Effects of Pumped Storage Hydro on Power Systems with Large Amount of Wind Power: A European Perspective

Master's Thesis within the Master's programme in Sustainable Energy Systems

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Abstract

The increasing capacity of power production that comes from renewable energy into the system has increased the need for a regulating, environmentally friendly production unit that is flexible enough in order to store energy and provide it into the system in case of sudden demand increase or contingency. These features fully characterize pumped-storage hydro technology, which can be a perfect complement to intermittent generation.

In this thesis a model was developed in order to emulate the European power system and check the impact of pumped-storage hydro (PSH) in different aspects of it. The effects of PSH on total system costs, interconnection between countries congestion as well as on the CO_2 emission mitigation were investigated in order for Europe to comply with the stringent environmental target that all countries have committed to follow.

The results show that PSH can have a significant positive impact on emission and system cost reduction, but it is difficult to comment on how the system will react on congestion before further study is conducted. For instance, a CO_2 reduction of up to 34.8% was observed when more PSH was introduced into the system, whereas a cost reduction between 7-8% was calculated. On the other hand, no evidence for relaxation of the load of the interconnections between countries was identified, since the loading of the lines remained within the same levels in most cases.

Index Terms: Pumped-Storage Hydro (PSH), wind power, European power system, GAMS, system cost optimization, hydro-wind coordination, hydro power scheduling

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I also thank everyone from the Energy Technology department who contributed to this thesis. Lisa Göransson for providing me with her thoughts and thorough knowledge with wind power, Lina Reichenberg who generously allowed me to use her own wind power data and Mikael Odenberger both for providing me with the hydro inflow data and the fruitful guidance on how to use it correctly.

I would also like to thank my family in Greece for their constant support, love and financial aid throughout my studies here in Sweden. Finally, a special thanks to Natasa for her comforting and calming words and actions, unquestionable love and vivid interest on my work.

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Gothenburg, August 2014

List of Nomenclatures

AC OPF	Alternating Current Optimal Power Flow
DC OPF	Direct Current Optimal Power Flow
DSM	Demand Side Management
ENTSO-E	European Network of Transmission System Operators for Electricity
GAMS	General Algebraic Modelling System
LMP	Locational Marginal Price
MIP	Mixed-Integer Programming
NTC	Net Transfer Capacity
PSH	Pumped-Storage Hydro

List of Symbols

Variables used in NO-PSH model:

$TCost$	total operational costs of the system
$PG_{i,FT,h}$	power production per country i and fuel type FT during time interval h
$PG_{i,Wind,h}$	power production per country that comes from wind power plants during time interval h
$PD_{i,h}$	electricity demand per country i during time interval h
$BB_{i,j}$	equivalent reactance between 2 different countries i and j
$Flow_{i,j,h}$	power flow between 2 countries i, j during time interval h
$\delta_{i,h}, \delta_{j,h}$	voltage angle for nodes i, j respectively during time interval h

Parameters used in NO-PSH:

N	number of studied countries
n	number of electricity production technologies
i, j	index of studied nodes
h	time interval
FT	source of electricity production by fuel type
$costdata_{i,FT}$	operational costs for each country and fuel type
$PGlim_{i,Wind}$	upper limit of wind powered electricity production per country
$Flowlimit_{i,j}$	power flow limit, i.e. transmission constraint, between 2 countries i, j
κ	number of iterations
$PG_{i,Wind,h_{\kappa}}$	power production per country that comes from wind power plants during each iteration κ
ΔP_{wind}	increase of wind power output between 2 successive iterations κ ***(scalar)***

Variables used in Wind-PSH model:

$PG_{i,PSH}$	production coming from PSH units for each country *i*

w_{i,h_p}	pumping rate if pumping
q_{i,h_g}	generation rate if generating
$pm_{i,h}$	pumping mode of the PSH system, on=1, off=0 ***(binary)***
$gm_{i,h}$	generation mode of the PSH system, on=1, off=0 ***(binary)***
$im_{i,h}$	idle mode of the PSH system, on=1, off=0 ***(binary)***

Parameters used in Wind-PSH:

η	efficiency of the PSH unit **(scalar)**
p,g	pumping and generation intervals' notations respectively
$costdata_{i,PSH}$	operational costs for each country for the PSH units
r_{i_g}, r_{i_p}	inflow to the reservoir of the PSH units for each country *i* during the generation intervals *g* and pumping intervals *p*
V_{i_g}, V_{i_p}	reservoir capacity of PSH units during the generation intervals *g* and pumping intervals *p*
$V_{i_{max}}$	maximum PSH reservoir capacity in each country *i*
V_{i_0}	initial level of PSH reservoirs in each country *i*
$V_{i_{final}}$	final level of PSH reservoirs in each country *i*
$PG_{i,PHS_{\lambda}}, PG_{i,PHS_{\lambda-1}}$	power production per country that comes from PSH units during each iteration λ and λ-1 respectively
$LMP_{i,h_{w/oPSH}}, LMP_{i,h_{with\ PSH}}$	LMP for each country *i* without introducing PSH into the system
$p_{i_{sell}}, p_{i_{buy}}$	buy and sell prices of the PSH units for each country *i*
ΔP_{PSH}	increase of PSH power output between 2 successive iterations λ ***(scalar)***

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List of countries’ abbreviations

PT	Portugal
ES	Spain
FR	France
BE	Belgium
NL	Netherlands
DE	Germany
CH	Switzerland
IT	Italy
AT	Austria
CZ	Czech Republic
PL	Poland
SK	Slovakia
HU	Hungary
SI	Slovenia
HR	Croatia
BA+ME	Bosnia & Montenegro (+ Serbian interconnections)
FYROM	Former Yugoslav Republic of Macedonia
BG	Bulgaria
RO	Romania
GR	Greece
FI	Finland
SE	Sweden
NO	Norway
DK	Denmark
UK	United Kingdom

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Chapter 1
Introduction

This chapter includes a short introduction into the thesis' subject and motivation. The background of the study is described and a few important terms are introduced for the first time. In the end of the Chapter, the overall objective of the thesis is presented as well as the specific tasks that were carried out during the project.

1.1 Background

A future European power system is expected to face some major challenges alongside with the expected increase of the wind power penetration levels in the years to come. One of them will be the need for network reinforcements to enhance the exchange capability between European countries in order even out the peaks or the valleys that are created in certain areas due to increased variable generation. Another reason that urges for effective transmission planning is the need for increased reliability and efficiency of an interconnected pan-European electricity network. Due to this expected increase in wind power output, more back-up generation will be needed. Therefore, pumped storage hydro could possibly constitute an economic solution of additional generation, in order to fully utilize renewable energy in a future system with larger penetration level of variable generation.

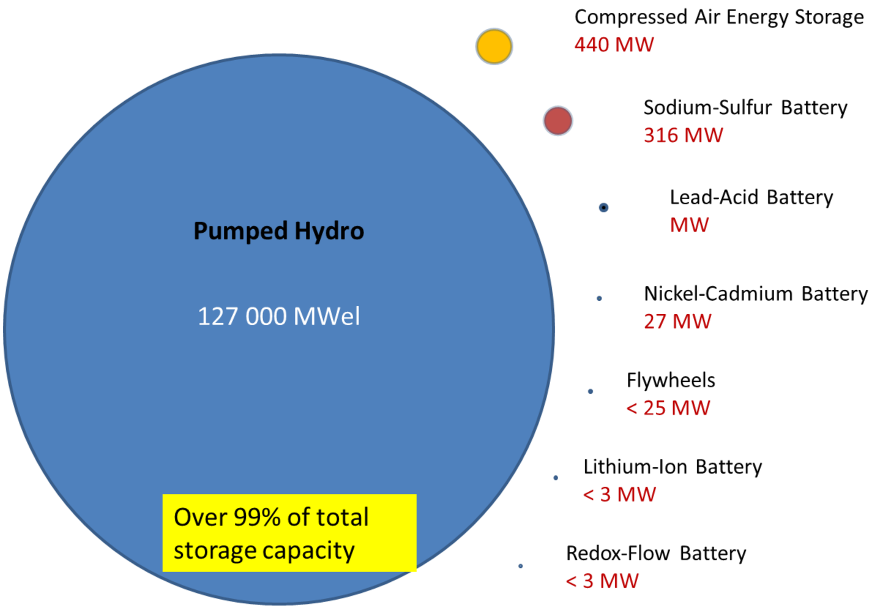

Figure 1.1 Worldwide installed storage capacity for electrical energy [1]

Due to its intermittent nature, a larger penetration of generated from renewable sources electricity is expected to put significant pressure into the grid. This might result not in the full utilization of both a cheap and an environmentally friendly generation source. In order to deal with issue a lot of technologies are already available, such as storage, demand side management, transmission planning, flexible generation [2]. This thesis will focus on the potential of pumped storage hydro which already accounts for 99% of all global storage capacity for electrical energy, as shown in Figure 1.1 [1].

1.1.1 Renewable energy generation

Hydro power is the most mature renewable energy technology and holds the major share of the gross electricity production among renewable energy sources (Table 1.1). However, for that reason and due to the fact that large share of European hydro capacity has been exploited, a future increase in electricity demand is not possible to be covered by further significant hydro capacity expansion. At this point, wind, mainly, and solar in the second place are expected to cover this demand and the reason is threefold. Firstly, due to EU's stringent targets to reduce its emissions by 2020 in comparison to the base year 1990. Secondly, both wind and solar energy are widely available resources; they are neither limited due to unequal resource allocation, as is for example geothermal or tidal and ocean energy, nor is it outcompeted for other use, as is biomass energy; it is much more profitable to produce heat than electricity from a biomass plant and the 123.3 TWh of biomass and renewable waste electricity production come to large extent from combined heat and power plants. The last reason that contributes to the further expansion of wind and solar power is the fact that they are currently more mature than the other competing technologies. Unless significant breakthroughs or regulations favouring other areas are encountered in the next few years, the economies of scale instruct that solar and wind will become even more competitive in the future.

Table 1.1 Gross Electricity generation from renewables in EU, 2010 [3]

	2010						
TWh	**Renewables**	Hydro	Wind	Solar	Tide, Wave and Ocean	Biomass and Renewable Wastes	Geothermal
EU-27	**699.3**	397.7	149.1	23.1	0.5	123.3	5.61
Share (%)	**100%**	57%	21%	3%	0%	18%	1%

1.1.2 Issues associated with increased wind and solar power penetration levels

However, due to the variable nature of wind, some issues are expected to arise in systems with high wind penetration levels of around or above 20%. One is the need for quick responsive back-up generation in cases wind output is not enough to cover the demand and another is excessive generation when the demand is not high enough. Both need investments, in order to fully utilize the available wind production. The solutions can span from advanced storage facilities and efficient transmission planning to active demand-side management measures. In this thesis, we will focus mainly on the role of pumped storage hydro.

In the report "Connecting the sun" [2] written by EPIA (European Photovoltaic Industry Association) the focus is particularly on how we can achieve large scale PV grid integration by the year 2030. Based on EPIA's scenarios for PV electricity penetration, a 15% penetration level should be considered a milestone even before 2030 with the real question being when a 25% penetration can be reached. The main weaknesses of PV, namely variability, lack of dispatchability and flexibility, are identified and solutions are suggested. Besides, it mentioned that it is already technically feasible to overcome these obstacles and the right measures are needed to ensure the reliability of such a system. ***Variability*** can be ensured through forecasting. However, although certain weather conditions can affect a lot the output of a single panel, the overall system is barely affected, as it is shown in Figure

1.2. There are two ways to deal with the ***dispatchability*** issue, especially during the afternoon peak, which is very close to the peak output of PVs. One is to shift the production that comes from PVs with storage facilities (Figure 1.3) and the second one is to shift the consumption to earlier hours through Demand Side Management (DSM) measures. The fact that solar panels are normally installed close to where consumption is also high, compensates for the lack of dispatchability through significantly lower transmission cost, whereas the complementary nature of solar and wind power can reduce the need for back-up capacity. ***Flexibility*** of the system can be ensured through the right mix of measures, such as storage, DSM, transmission planning, flexible generation. Storage, in particular, is expected to play a significant role to the deployment of large scale PV.

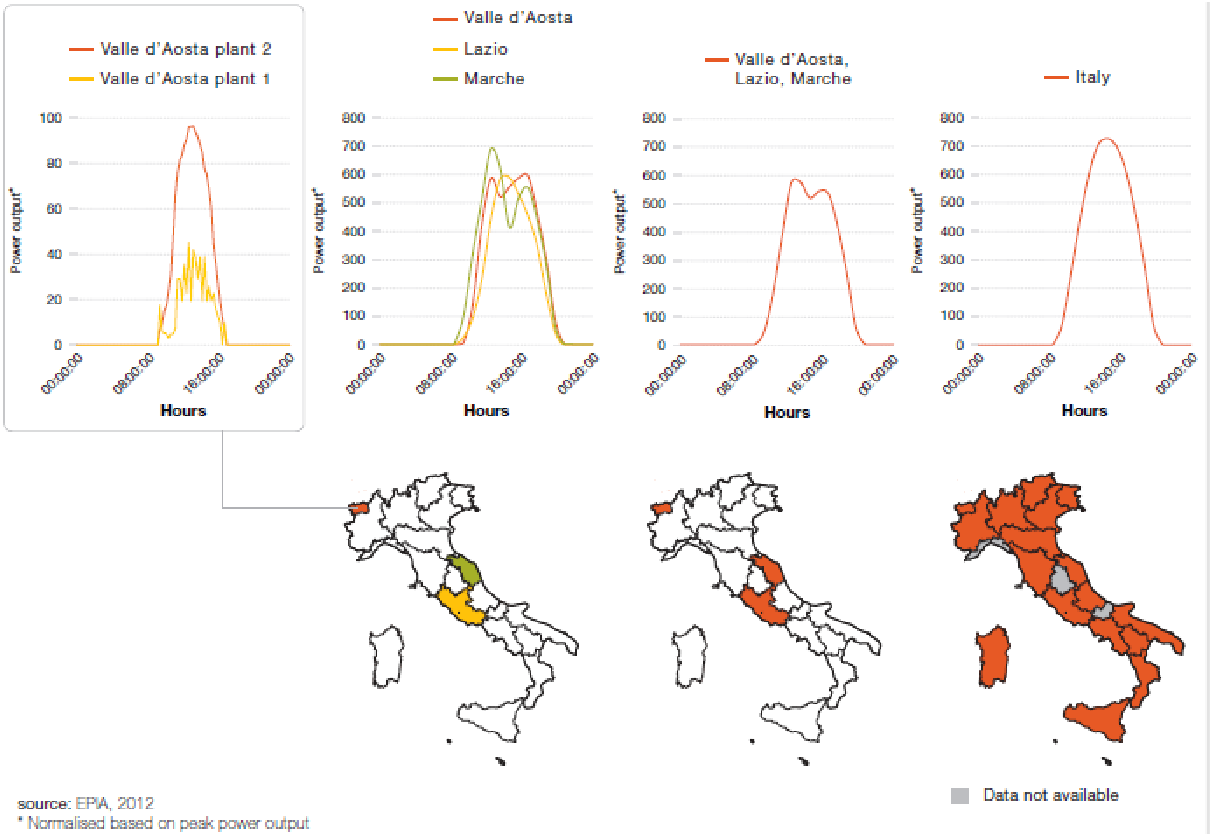

Figure 1.2 Comparison of daily PV variability (plant, region and country level) - Example of Italy (kW) [2]

Another concerning issue regarding the competitiveness of solar PVs is expected to be the need for curtailment. In some cases it will compromise significantly the stream revenues of PV system owners; hence it should be implemented very carefully and under extreme grid conditions. Nevertheless, the combination of PV with storage and DSM measures is expected to accelerate the competitiveness of PV.

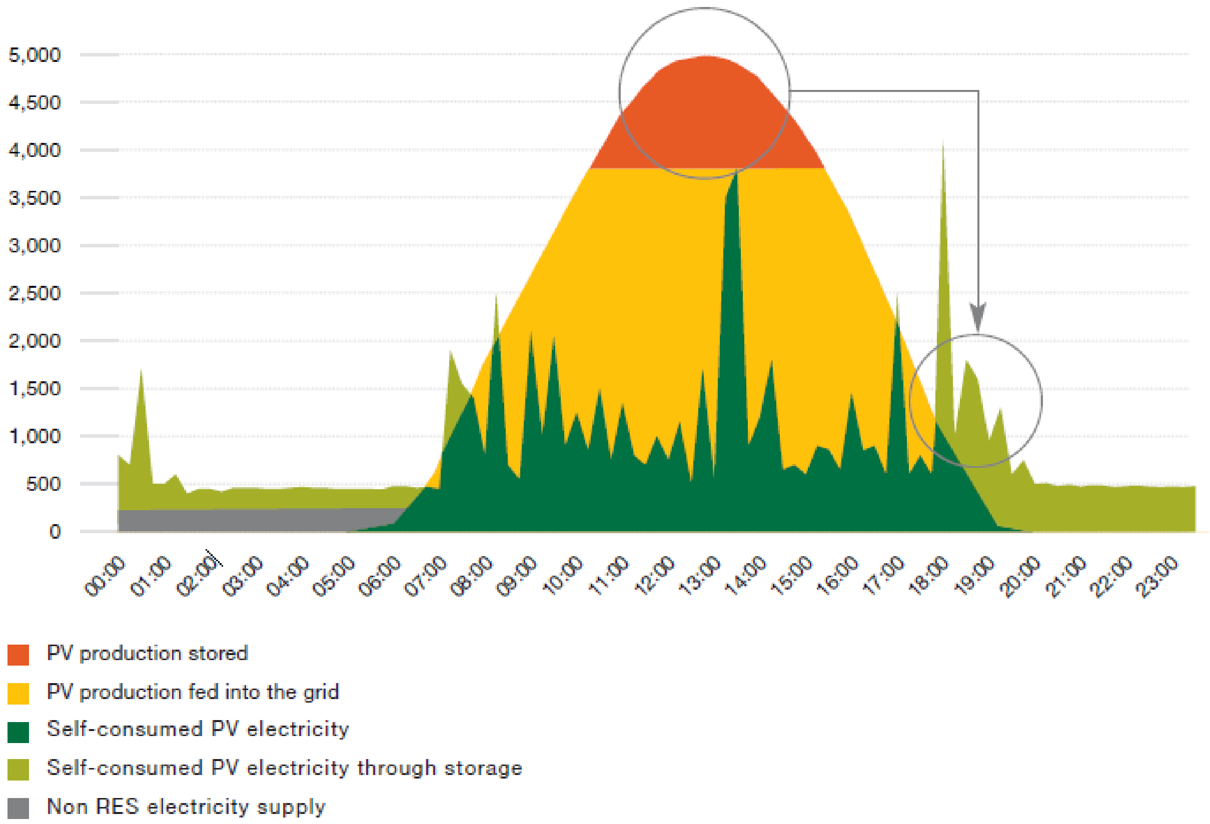

Figure 1.3 Peak shaving strategy using storage at household level (W) [2]

1.1.3 Pumped storage hydro power plant as a balancing measure to increased wind penetration

As mentioned earlier, there are several ways to deal with these problems and it is expected that a mix of all these measures will be operating simultaneously at a future power systems, since a single solution will remove flexibility and will take out important and useful characteristics that could be obtained if multiple measures would be functioning. Nevertheless, this thesis will solely focus on the effects of an extensive usage of pumped storage hydro units throughout the European region.

Pumped storage hydro can act as a supporting technology in case of increased wind power capacity in a system. The ability to ramp up or down quickly can compensate for the variable generation as well as offer frequency regulation services, whereas it can be also effectively used for back-up capacity, to avoid transmission congestion periods and offer more efficient transmission grid management, at large. The European electricity sector is under the process of developing into a single integrated European market. In this context, sufficient pumped storage capacity could not only offer flexibility and balance the grid locally, but it could also become a very efficient exporter of electricity to neighbouring countries when needed.

1.2 Objectives of the thesis

The objective of this thesis is to assess the role of pumped storage hydro capacity on the wind power penetration levels in a future integrated European power system, as well as to assess individual countries' characteristics. A single-node per country model was used and included also the Nordic countries, unlike similar research that this thesis has been developed and evolved from [4]. The main research questions that were tried to be answered can be summarized by the following:

- How would the system costs be affected in different scenarios of wind power or system development?
- What the implications on the transmission planning strategy and the electricity exchange between countries would be under different circumstances?
- How much more wind power would be able to penetrate into the system under the presence of PSH units?
- In which way would Scandinavian interconnections be affected and which ones are in need of expansion?
- What are the emission reductions that can be achieved by the implementation of PSH into the system?

1.3 Specific tasks to be carried out

In order to achieve the expected results, the following specific tasks were carried out:

- Task-1: Perform a literature review on the pumped storage hydro as well as wind power in Europe.
- Task-2: Collect the most recent data on the loads, generation and interconnection capacities (NTCs) of the European region, in order to update the existing model [4]. The model is also expected to be expanded to include the Nordic countries that were not included in the initial model.
- Task-3: Using general algebraic modelling system (GAMS), perform the calculations for different wind power output in Europe and find the optimal level of pumped storage hydro that is needed in order to operate as a back-up unit to compensate for the variability of wind, as well as the price difference that would make it profitable.
- Task-4: Define different scenarios for European power system expansion and identify where there will be larger need for reinforcements.
- Task-5: Check what the effect of pumped storage hydro is on emissions.

1.4 Organization of the thesis

The full report is concluded in 6 chapters, all of which with a clear purpose and content that is briefly described in the beginning of each chapter. The first chapter is an introduction to the subject and the thesis where the major concepts and scope of the thesis are presented for the first time. The second chapter included a more comprehensive literature review of all concepts that were introduced earlier, as well as a presentation of current and future development of wind power and pumped storage hydro in Europe. Chapter 3 introduces the reader to the model that was used and developed throughout the study, whereas chapter 4 includes the overview of the investigated case study along with data collection and the assumptions that were considered throughout the project. In the next chapter the most important and interesting results are presented, including effects of increased pumped-storage hydro units on transmission, system costs and emissions. Finally, chapter 6 includes the ultimate conclusions that can be drawn based on the simulated results.

Chapter 2
Literature Review

This chapter provides with a more detailed insight on the studied technologies as well as their development in a European context. The basic concepts around wind power and pumped storage hydro power plants and current and future trends of both technologies are the main focus, whereas a number of relevant papers are also reviewed. Finally, different approaches on European market design are described. The goal of this chapter is to identify potential gaps in the literature, so that this study can contribute to a better understanding of the investigated issues.

2.1 Wind power technology and development

Wind power is the most mature and widespread renewable technology after hydro power. The share of wind power production into the European network is expected to increase even further if Europe is to meet the strict environmental target set for 2020. This section will try to discuss the current state of wind power in the European region, what are the prospects for the future as well as present some of the problems that might come along with wind power expansion.

2.1.1 Uncertainty of generation, load and prices

Along with increased variable generation, various degrees of uncertainty are present. Hereafter, what are the sources of uncertainty and how have they been dealt with in literature will be presented. Assuming that demand is most of the times relatively predictable with low elasticity within a certain price margin and, hence, contains a smaller amount of uncertainty, this cannot be claimed for variable generation, such as wind and solar power. For instance, wind power generation forecasting is based on wind speed forecasts at various locations and time frames. However, wind might not blow in this area or it could blow, at different time frames than the predicted ones. This complicates the role of market modellers, such as retailers, TSOs, systems operators and researchers, due to the added uncertainty into the system. Nevertheless, this is not the only uncertainty factor. Prices are also affected, as the supply curve, and hence, the market settlement price, cannot be determined with accuracy, which adds another degree of uncertainty into the system. This becomes particularly important in day-ahead market operation. These two uncertainty factors have an adverse effect on the scheduling of pumped storage hydro, since they need to be accounted for in order to determine a viable and cost-effective schedule of the generation and pumping interval of the hydro unit.

There are various publications in literature considering these sorts of uncertainty. Balram et al [5] simulated the electricity market from a retailer's perspective under the uncertainty of electric vehicles. The case of electric vehicles is quite similar to the pumped storage scheduling problem, but instead of integrating EVs into the load, in the case of PSH, it needs to be simulated into the generation mix. The spot market price will be altered due to the introduction of new load or new generation into the system respectively. The charge and discharge cycle of the battery can be associated to the pumping and generating intervals of the hydro unit, or in other words, the charge and discharge or the upper reservoir. There are significant differences as well, as pumped storage follows a discharge pattern related to load and wind production, which is rather unpredictable, whereas EV charge/discharge cycle follows a certain behavioural patterns, which are considered to be generally more stable. In this study [5], a stochastic approach is used with the development of different scenarios for the spot price and conventional demand, in order to be used as an input to the EV aggregator model.

2.1.2 Wind power capacity factor

According to Boccard's study [6] on the average capacity factor of wind in different countries throughout a 5 year period, there is a discrepancy in the range of (35-21)/35 = 0.4 = 40% between the average estimate value found in the literature and the actual average capacity factor for all studied countries. In order to calculate the realized capacity factor, data on installed capacity and annual output, which are presented in Table 2.1, were extracted from various trusted sources for the years 2003-2007.

Table 2.1 Average capacity factors over 2003-2007 [6]

Area	EU15	DE	ES	DK	IT	UK	FR	PT	NL	AT	GR	SE	BE	PL	FI
Capacity (GW)	56.3	22.2	14.1	3.1	2.7	2.5	2.4	2.2	1.7	1.0	0.9	0.7	0.3	0.3	0.1
Energy (TWh)	97.7	39.5	28.8	6.1	4.2	5.3	4.2	3.8	3.5	2.0	1.9	1.2	0.5	0.5	0.2
Load share (%)	3.2	6.2	8.5	15.6	1.3	1.3	0.7	7.0	3.3	3.1	2.9	0.8	0.5	0.3	0.2
Capacity factor (%)	20.8	18.3	24.8	22.8	19.1	26.1	22.3	22.7	21.5	20.1	29.3	21.7	20.0	25.9	21.8

In this thesis, real wind speed data for the years 2007-2008-2009 were obtained from Lina Reichenberg from the division of Energy Technology, department of Energy & Environment, Chalmers University of Technology.

2.1.3 Current state of wind power in Europe

According to the data by EWEA [7], further 11 GW of wind power plants were installed in EU-27 in 2013 to reach a cumulative capacity of 115GW. Whereas Germany and Spain host almost half of the total European wind capacity (49.4%), in Denmark wind accounts for 27% of the total electricity consumption in the country. The share of wind power penetration levels into the electricity mix of individual countries and EU can be found in Figure 2.1, whereas Table 2.2 displays newly installed and total capacity during 2012 and 2013 for 25 European countries, including Switzerland, Norway, Bosnia & Montenegro and FYROM that are not part of the European Union.

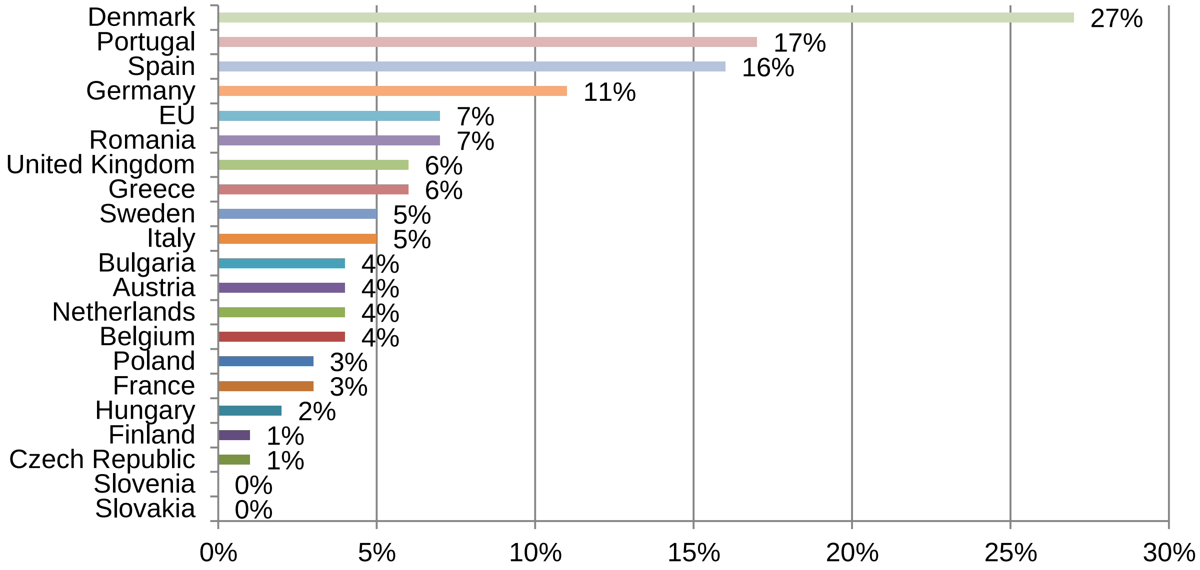

Figure 2.1 Wind power share of total electricity consumption in EU (7%) and in member states [8]

Table 2.2 Wind power installed in Europe by end of 2013 in MW (cumulative) [7]

Country	Country Code	Installed 2012	End 2012	Installed 2013	End 2013
Portugal	**PT**	155	4529	196	4724
Spain	**ES**	1110	22784	175	22959
France	**FR**	814	7623	631	8254
Belgium	**BE**	297	1377	308	1684
Netherlands	**NL**	119	2391	303	2693
Germany	**DE**	2297	30989	3238	33730
Switzerland	**CH**	4	50	13	60
Italy	**IT**	1239	8118	444	8551
Austria	**AT**	296	1377	308	1684
Czech Republic	**CZ**	44	260	9	269
Poland	**PL**	880	2496	894	3390
Slovakia	**SK**	0	3	0	3
Hungary**	**HU**	0	329	0	329
Slovenia	**SI**	0	0	2	2
Croatia	**HR**	48	180	122	302
Bosnia & Montenegro*	**BA+ME**	-	-	-	-
Former Yugoslav Republic of Macedonia	**FYROM**	0	0	0	0
Bulgaria	**BG**	158	674	7	681
Romania	**RO**	923	1905	695	2599
Greece	**GR**	117	1749	116	1865
Finland	**FI**	89	288	162	448
Sweden	**SE**	846	3582	724	4470
Norway	**NO**	166	703	110	768
Denmark	**DK**	220	4162	657	4772
United Kingdom	**UK**	2064	8649	1883	10531
Total		**11886**	**104218**	**10997**	**114768**
*No data availabe, assumed zero					
**Provisional data or estimate					

2.1.4 Future Scenarios on wind development

Wind power capacity is rapidly growing in EU and it is expected to further expand in the next decades. The strict environmental targets set by EU are a boost towards this direction. Nevertheless, despite this increase in wind capacity over the past decade, EU member states cannot be satisfied. The reason is that accumulatively they fall short the objectives they set for themselves in their National Renewable Energy Action Plans (NREAPs) for 2012 by approximately 1.5%. [8] Compared to EWEA's projections for the same year, where the real capacity exceeds the projection by 4% and considering that EWEA's scenario leads to a total capacity in 2020 of 230GW while NREAPs aim at 213GW, this lagging can be attributed to two reasons. [8] Either NREAPs are set to follow a steep increase in early years rather than in the end, or the targets closer to 2020 are not as ambitious as the ones during the first years.

According to EWEA [9], two scenarios were developed for the future of European wind power in 2020 and 2030; one is the baseline scenario with an accumulative target for 2020 of 230 GW, whereas the second one, the "high" scenario requires 265GW of total installed capacity in 2020. Both scenarios include targets for each member state country of EU-27 for onshore as well as offshore capacity. The final total share of wind in the European electricity consumption is projected to reach as high as 15.7% for the baseline and 18.4% for the high scenario, while in 2010 this share did not exceed 5.3%.

2.2 Pumped storage hydro power plant technology and development

Pumped storage hydro technology, which will be, hereafter, referred to as PSH, operates to large extent as a regular hydro power plant. The difference is the existence of an upper level reservoir, which is built at higher latitude than the lower level one. There are many different designs or variations of a PSH unit, but in the context of this thesis a specific design is assumed for all countries and unit. In this structure natural inflow, generating and pumping rates are considered as part of the interaction between the two reservoirs as it can be observed in Figure 2.2.

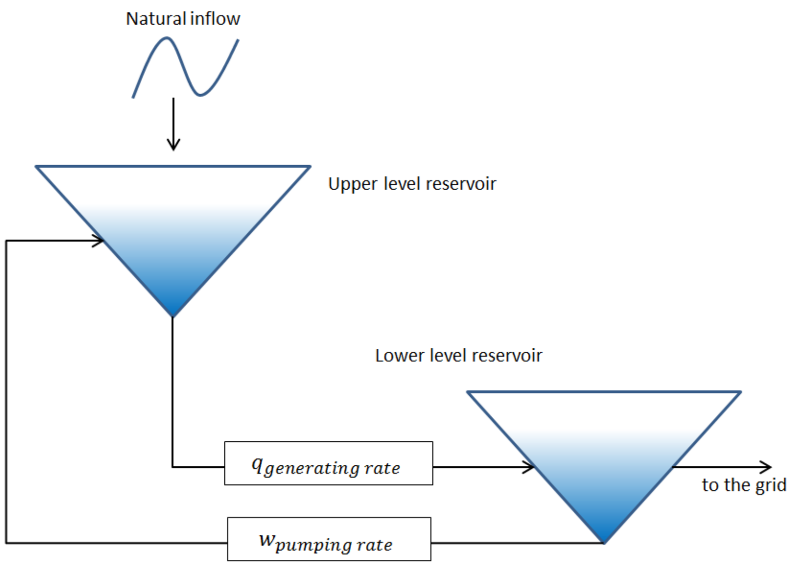

Figure 2.2 PSH model structure that is used throughout the study for all countries

2.2.1 Pumped storage hydro in Europe

The definition of pumped storage hydro according to ENTSO-e is the following [10]:

"A hydro unit in which water can be raised by means of pumps and stored, to be used later for the generation of electrical energy."

Despite being a net consumer of electricity, a pumped storage hydro unit encompasses a very interesting functionality: cheap energy can be pumped to the storage facility at higher latitude during hours of low demand and high renewable generation. For example, during night, when load is generally lower or summer months in the northern part of Europe, when there is minimal need for heating. Then this energy, which is stored in the form of a higher level dam can be released during peak hour demand and produce electricity, hence both gaining from the price difference between the two occurrences as well as compensating for periods of low wind or solar output. This function is very well suited to wind rather than to solar, because of two main reasons: solar power is very well correlated to the load (the time when solar panels produce more coincide with the noon peak demand) and the production of solar during night-time is zero.
The technology can be used in several applications. For instance, it can serve as a grid balancing unit in cases of outages thanks to its ability to ramp up to full production within minutes at low cost as well as its black start capability. Another possibility that PSH is already exploited for is primary and secondary regulation of the European grid. However, this paper will focus on the ability to enable other production units, such as renewable energy sources and it this specific case wind power run on the most optimal point of operation. [11]
Pumped storage hydro is a rather mature technology [1] and it is estimated that 42.6GW of PSH electricity generation capacity was installed by the end of 2011 in EU-27 [12]. According to Eurostat, the corresponding electricity generation was 29 TWh from 38 TWh pumped, yielding an average efficiency of all PSH units of 76.3%. The future of pumped storage in Europe, including Turkey, looks also promising with the licenced and planned pumped storage power plants projects almost doubling the existing capacity once they are completed [13]. Is this expansion enough, in order to handle the expected increase of European wind power capacity though? This is one question that this thesis will try to address.

2.3 Wind and pumped-storage coordination

In the work by Mohammad et al [14], the intra-hour coordination of wind and pumped storage was investigated considering also transmission constraints. The simulated systems were a 6-bus thermal-wind-pumped storage and the IEEE 118-bus system. The approach used, was by decomposing the mixed-integer programming problem into a master problem (optimal unit commitment and power dispatch) and several sub-problems (transmission network evaluation) by applying Benders decomposition. The results for both cases showed that the dispatchability of wind generation was improved and the wind curtailment was restrained. The systems' operating costs were reduced congestion and load curtailment was limited, while at the same time the penetration levels of wind production were increased and the intra-hour variability of wind was mitigated.

In the case of Garcia-Gonzalez's et al two-stage stochastic joint optimization of wind generation and pumped storage units [15], wind production uncertainty was also accounted for. Three scenarios were examined, namely those of uncoordinated operation (UO), joint operation, selling and buying (JO-SB) and joint operation, only selling (JO-S). The study had a different scope, as the objective of this model was maximization of profit in all three scenarios. The results yielded maximum profit in the case of JO-SB, whereas the JO-S scenario was close behind, despite an almost even penalty allocation between the two cases. This can be attributed to higher profits from pumped storage in JO-SB scenario, since the hydro unit participated more actively and, hence, efficiently in the market.

Khatod [16] also proposed an approach for optimal daily scheduling of a wind and pumped storage hydro system from an independent power producers' perspective. A capacity of 6 MW is assumed for the PSH unit and 5 $/MWh during pumping and 3 $/MWh generating mode. In order to assess wind curtailment a reference dump load is used. During high pricing periods, maximum amount of electricity is supplied, whereas during low price period a big portion of wind energy is stored in the form of hydro energy and then used to satisfy the contracted demand when price is higher.

In 2013, Helseth et al [17] created a model for optimal scheduling of a combined hydro thermal system that includes multiple hydro reservoirs, which was tested on a representation of Iceland's power system. Different cases were simulated and the results showed that pumping start-up costs largely affect the utilisation of pumped storage. Moreover, the more constraints were added into the model, the more realistic the results became.

The next couple of papers do not deal wind- PSH, but rather on wind-hydro model. However, the main principles are the same and they yield some results that could be of interest. Castronuovo and Lopes [18] present a wind unit profit maximization approach for the operation of wind-hydro unit. The hourly operation of the unit is determined and the results show a slight increase of the supplied power from the wind-hydro unit compared to the wind power plant alone. The full potential of the unit is not exploited, since the objective is profit maximization and not maximum supply of electricity.

In the report of Göransson et al [19], the role of Nordic hydropower is assessed, in order to facilitate a more efficient operation of the future European electricity system. The emphasis is mainly on the operation and trade between Norway, Sweden, Denmark, UK, Germany and the Netherlands and not on the need for transmission investments. For the modelling and analysis, the ELIN (long-term dynamic optimization model) and EPOD (linear cost-minimizing model applied to 1 year with a time resolution of down to 1 hour) models were used. 2012 was used as the base year and 2022 as the model year. The results under normal-year conditions show a Norway hydropower export of 6.5 TWh/year to Germany, 2.7 TWh/year to the Netherlands and 8.6 TWh/year to the UK. The overall net export over the whole year is shown in Figure 2.3. Another significant result from this study is the conclusion that investments in Norwegian hydropower is most likely to help towards higher utilization of Danish thermal generation than investments in Swedish wind power. Finally, by year 2020 Nordic hydropower will act as a distributor of low cost renewable electricity in Northern Europe.

It is evident that wind-hydro and wind-pumped storage hydro coordination has received a lot of attention recently. The main reason behind that is the potential behind the combination of the two technologies, but it is not the only one. Hydro power is a very mature technology and a vast amount of its potential is already exploited [13]. Although pumped-storage hydro is also a mature and well-known technology, its cost and low return of investment until recently has prevented further development of such type of plants. However, new configurations of PSH units, components' cost reduction and better wind forecasting and higher wind power penetration levels have raised the issue of wind-pumped storage co-operation in recent years. Therefore, the effects of more PSH power plants into the system need to be assessed and evaluated as well as optimal co-ordination algorithms between the two technologies in order to achieve the most effective cooperation and lower the system costs while increasing significantly the share of non-emitting technologies and exploiting all of the currently installed wind power capacity.

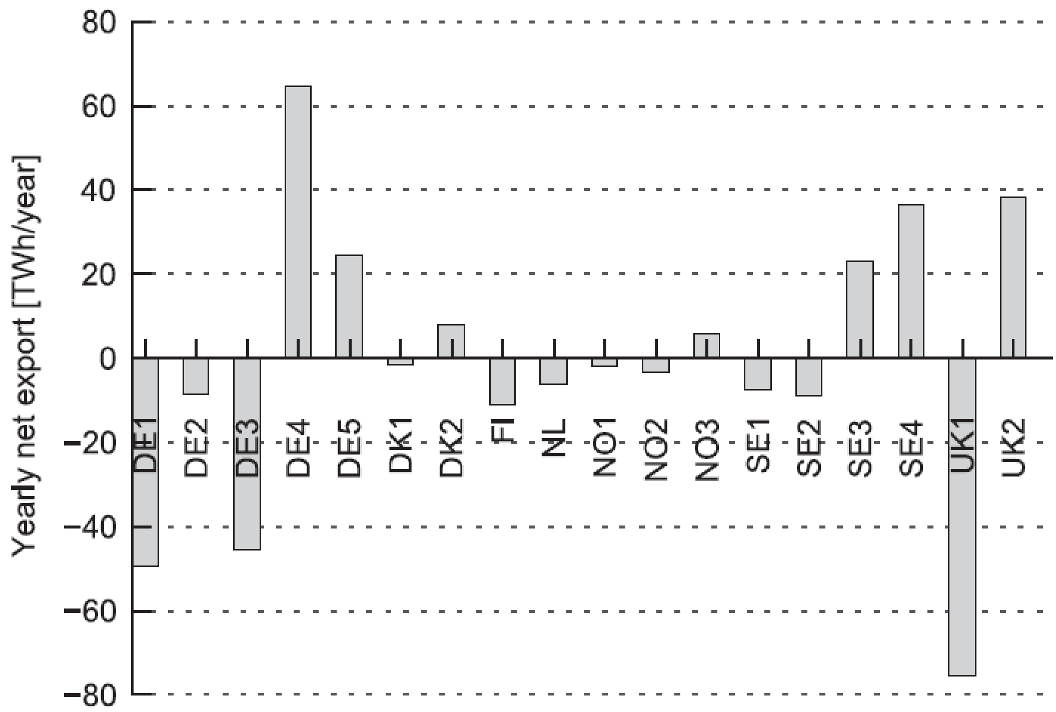

Figure 2.3 Yearly net export in year 2022 as obtained from the EPOD modelling for the regions investigated

The main contribution of this thesis lies in the development of a methodology and a model to evaluate the impacts of increasing capacity of PSH in the European power system on the performance of the power system as well as on the amount of wind power capacity that can be integrated in the system. Under this approach, the interaction between PHS and wind power can be analyzed when both PSH and wind power capacities are allowed to increase in step until maximum capacity of wind power and PSH is reached or when the network congestion occurs. The model is a multi-period generation scheduling model incorporating PSH based on a dc optimal power flow (DC-OPF) framework. The model is used to analyze the system for the cases with and without PSH.

2.4 Motivation of the thesis

In this context, the motivation of writing a thesis on the interaction between wind power and PSH technologies becomes very straightforward. The fact that there is no available research on the topic of pumped-storage and wind power co-ordination and its effects on the European power system was a major contributing factor for the subject of this thesis. It would be both very interesting and useful to see the actual effects of the two technologies in an interconnected European power grid, which is expected to become even more unified in the future. Therefore, the effects on costs, emissions and power flow between the countries are an area worth investigating deeper, especially under the current development plans and goals set by the EU.

Chapter 3
Methodology and Model Development

In this chapter a more detailed overview on the methodology and model development process that was followed will be given. Both a mathematical representation and the modelling process will be described and motivated. Throughout the chapter a few necessary technical details will be also presented.

3.1 Model Development

The model of this thesis is developed from a model proposed by A. Papaemmanouil et al [4] during his PhD at ETH, Zurich. The model was initially developed to assess and develop the problem of transmission planning in Europe under future uncertain conditions not only in generation, but also in power market development and environmental requirements. The model, therefore, serves as a platform for decision makers, in order to evaluate line reinforcement investment scenarios.

In the current model, which from now on will be referred to as Wind- PSH model, relevant data for generation and transmission and variable costs were extracted from the afore-mentioned publication, which was result of Papaemmanouil's work at ETH [4], whereas other data, such as load profiles for all investigated European countries were extracted from ENTSO-e's website [20] or form the work in the department of Energy & Environment at Chalmers University of Technology, such as wind speed and hydro inflow data. The main differentiations between Papaemmanouil's model and Wind- PSH can be summarized in three main areas:

1. This model is a system's total variable costs minimization algorithm, whereas Papaemmanouil's model was a social welfare maximization problem.
2. The introduction of separate PSH capacity for the investigated countries.
3. Wind- PSH was expanded, in order to include the Nordic countries, namely Finland, Sweden, Norway and Denmark, as well as UK. Therefore, the current model includes 25 countries-nodes compared to 20 countries included in the initial model.

3.2 Methodology

In the proposed methodology, a two-stage algorithm is developed and is shown in Figure 3.1. In the first stage, part of the European power system is simulated using 7 power production technologies, whereas in the second stage PSH capacities and PSH scheduling are also added to the system.

Two models have been developed and used under this methodology. The first model, named as NO-PSH, is based on the DC-OPF framework. NO-PSH is used in order to compare and assess the results of the second model, as well as give the calculated locational marginal price (LMP) for different countries as inputs to the second model, named as Wind-PSH.

Wind-PSH is used to analyze the cases where both wind and PSH power capacity are increased for all the countries in steps of 500 MW respectively, until each country reaches its capacity limit. Once all countries have reached their limits, the iterations stop and the results can be compared in respect to PSH capacity and wind power production levels.

The flow of work following this methodology can be summarized as follows:

Step-1: Run NO-PSH with increasing level of wind power only (in steps of 500 MW increase per country).

Step-2: When all countries reach their wind power capacity limit due to the network constraints, the final results on LMP are fed to the Wind-PSH model. The LMPs are used as inputs in order to be able to schedule PSH since PSH is assumed to buy energy when it pumps and sell energy when it generates with at LMP prices.

Step-3: In this step, we will try to see if more wind power can be added to the system if PHS is used. First the wind power production is increased by 500MW for each country. Then, PSH capacity per country is increased in 500MW step until all countries' capacities have reached their limits. Once all PSH limits are reached, wind power production is increased 500 MW more per country and this process continues until all countries have reached both limits.

In this approach, a DC optimal power flow (OPF) calculation is used as the main tool [21]. In comparison to the regular AC OPF, which is based on a total variable production costs minimization problem subject to non-linear constraints, the DC OPF is a simplified variation of the optimal power flow algorithm. In DC OPF, the Q-V equations are omitted and, hence, the result is a linear, non-iterative power flow algorithm.

The reason, why a step in the range of 500MW is implemented both for wind and later also for PSH penetration level increase, is two-fold. First of all, this step is big enough in order to still see a clear relation between different steps and different levels of wind power and PSH. On the other hand, a smaller step would require much more steps in order to reach the final maximum capacity and, therefore, much larger computing power. Thus, it was concluded that this step value is the most suitable for the current available computing power without compromising the results of the simulations.

As the number of iterations increases, each one is performed with an increased wind production for each country, until more wind penetration would cause a system violation. After the last iteration the LMP without any PSH unit for each country is retrieved as well as the total wind under the same system conditions. The first element will help simulate the hydro-thermal-wind scheduling, whereas the second can be used as an output in order to compare the system costs at maximum wind output with and without the implementation of PSH.

A double-loop is implemented in order to solve the DC OPF after the introduction of PSH units. If there is a violation in the system, then the PSH capacity is increased step-by-step, enabling system relaxation. Once the violations are dealt with and the system is operating normally, more wind is introduced into the system and the process is repeated until a further increase of PSH capacity either violates the PSH capacity constraint or it cannot yield a solution without violating the system constraints. Figure 3.1 is a flowchart of this process.

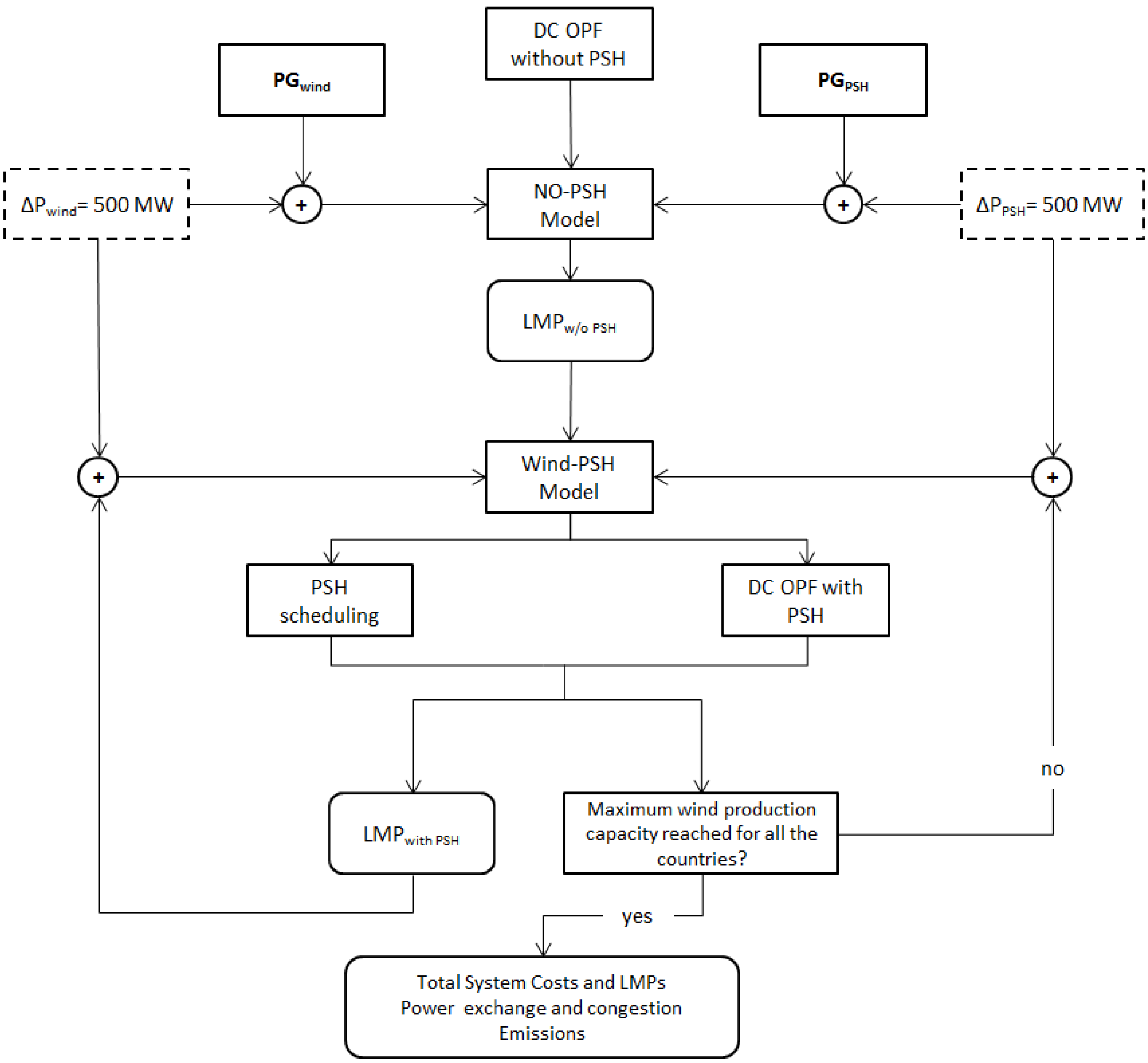

Figure 3.1 Proposed methodology of the evaluation process

3.2.1 Mathematical model

The mathematical model consists of two parts with two different objective functions, but both perform a DC OPF calculation of the system. The first model or the NO-PSH model minimizes the total costs for different steps of wind output without considering the PSH units. This is done, not only in order to calculate the maximum wind power production that does not violate the system's constraints before implementing PSH, but also to obtain an initial LMP value to be used as an input to the PSH scheduling. The second part, which is the Wind-PSH model, is again a minimization of total costs under DC OPF constraints, but now PSH technology is also introduced into the model. Thus, the mathematical problem is formulated as follows:

3.2.1.1 NO-PSH model

a. objective function:

The objective of the NO-PSH model was to minimize the following equation:

$$TCost=\sum_{j=1}^{N}\sum_{FT=1}^{n}\sum_{h=1}^{24} costdata_{i,FT} * PG_{i,FT,h} \tag{1}$$

The objective function (1) consists of a variable $PG_{i,FT,h}$, a parameter $costdata_{i,FT}$ and 3 summations over all the countries i, fuel technologies FT and throughout the 24 hours of the simulated day. The result of this equation gives the total cost of the system, which needs to be minimized.

b. capacity constraint:

$$PG_{i,Wind} \leq PGlim_{i,Wind} \quad , \forall \textit{country } i \tag{2}$$

Equation (2) controls that the maximum wind power production is not exceeding the expected output limit in each country based on the installed capacity and real wind speed data for years 2007, 2008, 2009. Further description on how these data were processed is given in Chapter 4.

c. line flow constraints

$$\sum_{FT=1}^{N}\left(PG_{i,FT,h}\right) - PD_{i,h} = \sum_{j=1}^{N} B_{i,j} * \delta_{j,h} \quad , \forall \textit{ country } i \text{ and hour h} \tag{3}$$

$$Flow_{i,j,h} = \left(\delta_{i,h} - \delta_{j,h}\right) * BB_{i,j} \quad , \forall i,j, \textit{ line } i\text{-}j \text{ and h} \tag{4}$$

$$Flow_{i,j,h} \leq Flowlimit_{i,j} \quad , \forall i,j \textit{ line }, i\text{-}j \text{ and h} \tag{5}$$

$$\delta_{i,h} - \delta_{j,h} \leq rad(45^{\circ}) \quad , \forall\ i,j \text{ and h} \tag{6}$$

From equations (3)-(6), the OPF constraints are formulated and equation (7) shows the step-by-step increase of wind output at each iteration κ. The problem is solved for different values of $PG_{i,Wind}$ for each iteration κ, as long as (2) is not violated:

$$PG_{i,Wind,h_{\kappa}} = PG_{i,Wind,h_{\kappa-1}} + \Delta P_{wind} \tag{7}$$

From this part of the model, a maximum wind output that does not violate the OPF constraints is retrieved as well as the LMP for each node of the system. In the second part, the system will be evaluated for increased wind output and PSH units.

3.2.1.2 Wind-PSH model

a. objective function

The final objective of the combined Wind-PSH model is to minimize the total system cost of the following equation:

$$TCost=\sum_{j=1}^{N}\sum_{FT=1}^{n}\sum_{h=1}^{24}(costdata_{i,FT} * PG_{i,FT,h}) - LMP_{i,h} * q_{i,h} + \ LMP_{i,h} * w_{i,h} \tag{8}$$

The objective function of Wind-PSH is the same as in (1), but now formed to include also cost of wind power and PSH production as well as reflect the need for profit maximization from the operation of PSH units.

b. capacity and line flow constraints:

In this part of the model, most of the constraints are same as in the respective NO-PSH model, besides equation (9), in which the PSH unit needs to be considered and added as well.

$$\sum_{FT=1}^{N}\left(\mathrm{PG_{i,FT,h}}\right) + q_{i,h_g} - \mathrm{PD_{i,h}} \sum_{FT=1}^{N}\left(PG_{wind_{i,FT,h}}\right) - \sum_{FT=1}^{N}\left(PG_{PHS_{i,FT,h}}\right) + w_{i,h_p} = \sum_{j=1}^{N}\mathrm{B_{i,j}}*\delta_{j,h} \tag{9}$$

Equations (2), (4), (5) and (6) are maintained from NO-PSH. However, equation (3), the nodal balance equation, is now including the wind production and the PSH scheduling, such as pumping rate w_{i,h_p} during the pumping intervals and the generating rate q_{i,h_g} during the generating intervals.

c. Pumped-Storage scheduling constraints:

$$V_{i,h_p} = V_{i,h_{p-1}} + r_{i,h_p} + w_{i,h_p} \quad \text{, where } pm_{i,h} = 1,\ V_{i,h_p} < V_{i_{max}} \tag{10}$$

Equations (10) show the hydro-thermal scheduling during the pumping interval p, considering the hydro reservoir level during the previous period and the natural inflow into the reservoir r_{i,h_p}. In the following equations (11), (12), (13) the scheduling during the generation interval is mathematically formulated and the starting and final reservoir levels are set:

$$V_{i,h_g} = V_{i,h-1_g} + r_{i.h_g} - q_{i,h_g} \quad \text{,where, } gm_{i,h} = 1,\ V_{i_p} < V_{i_{max}} \tag{11}$$

$$V_{i_0} = \frac{V_{i_{max}}}{2} \tag{12}$$

$$V_{i_{final}} = \frac{V_{i_{max}}}{2} \tag{13}$$

The exclusivity constraint, i.e. the fact that during an interval that pumping occurs for each country, the PSH cannot simultaneously generate as well, is illustrated by equation (14). Equations (15), (16):

$$pm_{i,h} + gm_{i,h} + im_{i,h} \ = 1 \tag{14}$$

$$0 \le w_{i,h_p} \le pm_{i,h} * PGlim_{i,PHS}/2 \tag{15}$$

$$0 \leq q_{i,h_p} \leq gm_{i,h} * PGlim_{i,PHS}/2 \quad (16)$$

During the time interval that the PSH units are neither pumping nor generating, the following equation (17), gives the hydro reservoir level:

$$V_{i,h_i} = V_{i,h-1_i} + r_{i.h_i} \qquad \text{, where, } im_{i,h} = 1 \quad (17)$$

The problem is solved for different values of $PG_{i,Wind}$ (7) and $PG_{i,PHS}$ for each iteration κ and λ respectively:

$$PG_{i,PHS_\lambda} = PG_{i,PHS_{\lambda-1}} + \Delta P_{PHS} \quad (18)$$

The fact that PG_{i,PHS_λ} increases gradually after each iteration we also need to constraint the pumping rate, which is the potential energy of the water in pumping mode in MWh, to the actual production from the PSH units:

$$q_{i,h_p} \leq \sum_{\mathrm{FT}}^{N} \left(PG_{PHS_{i,FT,h}} \right) * \eta \quad (19)$$

$$\sum_{h=1}^{24} \left(q_{i,h_t} \right) \leq \sum_{h=1}^{24} \left(w_{i,h_{t-1}} \right) * \eta + \sum_{h=1}^{24} \left(inflow_{i,h_{t-1}} \right) \quad (20)$$

Equation (5) is only used in this problem to determine where there is a need for transmission investment, and, therefore will not be a binding constraint.

Both models are implemented in General Algebraic Modelling System (GAMS) [22]. GAMS is a modelling tool for mathematical programming and optimization, which is broadly used for research purposes. The solver called XA was used both for the linear model NO-PSH and for the mixed-integer programming (MIP) model Wind-PSH.

Chapter 4
Case study: Data collection & assumptions

This chapter presents the data collection and processing procedure that was followed, in order to be used as the input of the developed models. Moreover, the main assumptions are described. In the end of the chapter, all the simulated cases are presented.

4.1 Wind speed data

The wind speed data were processed at a first stage and kindly provided by Lina Reichenberg. Lina has processed raw wind data for 52 regions in Europe and filtered them, so that each wind speed corresponds to a wind power output % from the total installed wind capacity. In the wind speed raw data the x-axis represents time and the y-axis speed. These raw data were converted into power output in a Gaussian output curve, where the x-axis represents the wind speed the the y-axis the how much power is produced percentagewise for any corresponding speed, as in Figure 4.1.

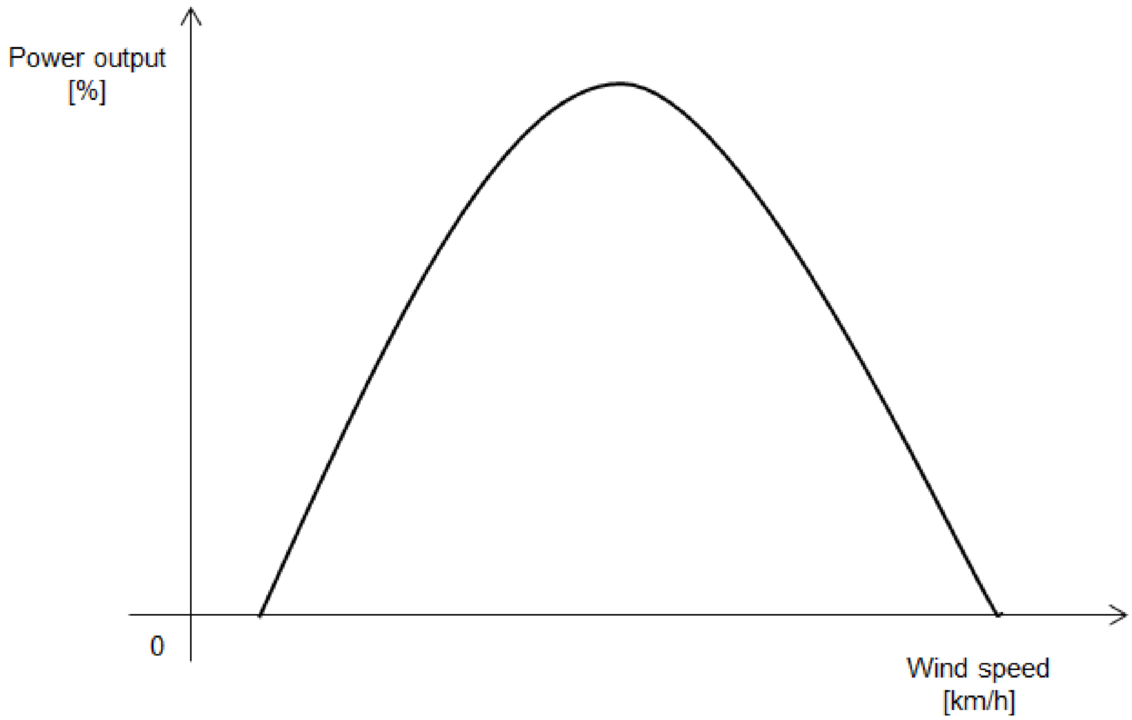

Figure 4.1 Example of wind speed raw data conversion into a Gaussian output curve

After obtaining these data for years 2007, 2008 and 2009 on a 3-hour resolution, wind speed data for the 15th of June and 15th of December 2013 were extracted and the average of each year was calculated for each country. Then the results were converted into an hourly resolution. There was no wind capacity data found for Bosnia & Montenegro, which are grouped into one node as well as for

Former Yugoslav Republic of Macedonia (referred to as FYROM), hence in this thesis it is assumed that they either have no wind power installed or the installed wind power in the country is too low. Regarding Croatia, there were no wind speed data available. For that reason, data from the neighbouring Slovenia were used assuming a 10% increase due to a more extensive coastline in Croatia.

Table 4.1 % of wind power capacity that is producing according to average wind speed data for the 15th of December of the years 2007, 2008, 2009

country \ hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
PT	25.0	25.0	25.0	18.5	18.5	18.5	16.3	16.3	16.3	14.5	14.5	14.5	10.8	10.8	10.8	13.9	13.9	13.9	16.8	16.8	16.8	15.2	15.2	15.2
ES	20.6	20.6	20.6	15.8	15.8	15.8	16.2	16.2	16.2	15.5	15.5	15.5	13.8	13.8	13.8	14.6	14.6	14.6	14.3	14.3	14.3	14.8	14.8	14.8
FR	14.9	14.9	14.9	12.5	12.5	12.5	13.2	13.2	13.2	13.5	13.5	13.5	14.5	14.5	14.5	14.0	14.0	14.0	14.3	14.3	14.3	13.0	13.0	13.0
BE	17.3	17.3	17.3	14.0	14.0	14.0	14.3	14.3	14.3	17.0	17.0	17.0	12.1	12.1	12.1	10.4	10.4	10.4	13.9	13.9	13.9	12.9	12.9	12.9
NL	14.4	14.4	14.4	13.6	13.6	13.6	14.6	14.6	14.6	13.1	13.1	13.1	7.2	7.2	7.2	2.9	2.9	2.9	7.5	7.5	7.5	10.4	10.4	10.4
DE	14.5	14.5	14.5	12.5	12.5	12.5	11.8	11.8	11.8	10.9	10.9	10.9	12.7	12.7	12.7	11.2	11.2	11.2	9.6	9.6	9.6	9.3	9.3	9.3
CH	5.0	5.0	5.0	4.5	4.5	4.5	5.9	5.9	5.9	6.2	6.2	6.2	6.8	6.8	6.8	3.4	3.4	3.4	3.5	3.5	3.5	2.9	2.9	2.9
IT	17.8	17.8	17.8	19.3	19.3	19.3	20.7	20.7	20.7	21.3	21.3	21.3	22.0	22.0	22.0	20.4	20.4	20.4	16.8	16.8	16.8	14.4	14.4	14.4
AT	12.1	12.1	12.1	10.7	10.7	10.7	9.8	9.8	9.8	10.5	10.5	10.5	13.4	13.4	13.4	14.3	14.3	14.3	11.5	11.5	11.5	13.1	13.1	13.1
CZ	23.9	23.9	23.9	22.0	22.0	22.0	22.3	22.3	22.3	23.9	23.9	23.9	32.4	32.4	32.4	30.8	30.8	30.8	24.5	24.5	24.5	28.4	28.4	28.4
PL	18.3	18.3	18.3	16.1	16.1	16.1	17.1	17.1	17.1	17.5	17.5	17.5	16.3	16.3	16.3	13.3	13.3	13.3	14.4	14.4	14.4	14.0	14.0	14.0
SK	12.0	12.0	12.0	11.9	11.9	11.9	13.1	13.1	13.1	15.9	15.9	15.9	18.5	18.5	18.5	19.7	19.7	19.7	21.2	21.2	21.2	22.3	22.3	22.3
HU	16.5	16.5	16.5	14.1	14.1	14.1	17.6	17.6	17.6	19.3	19.3	19.3	23.5	23.5	23.5	23.5	23.5	23.5	19.4	19.4	19.4	19.2	19.2	19.2
SL	19.1	19.1	19.1	19.6	19.6	19.6	19.2	19.2	19.2	19.4	19.4	19.4	27.6	27.6	27.6	26.4	26.4	26.4	21.7	21.7	21.7	18.6	18.6	18.6
HR	21.0	21.0	21.0	21.5	21.5	21.5	21.1	21.1	21.1	21.4	21.4	21.4	30.4	30.4	30.4	29.0	29.0	29.0	23.9	23.9	23.9	20.5	20.5	20.5
BA+ME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FYROM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BG	10.3	10.3	10.3	10.2	10.2	10.2	11.6	11.6	11.6	11.1	11.1	11.1	12.3	12.3	12.3	8.7	8.7	8.7	8.4	8.4	8.4	8.2	8.2	8.2
RO	14.5	14.5	14.5	14.4	14.4	14.4	15.2	15.2	15.2	16.3	16.3	16.3	18.4	18.4	18.4	17.0	17.0	17.0	17.4	17.4	17.4	18.6	18.6	18.6
GR	9.8	9.8	9.8	10.2	10.2	10.2	11.1	11.1	11.1	11.4	11.4	11.4	13.8	13.8	13.8	10.9	10.9	10.9	8.3	8.3	8.3	7.7	7.7	7.7
FI	12.5	12.5	12.5	13.7	13.7	13.7	12.5	12.5	12.5	10.0	10.0	10.0	7.2	7.2	7.2	5.8	5.8	5.8	6.9	6.9	6.9	7.7	7.7	7.7
SE	11.0	11.0	11.0	9.9	9.9	9.9	8.1	8.1	8.1	6.3	6.3	6.3	5.5	5.5	5.5	5.8	5.8	5.8	7.6	7.6	7.6	9.2	9.2	9.2
NO	18.6	18.6	18.6	16.7	16.7	16.7	13.5	13.5	13.5	9.3	9.3	9.3	8.8	8.8	8.8	11.5	11.5	11.5	13.8	13.8	13.8	16.4	16.4	16.4
DK	16.6	16.6	16.6	12.1	12.1	12.1	11.7	11.7	11.7	12.5	12.5	12.5	11.6	11.6	11.6	13.2	13.2	13.2	12.5	12.5	12.5	14.1	14.1	14.1
UK	19.2	19.2	19.2	18.4	18.4	18.4	18.9	18.9	18.9	18.8	18.8	18.8	19.5	19.5	19.5	22.7	22.7	22.7	19.7	19.7	19.7	21.0	21.0	21.0

Plotting Table 4.1 gives a wind production profile for each country throughout the reference winter day (Figure 4.2). However, this is only indicative, since due to the large amount of countries and the congestion of the values ranging from approximately 5-25%, it is difficult to get a clear picture. During the winter day, which is the 15th of December for years 2007-2009, the results for all countries but Belgium, Sweden and Denmark show an increased production in comparison to the summer day, as it can be seen in Figure 4.2 and Figure 4.3. In some cases such as Bulgaria, Italy, Slovenia, Croatia and Romania production increase spanned from 3 to 6 times more than during summer.

In Figure 4.2, no peaks are observed for individual countries, but the wind speed profile follows a rather consistent pattern for all European countries. Czech Republic is on the top producing countries with a 26% of total production followed by Slovenia, Croatia, UK, Hungary and Italy with a load factor ranging from 23.6% down to 19.1%. In order to derive the final maximum production, these values are multiplied with the total installed capacity in each country.

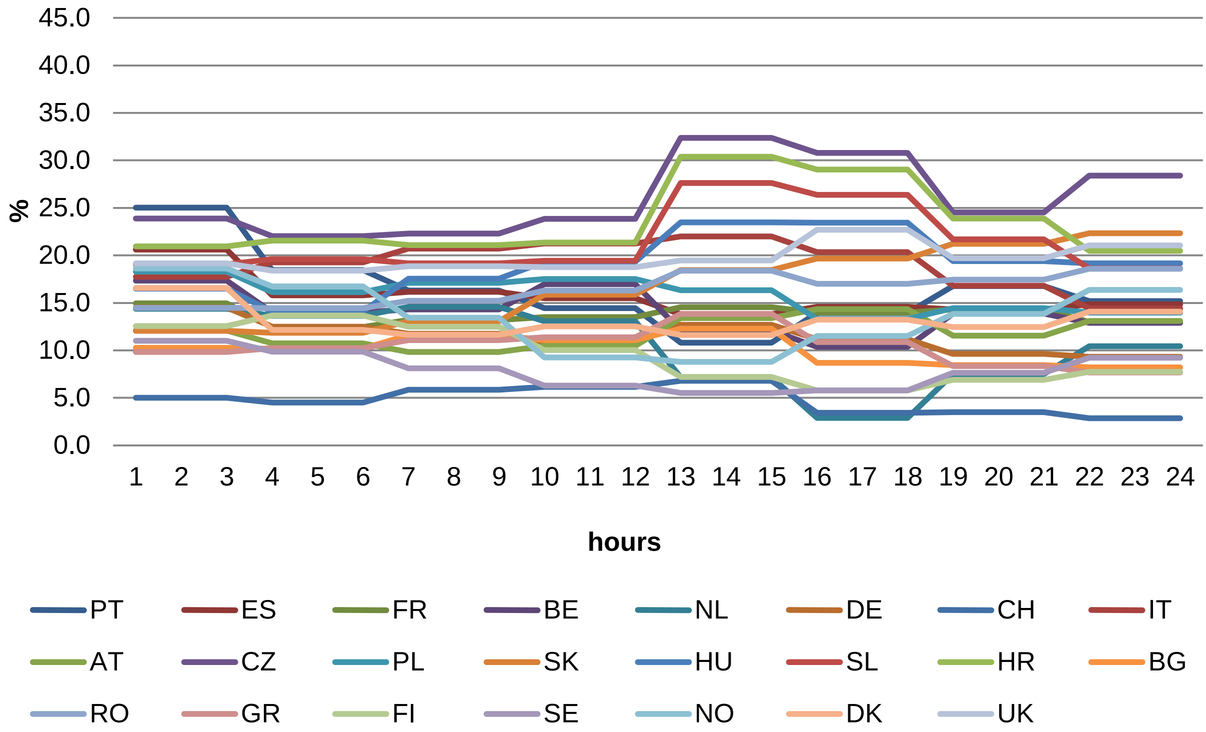

Figure 4.2 Graphical representation of Table 4.1

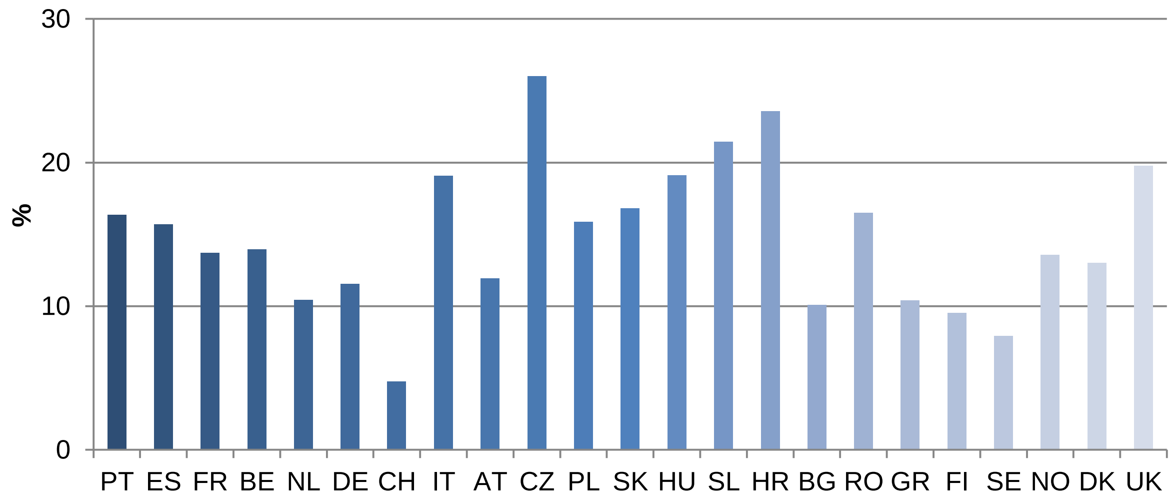

Figure 4.3 Average % of producing capacity throughout the reference winter day

Regarding the wind power production during the summer day, the smooth wind profile remains at large. It is evident though, that Czech Republic has an extraordinary peak from h3 to h12, whereas Belgium, Poland, Denmark and Portugal enjoy a few local peaks during afternoon and evening hours h13-h24. In Figure 4.5 the average wind resources throughout the random summer day is presented, where Belgium, Czech and Denmark are on the top averaging a production of 20.1-21%. On the other end, Bulgaria with a 1.7% average production of total capacity and Switzerland with 2.8% had the least wind resources for the chosen day of years 2007-2009.

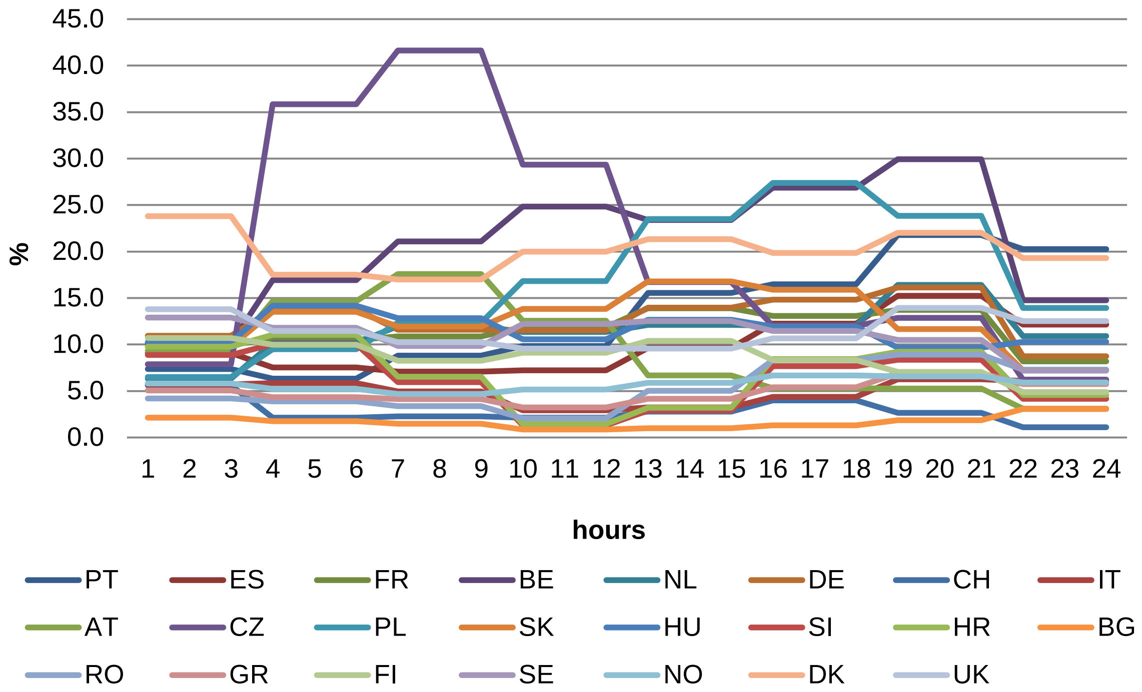

Figure 4.4 Graphical representation of wind power production levels during the reference summer day (15th of June) of years 2007, 2008, 2009

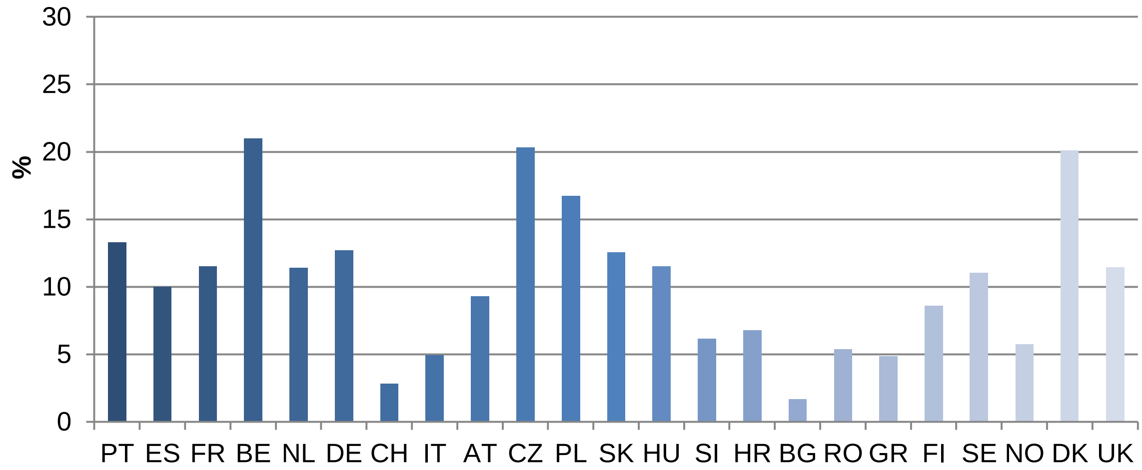

Figure 4.5 Average % of producing capacity throughout the random reference summer day

According to these data and the total installed wind power capacity, a maximum wind power production value, which is varying every 3 hours for each country, is created. Each iteration increases this power output of each country by 500MW as it can be seen in Table 4.2, which shows all iterations for the Winter 2013 case. If the maximum wind power output for one country is reached, then for all following iterations the wind power production is set to maximum. Thus, after the last iteration which in this case is the 10th iteration, all countries have reached maximum possible capacity according to the historical wind speed data from 2007, 2008 and 2009.

Table 4.2 Wind power output for each country in MW during 10 iterations for the Winter 2013 case at 12.00

Country	1st iteration	2nd iteration	3rd iteration	4th iteration	5th iteration	6th iteration	7th iteration	8th iteration	9th iteration	10th iteration
PT	500.0	683.0	683.0	683.0	683.0	683.0	683.0	683.0	683.0	683.0
ES	500.0	1000.0	1500.0	2000.0	2500.0	3000.0	3500.0	3553.8	3553.8	3553.8
FR	500.0	1000.0	1115.2	1115.2	1115.2	1115.2	1115.2	1115.2	1115.2	1115.2
BE	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0
NL	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5
DE	500.0	1000.0	1500.0	2000.0	2500.0	3000.0	3500.0	3671.6	3671.6	3671.6
CH	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
IT	500.0	1000.0	1500.0	1818.2	1818.2	1818.2	1818.2	1818.2	1818.2	1818.2
AT	176.0	176.0	176.0	176.0	176.0	176.0	176.0	176.0	176.0	176.0
CZ	64.2	64.2	64.2	64.2	64.2	64.2	64.2	64.2	64.2	64.2
PL	500.0	593.7	593.7	593.7	593.7	593.7	593.7	593.7	593.7	593.7
SK	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
HU	63.6	63.6	63.6	63.6	63.6	63.6	63.6	63.6	63.6	63.6
SI	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
HR	64.5	64.5	64.5	64.5	64.5	64.5	64.5	64.5	64.5	64.5
BA+ME	-	-	-	-	-	-	-	-	-	-
FYROM	-	-	-	-	-	-	-	-	-	-
BG	75.5	75.5	75.5	75.5	75.5	75.5	75.5	75.5	75.5	75.5
RO	424.0	424.0	424.0	424.0	424.0	424.0	424.0	424.0	424.0	424.0
GR	212.1	212.1	212.1	212.1	212.1	212.1	212.1	212.1	212.1	212.1
FI	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
SE	281.4	281.4	281.4	281.4	281.4	281.4	281.4	281.4	281.4	281.4
NO	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1	71.1
DK	500.0	598.1	598.1	598.1	598.1	598.1	598.1	598.1	598.1	598.1
UK	500.0	1000.0	1500.0	1976.1	1976.1	1976.1	1976.1	1976.1	1976.1	1976.1

It is quite obvious from Table 4.2 that many countries have already reached their maximum output from the 1st iteration. As iterations increase, it is evident that the total wind power output in Europe is increasing less and less. For example, the only increase from 7th to 8th iteration is Spain's output by 53.8MW and Germany's 171.6MW. The rest of the countries have already reached their maximum output before. The reason of having a 9th and 10th iteration is simply because Table 4.2 is a snapshot which only shows one hour of the whole day, at 12.00. However, maximum output according to the winter data occurs in Germany from hour 1 to hour 3 and can only be simulated by a 10th iteration.

4.2 Solar power data

Due to a lack of regional solar data a more simplistic approach was used regarding solar energy output. A flat capacity factor of 15% of total capacity is assumed for the year 2013, whereas this capacity factor is increased to 20% for year 2020, assuming that a technological development is both expected and needed in order to make solar power competitive compared to other electricity sources. It is not essential that this capacity factor depicts only efficiency improvement, but it can also compensate for a decrease in variable costs of the solar power, since the price is constant throughout the base case scenarios for all simulated years and cases.

4.3 Hydro inflow data

Assumed hydro inflow data were kindly provided by Mikael Odenberger who works with the department of Energy & Environment, division of Energy Technology at Chalmers University of Technology. The data were handed out on an hourly basis for the whole year. Thus, one winter and one summer day, namely the 15^{th} of December and the 15^{th} of June, were extracted and used later for the model for all winter and summer cases respectively. The hydro reservoir levels are always assumed between 10% and 90% of the actual reservoir limit for each country. No lower than 10% is allowed to avoid mechanical damage and no higher than 90%, in order to avoid spillage.

4.4 Grid model

The study includes 25 countries as well as the main interconnections between them. The model from Papaemmanouil [4] included 20 countries from Central Southern and Eastern Europe and the current model was expanded to include also Northern Europe namely the United Kingdom, Denmark, Sweden, Norway and Finland. In the context of this study one node-per-country is simulated and the nodes are interconnected only if a physical interconnection also exists. The grid model that was used in this study is presented in Figure 4.6.

The production mix of the countries-nodes includes 7 technologies for the NO-PSH model, namely hydro, coal, gas, nuclear, solar, wind and other renewables, according to data retrieved from the European Commission [7] [23]. Other renewables include technologies such as biomass, wave or tidal power. Wind-PSH model is simulated with 8 technologies, the same 7 from NO-PSH model, plus the pumped-storage hydro units. The load profiles of the countries were retrieved from publicly available data from ENTSO-E [20]

Regarding the cost of producing electricity, a marginal production cost for each technology and country was assigned in €/MWh. Then, depending on production mix and exchange between countries a locational marginal price for each country is calculated for each case, using the model described in Chapter 3.

4.5 Net transfer capacities between European countries

Net transfer capacities (NTCs) for the countries are extracted from ENTSO-E’s website [20] and were kept constant throughout the years (Table 4.3), as transmission investment decisions are a complex decision, difficult to predict and there were no data available in literature. Instead, the model results are expected to show where the biggest need for reinforcement is and what limits are violated in all cases.

Figure 4.6 Grid model of countries simulated in the models including the respective interconnections between countries

Table 4.3 NTC Values for the year 2010-2011 [20]

NTC Values 2010-2011					
Interconnection		MW	Interconnection		MW
PT	ES	1700	HU	HR	1200
ES	FR	1300	HU	BA+ME	700
FR	BE	3400	HU	RO	700
FR	DE	3200	SI	HR	1000
FR	CH	3200	HR	BA+ME	600
FR	IT	2575	BA+ME	FYROM	500
BE	NL	2400	BA+ME	BG	450
NL	DE	3850	BA+ME	RO	700
DE	CH	3500	BA+ME	GR	1000
DE	AT	2200	FYROM	GR	400
DE	CZ	2480	BG	RO	600
DE	PL	1200	BG	GR	550
CH	IT	4165	FI	SE	2050
CH	AT	1200	SE	NO	3895
IT	SI	580	IT	GR	500
AT	CZ	1000	SE	PL	600
AT	HU	800	SE	DE	610
AT	SI	900	SE	DK	1700
CZ	PL	1800	NO	DK	950
CZ	SK	2200	NO	NL	700
PL	SK	600	DK	DE	1500
SK	HU	1300	UK	FR	2000

4.6 Simulated cases and scenarios

The simulations ran for multiple cases. The base year was 2013, when the model tested 4 different days, two winter days (Wednesday & Sunday) and two summer days (Wednesday & Saturday). Then, based on data and estimates from several sources one more year was simulated. A future approach was simulated for year 2020 according to estimates from ENTSO-E [10] as well as two more cases with +20% wind power production and -20% wind power production, in order to evaluate different effects of wind production scenarios.

Hereafter, the base case will be referred to as Winter 2013 and includes real load data from the 11th of December 2013 publicly available on the website of ENTSOE-E [20]. Summer 2013 case uses similar load data from the 12th of June 2013. In the Winter 2020 case, apart from a different load scenario and production mix, the rest of the parameters were kept constant. The capacity factor for the solar power was also increased from 15% in 2013 to 20% in all 2020 cases. Regarding the Winter 2020 +20% and Winter 2020 -20% cases, a 20% increase and 20% decrease respectively of the wind power production and not the installed capacity is implemented. A table summarizing all the simulated cases and giving a brief description of a few characteristics of each one can be found below in Table 4.4

Table 4.4 Simulated cases

Case No	Name	Description
1.	Winter 2013	Base case – 11th December 2013 (load data)
2.	Summer 2013	Load data from 12th June 2013
3.	Winter 2020	2020 scenario based on ENTSO-E
4.	Winter 2020 +20%	Increased wind production by 20% compared to 3)
5.	Winter 2020 -20%	Decreased wind production by 20% compared to 3)

Chapter 5
Case Study: Results & Discussion

In this chapter the main results will be presented for all the simulated cases. Some preliminary conclusions will also be drawn before a more generalized perspective will be discussed in the last part of the chapter. The results are categorized under three main areas: effects on system costs and prices, effects on congestion and effects on CO_2 *emissions. In "Effects on system costs and prices" an insight on the total system costs with and without PSH as well as a snapshot of the LMP of all countries at 12.00 a.m. is presented. "Effects on congestion" groups the results into three main categories, namely Winter 2013, Summer 2013 and Winter 2020, which includes the three 2020 simulated cases. Finally, in "Effects on system emissions" possible* CO_2 *emission reductions due to the implementation of PSH are investigated and presented.*

5.1 Effects on system costs and prices

As described earlier, in this part of the Chapter the effects of the introduction of PSH into the European power grid will be analysed. This section is divided into six different parts. Each of the first five parts shows the total system cost curve in regards, first, to the wind power penetration levels increase per country when no PSH is included in the system and, secondly, to both the wind and PSH penetration levels increase per country. The third graph always shows the total system cost reduction between the 0% PSH utilization per country and the 100% PSH utilization, when all available PSH capacity is used for all the investigated countries. The sixth and last part of this section gives a visual understanding on what the LMP of all countries was during the 12th hour of the simulations for each case, i.e. 12.00 p.m.

Each country has a maximum PSH and wind power capacity, according to the installed capacity of each country. During the simulation steps of 0.5GW each were used both for wind and PSH. This practically means that whenever a graph indicates, for example 2.5GW of installed capacity (either PSH or wind power), all countries whose capacity exceeds the 2.5GW limit are set to 2.5 GW. The countries whose capacity is less than the current iteration's capacity are set to their capacity limit value. This results in a situation where the closer we get to the last iteration the less countries increase their production, since towards the end the vast majority of the countries has already reached their physical limit. This fact needs to be greatly acknowledged and considered when our analysis is conducted and before any final conclusions are drawn.

5.1.1 Winter 2013

According to Figure 5.1, the total system costs span from almost 298 M€ during the first iteration to around 290 M€ on the last iteration of 5GW wind power, where all countries have reached their capacity limit. Figure 5.2 shows the same relation, but the lower the line, in regards to total system costs gets, the higher the total installed PSH capacity is. Apparently, the total capacity difference is much less between the last two iterations that it is between the initial ones, since many more countries have already reached their capacity limit before 3.5 GW, hence, the price decrease is very small.

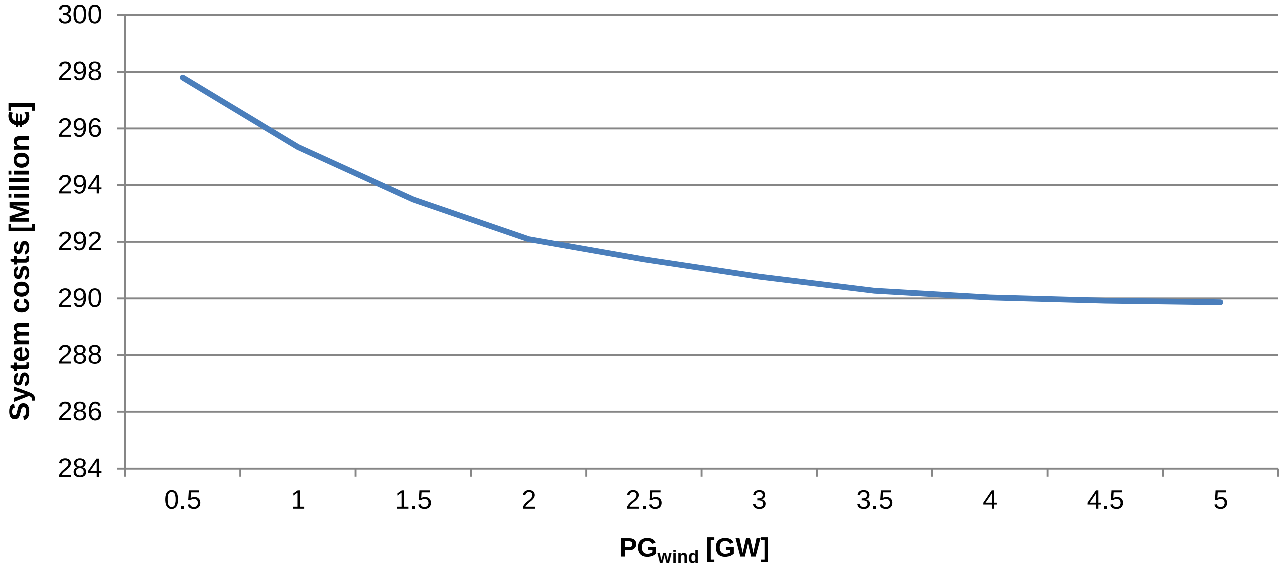

Figure 5.1 Total system costs for one day without PSH in the system, winter 2013

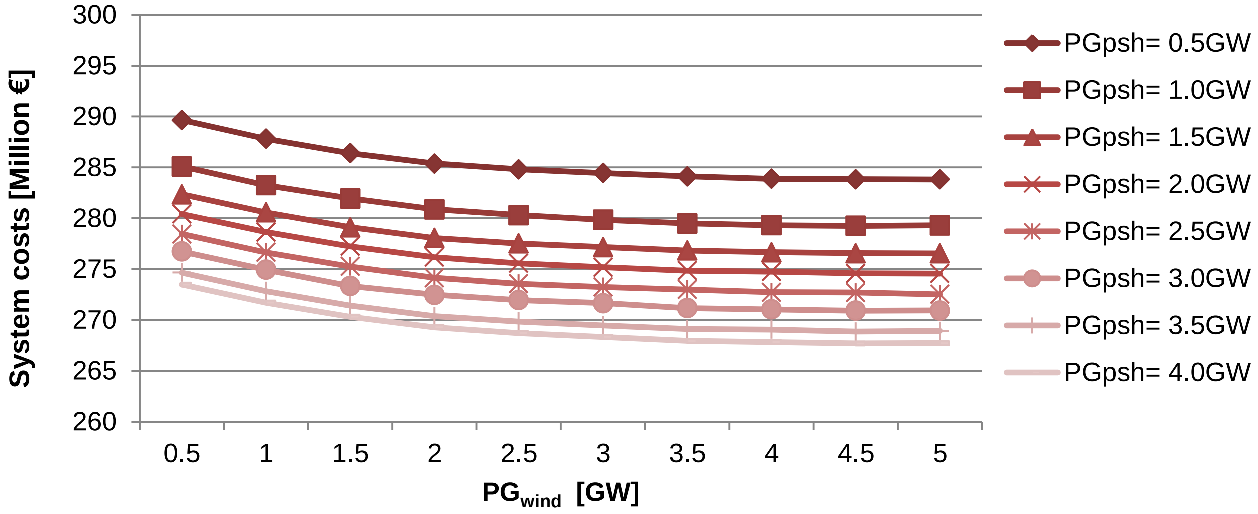

Figure 5.2 Total system costs for one day for different PSH penetration levels in the system, winter 2013

The difference between the system costs with no PSH and full PSH utilization is plotted in Figure 5.3. The green unmarked line in the middle is illustrating the percentagewise system cost reduction with different steps of wind power penetration levels. We can see that above 3 GW of wind power production, no significant further cost reduction is observed. More specifically, at the 3 GW step the total system costs are reduced by 7.72%, whereas at full wind power production of 5 GW this reduction is down to 7.64%. This is partly because most of the available wind production has been reached and partly because at this point and on there is no significant further reduction to be made due to more wind production.

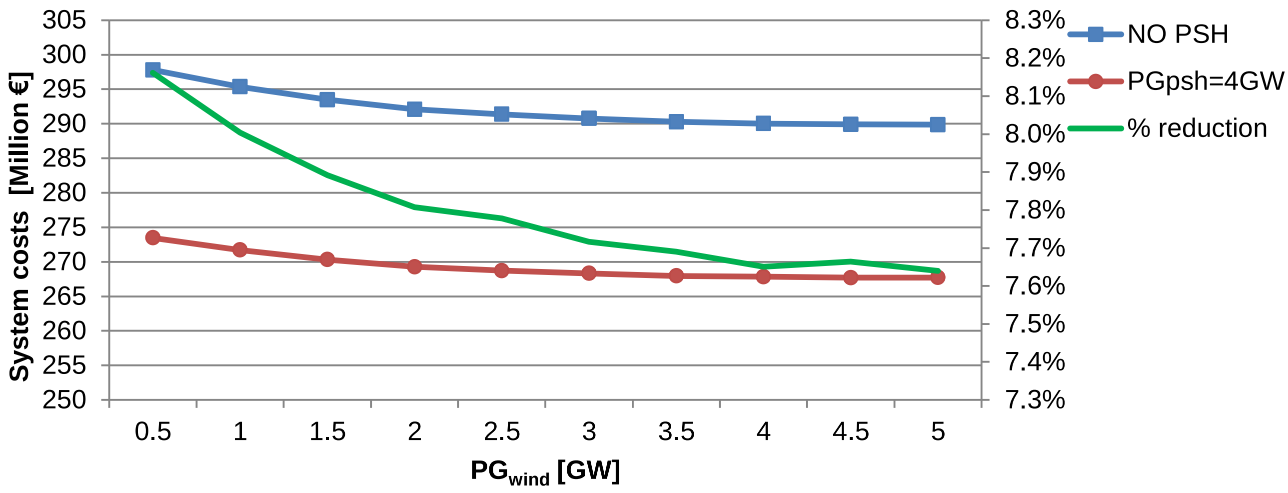

Figure 5.3 System cost difference between no PSH and maximum PSH case and % reduction for different wind penetration levels, winter 2013 case

5.1.2 Summer 2013

The results do not show a particular difference during the Summer 2013 case, besides the fact that the system costs have dropped considerably due to lower overall demand during the summer period. Both the drop in system cost as well as the same pattern that the system curve follows can be observed in Figure 5.4 and Figure 5.5 for the NO-PSH and the Wind-PSH case respectively.

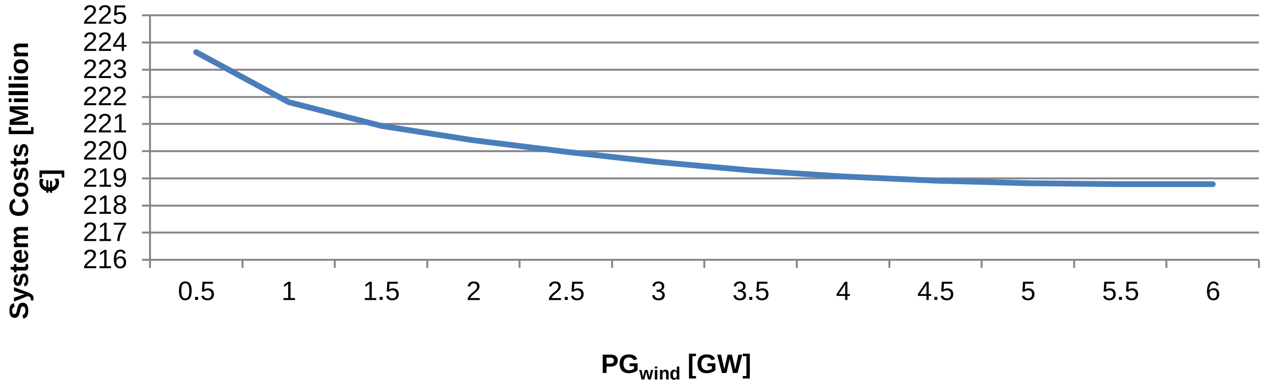

Figure 5.4 Total system costs without PSH in the system, summer 2013

In Figure 5.5, we can also see a slightly increased wind generation in comparison to Winter 2013, since the PG_{wind} axis is extended up to 6 GW during Summer 2013 compared to 5 GW during Winter 2013. On the other hand, PSH production levels do not indicate any significant changes as maximum installed PSH capacity per country is set at 4 GW in both simulated cases, according to the data.

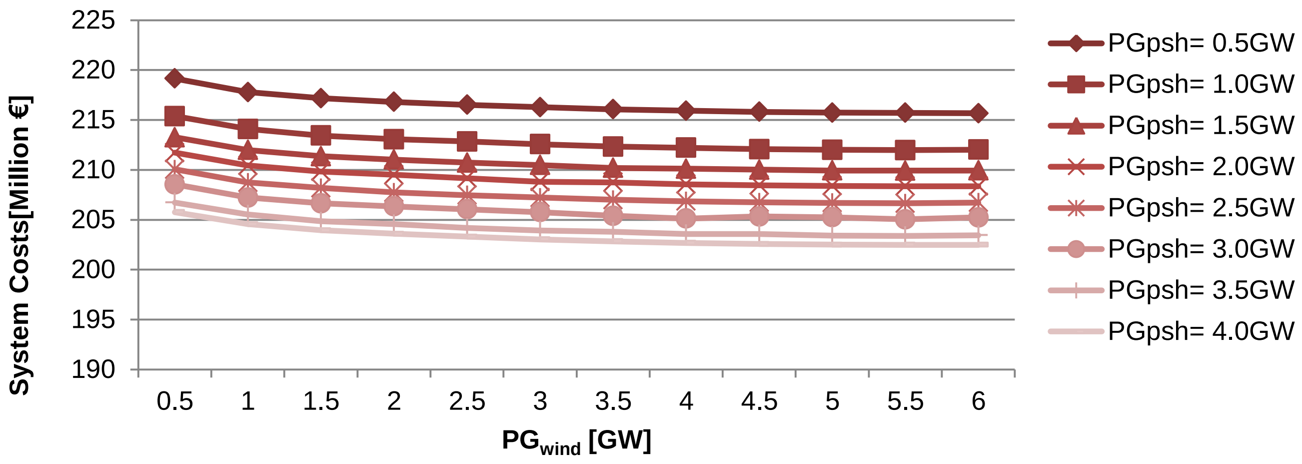

Figure 5.5 Total system costs for different PSH penetration levels in the system, summer 2013

What is slightly different compared to the base case scenario of Winter 2013 is that in Figure 5.6, the reduction percentage curve does not present a turbulent but rather a smooth slope which stabilizes between 7.5% and 7.4% cost reduction after the 8th iteration, which corresponds to 4 GW of actual wind power production from the countries that can provide this capacity.

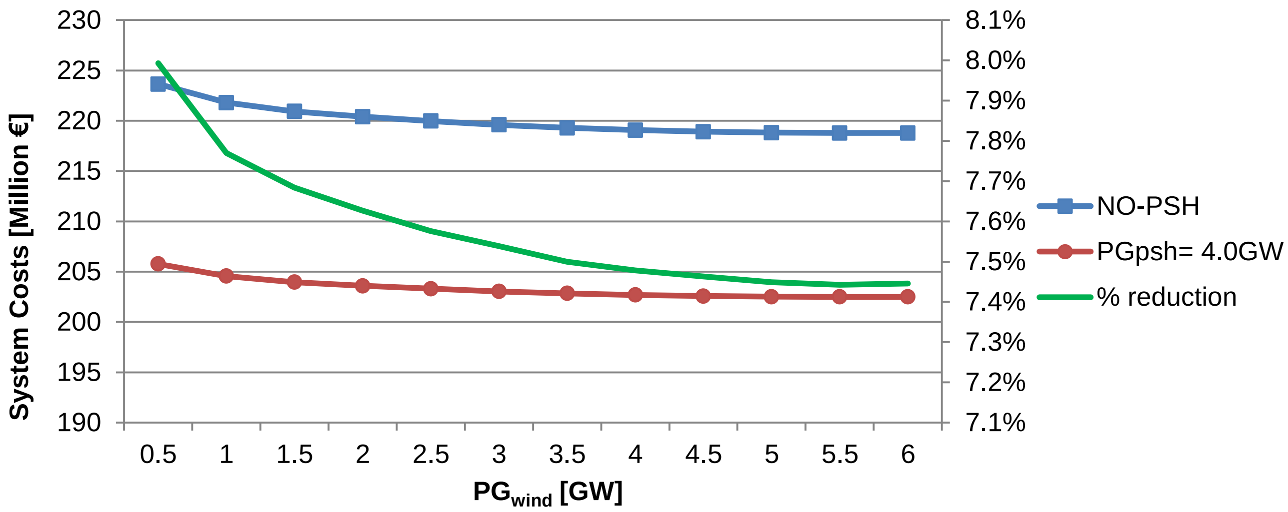

Figure 5.6 System cost difference between no PSH and maximum PSH case and % reduction for different wind penetration levels, summer 2013 case

5.1.3 Winter 2020

During the Winter 2020 scenario the system was simulated, in order to get a clear picture of how much the system costs are expected to increase and what the dynamics of the system are, namely whether the system has the same behaviour with different levels of wind power penetration. For that reason, a high wind scenario (+20% wind power production) and a low wind scenario (-20% wind production) were simulated, besides the base case Winter 2020 scenario.

Figure 5.7 and Figure 5.8 show that our system shows the same behaviour cost-wise. The graphs also show a large system cost increase of around 40% in many instances as compared to the Winter 2013 base case. This can naturally be attributed to the increased power demand, while no significant amount of wind power is introduced in the system. On the other hand this cost increase is reduced to around 35% for the NO-PSH scenario. This increase becomes over 46% with minimum PSH production and 36% with maximum PSH storage production for the Wind-PSH scenario. It should be noted here, that the maximum wind and PSH production between 2013 and 2020 differ considerably, but for maximum wind power production and same level of PSH production, which corresponds to the maximum level for 2013 case and a middle-range production (at 4 GW of PSH capacity) for 2020 the system cost increase is around 40%. Hence, we can say that introduction of PSH storage can help drive system costs down not only by more efficient usage of the wind power production through storage, but also through their actual production capacity by ruling out expensive technologies.

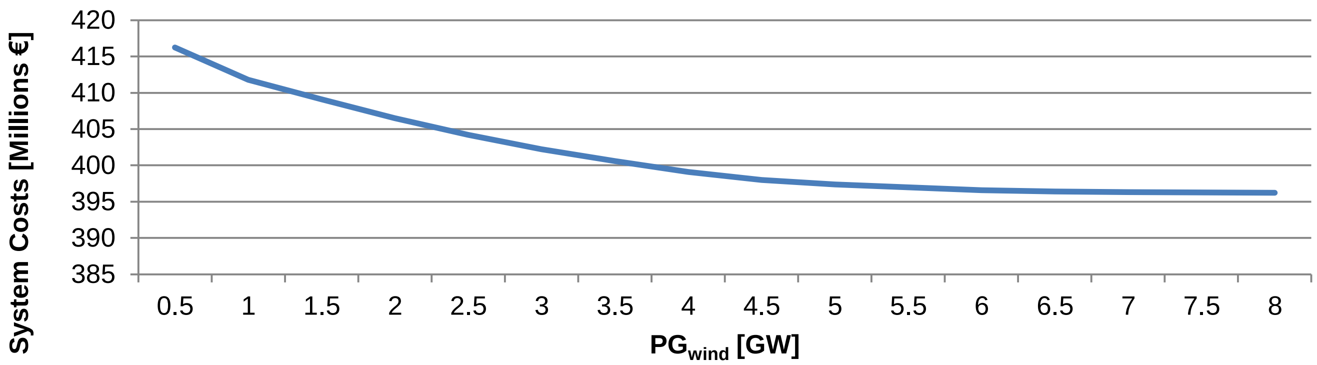

Figure 5.7 Total system costs during one day without PSH in the system, Winter 2020

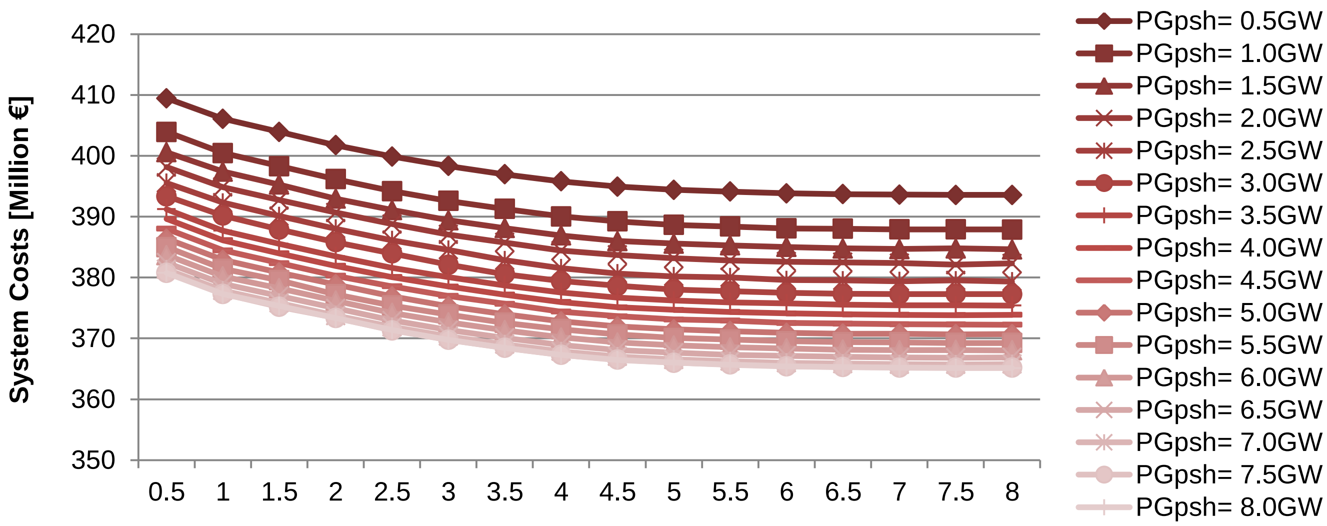

Figure 5.8 Total system costs for different PSH penetration levels in the system, Winter 2020

Looking at the same scenario, Figure 5.9 displays how wind power production contributes to the system cost reduction between the NO-PSH and Wind-PSH cases. Although with minimum production of wind power the reduction is over 8.5%, after the 10th iteration, hence 5 GW maximum production per country this reduction seems to stabilize below 7.9%. From that point and onwards, wind is not significantly causing the system costs to decrease, but the positive consequences of increased wind production are enlarged.

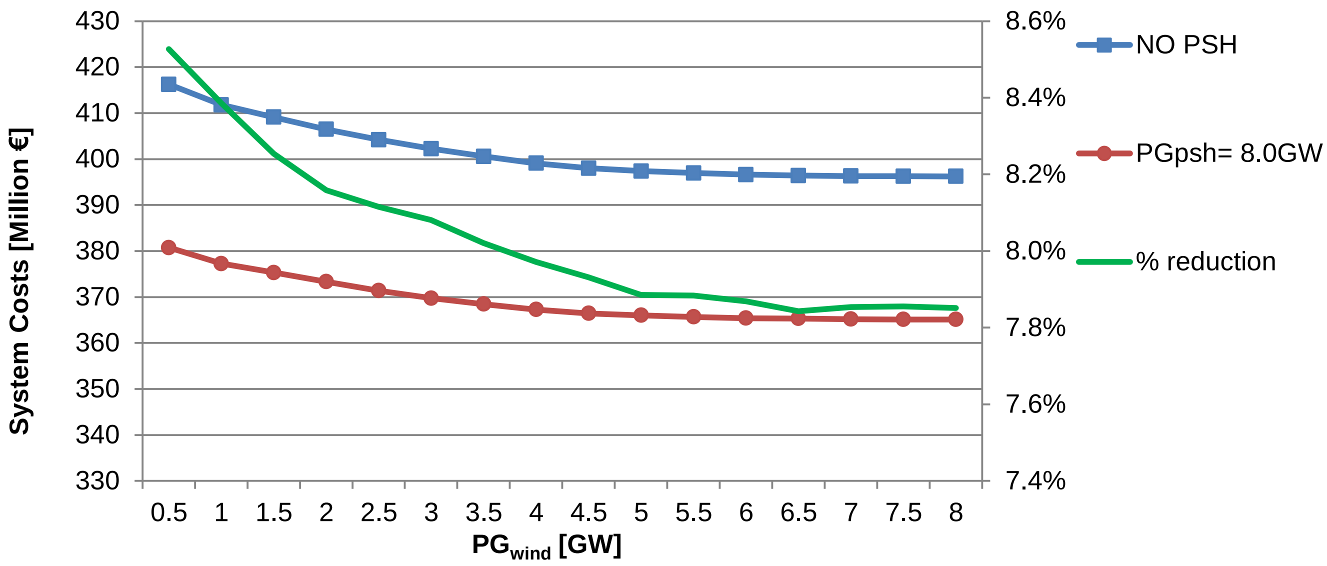

Figure 5.9 System cost difference between no PSH and maximum PSH case and % reduction for different wind penetration levels, winter 2020 case

5.1.4 Winter2020 +20% wind penetration

The Winter 2020 +20% wind scenario was simulated in order to see the system properties after introducing a considerable amount of extra wind into the already simulated 2020 future scenario. For that reason, 20% more wind is added to the maximum production of each country. That means that for the same iteration number, for instance the 8th iteration, hence 4 GW of maximum production per country, there is not the same amount of wind into the system between the 2020 and the 2020 +20% scenarios. This is because already during that iteration the total capacity of many countries that would be reached at the 2020 scenario is increased by 20% more during the 2020 +20%. In order to calculate how much more capacity is introduced after every 0.5 GW step, one needs to look at the specific wind power capacity of each country for each step and sum up the wind power capacity of all countries. This analysis has not been conducted within the framework of this thesis. However, what we are able to say is that at the end of all iterations of 2020 +20% case, the total amount of wind production into the system is increased by 20%. The same applies for the 2020 -20% case that is presented in 5.15.

The total system costs have been decreased in comparison to the base Winter 2020 case. However, this cost decrease for the NO-PSH scenario is in the range of 1.37% meaning that is not proportional to the amount of new wind that has been added to the system. These calculations can be easily conducted by comparing Figure 5.7 and Figure 5.10.

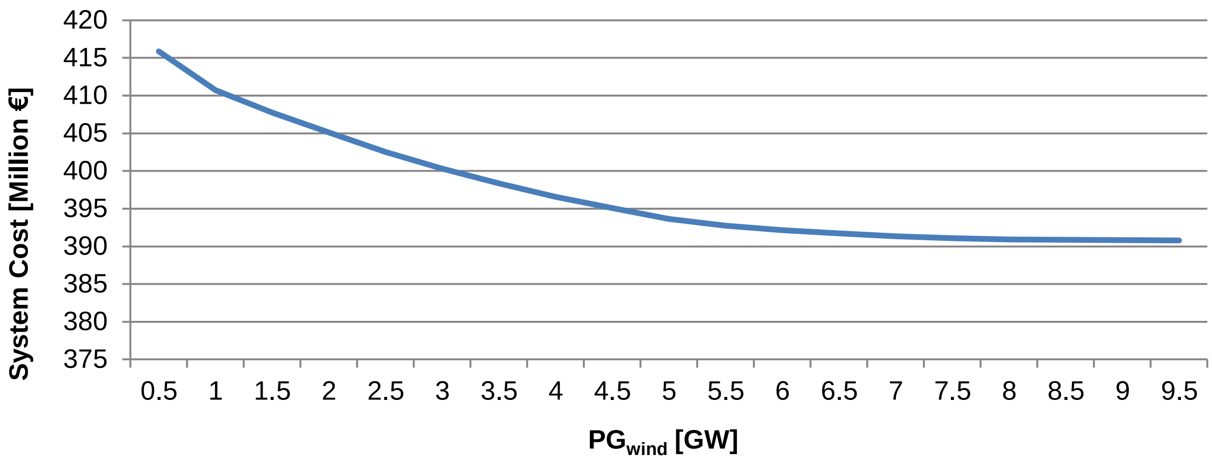

Figure 5.10 Total system costs without PSH in the system, winter 2020 +20% wind penetration

Taking under consideration the maximum available PSH capacity the previous number can be even smaller. For example, at 8 GW of PSH production the cost reduction is around 1.16%, which means that the system operational costs remain almost constant despite the new wind capacity, according to the results from Figure 5.8 and Figure 5.11.

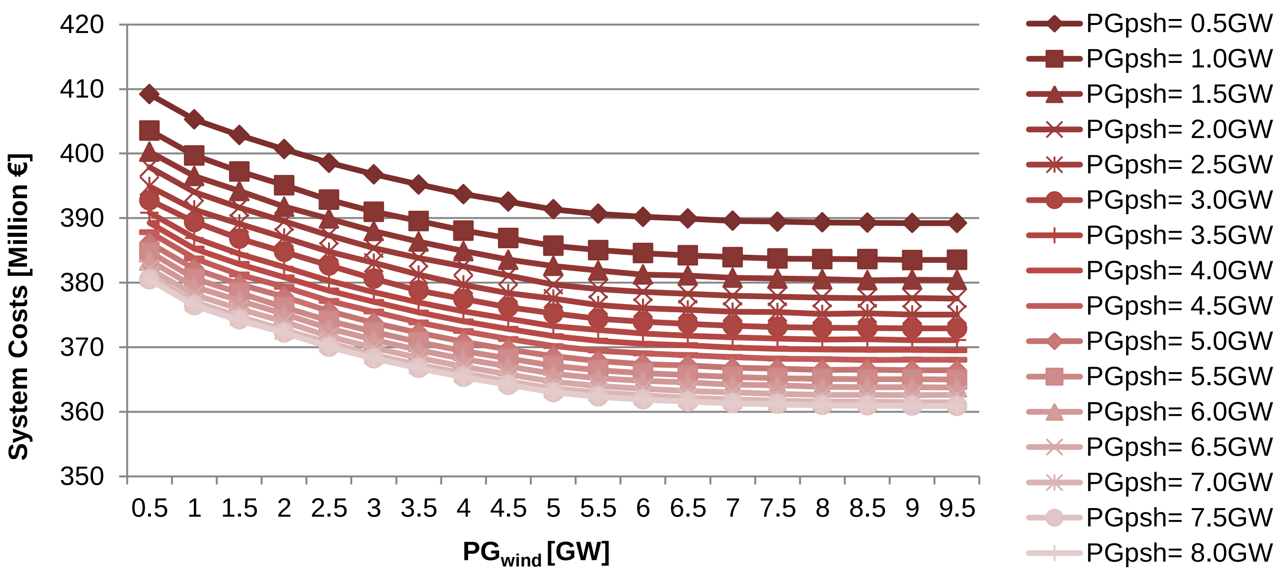

Figure 5.11 Total system costs for different PSH penetration levels in the system, winter 2020 +20% wind penetration

Regarding the system cost reduction due to the implementation of PSH, the numbers do not differ from the previous cases either. The share of cost reduction is dropping as more wind is introduced into the system. After the 13th iteration, hence 6.5 GW of maximum wind per country this decrease stabilizes below 7.7%.

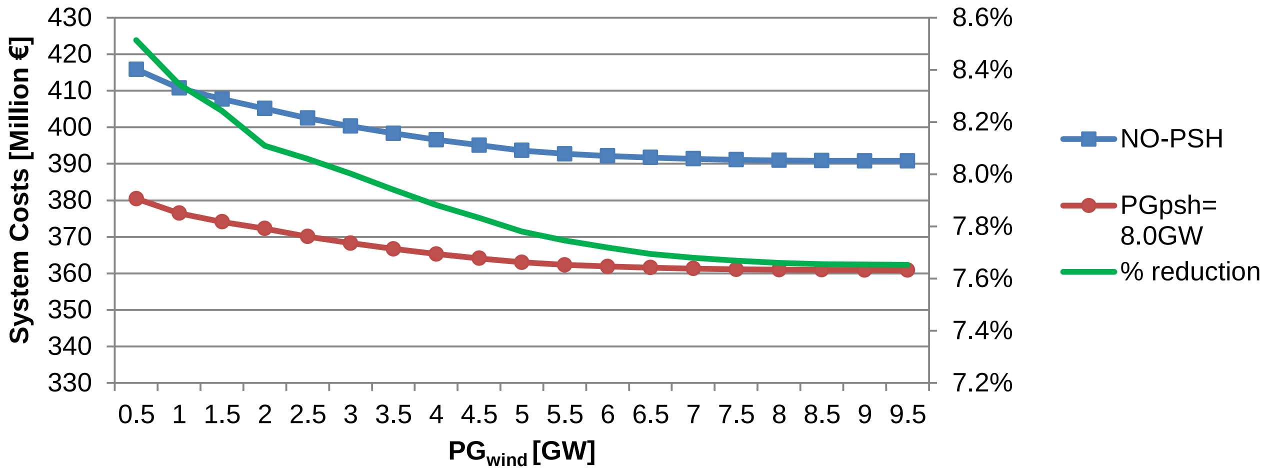

Figure 5.12 System cost difference between no PSH and maximum PSH case and % reduction for different wind penetration levels, winter 2020 +20% case

5.1.5 Winter2020 -20% wind penetratio

Winter 2020 -20% case was simulated to check the system's reaction to less renewable generation and in this case less wind production. As described in 5.1.4, we cannot see exactly how much less wind power production we have in individual iterations unless we add up the actual production from each country.

Figure 5.13 shows the price increase in the -20% case compared to the 2020 base case. The increase is 1.38% at the maximum wind production for the NO-PSH whereas the respective increase in the Wind-PSH model is 1.17% at maximum 6.5GW PSH production.

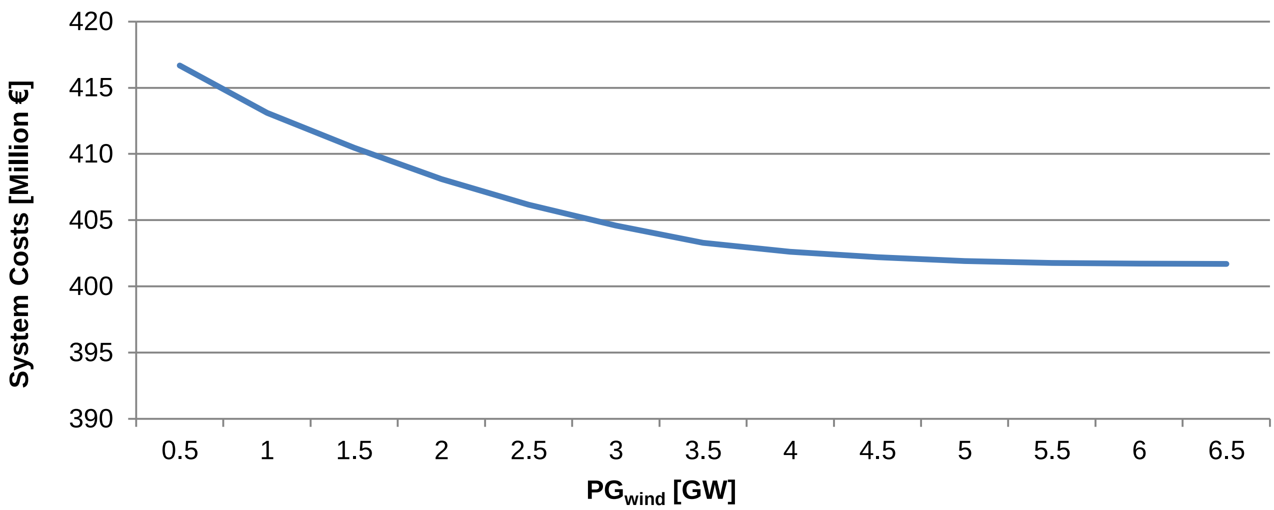

Figure 5.13 Total system costs without PSH in the system, winter 2020 -20% wind penetration

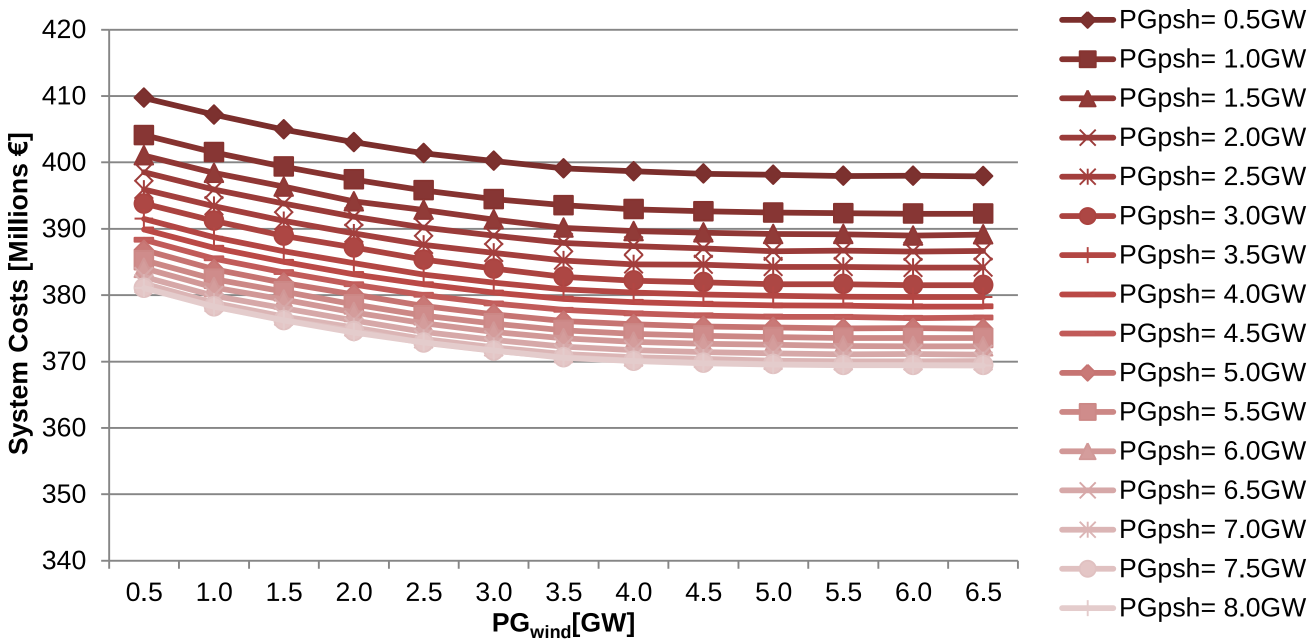

Figure 5.14 Total system costs for different PSH penetration levels in the system, winter 2020 -20% wind penetration

Looking at Figure 5.15, we can see that the cost reduction is stopped at a higher level, namely at around 8.05%. In all previous cases, the percentage of cost reduction was established from 7.85-7.45%.

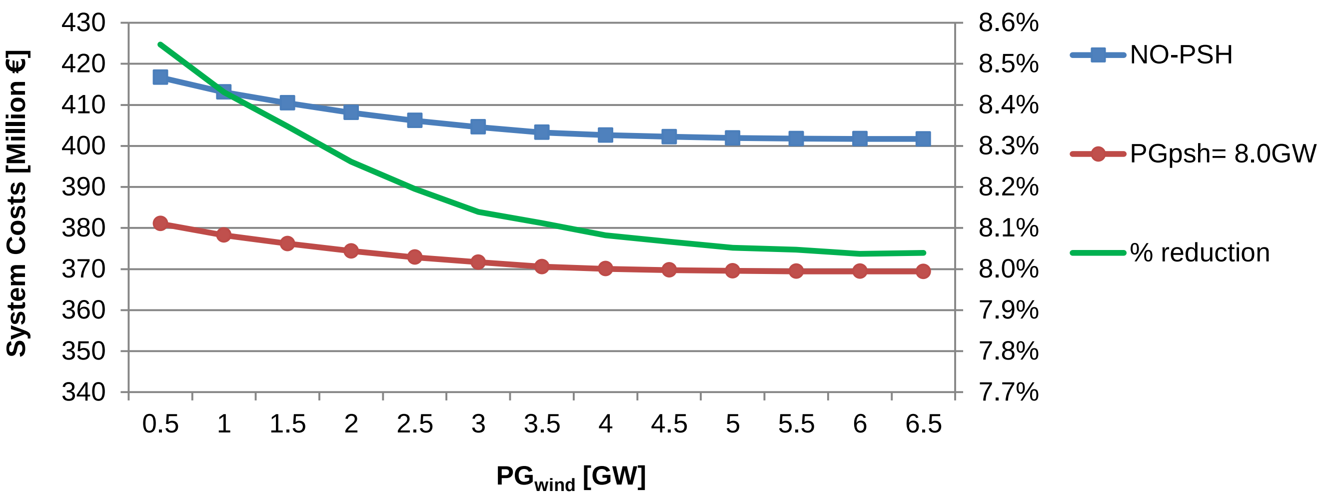

Figure 5.15 System cost difference between no PSH and maximum PSH case and % reduction for different wind penetration levels, winter 2020 -20% case

To sum up, we can say that the system costs are not heavily affected by wind power production or PSH production levels despite a noticeable change in the system costs when the specifications of the system also change. Additionally, there is a more significant change in the system costs when both PSH and wind power is introduced into the system. This decrease is less while more wind is introduced, hence in the 2020 -20% case yields the higher overall reduction rate among the simulated cases.

Table 5.1 Cost reduction between for all simulated cases

Case	% of cost reduction between Wind-PSH with max PG_{PSH} and NO-PSH model
Winter 2013	7.64%
Summer 2013	7.45%
Winter 2020	7.85%
Winter 2020 +20%	7.65%
Winter 2020 -20%	8.04%

Table 5.1 summarizes the cost reduction that can be achieved when full PSH capacity is exploited at full wind capacity for each specific case. We can see that the cost reduction varies from 7.45% in Summer 2013 to 8.04% in Winter 2020 -20%. In Figure 5.16 an attempt to visualize the difference in system costs between the simulated cases is attempted. Cases Winter 2013 and Summer 2013 are plotted in separate axes compared to the future 2020 cases, because of the large increase in costs during 2020. 2013 cases show a price difference greater than 32%. Summer 2013 is significantly different due to a lower load. On the other hand, the 2020 case do not have major price variations. For instance, 2020 +20% has 1.17% higher system costs compared to Winter 2020, whereas 2020 – 20% has lower total system costs by 1.15%. Since the major difference between the three cases is the wind power output, Figure 5.16 proves that load variations are a major cost driver, whereas wind output does not affect significantly the system costs.

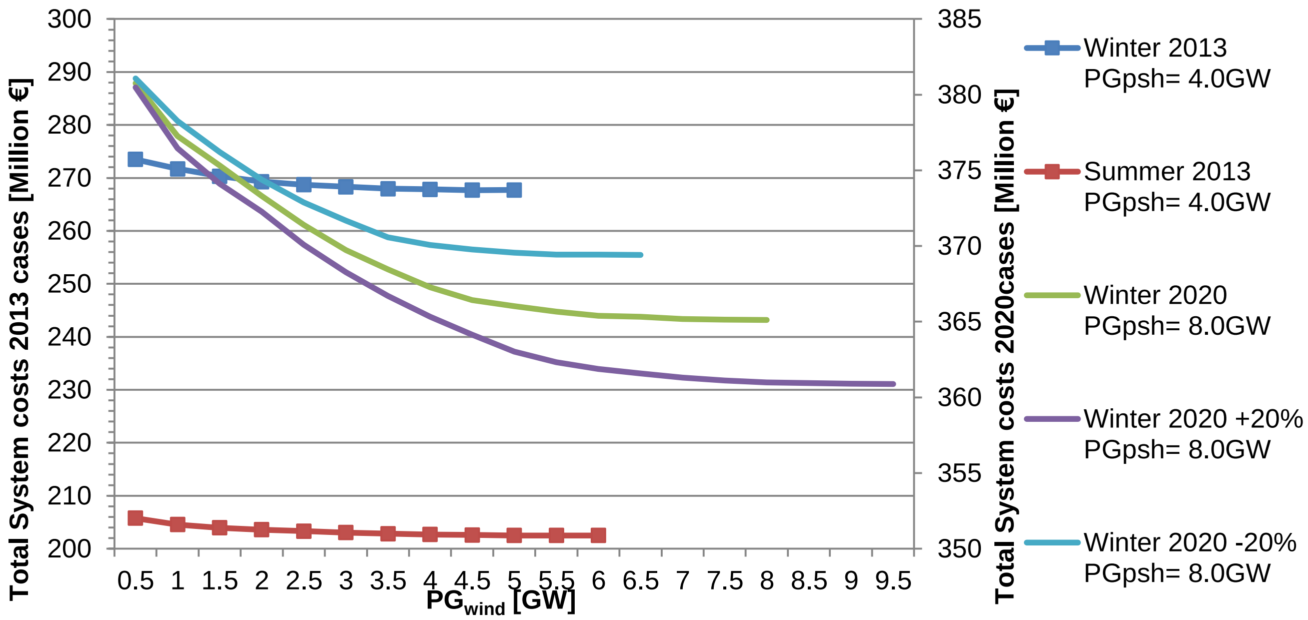

Figure 5.16 System cost overview for all simulated cases, Wind-PSH model

5.1.6 LMP map during the morning peak load (12.00) for multiple cases

When someone wants to get a clearer picture on the different bottlenecks, electricity mixes and generally conditions that prevail in different countries throughout the system as well as how these conditions affect the cost of producing electricity in the respective countries, the following LMP maps need to be constructed. The following figures illustrate the LMP in each country during the morning peak load hour at 12.00. When a country is red, this means that the LMP is the highest in Europe during the specific hour, whereas with green colour we can find the lowest LMPs among the simulated European countries. Nevertheless, the peak load LMP does not show which is the overall cheapest or most expensive country, since one country might have a high peak price, but then a long period of low price throughout the day or vice versa.

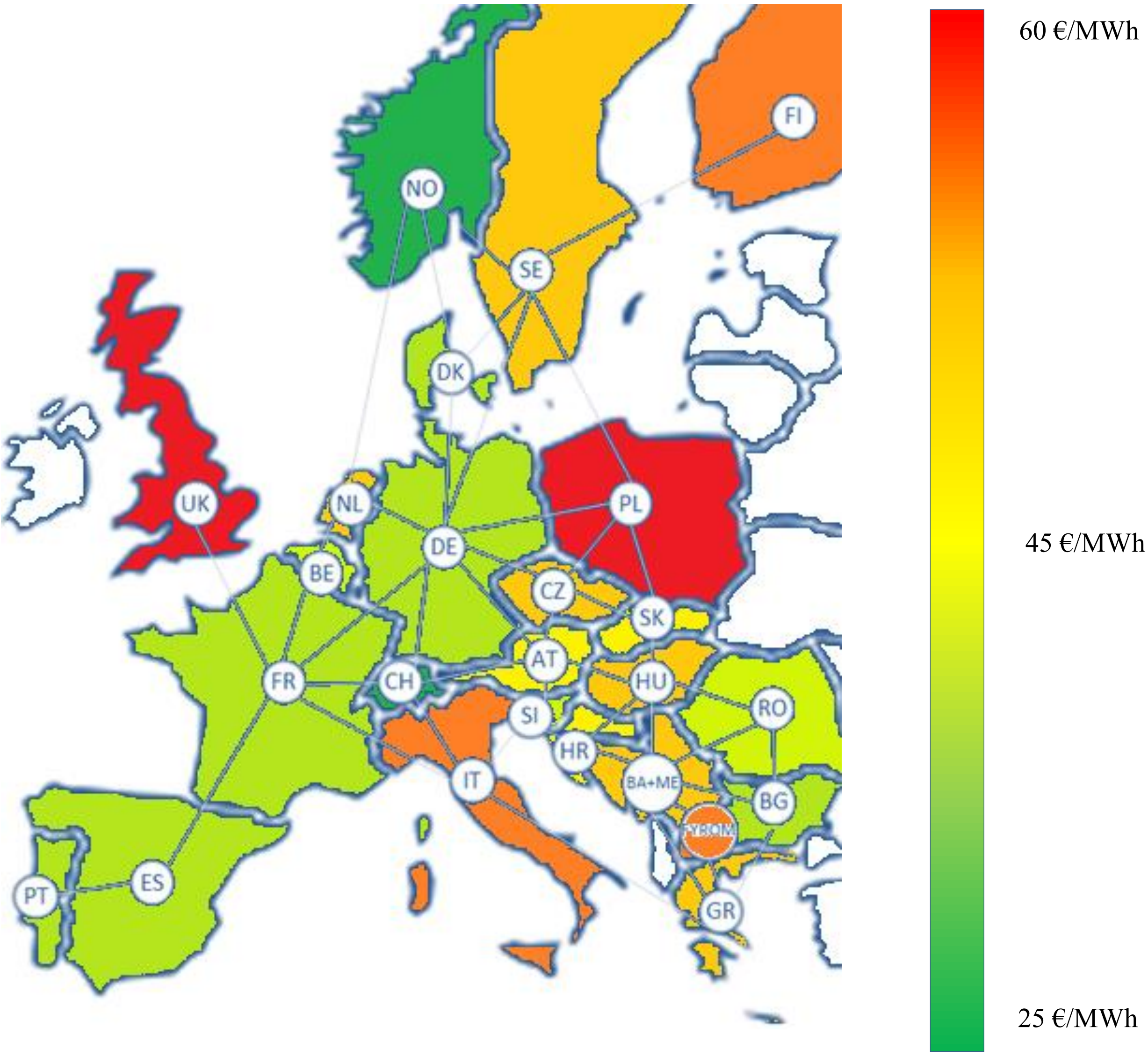

Figure 5.17 Winter 2013 LMP map during the morning peak load at 12.00 p.m.

Figure 5.17 represents the peak load LMPs during the base case scenario Winter 2013. Poland and the United Kingdom are the countries with the most expensive generation mainly due to the fact that their electricity mix is relying heavily on expensive technologies, such as coal and gas respectively. In the case of the United Kingdom, this fossil fuel dependence is worsened due to the creation of a bottleneck from France to UK. In the developed approach UK can only import electricity from France which is heavily occupied during the majority of the day. On the other hand, Norway and Switzerland are the cheapest countries because of their large hydro reserves.

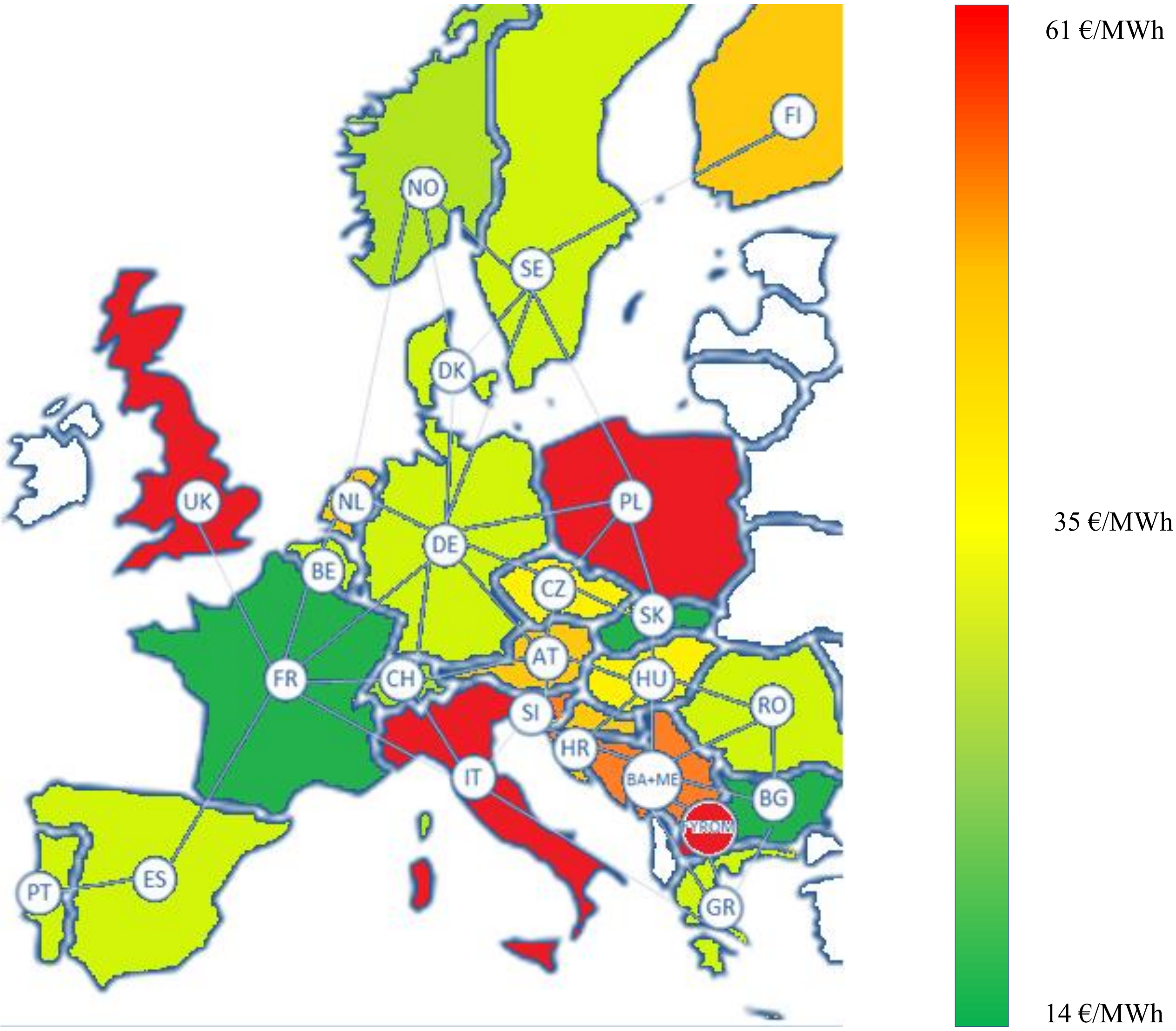

Figure 5.18 Summer 2013 LMP map during the morning peak load at 12.00 p.m.

As it was expected, the summer 2013 case is the one with the lowest LMP for the majority of the countries, as shown in Figure 5.18. One exception is Italy, which now joined along with FYROM, Poland and UK as the countries with the higher LMPs in Europe. Italy has always been among the 2-3 more expensive countries throughout the simulations due to the high dependency on imported electricity as well as the country's large gas powered production. However, the vast majority of the countries are now cheaper than before. A very obvious example is France, where the whole demand of the country can be solely covered by nuclear power, hence the LMP of 14 €/MWh. It is the same case for Bulgaria and Slovakia as well, whereas Norway and Switzerland might have changed to a lighter green colour due to the comparison to cheaper countries for this instance, but their LMPs have remained the same since the demand can be covered completely by hydro power.

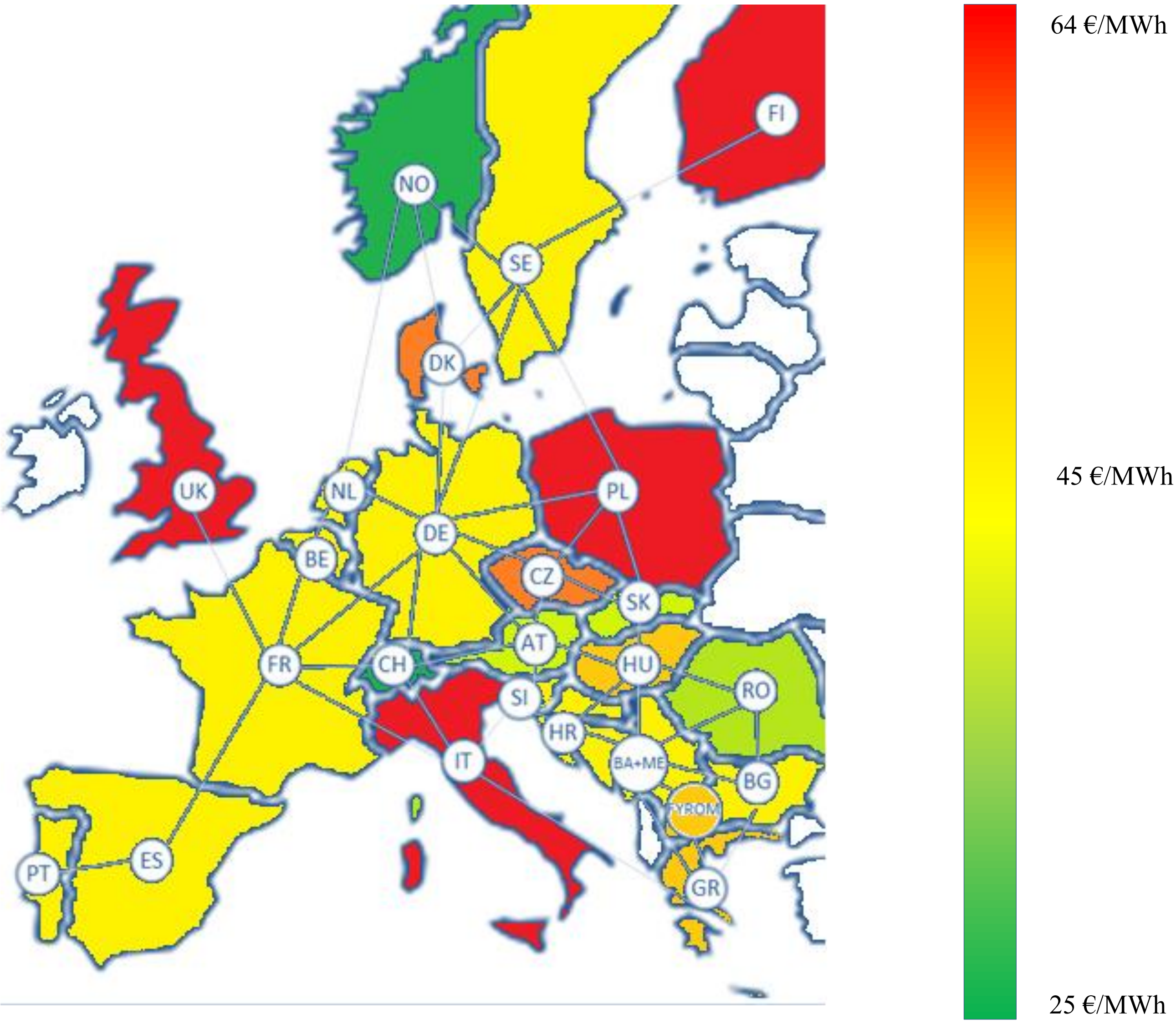

Figure 5.19 Winter 2020, Winter 2020 +20% and Winter 2020 -20% LMP map during the morning peak load at 12.00 p.m.

During all three Winter 2020 cases the map and, hence the LMP do not show significant variation, but remain rather the same. The biggest part of the map indicates a projected LMP above 45€/MWh. This can be attributed to the increased demand that is simulated in year 2020 in conjunction to the fact that the cost of electricity was kept constant in most of the cases, not sufficient production capacity was introduced in order to drive costs down and no additional transfer capacity was implemented either. Besides the shift towards the more expensive LMPs for all the countries, no significant changes can be observed in the relative price difference between the countries during the 2020 cases as compared to the previous cases.

Due to the almost constant LMP prices for all 2020 cases, a joint map can be used to illustrate all future scenarios (Figure 5.19). Indeed, the price changes are minimal and in every case less than 1€/MWh in order to become visible on the LMP map. This can mean that the amount of wind production into the system plays no significant role for the LMP of the countries, since wind power is never on the margin and the additional wind capacity that is introduced from the -20% case to the +20% is not sufficient to shift up another technology over the margin and change the price.

In general, countries in Figure 5.18 have a lower LMP price compared to Figure 5.17 and Figure 5.19. Once again, it is the load of the system as well as the electricity mix that play the most decisive role on LMP when the interconnection capacities are kept constant. It is also evident from the three LMP maps that countries which rely heavily on coal and natural gas production units, such as Italy, Poland and the UK are in every case among the countries with the most expensive LMP prices.

5.2 Effects on congestion

The effects of PSH and wind power on congestion are also an important factor for the reliability and security of supply of the system. It can actively point towards the problematic areas or interconnections and prevent major disturbances or even black outs from happening if the necessary investments are made where needed.

In this part of the thesis, the occupancy rate of each interconnection between the countries has been investigated. Lines that are operating above 80% of their total capacity for over 80% of the day are considered to be problematic and expansion of the capacity of the lines needs to be considered. In the second part of this paragraph a matrix with the average line traffic for all interconnections was constructed giving a second perspective on the congestion of the investigated interconnections.

5.2.1 Winter2013

All graphs in this and the following sections of this thesis measure congestion in absolute values, which means that the direction of the electricity flow is not taken under consideration. This was mainly done because it is the line occupancy rate that interests this part of the study. If absolute values are not considered, this would either result to lower average values due to the presence of negative (reversed) flows in some occasions or it would require presenting the data for both directions which would be hard to illustrate due to the high amount of lines.

In Figure 5.20 we can see that 10 lines operate at full or almost full capacity (above 80%) in either direction for the entire day for the NO-PSH model. At the same time, a total amount of 13 lines is operating above the critical limit of 80% of the day, whereas another 3 lines are congested for over 70% of the simulated winter day of 2013. Breaking down in regions the lines that are congested for over 80% of the day we can see that the big majority of the congested interconnections are either located in Central-Eastern Europe (6) or in Northern and Northern-Central connections (5). Only two troubling lines can be found in South-Eastern Europe (i.e. the Balkans). Sweden and Poland are involved as the one end of the interconnection in 3 cases which is the highest amount for individual countries

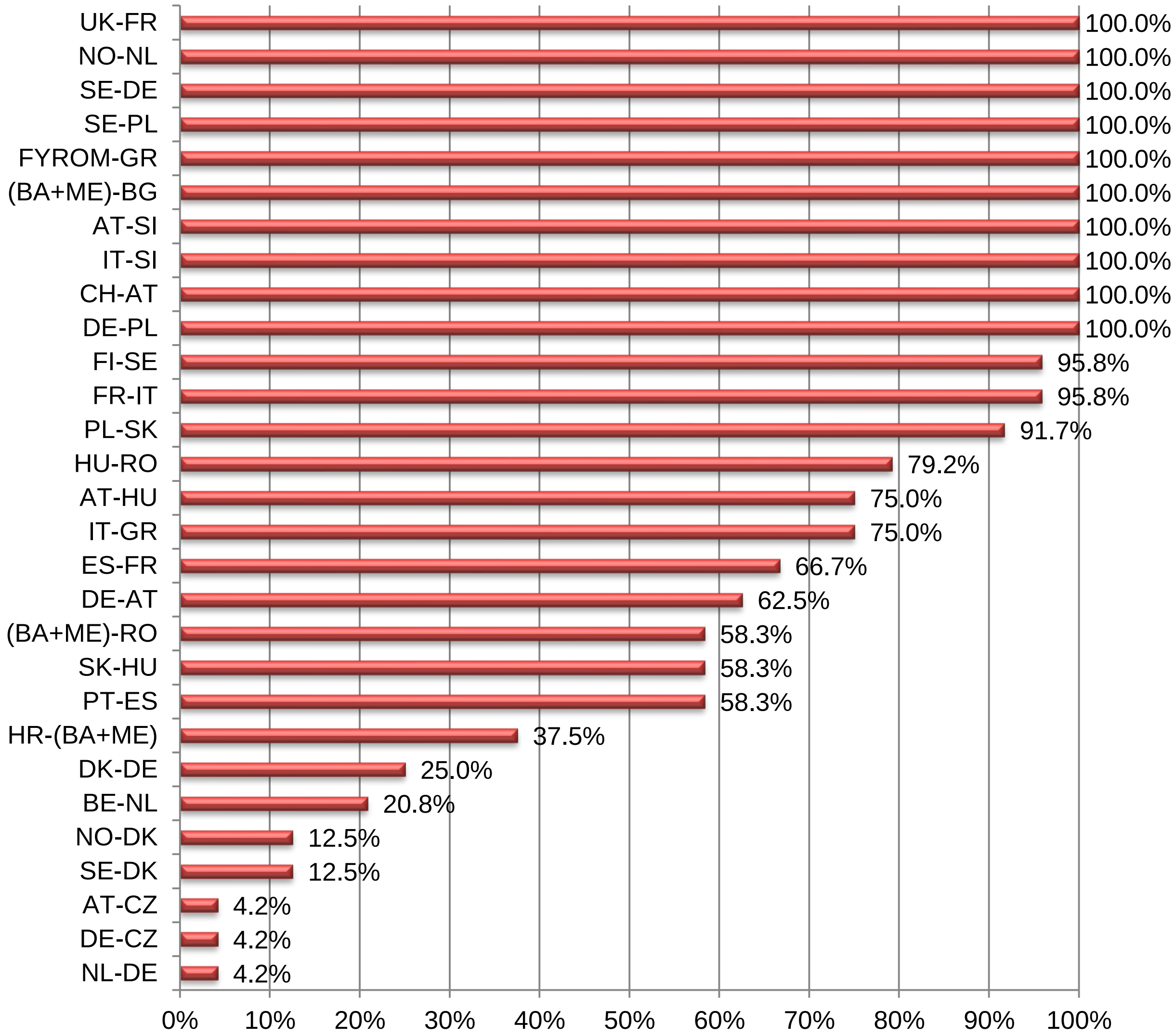

Figure 5.20 Amount of time line loading is above 80% of line capacity in absolute values, winter 2013, NO-PSH

The situation becomes a bit better for the system when PSH units are connected to the system (Figure 5.21), since it is now 8 lines congested throughout the days despite that the number of interconnections that are congested for over 80% of the time is increased to 14. The majority of the links that are congested remains the same, but there are a few new interconnections that are relaxed, such as Bosnia & Montenegro-Bulgaria while others have become more congested than before, such as Bosnia & Montenegro-Romania, Hungary-Romania. Nevertheless, the regional congestion seems to follow the same pattern as in the NO-PSH model

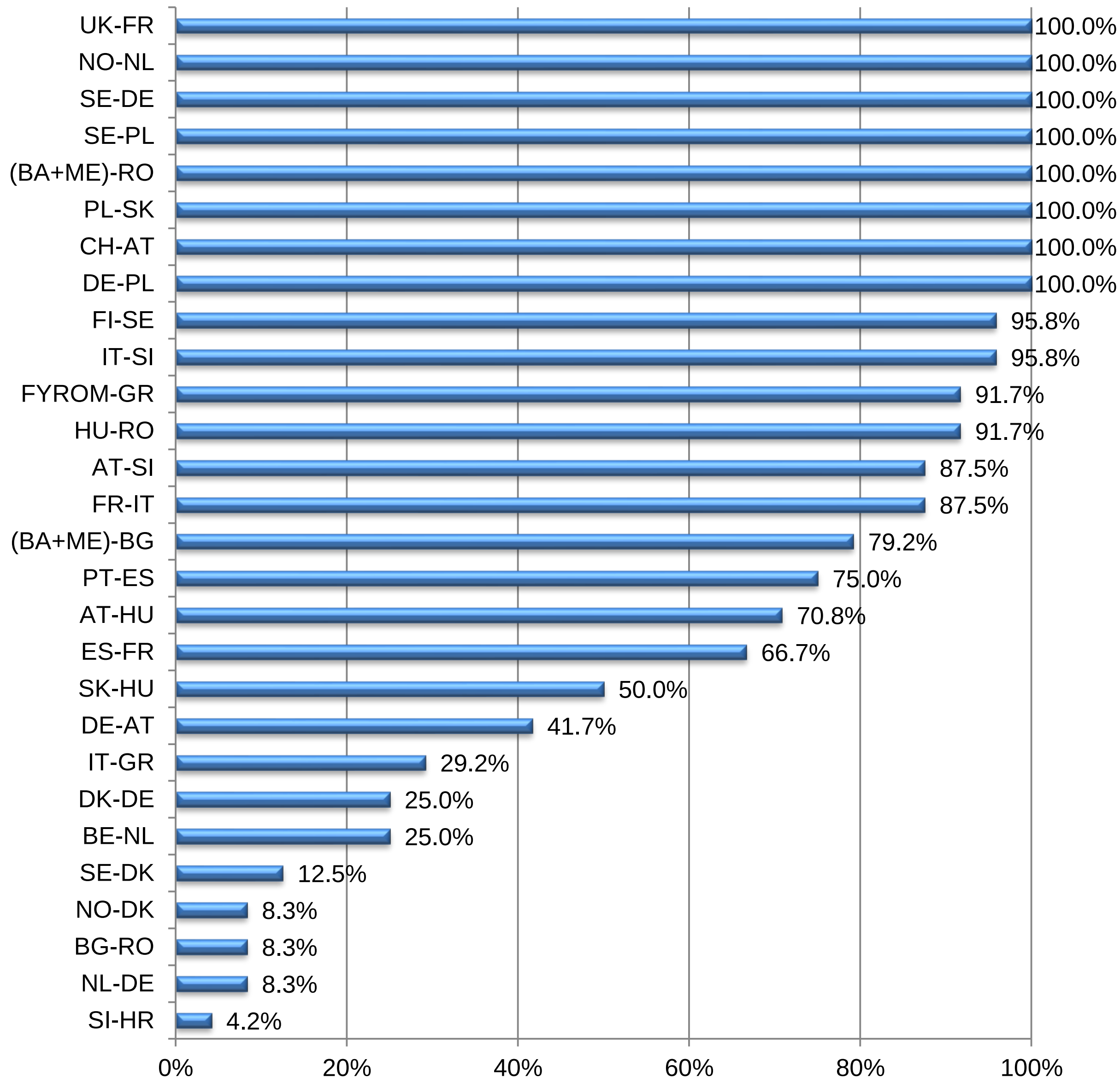

Figure 5.21 Amount of time line loading is above 80% of line capacity in absolute values, winter 2013, Wind-PSH

5.2.2 Summer 2013

Congestion looks worse over the summer as we see in Figure 5.22. The number of 100% congested lines has increased to 11 compared to 10 in Winter 2013 NO-PSH and of 80% congested lines to 14 from 13 in Winter 2013. Due to excess in cheap nuclear production France now features in 4 congested interconnections and the morphology of the congested lines has now changed a lot. Although the links between Northern and Central Europe remain heavily congested, new interconnections such as Portugal-Spain, Spain-France, France-Belgium, France-Germany Bulgaria-Romania have become more congested. In Central Europe besides the newly congested lines, two more lines remain heavily trafficked as during Winter 2013, making it the most problematic area in Europe during the summer 2013 day.

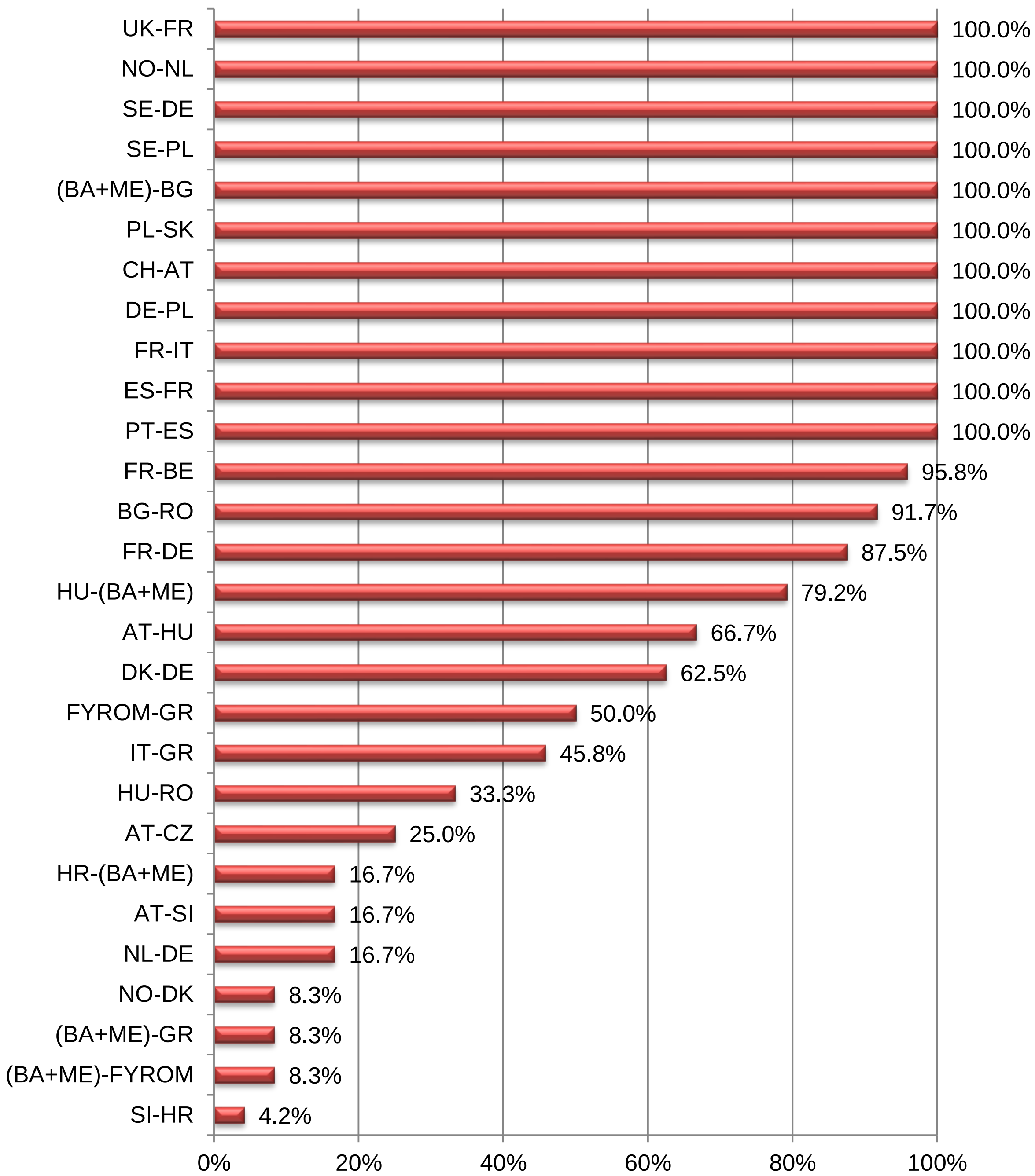

Figure 5.22 Amount of time line loading is above 80% of line capacity in absolute values, summer 2013, no PSH

Congestion is not resolved after introducing PSH units into the system as it is indicated in Figure 5.23. Both the amount of 100% congested and over 80% remained the same despite the fact that a few interconnections have changed to over-congested from under-congested and vice versa. The qualitative characteristics of the regional congestion remain also the same as in the NO-PSH model with a lot of congested lines in Central Europe and problems in connecting UK, Norway and Sweden to the continental part of Europe.

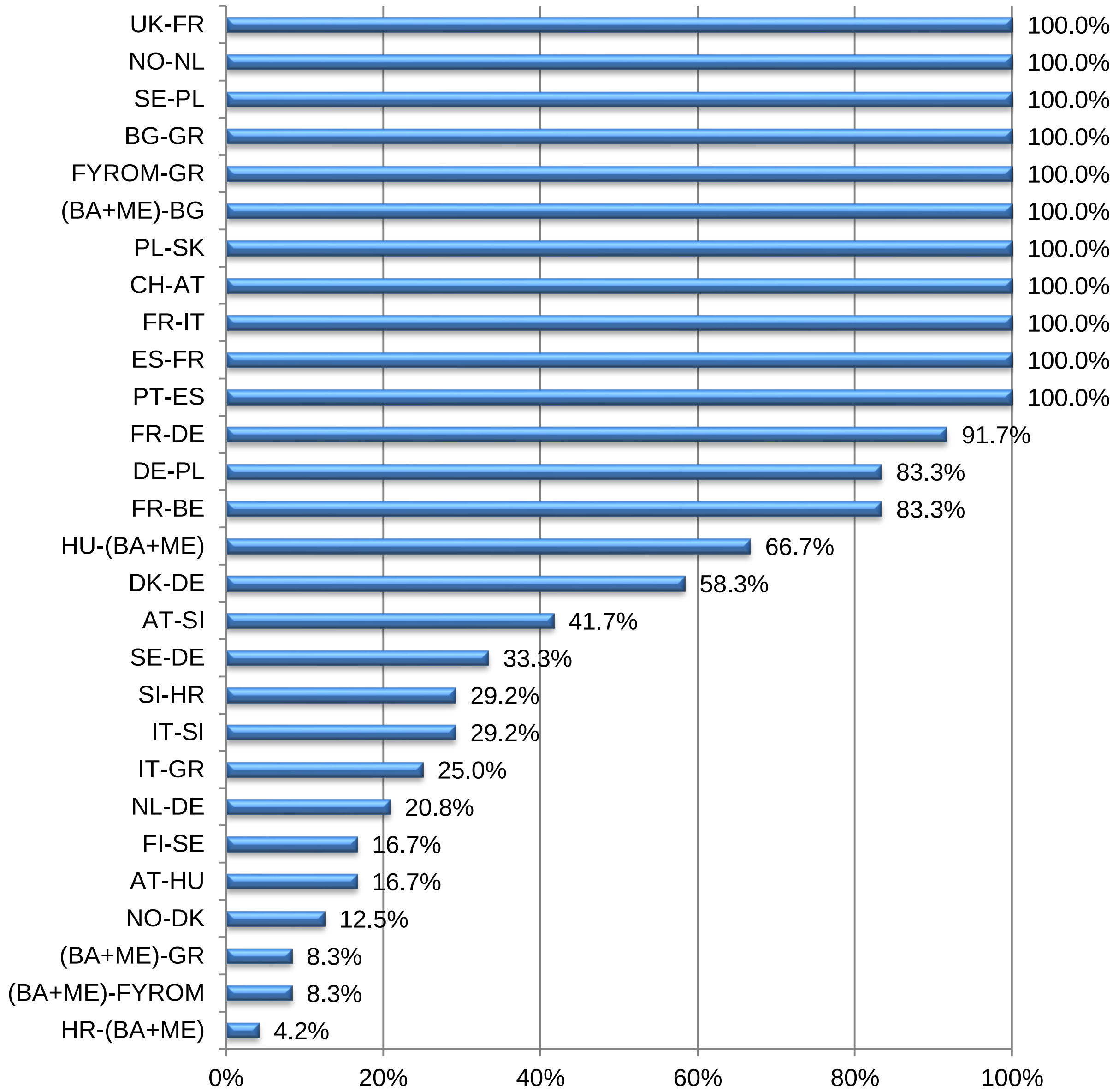

Figure 5.23 Amount of time line loading is above 80% of line capacity in absolute values, Wind-PSH

5.2.3 Winter 2020

For the case of Winter 2020, all three simulations for 2020, namely the Winter 2020, the +20% wind and the -20% wind are grouped in the same graph in order to get a better overview of the 2020 system. Therefore, the following graphs in Figure 5.24 and Figure 5.25 include data for 72 hours instead of 24, which corresponds to each simulated scenario

Figure 5.24 shows a reformed topology of the congestion during 2020 NO-PSH simulations. The results show that most of the Northern-Central connections are slightly relaxed, but not enough to avoid congestion for the majority of the day. On the contrary, Norway-Denmark line appears to be congested for the first time. Austria is also a hub in Central Europe with many interconnections that seem to be heavily congested for the entire 2020 scenario.

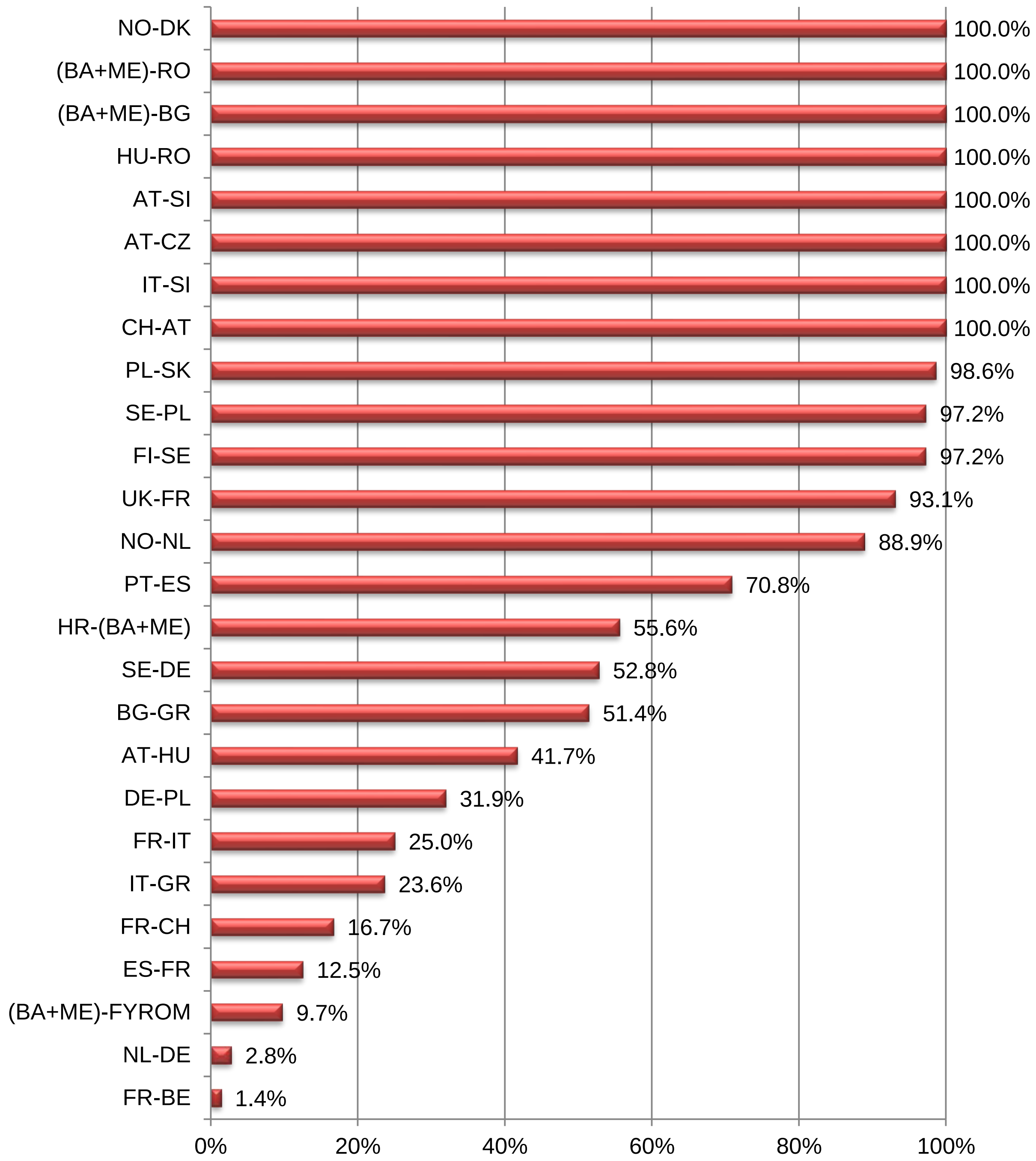

Figure 5.24 Amount of time line loading is above 80% of line capacity in absolute values, grouped winter 2020, +20%, -20% cases, no PSH

The congestion becomes even a bit worse in the Wind-PSH model, in which the topology has changed slightly again to become more similar to the 2013 scenarios with almost all Northern-Central Europe interconnections being the most congested ones in the entire Europe.

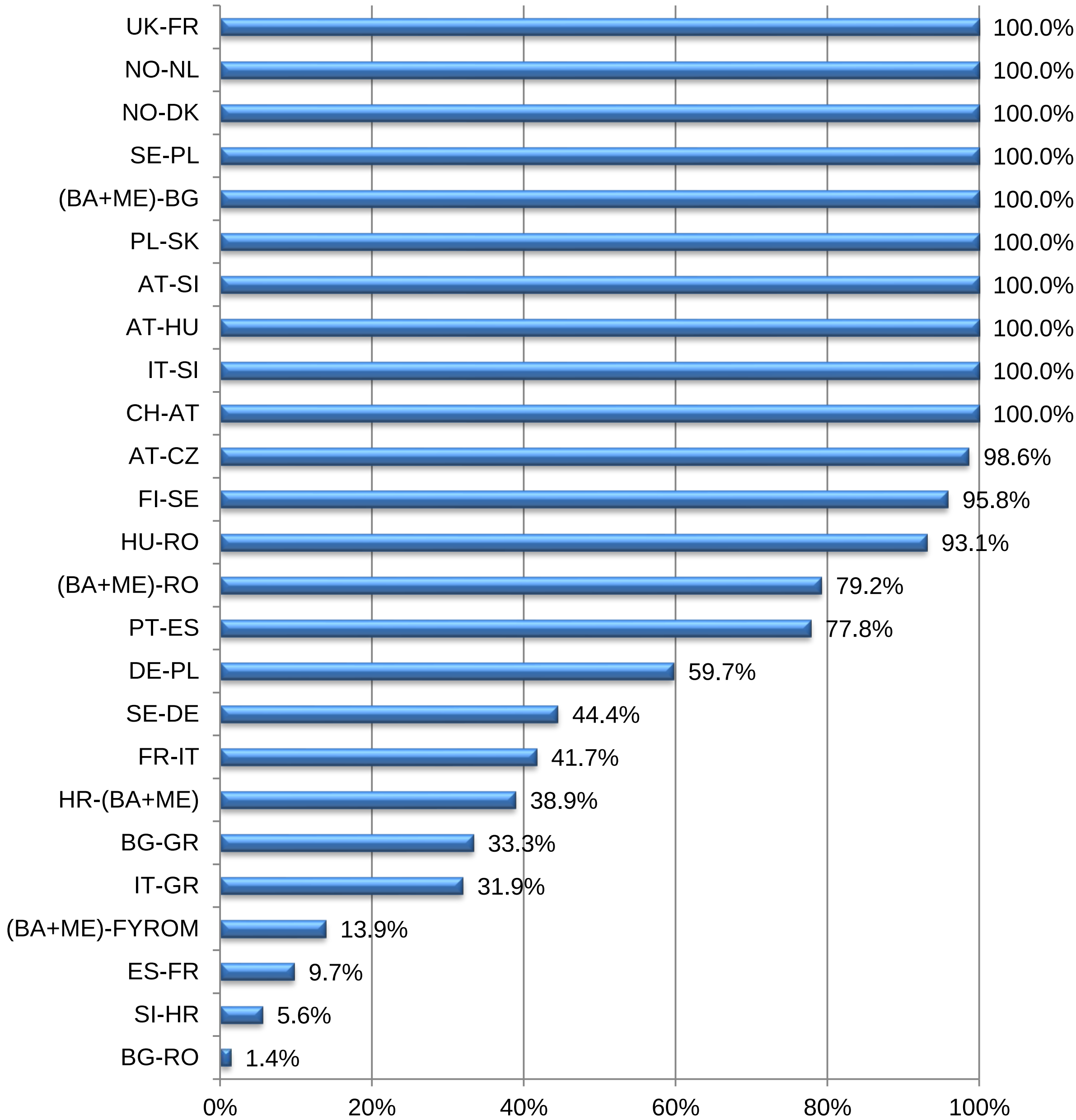

Figure 5.25 Amount of time line loading is above 80% of line capacity in absolute values, grouped winter 2020, +20%, -20% cases, Wind-PSH

After having sample from 5 different scenarios, it can be said that although a few interconnections become more or less congested depending on the state of the system, the majority of the heavily occupied lines remain the same regardless of the simulated scenario. For example, lines such as UK-France, Norway-Netherlands, Sweden-Poland, Switzerland-Austria, Poland-Slovakia appear in all cases. Despite the sample is not big enough some pre-mature conclusions whether a line accommodates enough power flow capacity or not can be drawn, especially for the above-mentioned lines.

Table 5.2 Overloaded interconnections for all cases, NO-PSH model

Interconnection	80% loaded over 80% of the day?			Total
	Winter 2013	Summer 2013	Winter 2020	
CH-AT	X	X	X	3
PL-SK	X	X	X	3
(BA+ME)-BG	X	X	X	3
SE-PL	X	X	X	3
NO-NL	X	X	X	3
UK-FR	X	X	X	3
FR-IT	X	X		2
DE-PL	X	X		2
IT-SI	X		X	2
AT-SI	X		X	2
FI-SE	X		X	2
SE-DE	X	X		2
PT-ES		X		1
ES-FR		X		1
FR-BE		X		1
FR-DE		X		1
AT-CZ			X	1
HU-RO			X	1
(BA+ME)-RO			X	1
FYROM-GR	X			1
BG-RO		X		1
NO-DK			X	1

Table 5.3 Overloaded interconnections for all cases, Wind-PSH model

Interconnection	80% loaded over 80% of the day?			Total
	Winter 2013	Summer 2013	Winter 2020	
CH-AT	X	X	X	3
PL-SK	X	X	X	3
SE-PL	X	X	X	3
NO-NL	X	X	X	3
UK-FR	X	X	X	3
FR-IT	X	X		2
DE-PL	X	X		2
IT-SI	X		X	2
AT-SI	X		X	2
HU-RO	X		X	2
(BA+ME)-BG		X	X	2
FYROM-GR	X	X		2
FI-SE	X		X	2
PT-ES		X		1
ES-FR		X		1
FR-BE		X		1
FR-DE		X		1
AT-CZ			X	1
AT-HU			X	1
(BA+ME)-RO	X			1
BG-GR		X		1
SE-DE	X			1
NO-DK			X	1

Regarding the contribution of PSH storage in relaxing the congestion from the busiest lines, we cannot draw any final conclusions yet as PSH had minimal influence and in some cases even put more pressure into the system.

Table 5.2 and

Table 5.3 summarize the interconnections between the countries that are heavily loaded for the NO-PSH and the Wind-PSH model respectively. From the tables we can, indeed, see that the majority of the links are identical in both models with very minor changes. In bold writing one can see the interconnections that only feature in one table. The conclusion that pumped-storage does not significantly affect the power flow volume between countries is further strengthened.

5.2.4 Average line loading – NO-PSH

In this part of the paragraph another measure to illustrate how congested a line is under different scenarios is used. Since the sample of simulated days is small this second approach tries to provide more validity to the results of this paragraph. Table 5.4 and Table 5.5 show the absolute average flow rates as a percentage of the total capacity of the line for NO-PSH and Wind-PSH models respectively.

In Table 5.4 the results of the NO-PSH model are presented. We can see that there are no big differences between these results and the results that include hours of congestion. For example, in Winter 2013 we have 16 lines with an absolute flow average over 80%, whereas 13 lines are congested for over 80% of the time in Figure 5.20. This mismatch occurs since a line might exceed the 80% average flow value without exceeding 80% of its capacity for over 80% of the time. However, this matrix is an easier way to check whether a line is busy during a specific scenario or this happens for all simulated cases due to limited capacity. It is interesting to see how different lines are busier only during 2013 scenarios, such as Germany-Poland or Austria-Hungary links or during 2020 scenarios like the Austria-Czech Republic line, while others are only busy during one scenario like Hungary-Bosnia & Montenegro which is over 90% full in Summer 2013, but 11.2% in Winter 2013 and without any traffic at all for the 2020 and 2020 +20% scenarios. On the contrary, Italy-Slovenia is operating at full capacity at all instances, besides summer 2013 when 56% of total capacity is flowing on average.

Table 5.4 Average line loading for all simulated cases without PSH

Interconnection	**Winter 2013**	**Summer 2013**	**Winter 2020**	**Winter 2020 +20%**	**Winter 2020 -20%**
PT-ES	58.3%	100.0%	83.8%	85.4%	80.2%
ES-FR	72.3%	100.0%	64.1%	63.0%	65.3%
FR-BE	35.4%	97.8%	49.1%	46.7%	51.0%
FR-DE	29.5%	94.9%	12.5%	11.2%	13.3%
FR-CH	12.5%	29.6%	60.7%	59.2%	62.4%
FR-IT	96.3%	100.0%	51.4%	53.5%	48.8%
BE-NL	32.5%	15.7%	43.9%	42.7%	43.2%
NL-DE	36.4%	75.4%	23.7%	18.9%	29.0%
DE-CH	11.1%	31.5%	44.6%	41.8%	47.4%
DE-AT	70.7%	18.7%	34.1%	30.0%	39.0%
DE-CZ	59.2%	36.5%	29.0%	32.4%	27.5%
DE-PL	100.0%	100.0%	46.8%	52.1%	44.0%
CH-IT	15.5%	6.4%	15.5%	15.5%	15.5%
CH-AT	100.0%	100.0%	100.0%	100.0%	100.0%
IT-SI	100.0%	56.0%	100.0%	100.0%	100.0%

IT-GR	89.2%	72.4%	43.9%	42.5%	45.3%
AT-CZ	40.1%	51.5%	100.0%	100.0%	100.0%
AT-HU	89.1%	89.1%	66.5%	69.8%	66.6%
AT-SI	100.0%	42.8%	100.0%	100.0%	100.0%
CZ-PL	23.2%	42.4%	10.6%	11.0%	10.8%
CZ-SK	6.2%	12.5%	13.5%	13.2%	14.1%
PL-SK	95.7%	100.0%	99.7%	100.0%	99.0%
SK-HU	63.2%	50.0%	9.7%	10.5%	10.5%
HU-HR	30.0%	35.6%	43.1%	41.9%	43.8%
HU-(BA+ME)	11.2%	91.0%	-	-	0.8%
HU-RO	90.2%	73.5%	100.0%	100.0%	99.2%
SI-HR	42.7%	46.7%	43.4%	43.4%	44.9%
HR-(BA+ME)	72.2%	43.9%	86.2%	83.8%	86.7%
(BA+ME)-FYROM	33.8%	27.5%	59.3%	59.6%	59.4%
(BA+ME)-BG	100.0%	100.0%	99.0%	99.3%	98.6%
(BA+ME)-RO	79.6%	17.5%	100.0%	100.0%	100.0%
(BA+ME)-GR	23.3%	42.8%	42.4%	42.9%	42.4%
FYROM-GR	98.7%	77.8%	35.1%	35.6%	35.1%
BG-RO	27.2%	95.4%	42.4%	42.2%	42.7%
BG-GR	21.0%	18.2%	64.7%	64.0%	65.9%
FI-SE	92.1%	51.4%	97.3%	96.3%	97.4%
SE-NO	32.9%	6.3%	36.1%	37.0%	35.1%
SE-PL	87.4%	98.1%	99.3%	100.0%	95.6%
SE-DE	98.4%	88.0%	70.8%	63.3%	77.1%
SE-DK	57.7%	25.9%	12.5%	13.5%	12.3%
NO-DK	38.8%	57.2%	100.0%	100.0%	100.0%
NO-NL	100.0%	100.0%	92.3%	94.1%	88.2%
DK-DE	48.7%	85.1%	33.8%	27.8%	38.3%
UK-FR	100.0%	100.0%	95.0%	97.0%	93.1%

5.2.5 Average line loading – Wind-PSH

Table 5.5 Average line loading for all simulated cases with PSH

Interconnection	Winter 2013	Summer 2013	Winter 2020	Winter 2020 +20%	Winter 2020 -20%
PT-ES	80.7%	100.0%	85.4%	77.7%	91.7%
ES-FR	80.7%	100.0%	51.8%	54.2%	52.0%
FR-BE	29.5%	95.2%	41.5%	39.3%	43.4%
FR-DE	35.9%	93.2%	20.5%	23.9%	17.1%
FR-CH	30.3%	40.6%	52.0%	50.2%	52.5%
FR-IT	89.9%	100.0%	63.5%	66.1%	62.7%
BE-NL	48.1%	19.0%	47.4%	42.7%	51.4%
NL-DE	39.0%	76.8%	17.6%	17.1%	18.3%
DE-CH	8.0%	22.4%	33.7%	31.3%	37.1%
DE-AT	74.8%	34.6%	14.7%	14.5%	17.5%
DE-CZ	59.8%	26.8%	45.5%	50.1%	40.2%
DE-PL	100.0%	89.6%	83.1%	89.0%	76.9%
CH-IT	15.0%	4.6%	15.5%	15.5%	15.5%
CH-AT	100.0%	100.0%	100.0%	100.0%	100.0%
IT-SI	98.8%	49.6%	100.0%	100.0%	100.0%
IT-GR	70.0%	54.2%	47.4%	46.8%	48.2%
AT-CZ	13.8%	13.0%	98.8%	100.0%	100.0%

AT-HU	87.0%	32.0%	100.0%	100.0%	100.0%
AT-SI	91.6%	70.8%	100.0%	100.0%	100.0%
CZ-PL	22.6%	43.1%	22.4%	22.7%	22.4%
CZ-SK	10.9%	13.0%	6.8%	6.9%	6.5%
PL-SK	100.0%	100.0%	100.0%	100.0%	100.0%
SK-HU	68.6%	19.3%	14.9%	16.0%	15.0%
HU-HR	25.0%	28.9%	28.7%	28.6%	29.0%
HU-(BA+ME)	2.2%	83.5%	9.7%	10.5%	8.8%
HU-RO	97.8%	62.1%	96.2%	95.5%	96.7%
SI-HR	40.4%	69.8%	53.4%	53.1%	54.0%
HR-(BA+ME)	47.3%	47.7%	68.8%	69.4%	68.3%
(BA+ME)-FYROM	36.9%	41.2%	47.9%	46.3%	50.4%
(BA+ME)-BG	88.5%	100.0%	100.0%	99.7%	100.0%
(BA+ME)-RO	100.0%	21.4%	86.5%	86.8%	87.9%
(BA+ME)-GR	20.8%	60.6%	32.8%	30.5%	34.5%
FYROM-GR	97.4%	100.0%	29.1%	27.7%	30.2%
BG-RO	50.3%	14.0%	39.2%	40.4%	38.4%
BG-GR	18.4%	109.1%	57.6%	56.5%	58.6%
FI-SE	95.9%	60.2%	95.9%	95.0%	95.5%
SE-NO	31.2%	6.1%	35.1%	37.8%	32.0%
SE-PL	87.2%	100.0%	99.0%	99.2%	99.5%
SE-DE	98.6%	67.7%	57.4%	66.7%	50.2%
SE-DK	56.7%	36.7%	12.3%	15.5%	12.3%
NO-DK	36.1%	55.7%	100.0%	100.0%	100.0%
NO-NL	100.0%	100.0%	100.0%	100.0%	100.0%
DK-DE	48.4%	86.1%	23.9%	22.8%	25.4%
UK-FR	100.0%	100.0%	100.0%	100.0%	100.0%

Similar remarks can be noted for Table 5.5, where the Wind-PSH results are illustrated. However, it might be more useful to compare the two tables in order to evaluate whether PSH is helping relieve congestion or makes it worse.

By looking at the average congestion for each scenario, we can see that the biggest difference between the two models occurs during Winter 2020, when average traffic is 59.4% for the NO-PSH model, 1.8% more than in Wind-PSH model. On the other hand, the only scenario where Wind-PSH has more traffic is during Winter 2013, but only with just 0.26% over the NO-PSH average traffic of 59.6%. In general, if all the scenarios can be grouped, NO-PSH scenario requires slightly more line traffic than the Wind-PSH model. However, the change is that small, in the range of 0.94%, that it is again difficult to draw accurate conclusion on the effect of PSH on congestion. On top of that these results are also contradicting with the results for PSH in the previous paragraphs, which make any further analysis difficult to base on concrete results. All in all, this average line traffic approach cannot provide more useful information about the congestion of the system other than the clear overview of the system’s line traffic.

To sum up, the effects of PSH on congestion are not obvious, but the results of the simulations are a helpful tool in order to pinpoint towards the correct direction for further investigation on whether the lines that were highly congested should be considered for future transmission investment. The results also showed an insufficient connection between Northern Europe, namely the United Kingdom, Norway and Sweden to the mainland of Europe. This weak link is possible to create instability or other problems in the system, especially in case of contingency. However, a more through contingency analysis must be conducted before any final conclusion can be drawn on that matter.

5.3 Effects on system emissions

Another very important area that PSH can contribute to, is greenhouse gas emission mitigation. By adding PSH capacity into the system the more expensive and usually emitting technologies, such as gas, oil and coal are bound to shut down. On top of this, PSH is a quick response technology which can provide the system with its stored energy in case of a sudden demand increase or a contingency situation.

5.3.1 CO_2 emission reduction due to PSH

Emission reductions were also calculated as part of the project, in order to assess what the influence of PSH is on a greener electricity mix. First, total CO_2 emissions were calculated after the initial calculations without the introduction of PSH. Then, the results of the simulations with PSH into the system were considered and the new emissions were calculated. The process of extracting the CO_2 emissions is simple. Carbon content for coal of 25gC/MJ and for natural gas of 15gC/MJ is assumed, values that originate from the division of Physical Resource Theory [24]. Moreover, an overall conversion efficiency of 33% and 40% for coal and natural gas power plants is assumed. Hence, the formula for calculating the CO_2 emissions is:

$$Emissions\ [tCO2] = \frac{PG}{\eta}\ [\frac{TWh\ el}{\frac{TWh\ el}{TWh\ fuel}}] * CarbonContent\ \left[\frac{tC}{MJ\ fuel}\right] * \frac{44}{12}\left[\frac{t\text{CO2}}{tC}\right] * 3600\ [\frac{s}{h}] \tag{20}$$

Table 5.6 CO_2 reduction caused by introduction of PSH into the system

	No PSH in the system	With PSH	% of CO_2 reduction
Winter 2013	918 900 tonsCO_2/day	825 960 tonsCO_2/day	10.04%
Summer 2013	677 600 tonsCO_2/day	594 930 tonsCO_2/day	12.2%
Winter 2020	1 983 700 tonsCO_2/day	1 611 900tonsCO_2/day	18.7%
Winter 2020-+20% wind	2 400 900 tonsCO_2/day	1 565 020 tonsCO_2/day	34.8%
Winter 2020--20% wind	2 040 900 tonsCO_2/day	1 659 040 tonsCO_2/day	18.7%

From these results, it is obvious that the implementation of PSH has a positive effect not only on the system costs, but also on emissions. This reduction spans from 10% to 34.8%. The difference in emissions reduction between the winter 2013 and summer 2013 cases can be mainly attributed to the fact that despite the load being decreased during the summer, the PSH penetration levels are kept constant. Therefore, PSH can replace larger part of emitting technologies, such as coal and natural gas.

Accordingly, the emission reduction is between almost two and more than three times larger during the 2020 cases. In the 2020 case CO_2 emitting generation is substituted to large extent by clean hydro and solar power, while part of the old coal and oil power plants are phased out by 2020. Although the next couple of results might seem contradictory there is an explanation for it. First of all, in the +20% scenario the extra wind power production has replaced a big amount of polluting generation after the marginal technology. In addition to the introduction of PSH capacity into the system the result is a very big CO_2 reduction of 34.8%. On the other side, the -20% scenario's 18.7% reduction also seems big at a first glance. However, in this case natural gas is on the margin in a lot of cases, which includes less carbon content and is more energy dense than coal. For that reason, the CO_2 emission mitigation is possible to be equal to the Winter 2020 case which includes a larger amount of clean wind power production. Thus, the extended use of PSH into the system fully utilizes electricity that comes from variable sources.

Chapter 6
Conclusion

This chapter summarizes the work that has been carried out throughout the thesis as well as the main results and conclusions

6.1 Conclusion

Pumped-storage hydro is a technology that could solve several problems that arise by the increasing penetration levels of wind and solar power technologies. In this thesis, the main focus was to evaluate PSH as a technology to achieve more cost-effective and environmental friendly power production, while relieving congestion.

Regarding system cost reduction, PSH is a very good option which can help the total system costs sink by around 8%. In conjunction with increased wind power production this reduction can fall down to around 7.5%, but this combination provides different advantages besides the fact that wind power technology can actively address some of the biggest current energy problems. The impact of PSH on CO_2 emissions is very big according to the results produced by the proposed models and this is another reason that makes PSH more competitive in a future integrated European market considering that Europe needs to meet some very stringent environmental targets. Finally, no signs that congestion can be substantially relieved were produced by this study, but PSH is not contributing heavily on congestion either. According to this work, it rather depends on the system characteristics and the state of the system whether PSH can act as a relieving factor or as an extra pressure in the system. In a nutshell, the following points can be summarized

- Effects on system costs
  - Total system cost can be reduced by 7.5-8% after the introduction of PSH, both due by replacing more expensive generation as well as by producing during peak hours.
  - Load variations are much more significant factor than variations on wind power output to determine system costs and LMPs.
- Effects on congestion
  - No signs that PSH could neither help avoid line congestion between countries nor favour the creation of additional bottlenecks.
  - The effects of further expansion of PSH need to be investigated.
- Effects on emission mitigation
  - Pumped-storage hydro could play a decisive role on mitigating CO_2 emissions, as the introduction of PSH into the system could reduce emissions from 10% down to almost 35% compared to a PSH-free electricity mix.
  - The amount of CO_2 reduction is strongly associated with the electricity mix as well as the penetration levels of renewable energy sources into the system.

Pumped-storage hydro is indeed an emerging technology that can help towards a better integration of the European power system, but there are still a few issues left to be looked into before an investment decision is taken on expanding substantially the PSH in Europe.

6.2 Future work

There are a lot of areas towards which this work can be extended in the future. In this paragraph some of these areas will be mentioned. Due to lack of time, resources or both, there are certain questions that were either not answered or not investigated at all in the context of this thesis. In the current model no investment costs for pumped-storage, transmission lines or newly installed generation is assumed. Future research could include such investment costs, in order to enhance the credibility of the model. Another area to further continue researching on this area could on different characteristics of PSH and how these could affect the system overall. For instance the topology of the PSH capacity can be further investigated and whether more PSH capacity in Switzerland would be better than more capacity in the Nordics or than an evenly spread development throughout Europe. Finally, a thorough cost-benefit analysis needs to be conducted before concluding whether PSH is the best alternative for extensive future development. Summing up, a few indicative areas towards which future research can be directed could be divided into:

- Economics of PSH
    - ➢ Cost-benefit analysis for PSH units. Is it already a cost-effective solution? If not, under which conditions will it become viable to further expand PSH investments in more countries?
    - ➢ Compare PSH to other storage solutions available on the market.
- Topology of PSH
    - ➢ Evaluate the effects of different locational characteristics for future PSH investment decisions
    - ➢ Evaluate the effects of different configurations and technologies around PSH in certain regions in Europe
- Expansion of the model into time and future
    - ➢ Simulate more days of the year to increase the credibility of the results
    - ➢ Expand the model into more years into the future with more possible scenarios
    - ➢ Evaluate how different investment scenarios would affect the valuation of PSH technology

All in all, there are many more areas to expand this project into the area of PSH, which could help the future expansion of the technology into the European power system.

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