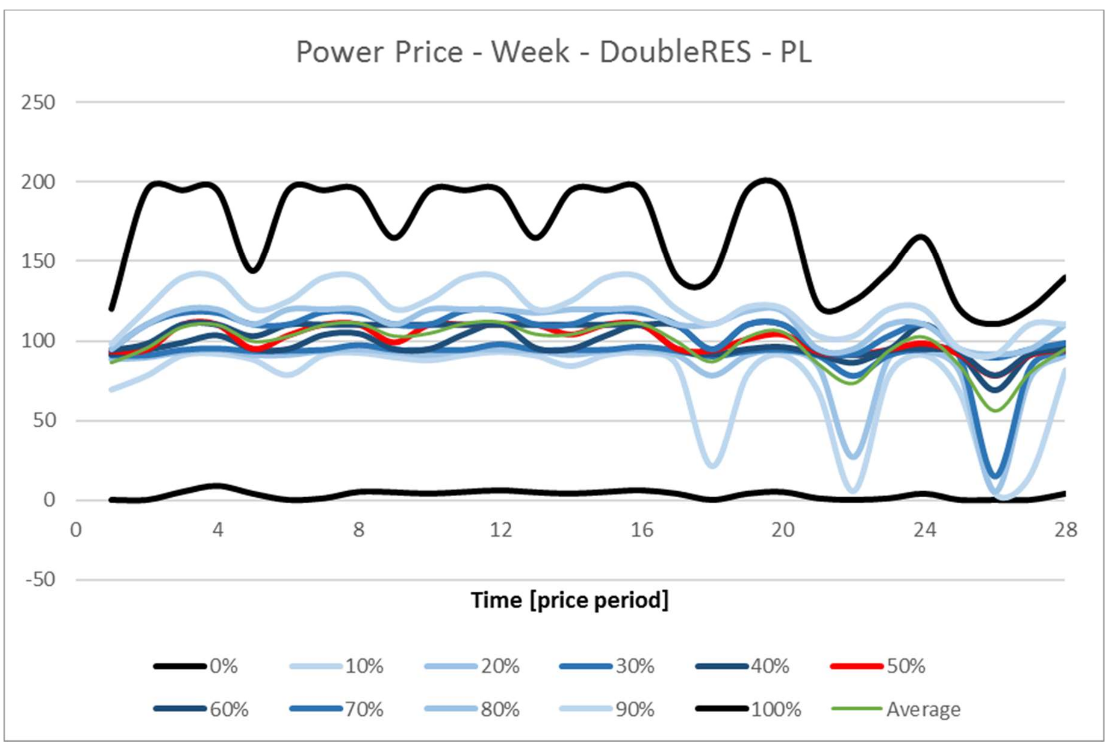

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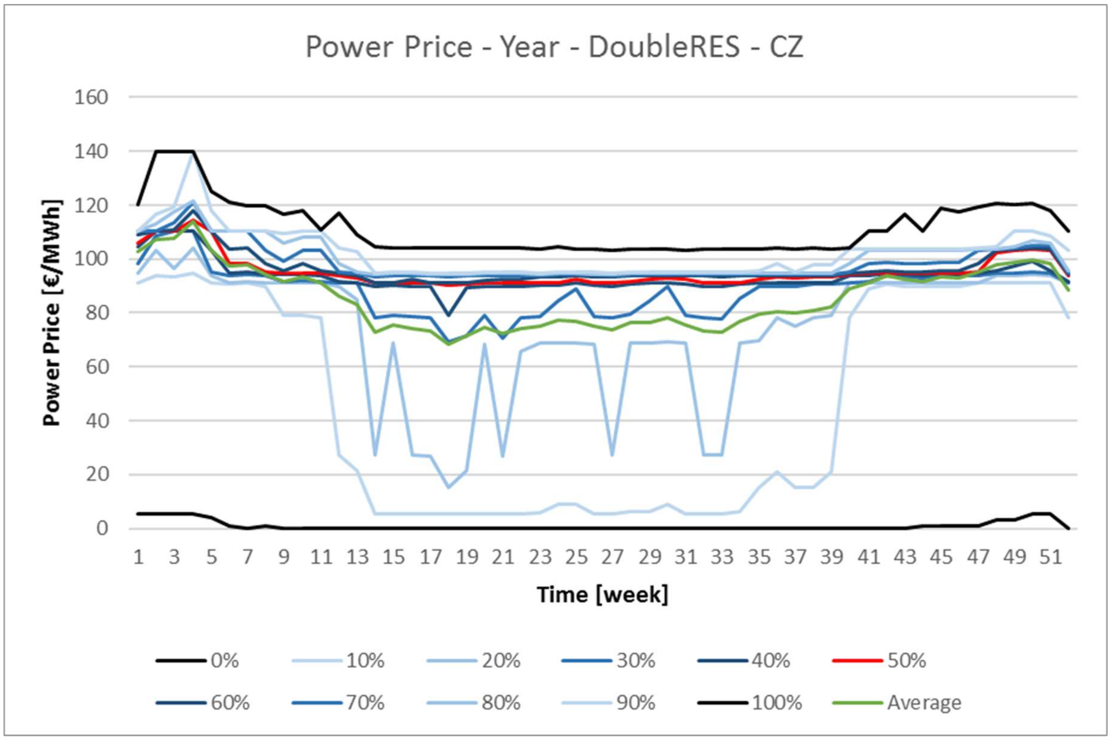

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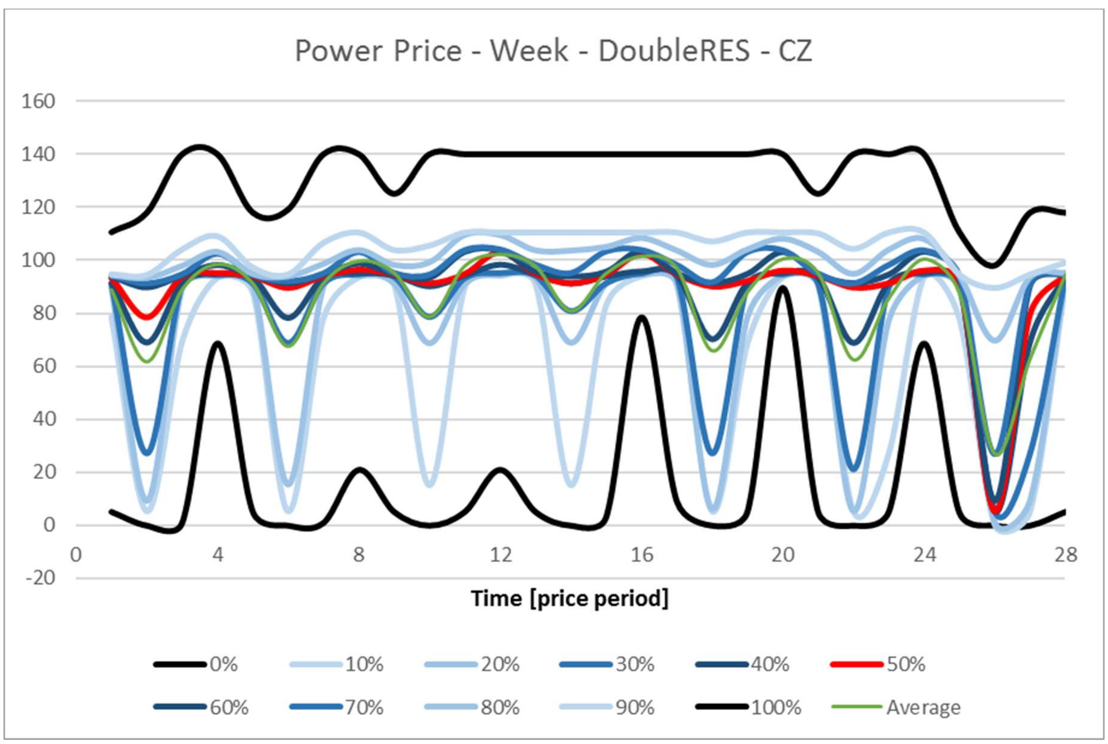

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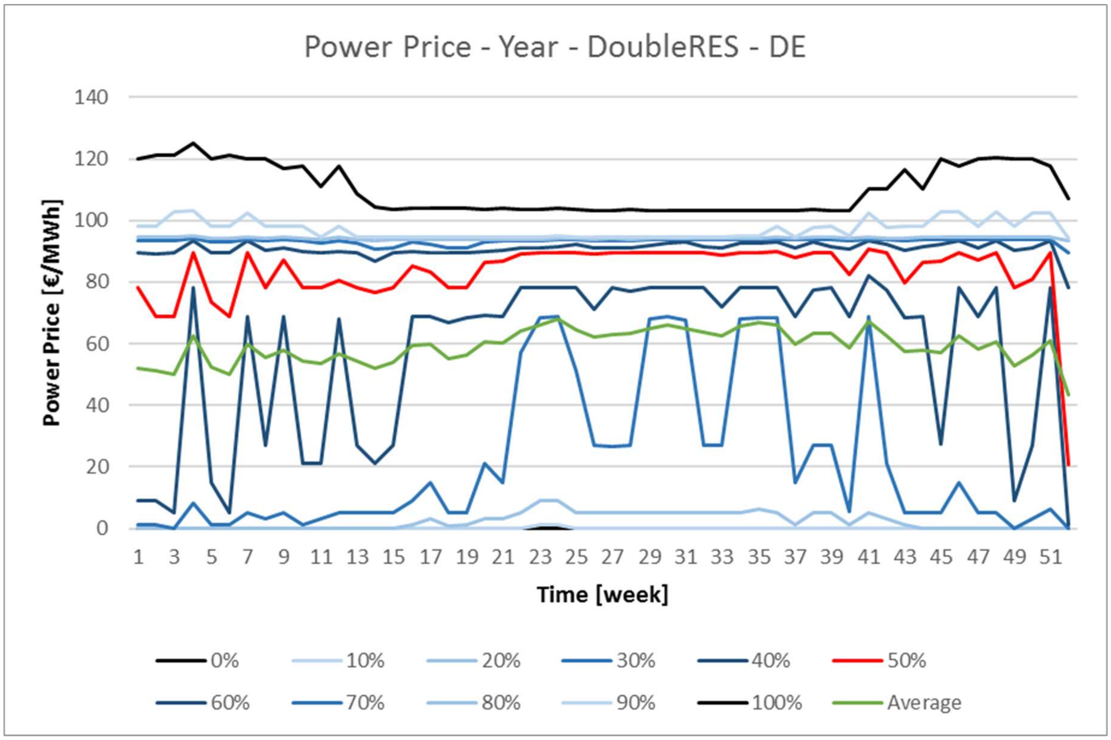

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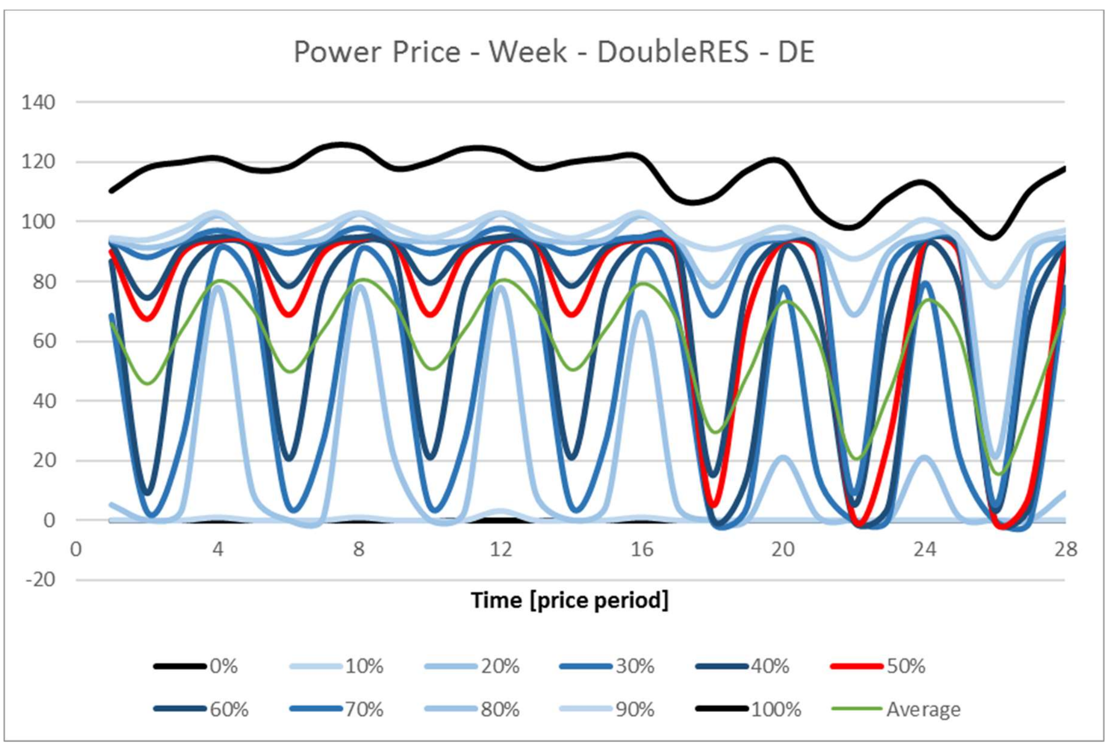

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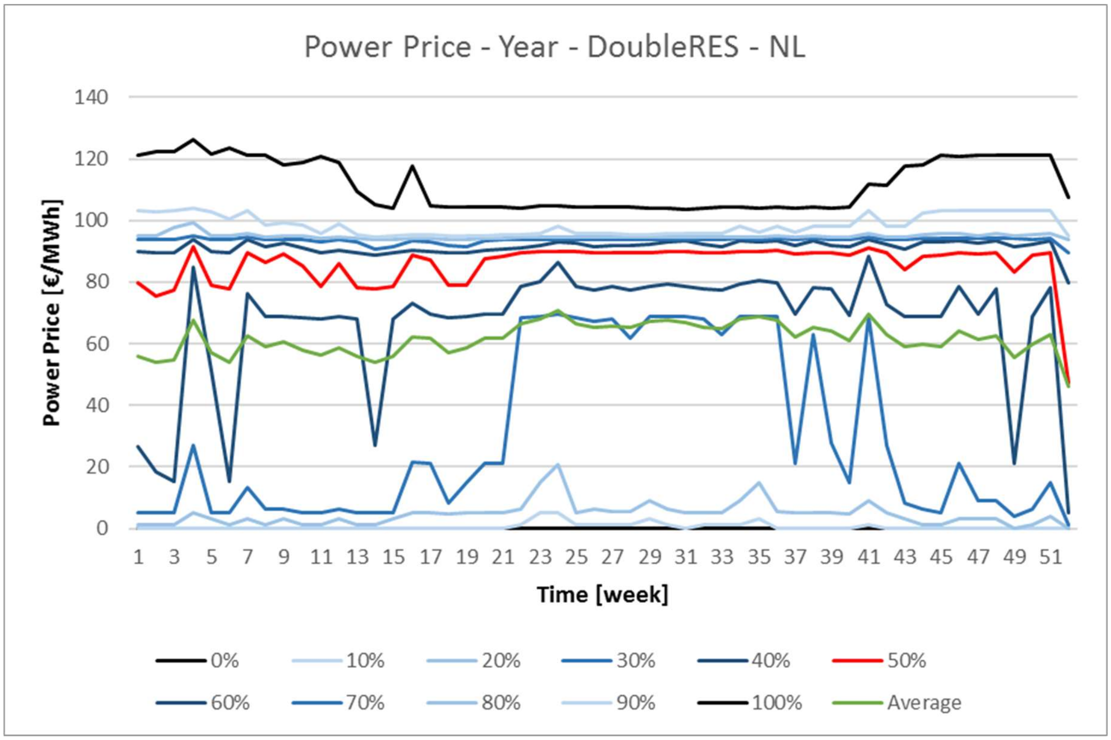

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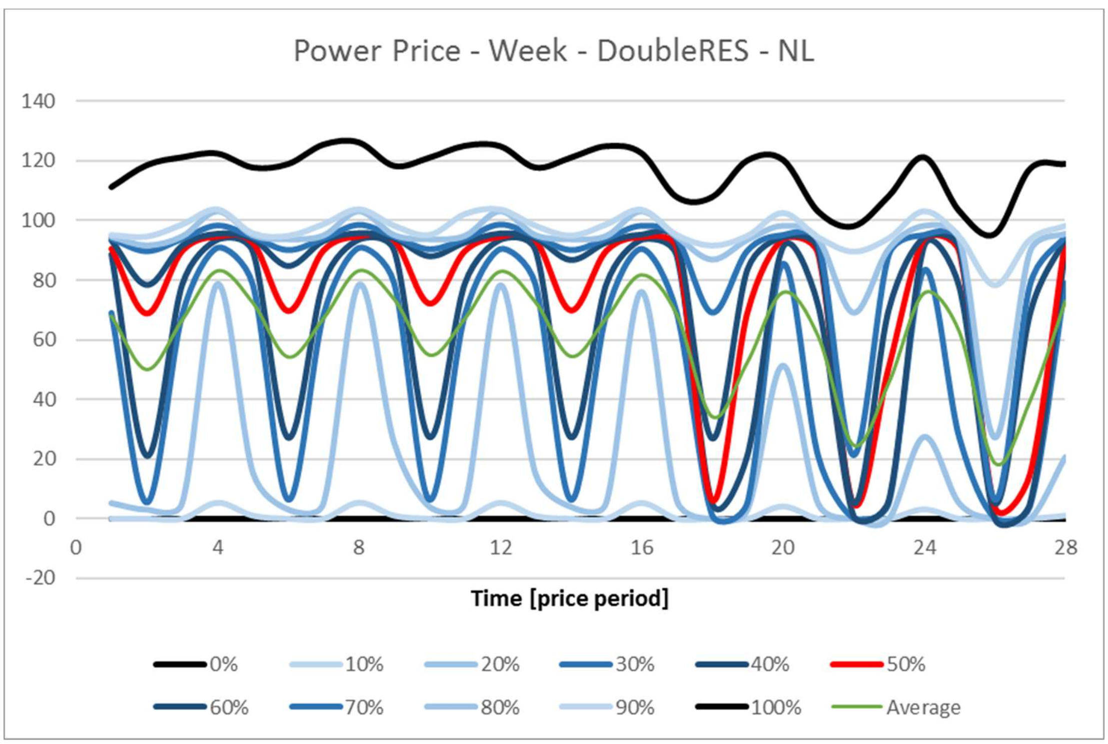

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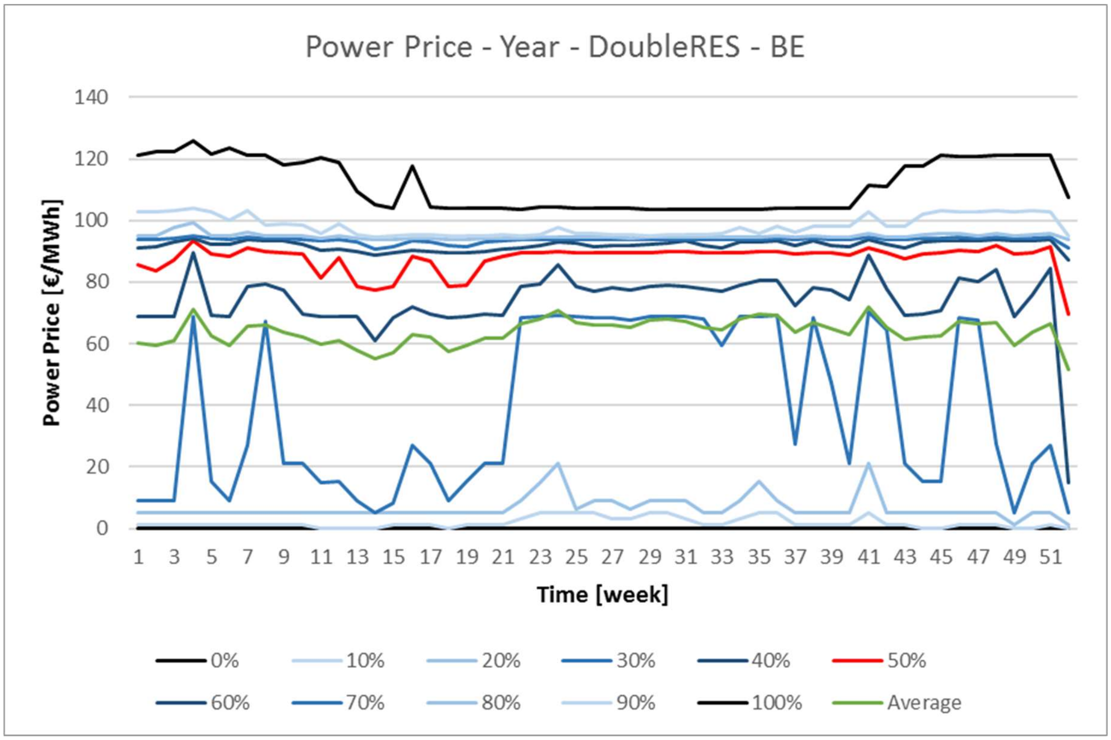

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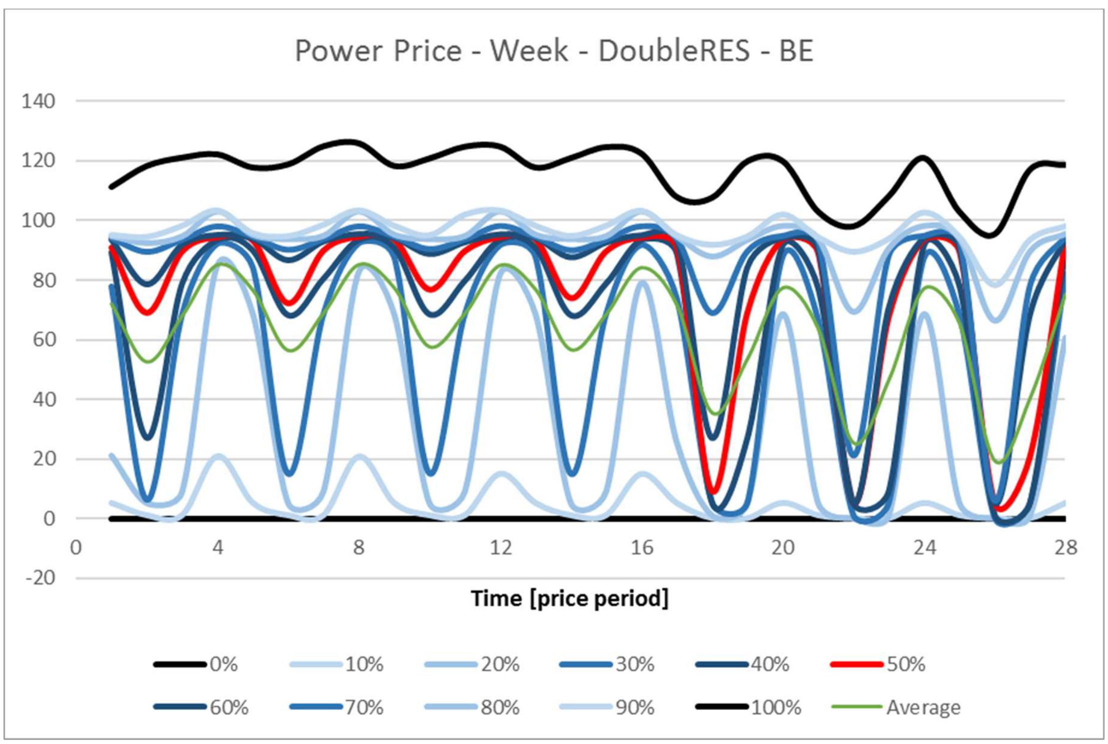

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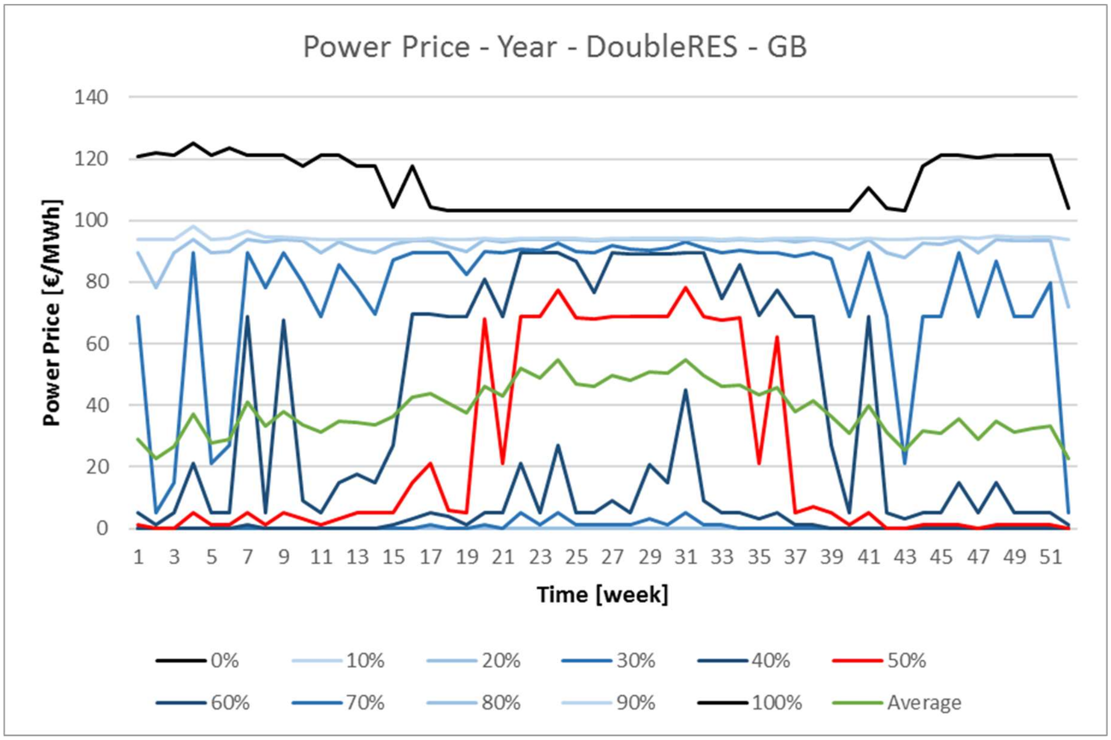

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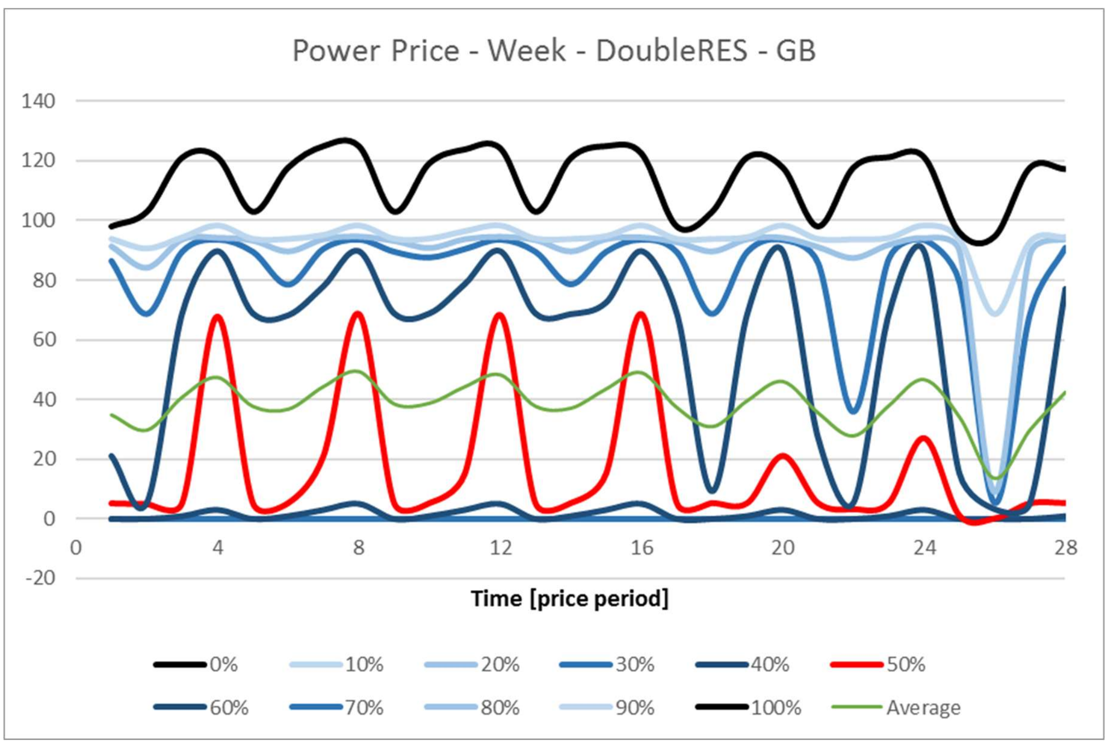

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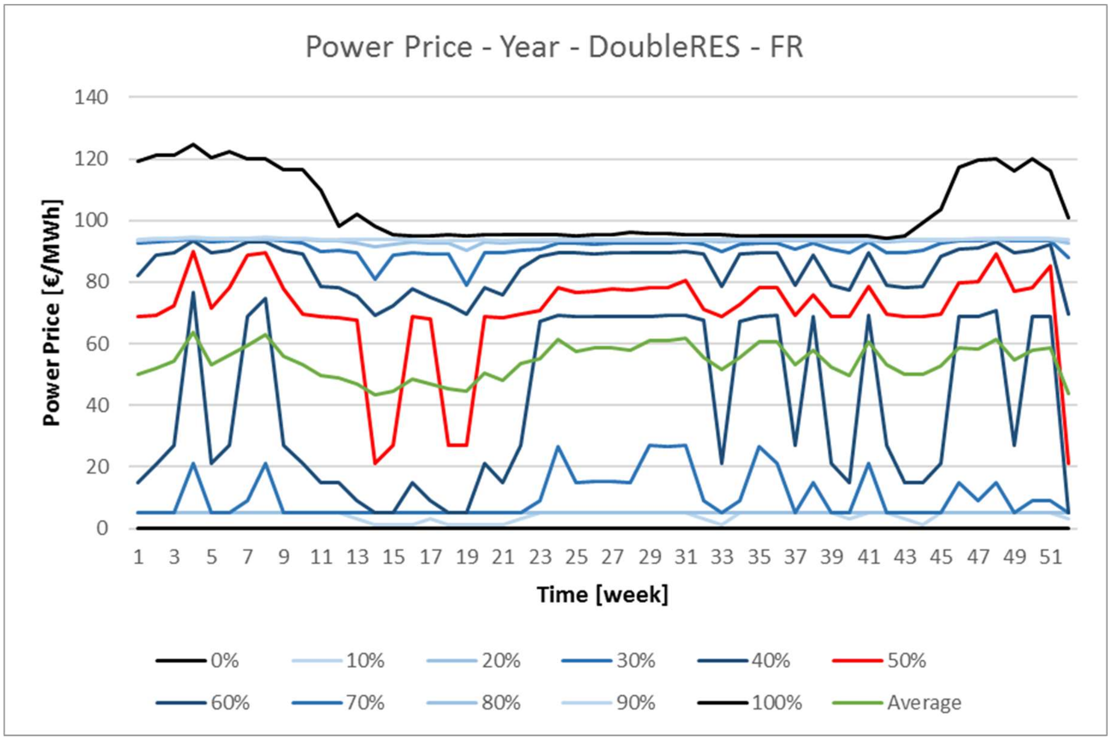

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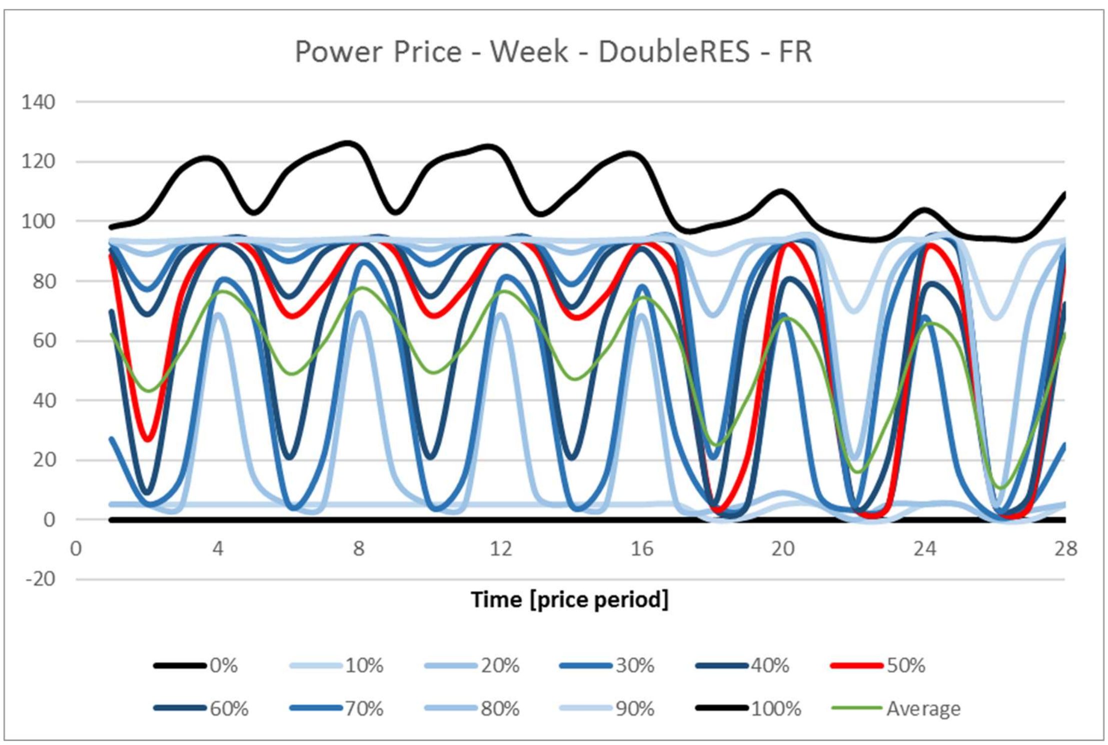

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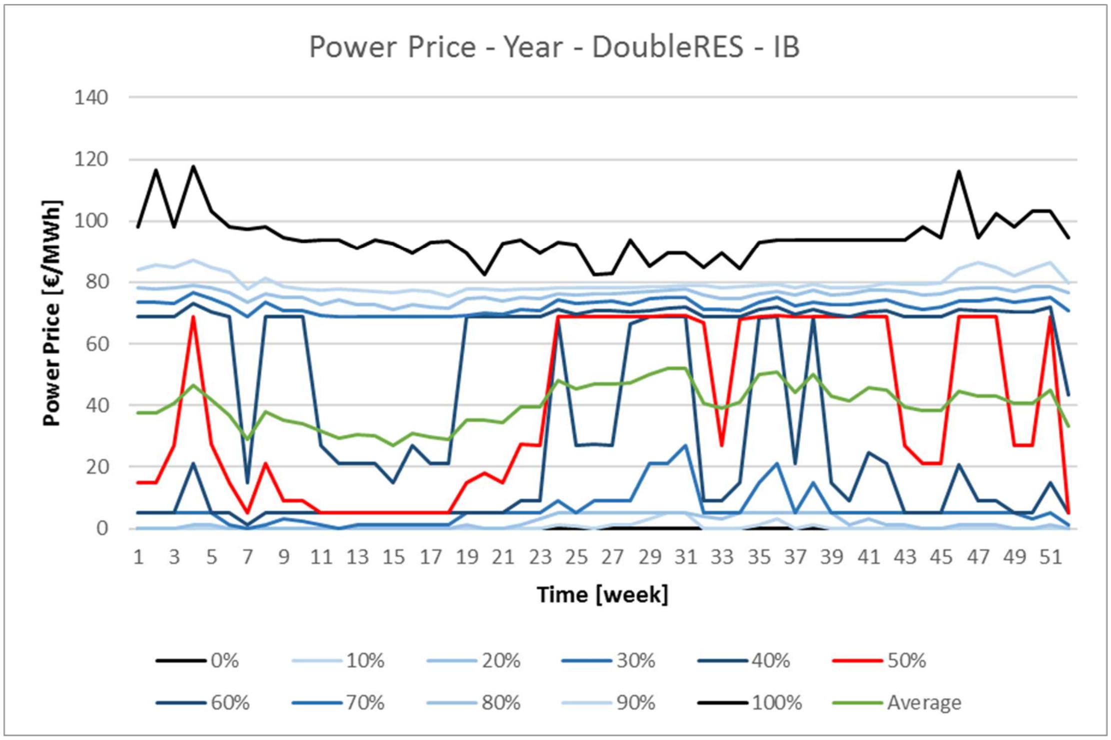

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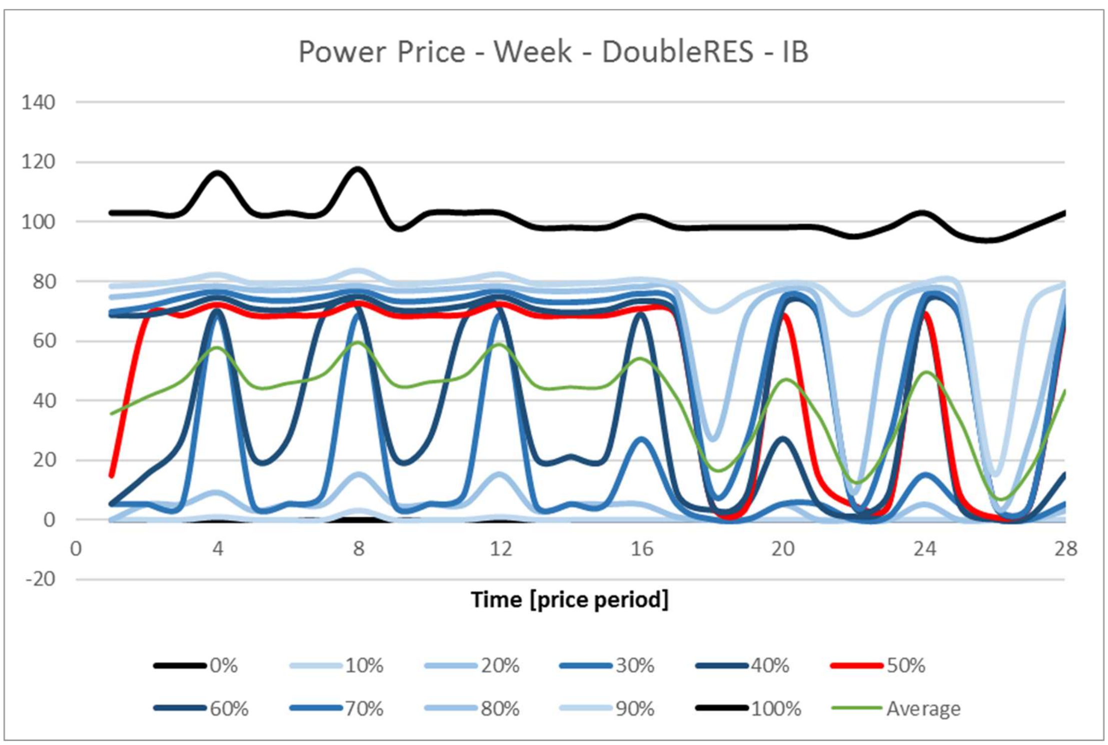

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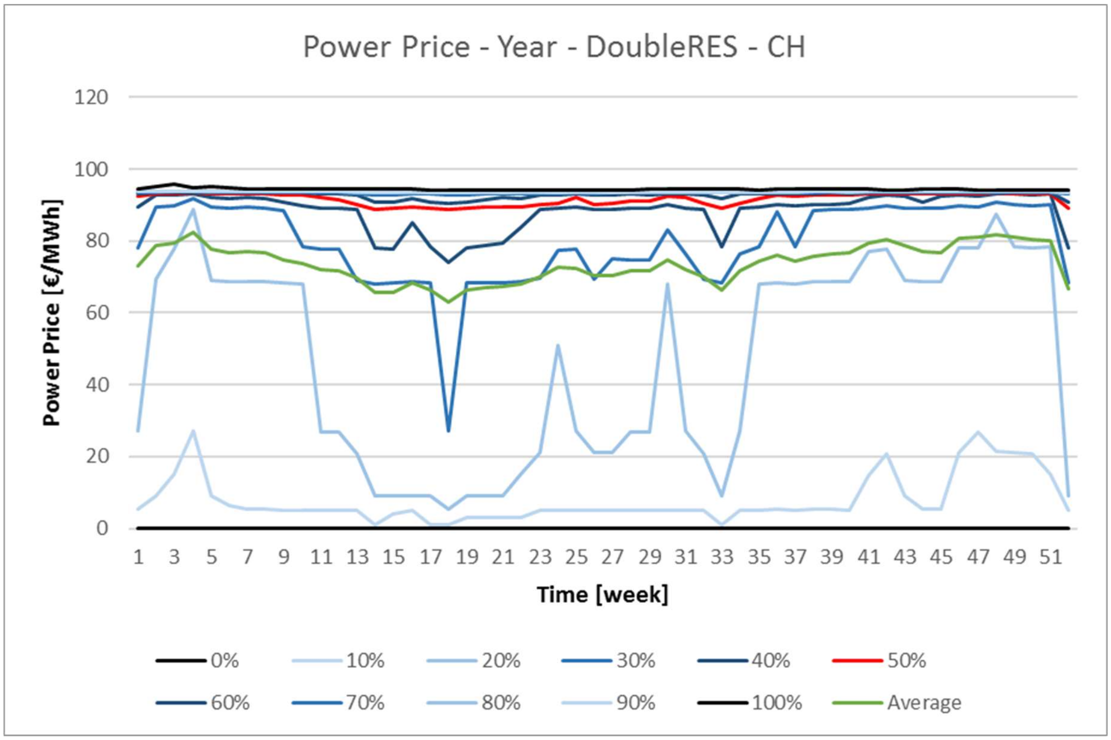

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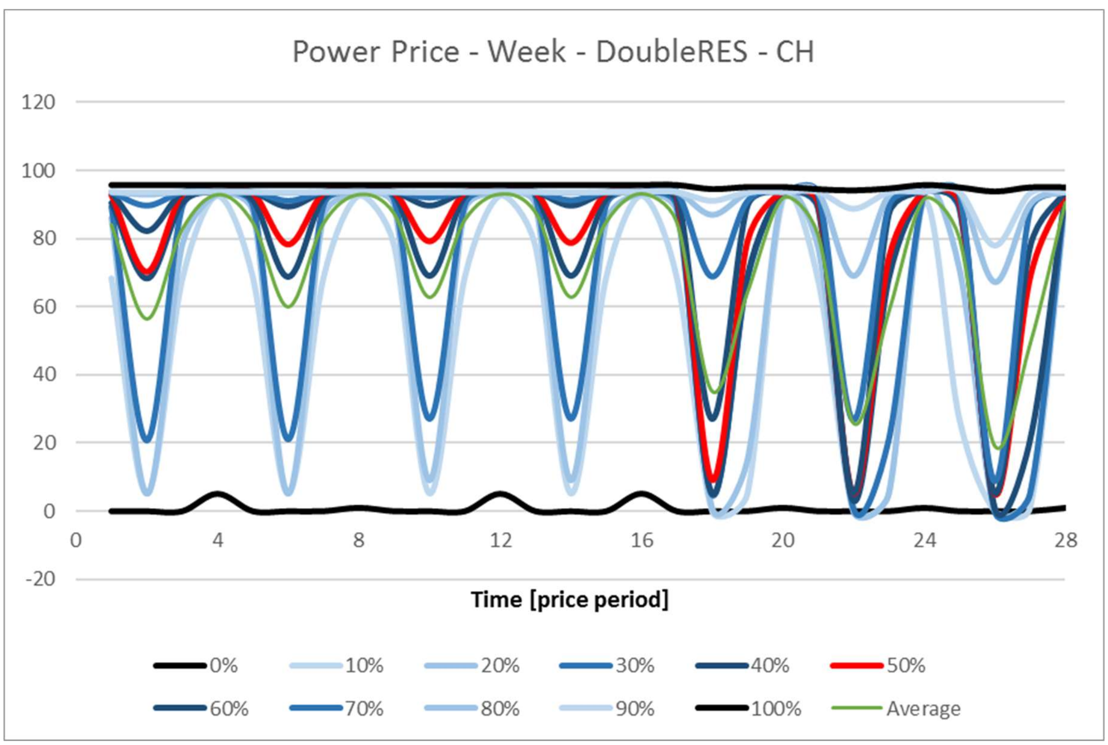

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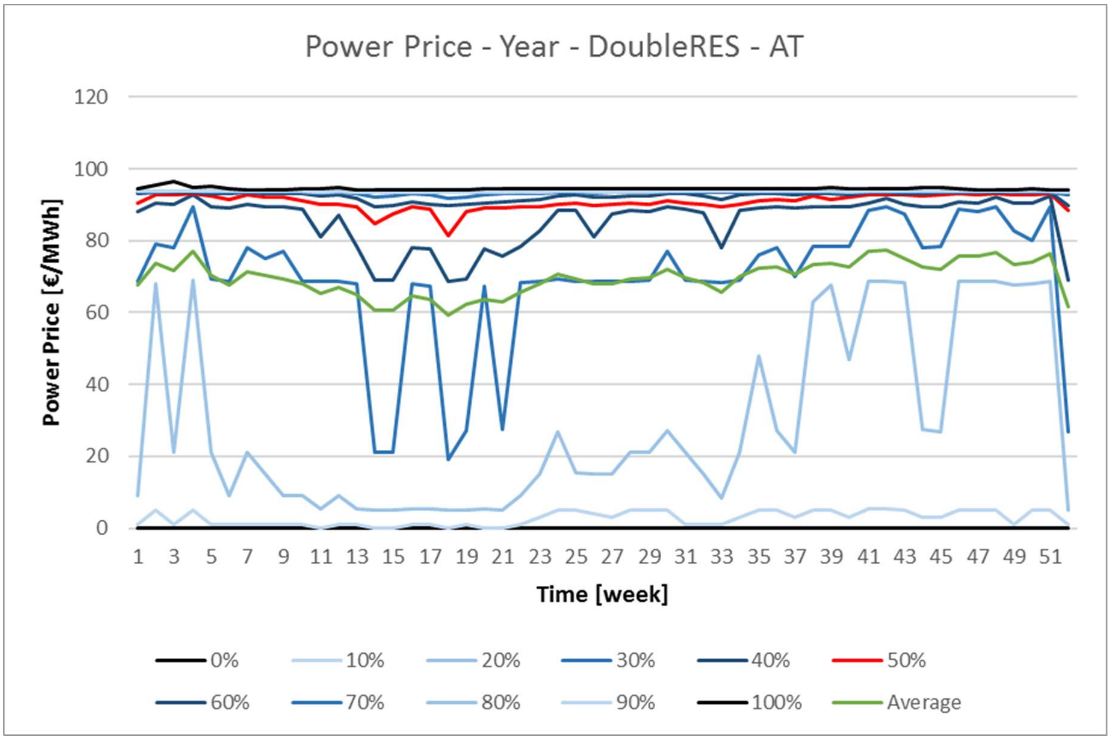
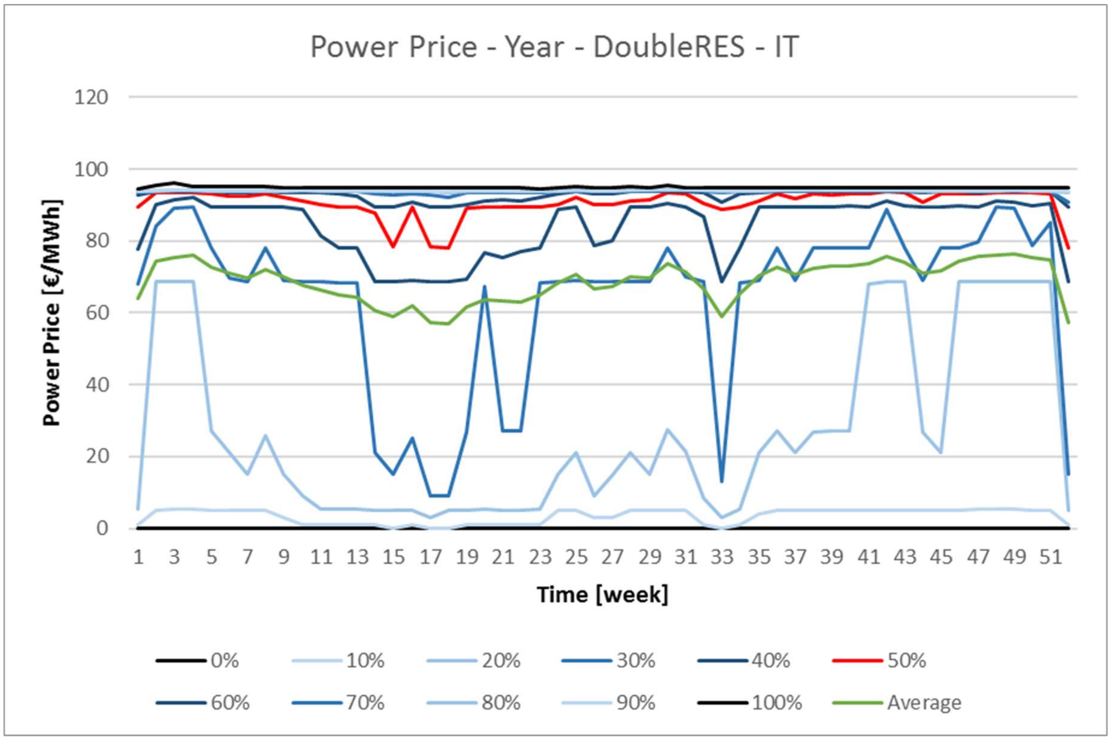


Figure 303

Figure 304



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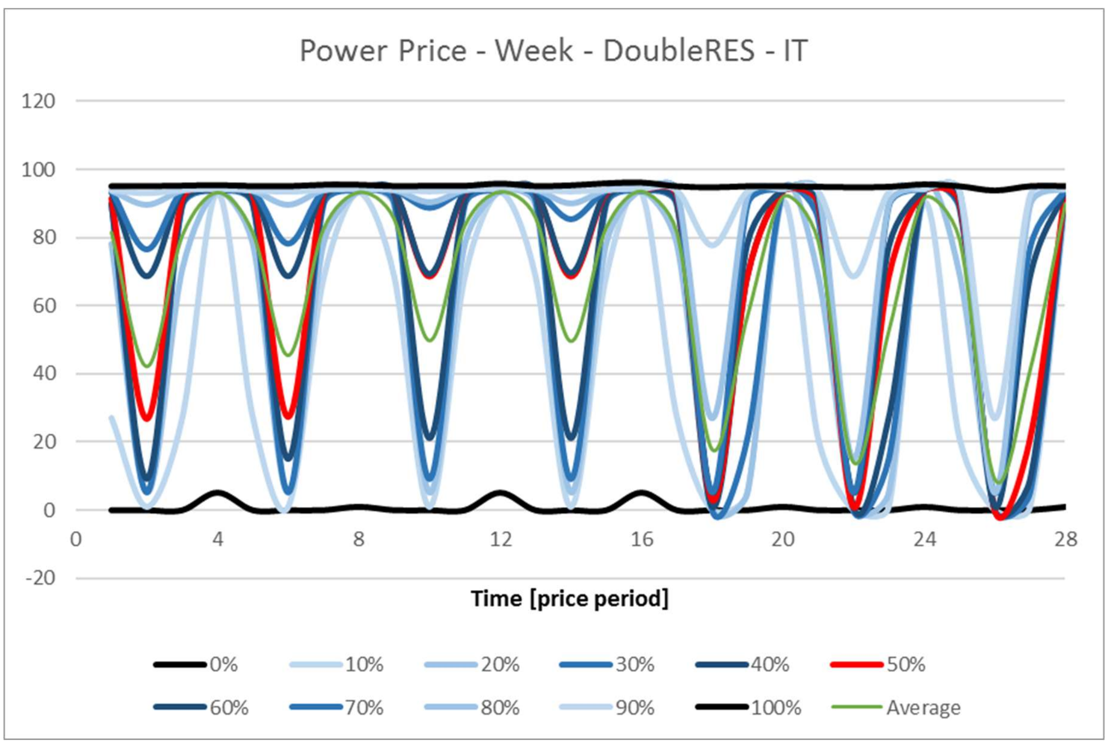

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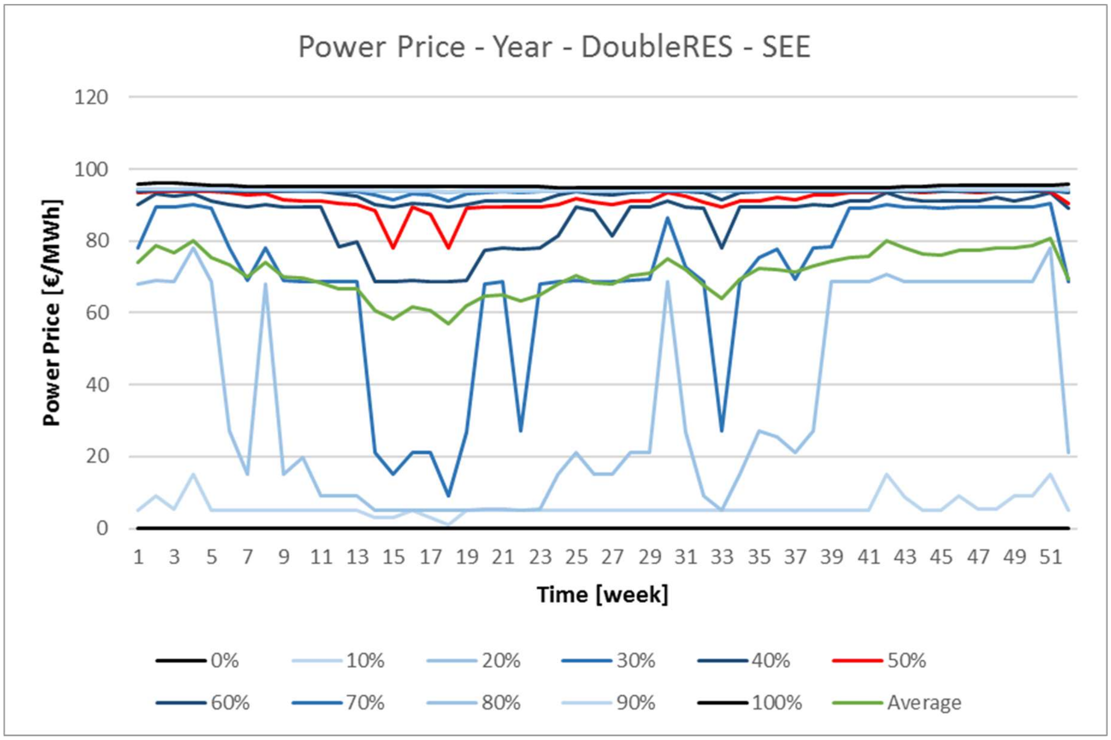

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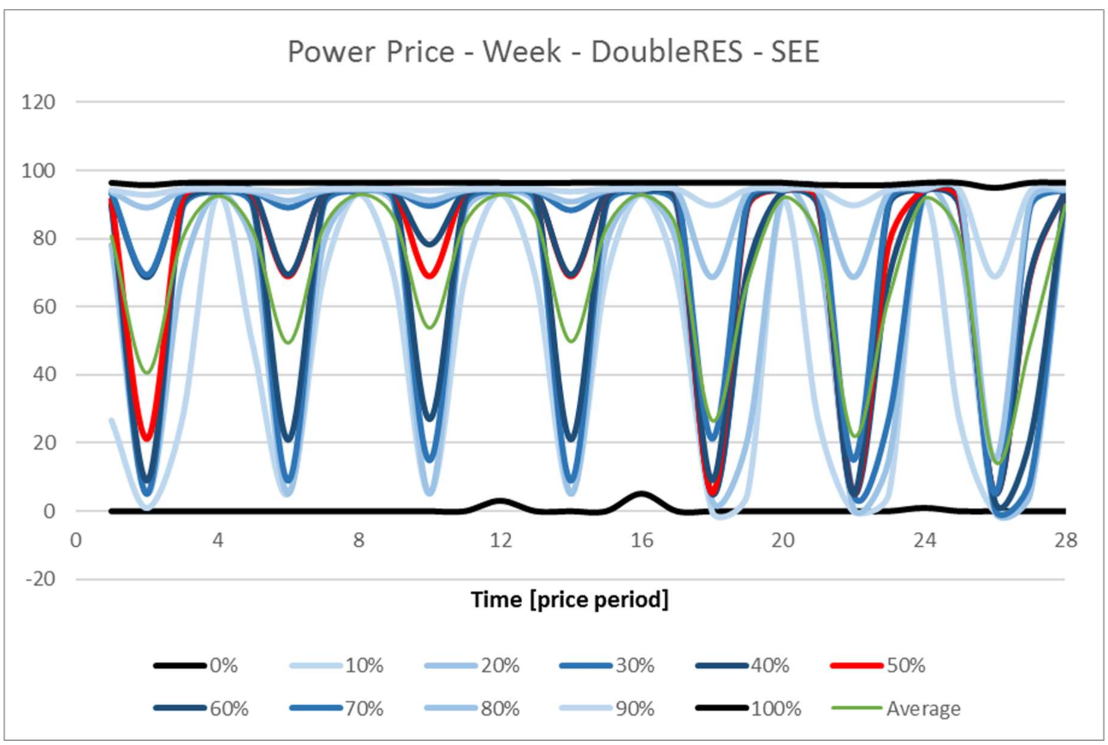
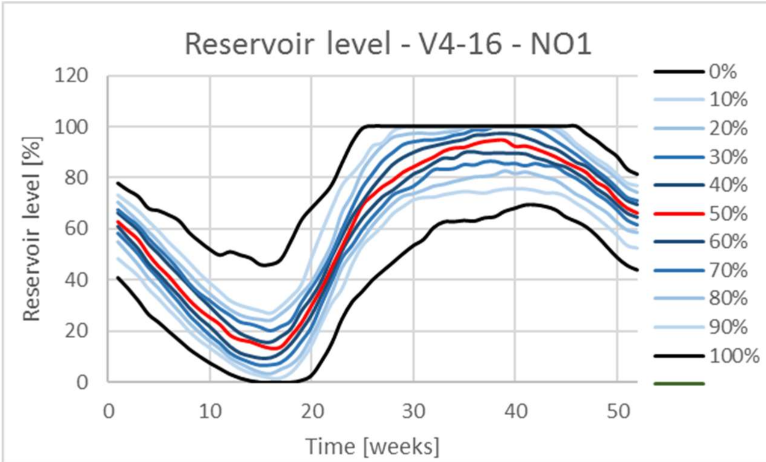


Figure 308

8.7.5 Reservoir level – V4-16



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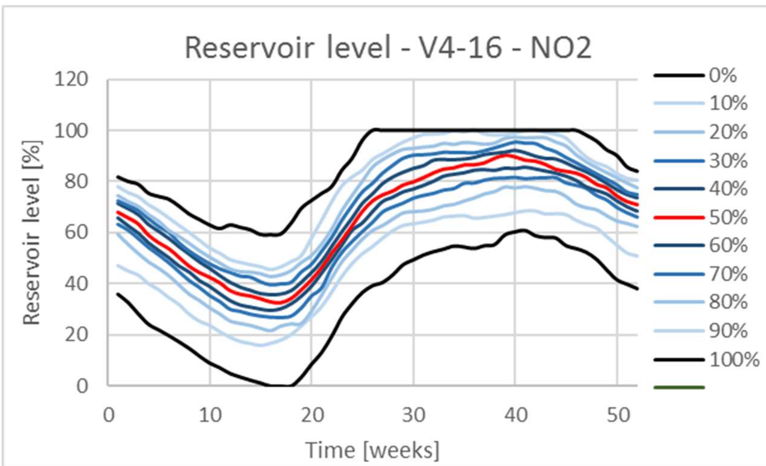

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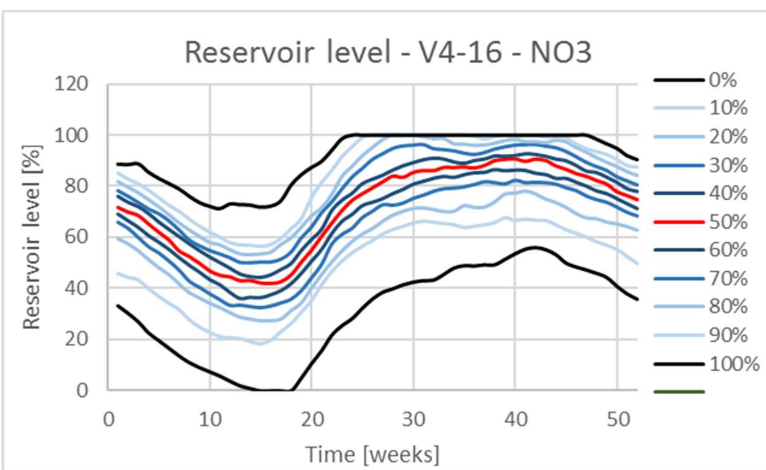

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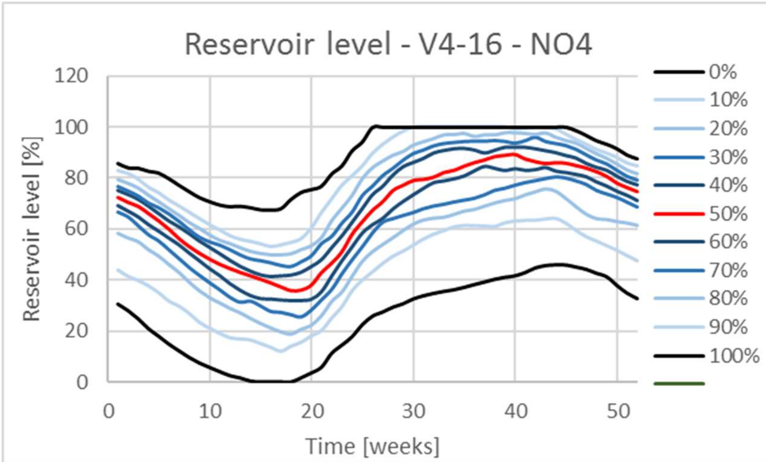

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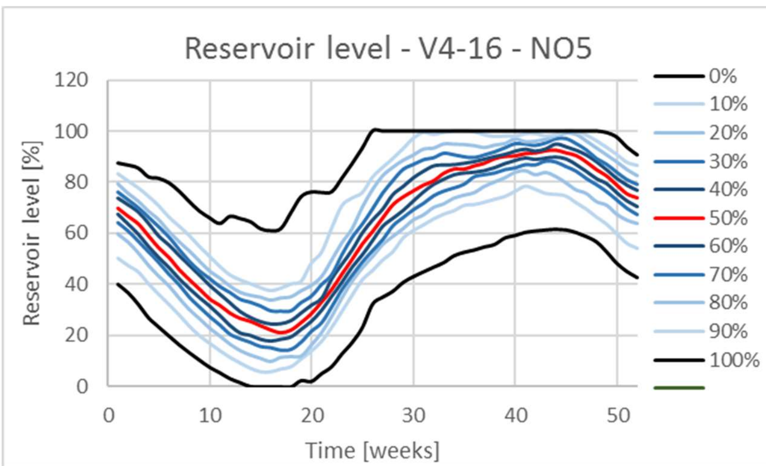

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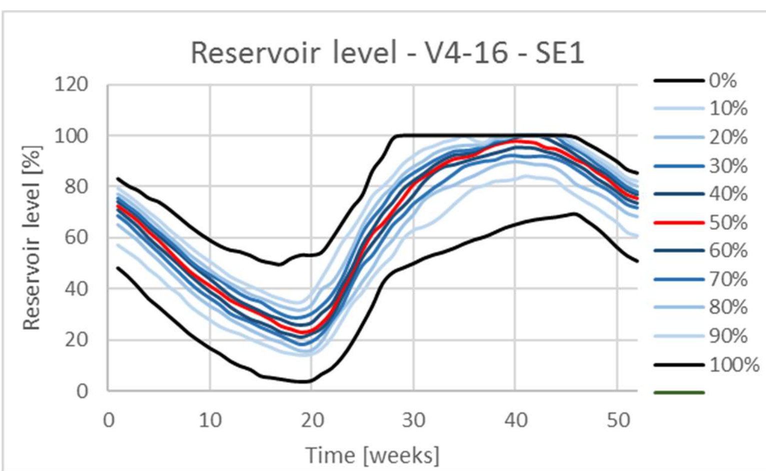

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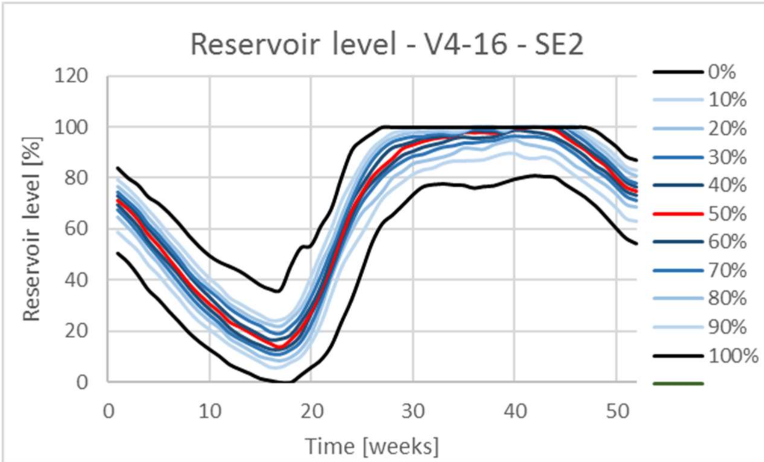

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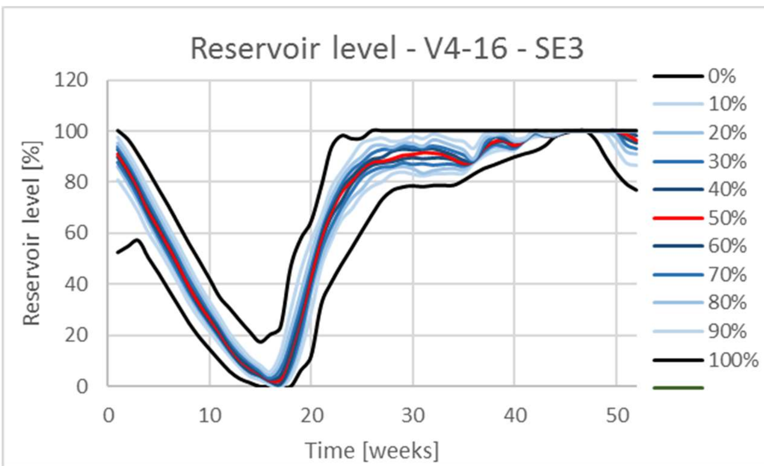

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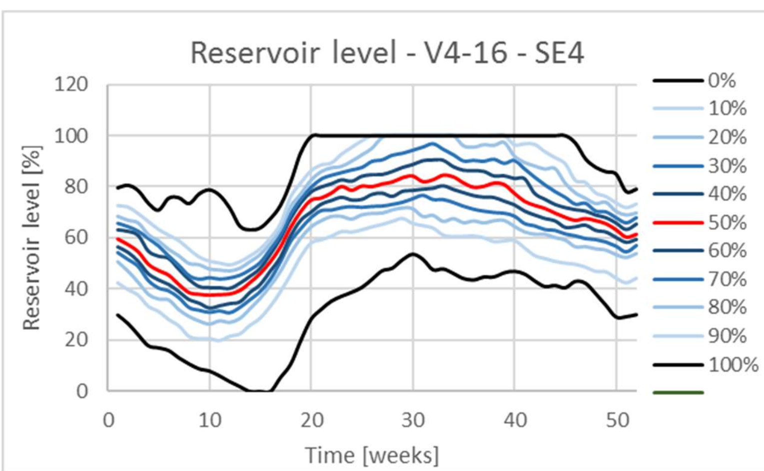

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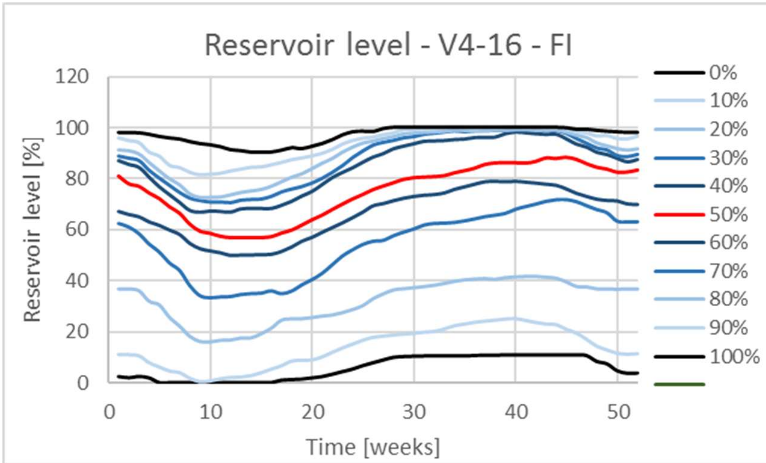

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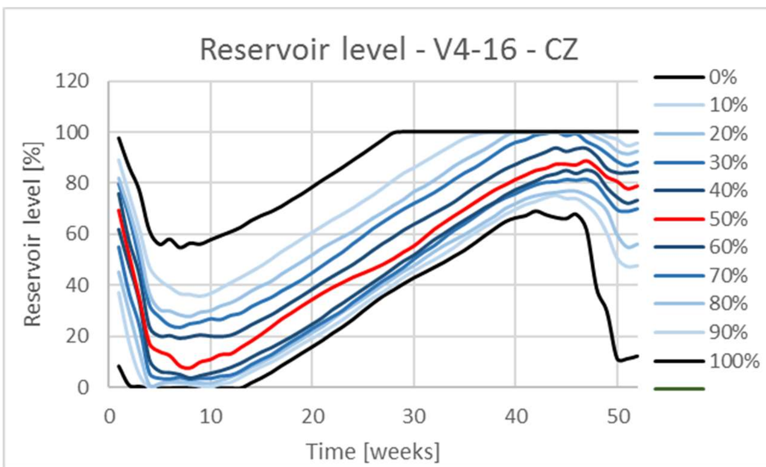

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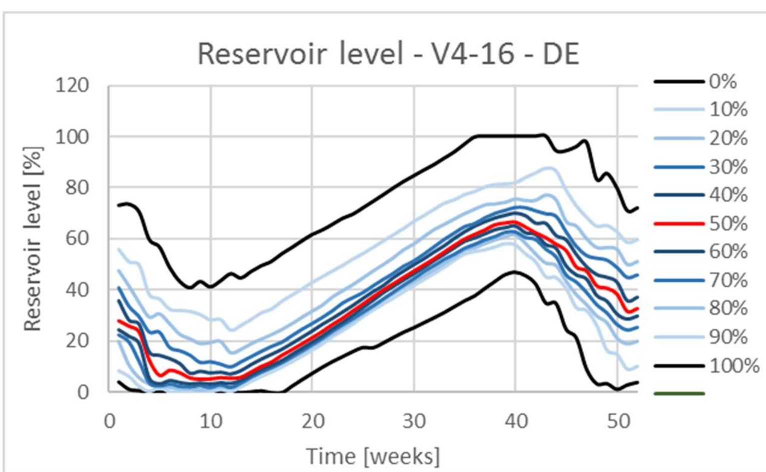

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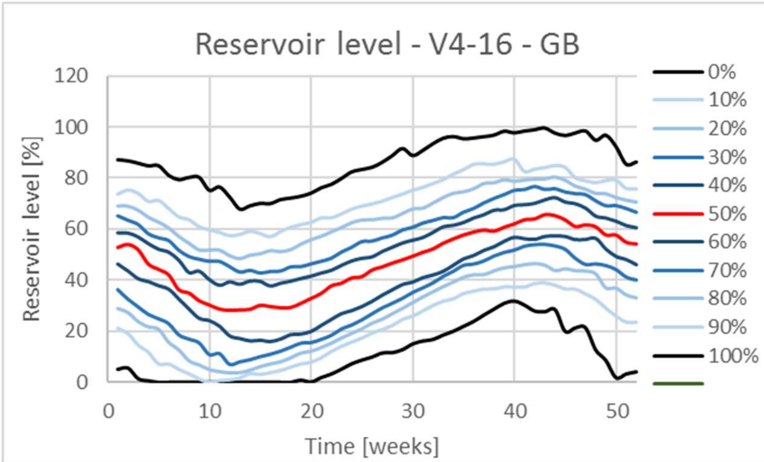

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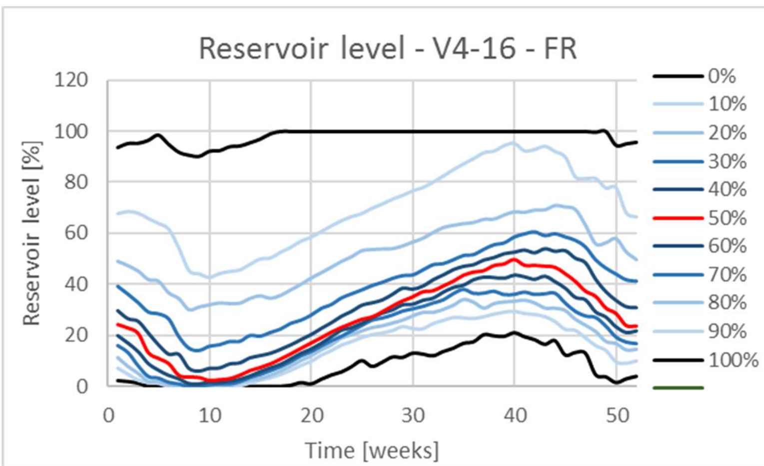

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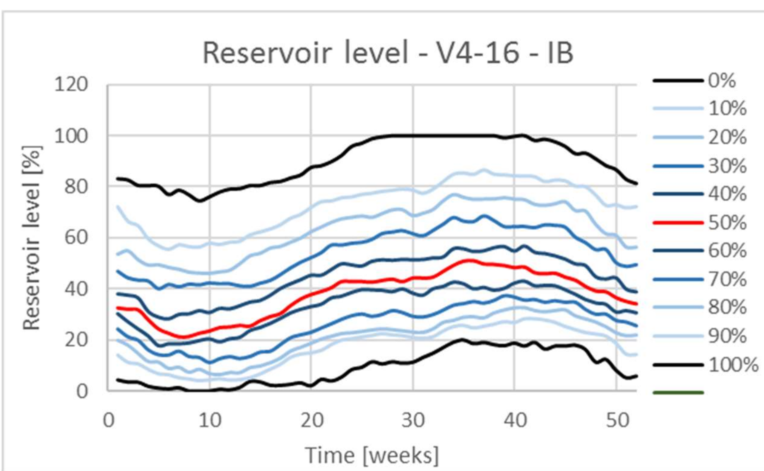

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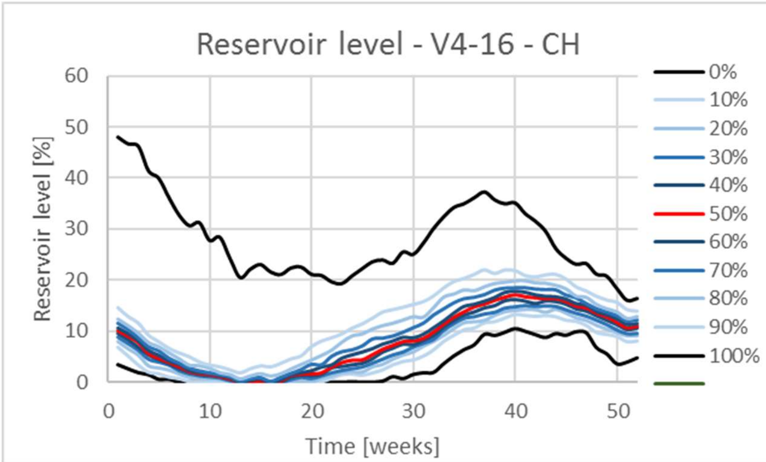

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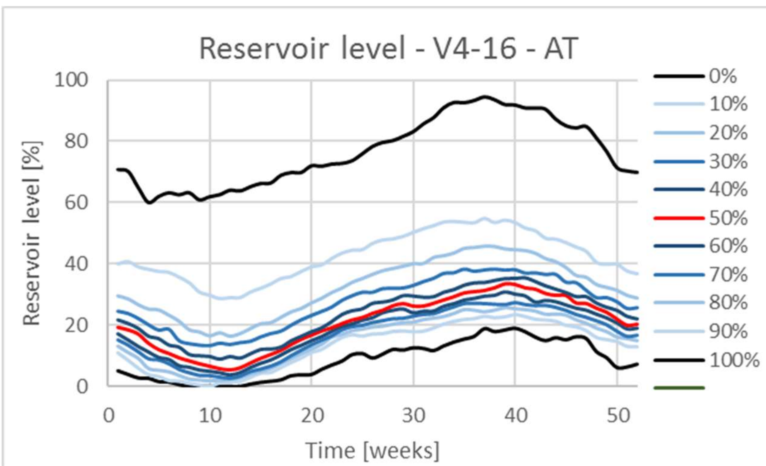

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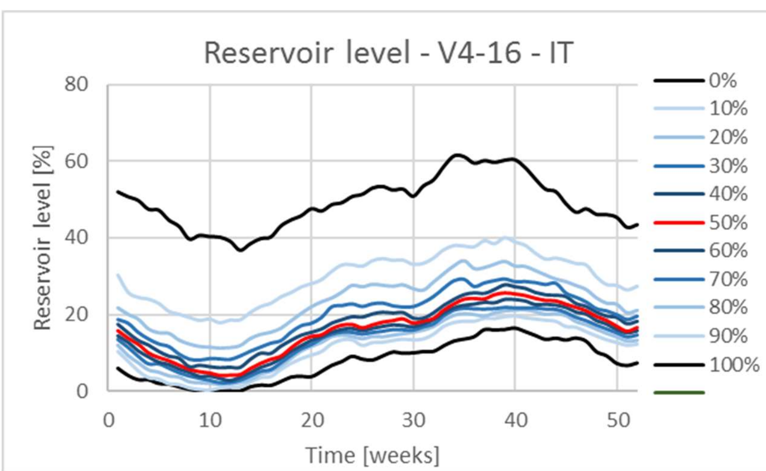

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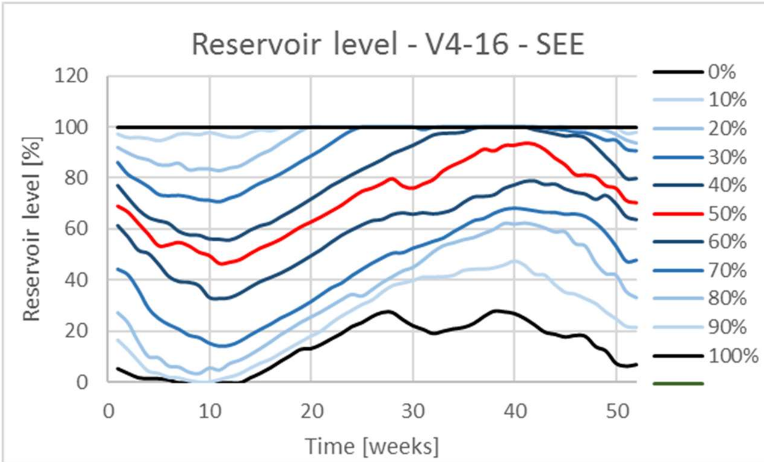
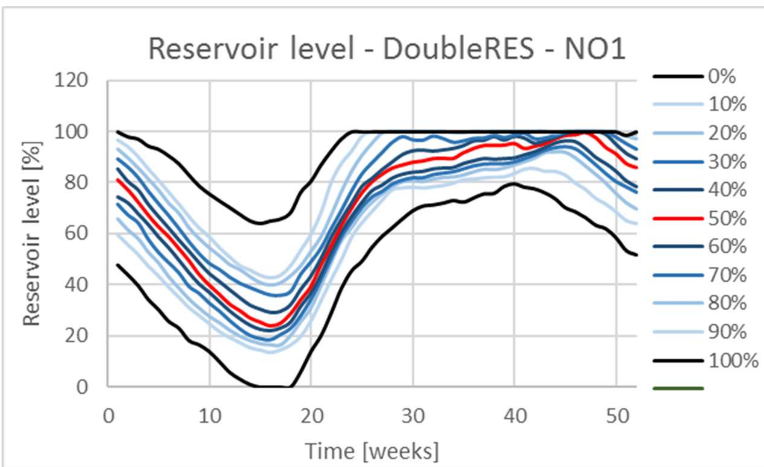


Figure 327

8.7.6 Reservoir level – DoubleRES



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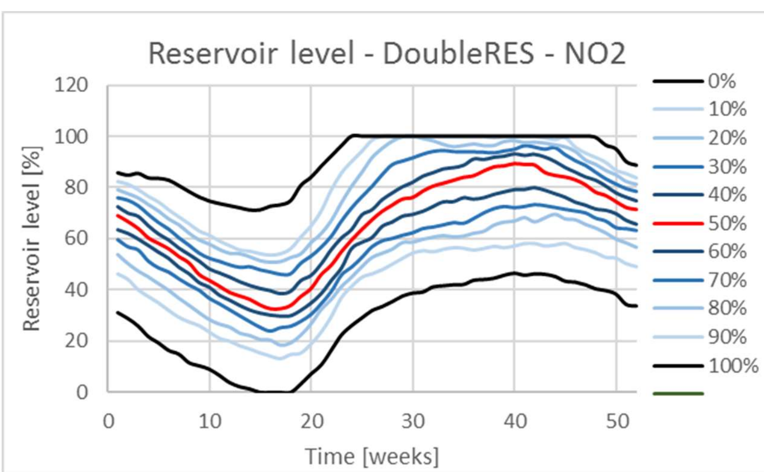

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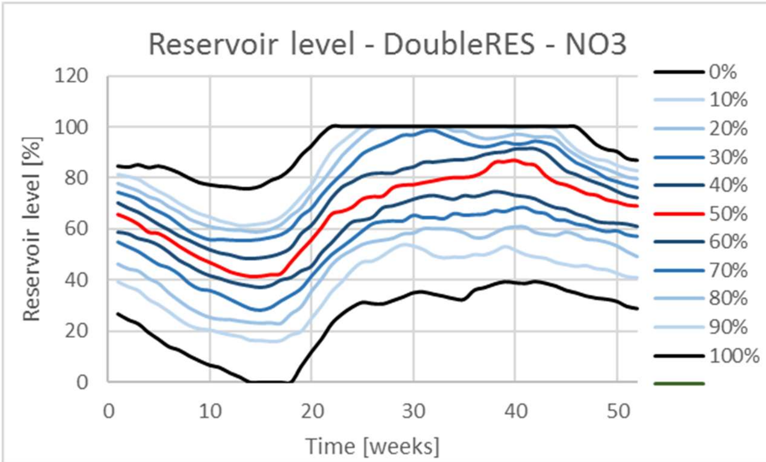

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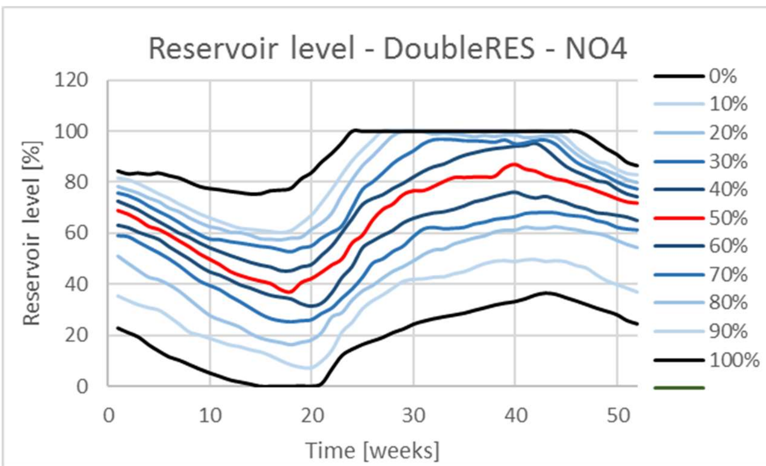

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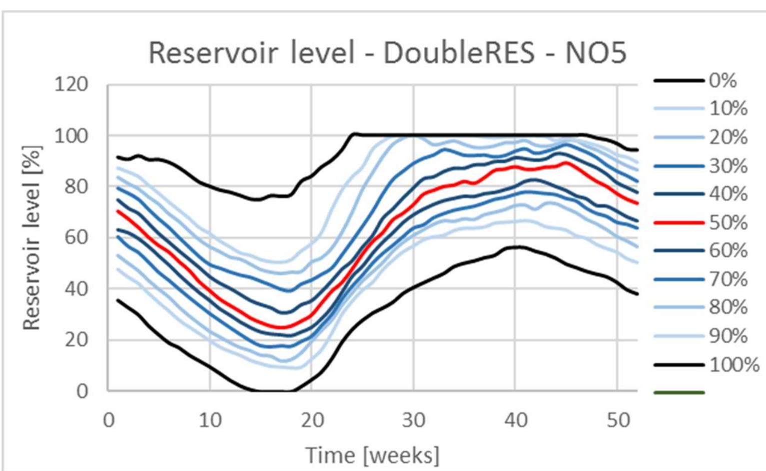


Figure 332

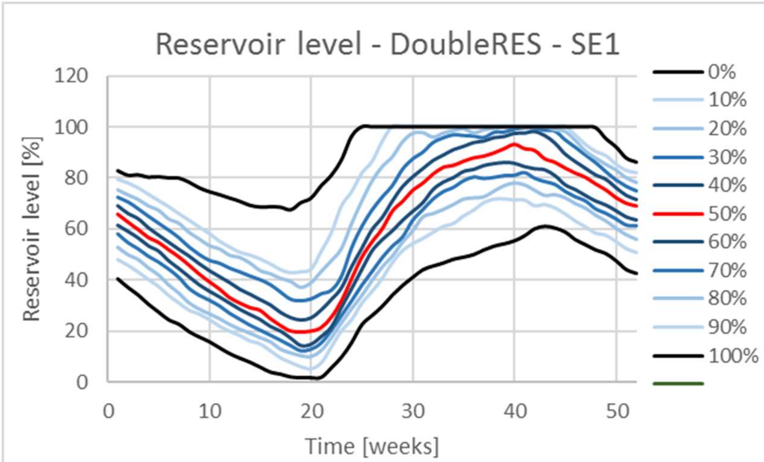


Figure 333

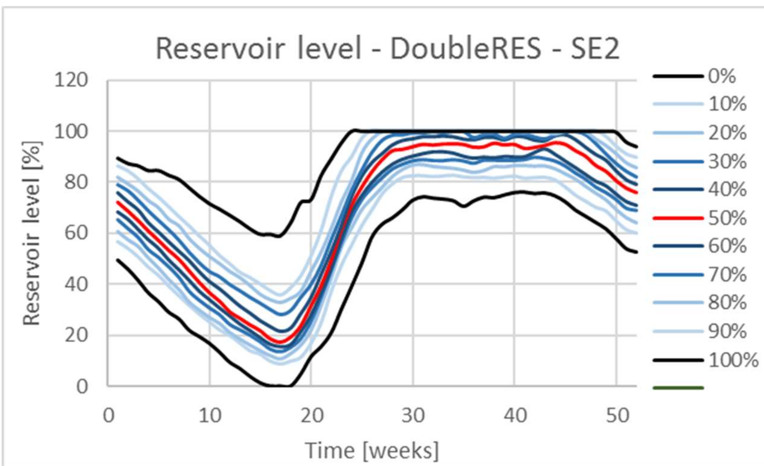
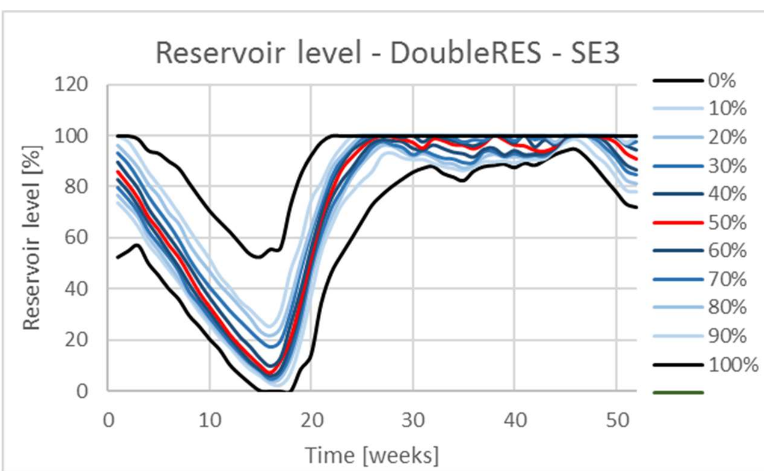


Figure 334



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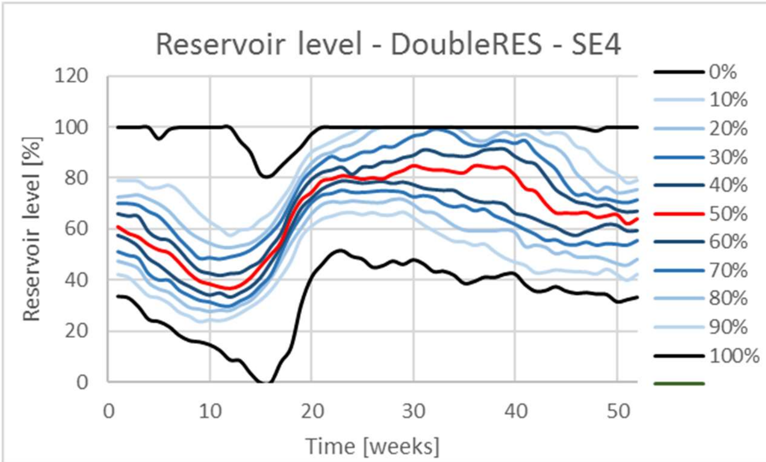

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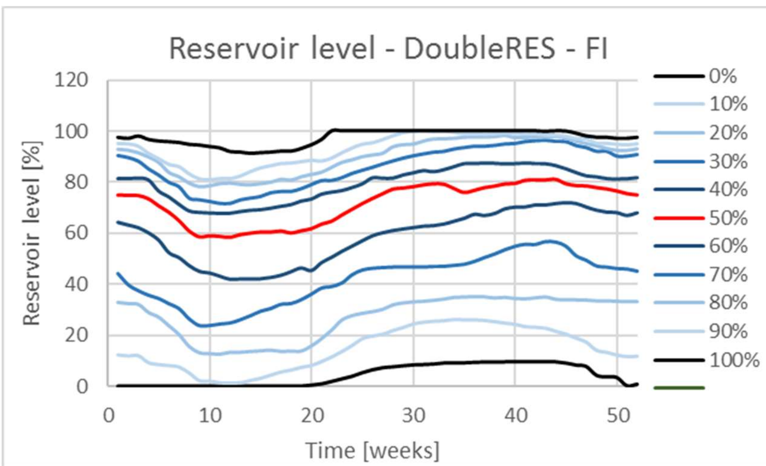

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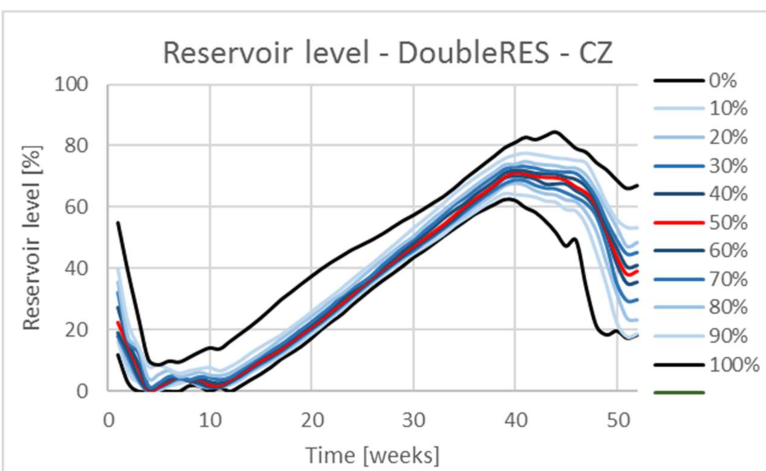

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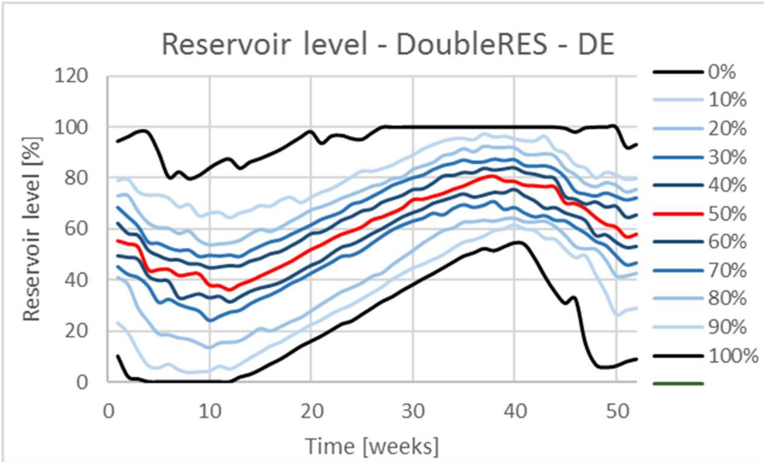

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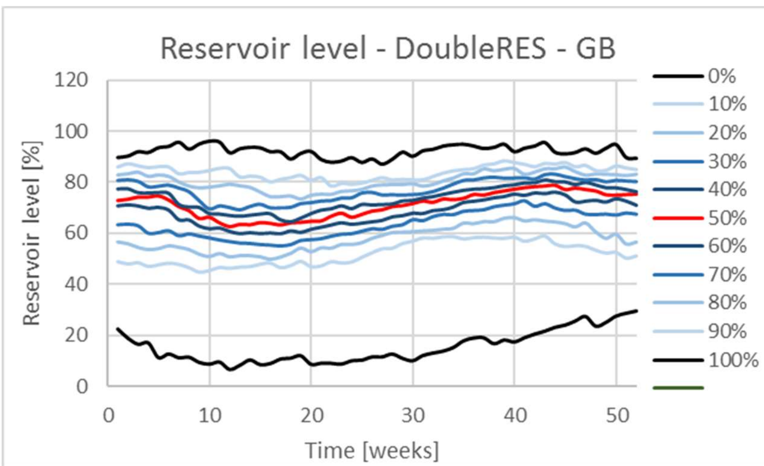

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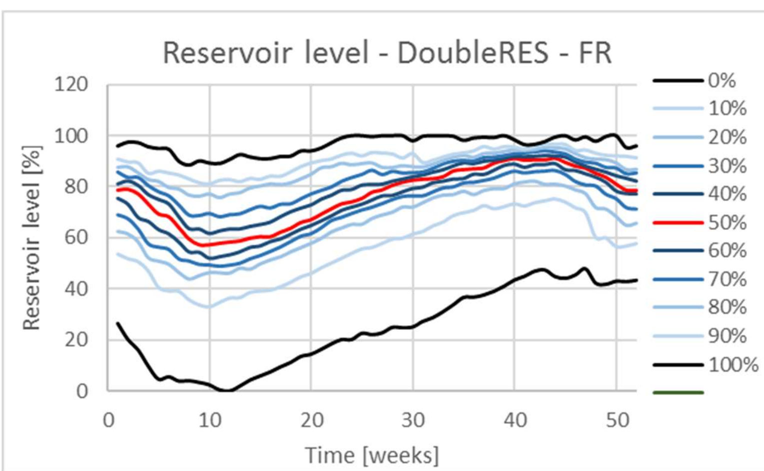

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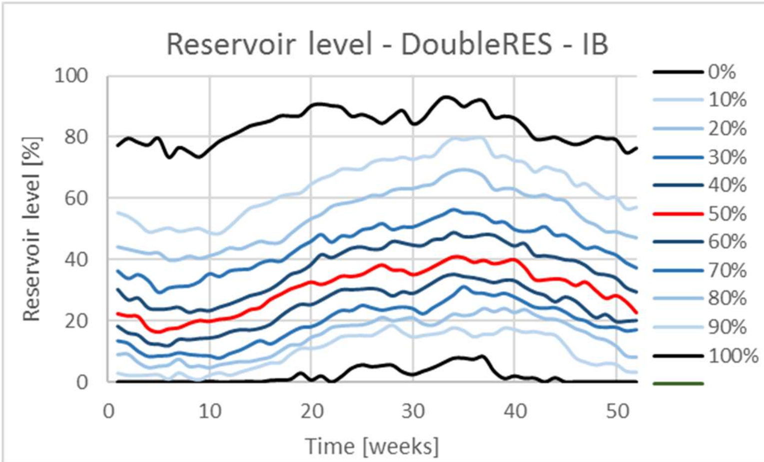

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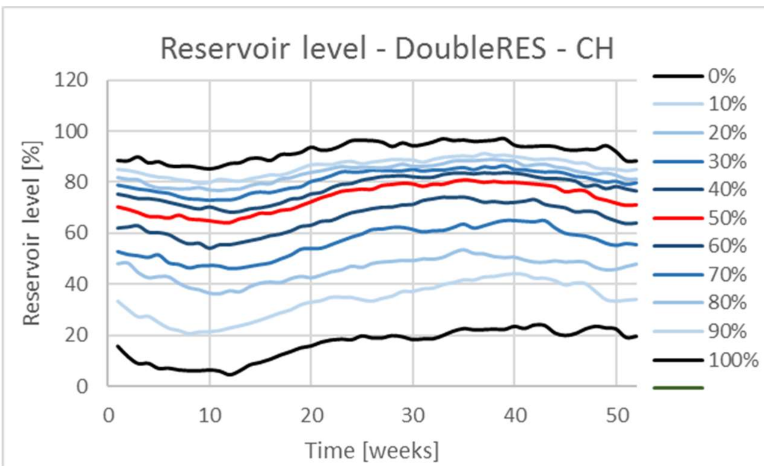

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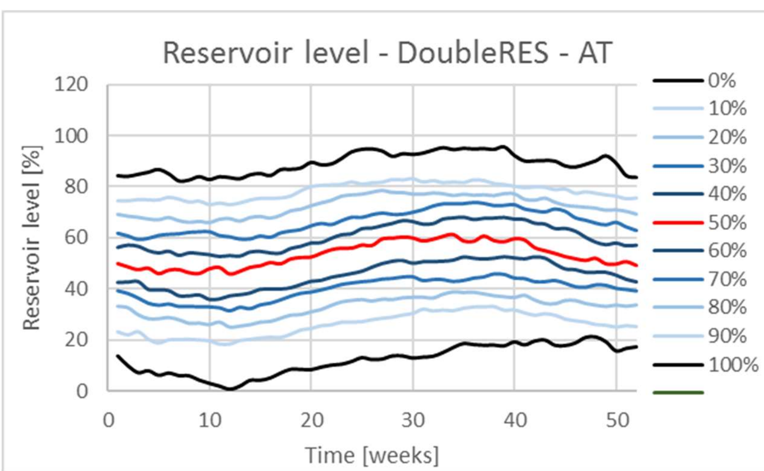

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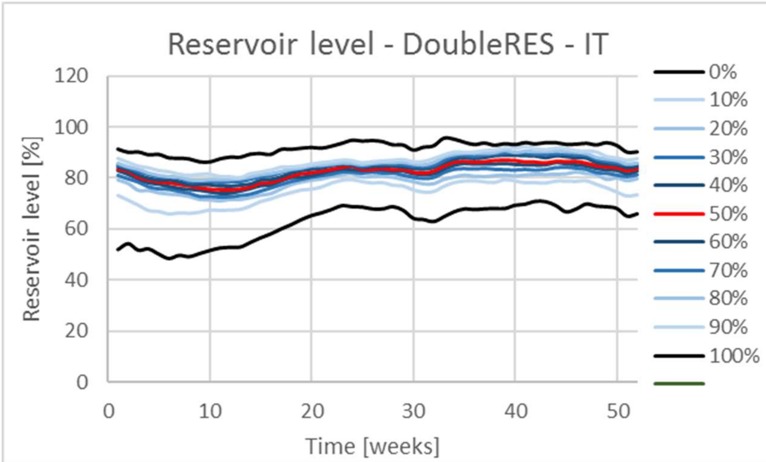

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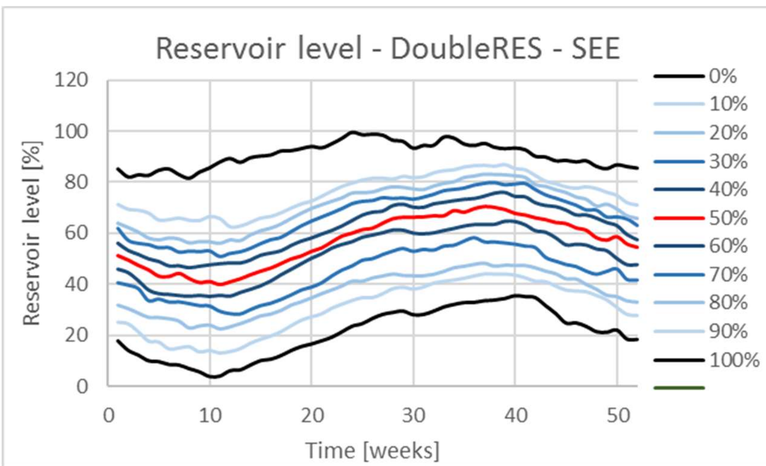

Figure 346