UNIVERSIDAD PONTIFICIA COMILLAS

ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

MÁSTER OFICIAL EN EL SECTOR ELÉCTRICO

Master in Economics and Management of Network Industries

TESIS DE MÁSTER

Impact of Large Scale Wind Power Integration on Operating Reserves in Spain

AUTOR: **Metin INAN**

MADRID, February 2014

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AUTOR: **Metin INAN**

SUPERVISOR: **Pablo FRIAS MARIN**

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Summary

English:

Wind power besides its benefits at large scale integration levels brings certain challenges into electricity systems. The most concerned drawbacks are due to the variability of wind energy and the accuracy of forecasting the wind power production.

These characteristics of wind power cause some negative effects regarding the operation of power systems both on the long and short-term such as the need of voltage management, transmission or distribution losses, increase in operating reserves, discarded wind energy and system reliability issues.

The purpose of this thesis is to demonstrate the impacts of wind power in Spain on operating reserves and to quantify the additional costs -if there is any- due to the integration of large scale wind power.

Español:

La energía eólica además de sus beneficios en los niveles de integración a gran escala trae algunos retos en los sistemas eléctricos. Los inconvenientes más afectados son debido a la variabilidad de la energía eólica y la exactitud de la predicción de la producción eólica.

Estas características de la energía eólica causan algunos efectos negativos sobre el funcionamiento de los sistemas de energía, tanto en el corto y largo plazo, tales como la necesidad de la gestión de tensión, las pérdidas de transmisión o de distribución, aumento de las reservas, la energía eólica vertida y problemas de fiabilidad del sistema.

El propósito de esta tesis es demostrar los impactos de la energía eólica en España en reservas y cuantificar los costes adicionales -si hay alguno- debido a la integración de la energía eólica a gran escala.

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1. INTRODUCTION & OBJECTIVES

In the last century European electricity markets started an evolution in the generation side. With the aim of covering 20% of electricity demand with renewable energy sources (RES) until 2020, many member states have implemented incentive mechanisms for RES. Among these renewable energy technologies some of them appeal more investors thanks to reaching a certain level of technology maturity level. Statistics show us that especially wind energy is the leading RES that is preferred by investors. Some countries already supply more than 10% of the total gross demand by wind energy, e.g. Denmark, Germany and Spain. However, integration of large scale wind power into the electricity system brings some challenges together with its benefits. One of the most discussed drawbacks of wind power is variability and the accuracy of predicting the variability.

In an electricity system, demand and supply should be balanced for any time scale; from second to hours. This balance is held at 50 Hz in EU countries. In the case of consumption increase over generation, power system frequency starts falling below 50 Hz and if the generation is more than the consumption then frequency rises. In order to prevent these diversions from the system frequency balance, system operators can use some balancing tools like balancing reserves, load management, cross-border trade, energy storage or RES generation curtailment. This thesis aims at analyzing the impact of large scale wind power integration over system operating reserves. In many studies it has been shown that variable wind generation increases the fluctuations of net load[1] and the accuracy of forecasting techniques to predict wind power generation is questionable. Errors in forecasting wind energy results in imbalance in the power system and this imbalance is mostly covered by operating reserves. These reserves burden extra cost over the total electricity system in other words we can say that wind power increases system reserve costs.

There are several studies held to observe the effect of wind power on operating reserves in different countries, namely Ireland, UK, Denmark, Nordic region and Germany. Some common results indicate that the cost of additional system reserves is insignificant. In addition, increasing reserve capacities can be supplied by current generators and there is no need to make new investments in facilities. However, the study results vary according to the penetration level of wind power, interconnection capacity, generation mix, deployment of wind power plants, regulation and market rules of power system in each country. In brief, each system has its peculiar characteristics and the impact of wind power integration may not be the same for another country. Also, a system study

[1] Net load is the load that remains after covering a part of the demand by wind power generation. In other words, net load = total demand load – generated wind energy.

that quantifies the impact on the system reserves in Spain is lacking and there are some commonly-held beliefs in the industry without any evidence claiming that variability of wind power will increase system reserve costs significantly. Moreover, Spain is one of the countries with high wind penetration and as it is mentioned in various studies that above some penetration levels, i.e. 10%, the effects of wind power on system reserves will be much stronger. Consequently, based on the reasons stated above there is a need for a research on this area of the Spanish electricity industry.

The objective of this thesis is to analyze the relation between wind power penetration levels and operating reserves in Spain according to probabilistic methodology. If the integration of large scale wind power into Spanish electric power system leads to an increase in operating reserves as it is stated in different studies, then the cost of increase in operating reserves will be computed to give an idea whether these costs are high or low compared to the results from previous studies in different countries.

This research starts with a brief history of wind power development, incentive mechanisms devised to promote the technology, challenges to integrate large scale wind power and the pioneers of wind power in Europe in chapter 2. In chapter 3, balancing mechanisms in electricity markets and the impact of wind power integration on operating reserves are explained based on literature review. Later in chapter 4, the Spanish power system with its main features; renewable energy support schemes, generation mix, interconnection capacity and wind power deployment, is described. In chapter 5, basic statistics of wind power production and electricity demand load data are examined and a probabilistic methodology is held to estimate the impact of increasing wind power penetration on operating reserves in Spain. Lastly, in chapter 6 the final results and conclusions are presented.

2. WIND POWER IN EUROPE

Electricity generation from wind power dates back to early 1970s when the first oil crisis emerged, even though before the wind power had been used to provide mechanical energy for years. The global oil crisis triggered the governments to give financial incentives to research and develop the wind power technology. Gradual developments in wind turbine technology continued until late 1990s when the wind energy has started to be integrated into electric power systems. During 1990s, the wind capacity all over the world doubled almost every three years and together with these progresses significant cost reductions have been observed. (Ackermann T., 2005)

The investment boom in wind energy during the 1990s made it the fastest growing energy technology as percentage of yearly growth of installed capacity. However, this growth concentrated more in some regions; by the end of 2012 Europe is the leading region with 39% of total energy capacity in the world, Asia recently increased its wind capacity to 35% (mainly by China and India, only these two countries, respectively, contribute 27% and 7% of the installed capacity in Asia) and the third biggest capacity investment made is in North America by 24%, whereas the rest of the world comprises less than 3% (Ackermann T., 2005), (GWEC, 2012). To better understand this propulsion to wind power technology in Europe we should have a look at the support and promotion initiatives that are put into practice.

2.1. Initiatives to Promote Electricity Generation from RES in EU

Renewable energy sources started to capture the attention of EU Commission beginning from late 1980s due to its assistance to security of supply and reduction in greenhouse gases. The commission published a White Paper (Energy Policy for the European Union, 1995) in which communicated the advantages and contributions of RES to electric power systems and formulated a strategy to promote them. One year later the published Green Paper (Energy for the Future: Renewable Sources of Energy, 1996) outlined the main framework of the strategy. First of all, it mentions the existing unstable and unpredictable RES support framework at that time and indicates to the necessity of a more established extensive structure. The aim to reach by 2010 is set as doubling the share of RES. To achieve this, market based instruments and liberalization in the electric power systems are suggested. As additional measures the EU Commission introduces renewable energy credits (green certificates) which were first realized in the US under the name of renewable portfolio standards. This scheme obliges electricity suppliers to meet established RES quotas either by producing with RES or purchasing green certificates from RES generators. On the other hand, feed-in tariffs and other types of subsidies are not favored in the Green Paper provided that when the competition in the energy markets increase, these RES incentives should be replaced by market oriented measures. In addition to these measures, tax exemption is also proposed for electricity generation from RES. Lastly, the Green Paper even at that time argues the competitiveness of RES with conventional generation units in terms of costs (Laumer V., 2005).

In 1997, the Commission published another White Paper that does not pursue a pure market-driven approach. This White Paper also puts forward a formulation to the question of how an appropriate price that will be paid to generators should be defined. According to this formulation the price should at least be equal to the wholesale price of electricity at which low voltage grid operator buys and a premium for the social and environmental benefits of RES (Laumer V., 2005).

On the other hand, European Parliament defended that liberalization initiatives may harm the competitiveness of RES. Therefore, the Parliament supported the feed-in tariff model together with non-discriminatory access to the grid. A report on feed-in tariff directive was published by the Parliament in 1998 which advises to give the right EU member countries to choose between feed-in tariffs and tender system or both of them. Additionally, it states that the grid operators must receive all the electricity provided by RES without considering any upper limits. Later in 1999, European Commission published a Working Paper in which states that the existence of different support schemes would make the transition to a single market difficult and after examining different support schemes comes up with the proposal of feed-in premiums that are given over the wholesale price. It is concluded that with feed-in premium scheme competition in the market can be introduced without a specific quota and it also provides a certain amount of security to investors. In 2000, the European Commission quitted the initiatives of support scheme harmonization and endorsed the existence of different schemes at the same time. It came out that market mechanisms that were being promoted resulted in comparatively inefficient, whereas during this duration the revised feed-in tariffs facilitated the take-off of photovoltaic industry. (Laumer V., 2005) Moreover, the European Commission published the Directive 2001/77/EC in which sets RES target as %12 of gross energy demand by 2010. With this Directive, member states were encouraged to set their national support schemes and to achieve their established national targets. Furthermore, in another communication released by the European Union, 2020 renewable targets were set as 20% of the final energy consumption (De Jonghe C. et al., 2008).

Briefly, for the short term, the existence of different national RES support systems has been encouraged so that different solution methods can be developed. For the medium term, as a transition process to single market, collaboration of neighbor countries with similar schemes has been suggested. The integrated countries that can be showed as example are Germany, France and Spain with feed-in tariffs, Sweden and Norway with renewable energy credits system. Lastly, in the long term, these aggregated regions will optimize the existing supporting scheme in their region and harmonization process will start between these regions (De Jonghe C. et al., 2008).

Although the member states are free to choose any support system, currently the most popular scheme in EU is the price based mechanisms (feed-in tariffs, feed-in premiums) that are adopted by the majority including the leading wind energy producers like Denmark, Germany and Spain, whereas only a few countries carry out quantity based mechanisms (tenders, green certificates). The underlying reason of wind power development in Denmark, Germany and Spain has been regarded to be feed-in tariffs scheme, as the investors financial risk is largely reduced with fixed long term contracts. Additionally, these countries decrease the fixed payment streams after a certain period of time (e.g. 5 years) to mitigate the excessive rents of wind power plants and they can set different tariffs for different technologies to increase the development of less mature RES technologies by attracting more investment for them (Ackermann T., 2005).

The benefits and drawback of each system can be summarized as follows (Battle C. et al., 2011). As it was stated feed-in tariff scheme reduces investment risk by creating a stable environment and giving long term certainty for investors. Moreover, as RES producers do not have to compete in the wholesale market with other market agents, there is no entry barrier for these generators with feed-in tariff scheme. On the other hand, feed-in tariff levels are difficult to establish properly without rewarding RES generators excessively due to the information asymmetry between regulators and RES generators. The producers that benefit from this scheme also have no incentive to react to market signals and reduce their imbalances, unless the system oblige them to be responsible from their imbalance.

Feed-in premiums lead the producers to react according to price signals, i.e. the ones that can change their production level (biomass, small hydro etc.) may produce according to market prices and others like (wind, solar etc.) can organize their maintenance program taking into account the market signals. Big companies can expand their generation portfolio with RES and may exert market power by adjusting their marginal generators under feed-in premium scheme.

Green certificates or renewable energy credits are economically the most efficient support scheme if the renewable market has reached to a certain maturity, as this scheme stimulates market agents to comply their renewable quotas by competing with each other. However, the producers under this scheme are exposed to wholesale market price fluctuations and uncertainty. Furthermore, as in feed-in premium big generators can create market entry barriers to small RES generators by investing in their own RES units and not buying energy or green certificates from small RES generators.

Tendering or auctioning scheme is another quantity based mechanism in which regulator decides the amount of renewable capacity needed in the system for a period of time and invite all market participants to tenders for the determined capacity. As this scheme offers a long-term contract with fixed remuneration, it reduces investment risk as in feed-in tariffs. Yet, tenders do not face the difficulty of determining proper remuneration (e.g. due to information asymmetry in feed-in tariffs), since the participants bid their best price in tenders. Market agents can form partnerships to participate at tenders which results in cost efficient projects. On the other hand, to be successful with this system, again the market should reach a certain maturity level. Experiences in different countries show that under immature renewable market conditions, participants might underestimate their costs and bid so low that even they cannot recover their costs and cannot finish the project.

2.2. Challenges Facing Integration of Wind Power into Power Systems

Wind power has some negative impacts on power systems apart from its benefits, i.e. contributing to security of supply and greenhouse gas reductions. As Holttinen et al. illustrate, the negative impacts can be classified as short-term effects and long-term effects (2005) (Figure 1). On the short-term, there are several effects regarding the operation of the system; the need of voltage management, cycling losses, transmission or distribution losses, increase in operating reserves and wind curtailment, whereas on the long-term the impacts relates to the system reliability.

Voltage management or in another name reactive power regulation is required to maintain the voltage in the transmission grid within defined ranges. The regulation of reactive power is handled locally in related areas where the wind power is situated. With the developments in wind turbine technology currently wind generators are able to adjust their reactive power and the effect of wind farms on voltage management has been minimized.

Another impact of wind power on the short-term is the losses caused in electric power system. At high penetration levels of wind energy, conventional generators start to operate at partial load and due to the variability and uncertainty of wind energy, start-ups, shut-downs and ramping rates of conventional generators also increase. All of these cause the conventional generators to decrease their lifetime due to plant and equipment wearing, to increase the fuel consumption, to lengthen the duration of return on investment due to less hour of operation, in short, to operate inefficiently below the optimum operating levels.

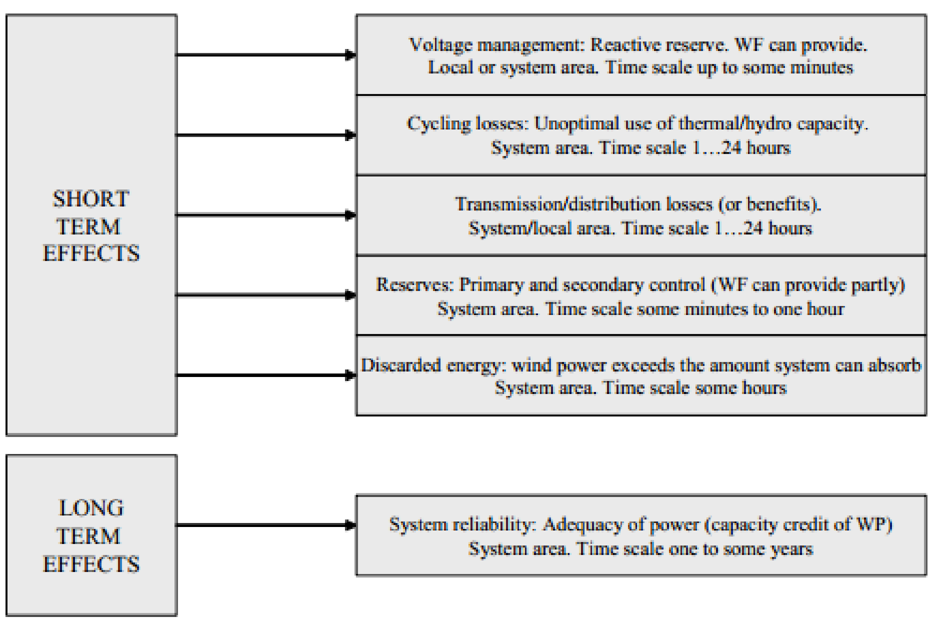

Figure 1: Power System Impacts of Wind Power [24]

Additionally, wind power has impacts on transmission and distribution grid as well. The impact on the grid can be either positive or negative by increasing or decreasing the losses. This phenomenon depends on if the wind farms are close to the load (decrease in loss) or far from it (increase in loss). Moreover, if the wind power is concentrated in some regions and the load is in another, congestion in the grid tends to increase which incurs another cost. Furthermore, connection of wind farms to the grid that are far from load may require building new transmission capacity.

The last issue in short-term is the curtailment of wind energy. When the installed wind power capacity reaches to high penetration levels in a power system, sometimes it becomes necessary to discard the extra wind energy in order not to shut down thermal units that operate at partial load (depending on if the system allows energy curtailment). As the impact on operating reserves is the subject analyzed in this thesis and the issue is explained elaborately in chapter 4, it will not be discussed in detail here.

For the long-term, power systems determine adequate installed capacity to meet the peak demand in the long-term. The adequacy of system is evaluated according to the probability of load loss with an index (Loss of Load Probability). Since the wind power replaces conventional generators, information about the availability of wind power should be obtained. This availability is put into terms the ability of wind power to replace conventional generators (capacity credit). It is shown that increasing wind power penetration rates after a certain limit does not change the capacity credit of wind power plants so at high penetration levels the system needs more peaking units and less base load capacity to make room for wind power.

Variability is not something new in electric power systems. The demand load also has a fluctuating profile. However, load forecasts give more accurate previsions than in wind energy. Although the forecasting techniques for wind energy are being improved, it is not expected to reach to same accuracy levels as in load. The underlying reason is that demand load has more predictable diurnal and seasonal patterns (Holttinen H., 2004). On the other hand, wind energy does not show any consistent pattern.

Prediction of wind energy can be made based on weather forecasts and time series analysis. Especially for shorter time scales, models with meteorological forecasts of wind speeds are the main tools to depict the production levels (Holttinen H., 2004). Reliability of these forecasts increases in proportion as it approaches to the real time. In day-ahead markets (24-36 hours before dispatch) forecasts have an error margin (mean absolute error) of 20% of the installed capacity. Yet, the predictions made a few hours before real time gives 5-7% error (De Vos K. et al., 2009). Hence, since the forecast errors increase the need for operating reserves which incur additional costs on the power system, it is important to give wind power plants the chance to update their forecasts and to change their production levels at intraday markets.

2.3. Large Scale Wind Power Integration in Europe

As it was stated before Europe is the leading region in wind energy by 39% of installed wind power capacity in the world. According to the statistics given by the European Wind Energy Association (2012), main wind energy producers in terms of total installed capacity (Figure 2) can be listed as Germany (30% of Europe total wind power capacity), Spain (22%), the UK (8%), Italy (%8) and France (%7), whereas according to wind power penetration in power systems (Figure 3) Denmark is the country that covers the demand consumption by highest wind energy ratio which is 27.1%. It is followed by Portugal where the penetration rate is 16.8% of the demand load, Spain (16.3%), Ireland (12.7%) and Germany (10.8%).

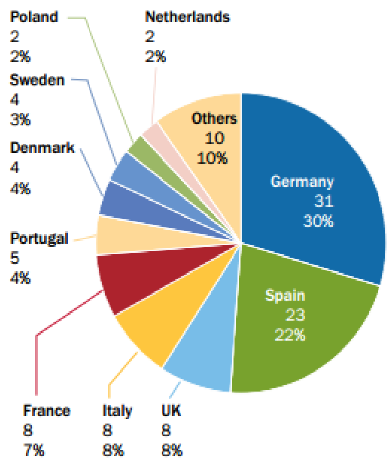

Figure 2: Market Shares for Total Installed Capacity [17]

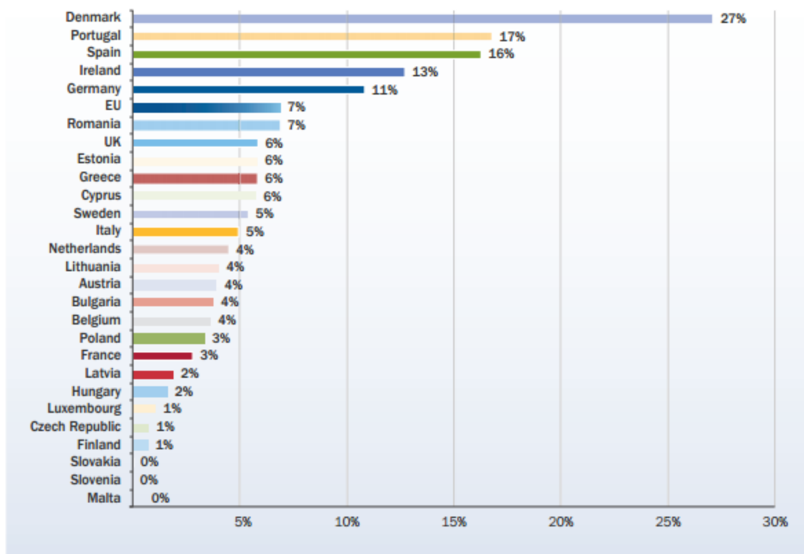

Figure 3: Wind Power Share of Total Electricity Consumption in EU [17]

Despite the economic crisis, Europe has increased its wind power capacity to almost 110 GW with new investments by 12.74 GW in 2012. Over all the new power capacity installed in EU (Figure 4), the wind power constitutes 27% of it and the wind energy produced meets 7% of total electricity demand. According to 2012 reports (Figure 5), Germany ranks in the first position with highest investment ratio which is 20% of total new power capacity installed in Europe. The UK comes after Germany by 16% while Italy is the third (11%) and the rest follows as Spain (9%), Romania (8%) and Poland (7%). Regarding the wind offshore power investments, for the first time in EU it passed the level of 1 GW installed capacity per year in 2012 and the investment level is expected to reach to 3 GW per year until 2017 (EWEA, 2012).

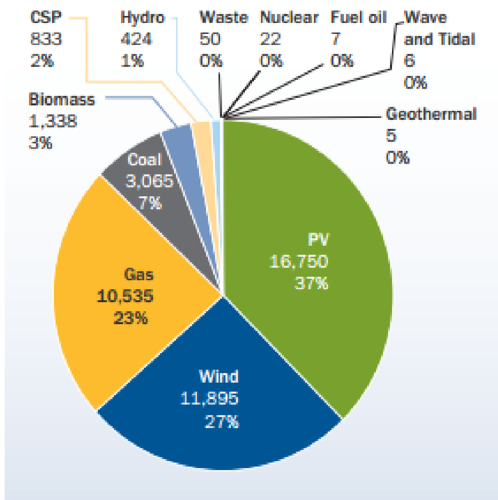

Figure 4: Share of New Power Capacity Installations in EU [17]

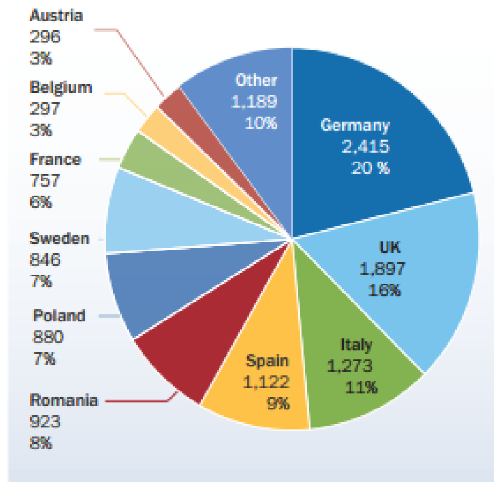

Figure 5: EU Member State Market Shares for New Capacity Installed [17]

2.3.1. Denmark

Danish electric power system is composed of two separate synchronous systems; Eastern Denmark and Western Denmark. Eastern Denmark belongs to Nordic regional power group (NORDEL) that includes Norway, Sweden, Iceland and Finland, whereas western part belongs to Continental Europe regional power group (UCTE). However these two separate systems are connected to each other by Great Belt Power Link transmission line since September 2010 (energinet.dk). Yet, both parts are connected to Sweden and Germany and Western Denmark has also connection with Norway by a transmission line (Holttinen H., 2005), (Kling W. et al., 2011). Most of the wind power capacity is situated in the western part (%77 of total country wind power capacity in 2009) (Jacobsen H.K. et al., 2010).

At the end of 2012, Denmark had 4.162 MW of installed wind capacity of which comprise 3.237 MW onshore and 922 MW offshore. The wind energy produced in 2011 which is equal to 9.765 GWh, met 28.3% of total electricity consumption according to Danish system operator. For the year 2012, wind energy penetration is stated to be 30% of the total demand. Denmark approved the new wind power target of 50% wind energy penetration by 2020 provided that the long term 100% renewable energy target is set by 2050 (GWEC, 2012).

Onshore wind power receives 3 Eurocents/kWh for the first 22.000 full load hours. In 2014 a ceiling price of 8 Eurocents/kWh will be added to the system, while offshore wind power is paid with a feed-in tariff for the first 50.000 full load hours according to the resulting price of tenders held by the system operator (GWEC, 2012).

2.3.2. Germany

German electric power system invested in 2.415 MW of wind power in 2012 and with this installed capacity, total capacity reached at 31.308 MW (30% of total European capacity). On the other hand, due to the large electricity demand in the country, produced wind energy only covers 10.8% of total consumption (GWEC, 2012).

After the Fukushima disaster in Japan, Germany decided to close its nuclear power plants by 2022 and the energy supplied by nuclear plants will be compensated by the increase in RES generation. To do so the Renewable Energy Sources Act has been amended to increase incentives for RES investments. The new renewable energy target is set to cover the 35% of total electricity consumption by 2020 (GWEC, 2012).

German RES policy set the onshore wind energy tariff at 8.8 Eurocents/kWh for five year duration plus wind power plants equipped -before 2015- with advanced technological capacities are paid an extra service bonus of 0.47 Eurocents/kWh, if a plant has old system and changes with a new one then receives another bonus of 0.49 Eurocents/kWh. For offshore wind energy, the tariff is set at 15 Eurocents/kWh for at least 12 years. However, since the investment in offshore wind power is financially riskier than other technologies and interconnection rules are still unclear for offshore projects, German system operator gives an additional starter bonus of 2 Eurocents/kWh to increase the investments. Additionally, an optional tariff is offered to offshore investors. The investors can either choose a tariff of 19 Eurocents/kWh for 8 years or they can continue with standard offshore tariff at 15 Eurocents/kWh for 12 years. Another method of remuneration can be made through feed-in premiums in which the premium levels are calculated as the difference between feed-in tariff and monthly average of wholesale market price. The switch between feed-in tariffs and feed-in premiums are allowed monthly (GWEC, 2012).

2.3.3. Ireland

Irish electric power system is a small and almost isolated power system with two High Voltage Direct Current (HVDC) interconnections (400 and 500 MW) to Britain. The system unites the two countries in the island (Northern Ireland and Republic of Ireland) synchronously under the control of system operator EirGrid and they both participate at Irish electricity market (Single Electricity Market). %12.7 of electricity consumption in the island was covered by wind energy in 2012 where sometimes the instantaneous penetration level reaches 50% (Foley A.M. et al., 2013). Together with 125 MW wind energy installed in 2012, total installed wind power capacity in the island currently amounts up to 1.738 MW.

The remuneration of onshore wind energy is guaranteed by feed-in tariffs scheme which are paid for 15 years. For onshore wind power plants that have more than 5 MW capacity the reference price is 6.6 Eurocents/kWh whereas for the ones equal to or less than 5 MW the price is 6.9 Eurocents/kWh. Additionally, beginning from 2009 the Irish power system included offshore wind energy to its support scheme. The tariff for offshore wind energy is set as 14 Eurocents/kWh for 15 year duration (REFIT, 2012).

Due to the EU Renewable Energy Directive (2009/28/EC), Ireland's RES target is set as providing renewable energy at 16% of the total system energy consumption, while the electricity power sector should meet the 40% RES target of covering total electricity demand by 2020 (EirGrid).

2.3.4. Britain

British electric power system (National Grid) consists of England, Scotland and Wales. It has HVDC interconnections with France, the Netherlands, Northern Ireland and Republic of Ireland by subsea and underground cables. These interconnections enable trade between British and Irish, Continental European electric markets by transmitting power in both directions [33].

The total installed wind power capacity in UK was recorded as 8.445 MW at the end of 2012 in which year the new wind capacity installations were equal to 1.897 MW (1.043 MW onshore, 854 MW offshore) which made UK the second biggest wind power investor in EU by 16%. The wind energy produced for the same year showed an increase of 33% compared to 2011 and with this energy 5.5% of total electricity demand has been supplied (GWEC, 2012).

According to the 2009 EU Renewable Energy Directive, the renewable target of UK was set as 15% of its total energy consumption by 2020. To achieve this target, British system operator created three different scenarios for the future; slow progression, gone green and accelerated growth. Under the Slow Progression scenario, total wind generators will amount up to 16 GW of installed capacity, 10 GW of which is offshore by 2020. The Gone Green scenario enables EU 2020 targets to be met and it states that total 30 GW (17 GW offshore) of wind power capacity will be installed by 2020. Lastly, with the Accelerated Growth scenario, the power system will include total 39 GW (24 GW offshore) of capacity by 2020 [34].

The UK has different renewable energy support schemes; renewable obligation, feed-in tariff, carbon price floor, capacity mechanism and a new form of feed-in tariff with contracts for difference. The renewable obligation scheme obliges electricity suppliers to include a portion of RES, which is set annually, in their portfolio. Renewable obligation of onshore wind power is set at 9% Renewable Obligation Certificate (ROC) for the years 2003 – 2007. Feed-in tariffs are paid to renewable generation units that have less than 5 MW of capacity, whereas feed-in tariff with contract for differences encourage the investment in low-carbon technologies with a fixed remuneration (Department of Energy and Climate Change).

3. WIND POWER INTERGRATION IN ELECTRICITY MARKETS

3.1. Electricity System Balancing Mechanisms

Electricity system balancing starts with long-term contracts and in the short-term continues with day-ahead market which is held prior to real-time electricity dispatch. Once the day-ahead market closes, in some electric power systems additional balancing mechanisms are initiated such as intraday and balancing or real time markets to correct the imbalance that occurs between the generation/load schedules in the day-ahead market and the updated available production/consumption levels. Also, these markets can be an opportunity for the market participants to correct their imbalance positions in shorter terms prior to dispatching.

3.1.1. Real-time Energy Market

Real-time energy market is a balancing mechanism mainly takes place in US. In this spot market, generation and load units that are not committed to day-ahead market can make offers. According to the offers every five minute Locational Marginal Prices (LMP)[2] are calculated by the system operator taking into account the actual grid operating conditions. Transactions are settled hourly and the assigned generation and load units are paid monthly according to the LMP at where the energy is traded (PJM).

3.1.2. Intraday Markets

On the other hand, in most of the European countries there exist intraday and balancing markets. In the intraday markets, generators and consumers can improve their day-ahead market schedules by making

[2] Locational Marginal Price is the marginal price of electricity at the location where the energy is traded. This price besides energy costs includes also congestion and loss costs.

buy or sell offers. The reasons of changing the day-ahead programs may vary; a decrease in production can be expected due to some problems, over/underestimation of generation levels for wind energy etc. Intraday markets carry on transactions in a sequence of various trading sessions, depending on the country, until one or a few hours prior to real-time dispatching.

3.1.3. Balancing Markets

When the intraday market is closed, the responsibility of balancing generation and demand is on the shoulders of system operator. This means that when the system operator calls gate closure[3], market participants are not allowed to commit any market transaction anymore but any possible imbalance between demand and generation should be handled at real time by system operator. For this purpose, system operator has a tool that is called balancing market. With this mechanism, system operator tries to secure the supply of load in the short-term with a market mechanism and to keep the system in balance (ETSO, 2003).

The difference between balancing market and previous competitive markets is that while in day-ahead and intraday market, market agents interact with each other as trading party, in balancing market, system operator appears as the only counterparty to the transactions. By the time of gate closure, each market participant notifies the system operator about their expected physical position at real time and within the balancing market, they can make offers to inject energy into the system or bids to withdraw energy from the system to the extent to which they want to be paid (for selling energy) or to pay (for buying energy) to deviate from their notified positions. Before the gate closure, the system operator receives all the offers and bids and in case of need for balancing reserves, they allocate the offers and bids according to the least cost principle, provided that this is valid if only exists a market, i.e. primary reserves are purchased as compulsory service and the allocation is not based on least cost principle. The balancing energy price can reflect only energy cost (€/MWh) or both energy and capacity costs (€/MW). Even in some unusual cases start-up costs of generation units can be compensated as well. Remuneration of balancing reserves can be based on two options; marginal pricing in which all the offers and bids in a specific period are paid at a single clearing price or with pay-as-bid system balancing service providers receive what they ask for in their offers and bids. Balancing costs that are born by the system operator can be allocated either to all users or only to the users with an imbalance in their portfolio or a combination of the two models. Furthermore, depending on the electric power system, suppliers can be obliged to submit all of their

[3] The gate closure time differs from one country to another; it can be a rolling deadline, half-hour or hourly intervals or can be set at specific times during the day.

available capacity to the market and this available capacity can be used to offset imbalances only within the control area or also to solve transmission constraints (LDK, 2012).

In addition to the procurement of aforementioned regulating reserves, the system operator encourages market participants to minimize their imbalances. To do this so, Balance Responsible Parties (BRPs) are created who are financially responsible from imbalance costs of market participants. Generally, all the market participants are required to be a BRP or to join a BRP that aggregates different generation and load units under a portfolio. Therefore, all the market agents are either directly or indirectly subject to balancing market rules (ERGEG, 2009).

The system operator determines imbalance settlement price according to the cost of balancing energy that is procured through balancing mechanism. Taking into account the imbalance settlement price the system operator charges imbalance fees to BRPs as the amount of net deviation from their scheduled energy delivery. Imbalance fees can be determined through single or dual pricing scheme.

Under single pricing scheme, imbalance price is given by the marginal procurement price of balancing services. The same price is applied to all BRPs with imbalance. However, while BRPs with negative imbalances are charged this single price, BRPs with positive imbalances are rewarded according to the same single price. In the end, the loss and the gain of system operator will balance each other. In other words, all the system balancing costs will be transferred to the responsible agents and the system operator will not have any residual imbalance charges at hand. However, it is discussed that this approach may lead some generators to speculate on the direction of the system imbalance by intentionally deviating from a balanced schedule. For instance, if a generator expects the system imbalance to be negative, then it can decide to produce more than its scheduled program to reduce the total system imbalance so that they can capture additional income from balance settlement mechanism. Although it is questionable if the generators would risk their position on the basis of a very short time period, to avoid such an undesired incentive, in some electric power systems dual pricing method is applied (Vandezande L. et al., 2009).

Dual pricing scheme requires BRPs to pay differently according to their negative or positive imbalance. BRP imbalances that have the same sign with the system imbalance are calculated based on the procurement costs of balancing services, whereas BRP imbalances with opposite sign are calculated based on the day-ahead market price. As the imbalance pricing is different for negative and positive imbalances, the dual pricing scheme is not a zero-sum game for the system operator, that is, a certain amount of money remains to the system operator after imbalance settlement. This amount is generally used to rebate the transmission tariffs which are distributed among all transmission grid users. Hence, this exercise implies a money transfer from inflexible users (e.g. wind farms, if the system renders RES responsible of their imbalance) to average grid users. Moreover, if a BRP has more than one generation or load unit, it can reduce its imbalance costs due to the intra-firm netting[4]. Under these conditions, small market agents are at a disadvantage compared to big companies that can combine more generation/load units. Therefore, the intra-firm netting creates market entry barriers for smaller agents (Vandezande L. et al., 2009).

3.1.4. Electricity System Balancing Mechanisms in Spain

In Spain, electricity system balance is maintained by different mechanisms depending on the time period before real-time dispatch. Time sequence of these markets and mechanisms is as following; long term markets, day-ahead market, management of network constraints, intraday, balancing markets and operating reserves. Weeks, months and even years before the generation and dispatch of energy, agents in energy markets make long-term contracts with various duration periods of delivery (yearly, monthly etc.). These transactions take place in long term markets which consist of forward (physical) and futures (financial) contracts[5] (Energia y Sociedad).

The Spanish electricity day-ahead market receives offers for energy sale and purchase until 10:00am[6] of the day before of actual dispatch. The Spanish electricity system has two generation regimes; general and special regime[7]. For each hourly period of next day, generators and consumers under general regime are obliged to make their offers to the market operator with their all available capacity, keeping the bilaterally contracted capacity out of this obligation (Operador del Mercado Eléctrico - OMEL).

Generation offers can be either simple or complex bidding. Simple bidding consists of a quantity and corresponding price of energy, while complex bidding may incorporate some technical or economical conditions such as load gradients, indivisibility, minimum income, scheduled stop etc. The load gradient rate sets the maximum difference between the starting hourly power and the final hourly power of

[4] Intra-firm netting occurs when opposite imbalances of different generation and load units cancel out each other. For instance, one generator has 12 MW of negative imbalance and another has 7 MW of positive imbalance so the net imbalance is equal to 5 MW of negative imbalance. BRP pays only the imbalance price corresponding to the net imbalance amount, instead of paying separately 12 MW of negative imbalance fee and 7 MW of positive imbalance fee.

[5] Market participants who do not want to rely on price uncertainties of day-ahead market can reach a bilateral agreement for a long term (forward contract) that requires physical transmission of contracted energy, whereas any agent who is not interested to physically buy or sell energy but to take advantage of short-term price variations in time can join exchange markets to trade financial energy products (futures contract).

[6] The gate closure time in Spanish electricity market has been changed recently to 12:00 pm (OMIE).

[7] In order to register under special regime, generators either must produce equal or less than 50 MW or they should be self generators (Operador del Mercado Eléctrico - OMEL).

production unit to prevent the sudden program changes in the production unit that is unable to comply technically. Indivisibility condition allows fixing a minimum operating value in the first block of each hour. The minimum income condition allows the generation unit to participate to production schedule provided that a certain amount of minimum income should be received, in addition to the variable energy remuneration. The scheduled stop condition allows production units to give a scheduled stop for three hours at most in case of being withdrawn from the supply-demand matching process due to the minimum income condition.

All the generation and demand offers, respectively, are listed in an increasing and decreasing order of price. Later, supply and demand curves are created for each hour of the next day by OMEL. The intersection point of these curves gives the market clearing price for each period. The generation and demand offers that are, respectively, below and above the market price are accepted by the market operator. The difference between the matching processes of simple or complex bids is that complex matching method introduces the complex conditions into the simple matching method (Figure 6).

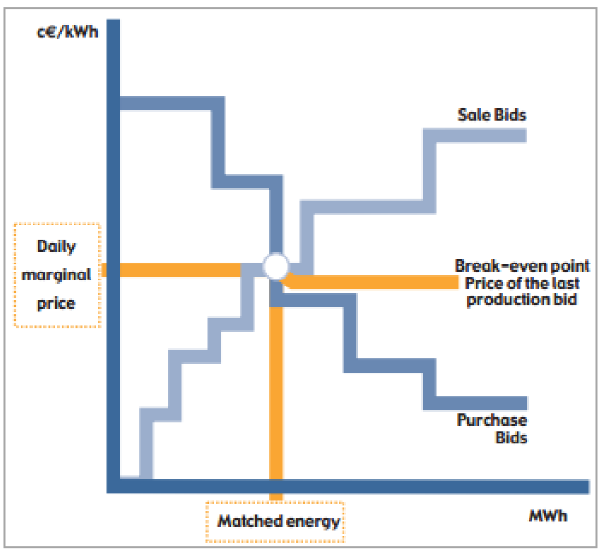

Figure 6: Daily Market Supply and Demand Curves [35]

When the market operator obtains the base daily operating schedule at 11:00 am, it is notified to the system operator to analyze the technical feasibility of operation schedule in order to be sure that the grid security and reliability of supply is secured. If the final schedule from the day-ahead market, production under the special regime, bilateral and international contracts is not in the security limits, the system operator changes the generation schedule to solve the technical constraints by 2:00 pm. This process includes two phases. In the first phase, the system operator determines the congestions in the grid that may impact the operation of base daily schedule and decides on the schedule modifications to resolve the problem. If the congestions are due to the production of several generators in one area, then the system operator handles the congestions according to zones. If within the zones there are different modification alternatives, then the cheapest options are preferred. In the second phase, the necessary modifications are introduced by the system operator. The agents that are in the first or second constraint solving phase can submit bids to increase or reduce their scheduled energy. The modifications costs can be charged to the load units proportional to their responsibility in the congestion. When the system operator resolves the system constraints, it notifies the market operator the final daily operating schedule (OMEL).

After the day-ahead market, market agents can make adjustments to the final daily schedule in the intraday market. The purpose of these adjustments can be correcting production forecast errors, i.e. wind energy, changing the production due to the equipment and power system failures or taking some strategic decisions. The intraday market in Spain consists of six consecutive sessions and the first session starts at 4:00 pm. The timetable of these sessions can be seen in Table 1 (OMEL).

	SESSION 1º	SESSION 2ª	SESSION 3ª	SESSION 4ª	SESSION 5ª	SESSION 6ª
Session Opening	16:00	21:00	01:00	04:00	08:00	12:00
Session Closing	17:45	21:45	01:45	04:45	08:45	12:45
Matching Results	18:30	22:30	02:30	05:30	09:30	13:30
Reception of Breakdowns	19:00	23:00	02:45	05:45	09:45	13:45
Constraints Analysis	19:10	23:10	03:10	06:10	10:10	14:10
Adjustments for Constraints Publication PHF	19:20	23:20	03:20	06:20	10:20	14:20
Schedule Horizon (Hourly periods)	28 horas (21-24)	24 horas (1-24)	20 horas (5-24)	17 horas (8-24)	13 horas (12-24)	9 horas (16-24)

Table 1: Timetable of Intraday Market Sessions [35]

All the day-ahead market participants and agents with bilateral contracts can present bids to the intraday market. However, these agents can only bid in the hourly periods that they have participated in the day-ahead market. The bids can be in the form of simple or complex bidding and matching process is same as in day-ahead market.

Operating reserves are called just after the closure of day-ahead market. First of all, the new reserve market –additional upward reserves– that has been created to increase the security of system, opens at 2:00 pm of day-ahead and receives the additional upward reserve offers (MW) of authorized generators (the thermal power stations under ordinary regime and generation units under the special regime that can control its production) during 30 minutes before closure. Once the additional upward reserves market is closed, the Spanish system operator calls secondary reserves market (upward and downward). Participant generation and load units must bid in the form of capacity (MW) by 3:30 pm of day-ahead. On the basis of the provisional daily schedule, the system operator assigns the secondary control reserves by 4:00 pm. Following the secondary reserves market, all the available generation units are obliged to bid all their available reserve capacity in MW, both upwards and downwards, together with the corresponding energy price €/MWh for each of the hourly periods of the following day in the tertiary reserves market by the last hour of the day-ahead (11:00 pm).

Lastly, just after the intraday market, if the forecasted imbalance between generation and demand appears to be equal or more than 300 MWh, deviation management market (the balancing market in Spain) is called to purchase additional energy a few hours before real-time dispatching. Once the reserve requirements to cover the deviations are announced, authorized generation and load units submit offers and bids in the form of energy (MWh) with corresponding energy price (€/MWh) in 30 minutes. Furthermore, additional upward reserve service providers are obliged to bid in the balancing market at least the difference between the energy scheduled in the intraday market and the reserve committed in the additional upward reserve market. The Spanish balancing market applies a dual pricing scheme; if a BRP has an imbalance that is in the opposite direction of the system imbalance, it is charged the day-ahead spot market price, whereas the BRPs with the same imbalance sign that contributes to the total system imbalance are charged the average price of balancing services (secondary, tertiary and balancing reserves). All the assigned generation and pumping units are remunerated based on marginal pricing in each period of dispatching and the imbalance settlement price is calculated according to the costs incurred through the purchase of balancing reserves (Red Eléctrica de España, 2011).

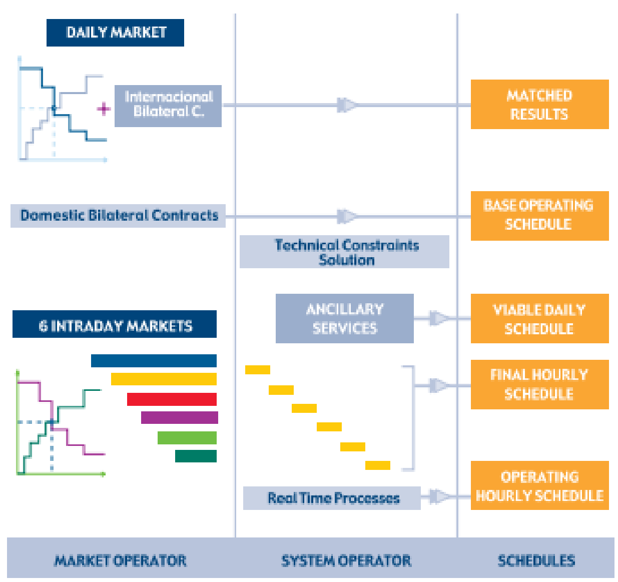

Figure 7: Sequence of Processes in the Electricity Market [35]

3.1.5. Ancillary Services

After the gate closure all the responsibility of balancing demand and generation belongs to system operator. The system operator tries to strike this balance in an economically efficient way within specific quality and reliability measures. To perform this duty some ancillary services are supplied by the system operator such as frequency and voltage control, transmission grid security, black start capability and economic efficiency of grid management (Belmans R. et al., 2012). Voltage control is carried out by providing reactive power services to the system. Black start capability is the ability of a generation unit to restore its generation capacity without relying on external resources from electric power system, such as transmission grid. In this thesis the focus is on active power services and frequency control so other ancillary services will not be explained in detail.

3.1.5.1. Operating reserves

According to Ela E. et al., operating reserves are defined as the real power capacity that can be called in order to equalize an imbalance that occurs between generation and load during the operating time frame. An imbalance may result from power system equipment failures, load forecast errors or variability in generation outputs. Balancing generation and load at all time scales is important due to proper operation of the system besides serving load reliably. In each electric power system the frequency is set at a nominated frequency value, i.e. 50 Hz in EU. If generation and load cannot be held in balance, the frequency deviates from the specified values and this might cause damage on system elements. Therefore, operating reserves are necessary for frequency control reasons (2010).

Operating reserves can be classified according to synchronization of generators (spinning or non-spinning), type of event (contingency, load following etc.), response direction (upward and downward) and response time (primary, secondary and tertiary) (Kling W. et al., 2011). There is no common definition for operating reserve types in the literature and they do differ from one system to another.

Regarding synchronization of generators to the system there are two operating reserve services; spinning and non-spinning reserves. Rebours Y. et al. compare the different definitions of spinning reserves from literature and come up with a more comprehensive one. Spinning reserve is the unused capacity (of generators or consumers) that can be activated by the system operator and that is provided by devices that are synchronized to the network and able to affect the active power (reduce or increase). Whereas the difference of non-spinning reserve is that it is not currently synchronized (connected) to the system but can be online with a delay (2005).

Furthermore, operating reserves can be categorized according to type of event that they face. Contingency reserves are held to use in case of contingency events such as the failure of a generator or transmission line. If the event is not instantaneous but takes longer time i.e. wind ramps, forecast errors, then this is called ramping reserve. The last reserve type under event categorization is load following reserve that is used under normal system operation conditions (non events) to maintain area control error and frequency (Milligan M et al., 2010).

Another classification of reserves is made by reserve response direction; upward and downward. Upward reserve is called when the load is more than generation to serve the unsupplied load. This can be done by increasing generation or reducing load. On the contrary, downward reserve is activated when generation exceeds load and this can be handled by reducing generation or increasing load (Milligan M et al., 2010).

In addition to these, operating reserves are also classified according to time of response and in this study this classification will be used. Union for Coordination of Transmission of Electricity (UCTE) that is now part of European Network for Transmission System Operators for Electricity (ENTSO-E) defines operating reserves under this category as primary, secondary and tertiary control reserves (Figure 8).

Primary reserve is activated when system frequency deviates from nominated frequency level which is 50 Hz by 20 mHz because of a disturbance in system or small variations in generation and load. The activation is initiated automatically within seconds by speed regulators that are integrated to generation units and by automatic load shedding control in load. It must be fully operational within 30 seconds. In Spain, for the deviations smaller than 100 mHz imbalance should be corrected within 15 seconds and for up to 200 mHz deviations this duration can vary between 15-30 seconds. The aim of this reserve is to control and stabilize the frequency deviation at a stationary value. Determination of primary control reserves among ENTSO-E members depends on the share of energy produced in each country over total energy produced in all member countries:

$$P_{pri.}^{country} = \frac{E_{prod}^{country}}{\Delta f_{\max ss} \sum_{ENTSO-E} E_{prod}^{country}} \Delta P_{cont.}$$

where $\Delta f_{max,ss}$ and P_{cont} refer to, respectively, the tolerable maximum deviation of 0.18 Hz and the worst case contingency of 3000 MW (Milligan M. et al., (2010).

If the deviation in generation and load balance is bigger, then secondary reserve is automatically activated by automatic generation control (AGC)[8]. The response time of this reserve varies among different

[8] AGC is a centralized automatic control center to adjust the power outputs of different generators in a region.

countries. According to UCTE, secondary reserve becomes active 30 seconds after a contingency event that causes large variations and must be fully operational within 15 minutes. Besides restoring primary reserves, its objective is to bring back the stabilized frequency to the preset value and decrease the area control error[9]. ENTSO-E members are required to hold secondary reserves according to the maximum yearly load in their territory:

$$P_{sec.}^{country} = \sqrt{a \cdot L_{\max} + b^2} - b$$

where a and b were established empirically as10 MW and 150 MW (Milligan M. et al., (2010).

Lastly, tertiary control reserve is activated within 15 minutes that is a slower response reserve and can be used for hours. Its objective is to relieve secondary reserves by restoring them to bring back the frequency. Tertiary reserve is provided by changing the dispatch and unit commitment manually and it is called regionally by the system operator. Both generation and load units can provide this service. The level of tertiary reserve requirements that will be set in a country is determined by that specific country (Milligan M. et al., (2010).

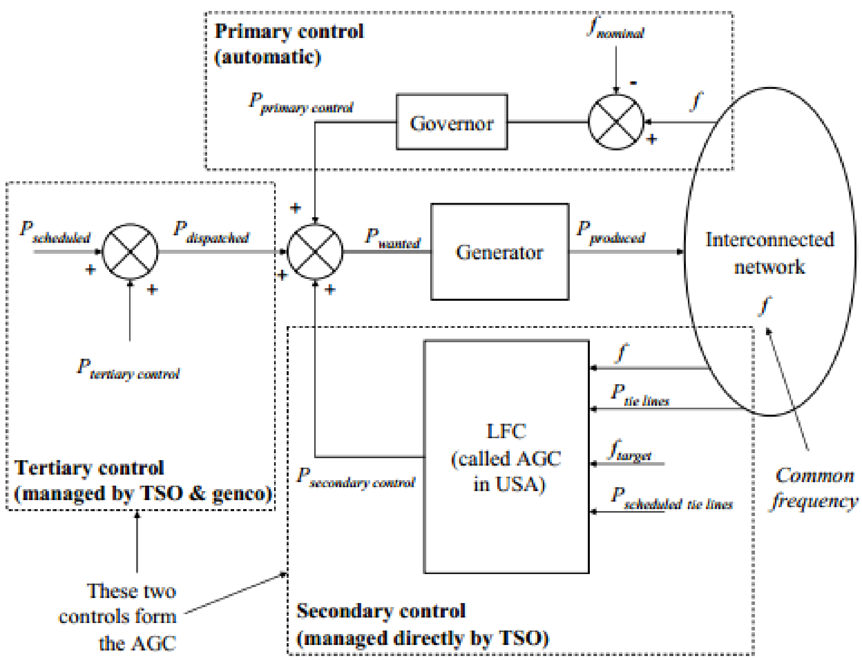

Figure 8: Framework for Frequency Regulation within the UCTE [39]

9 Area control error is the deviation of power exchange programs with other control areas.

3.1.5.2. Procurement and remuneration

System operators are the responsible party to obtain ancillary services. The procurement of ancillary services can be realized through four different approaches; compulsory provision, bilateral contracts, tendering and spot markets. In some systems, when generators ask for connecting to the grid, as a condition of permission they are imposed compulsory provision of a certain type and amount of ancillary service. In bilateral contracts, system operator and service providers negotiate the quantity, quality and price of the service that will be purchased. The difference between these two methods is that bilateral contracts do not reveal contract terms so they lack of transparency while the compulsory provision method is based on non-discriminatory basis and the service providers that are in the same class provide the same relative amount of compulsory service. In tendering method, ancillary services are procured over long durations, i.e. one year, whereas in spot market service providers bid for shorter periods such as one week or even less and another difference among these two methods is that standardization of products in tendering is less compared to spot market. The latter two methods are better off than the former ones in terms of enhancing transparency and fostering competition (Red Eléctrica de España, 1998).

Ancillary services might be remunerated or non-remunerated. Although not making any payment for ancillary service is more favorable for the system operators, this would lead service providers to charge these extra costs on electricity prices. Remuneration can be based on three types of price; regulated price, pay as bid price or a common clearing price. Regulated price is determined by system operator and the same price is applied for all providers. With pay as bid price, if the service provider's bid is accepted then it is remunerated over that price. Lastly, in a common clearing price system, all the suppliers that bid less than or equal to marginal price receive the system clearing price (the most expensive accepted offer or the least expensive rejected offer) (Red Eléctrica de España, 1998).

Remuneration can be composed of different parts to compensate different costs incurred by the service provider; fixed allowance, availability price, utilization payment, utilization frequency price and an opportunity cost are some possible components. Under fixed allowance and availability price schemes, provider is getting paid for the fixed costs that they are exposed to for making a certain amount of service available. While utilization payment is used to pay for the actual amount of energy provided whereas with utilization frequency scheme service provider receives a payment that depends on the number of times when it is called to provide service and this component intends to cover the costs that provider may assume each time when it starts to deliver the service. Finally, opportunity cost secures the extra profit that could be made if the service provider had used its product in another market such as selling energy in spot markets, instead of giving the service (Red Eléctrica de España, 1998).

In Spain operating reserves are categorized in three groups; primary, secondary and tertiary control reserves. In addition to these, recently the system operator introduced a new reserve mechanism under the name of additional upward reserve capacity. Primary control service in Spain is obligatory and it is a non-remunerated service. Primary control service requires all generation units to operate with 1,5% of their nominal capacity. If a generator technically is not available to give this service due to the lack of adequate equipment (speed governors) then it should contract its service obligation with another generator that can do for it (REE, Procedimientos de Operación del sistema: P.O. 3.1).

On the other hand, secondary control reserve is not obtained through compulsory provision method but through tendering or spot market, only in France it is procured by bilateral contracts. While in Spain there is a spot market for secondary control reserves and participants of this market consist of generation and load units that are authorized by system operators. Secondary regulation service is managed by regulation zones (currently ten zones) in Spain. Regulation zones consist of different numbers of generation units that are capable of providing the service. The Spanish TSO (Red Eléctrica de España - REE) decides and announces each day necessary secondary reserve level for each period of next day by determining the relation of required downward and upward reserve levels for regulation zones and maximum-minimum acceptable offer values. Secondary control reserve is determined according to function of statistical uncertainty of electricity demand, generation and equipment failure probability. Any generation unit that wants to provide secondary regulation service should give an offer in the secondary reserve market in the form of upwards and downwards reserve capacity (MW) with its corresponding price, in €/MW, for each one of the hours of next day. When system operator assigns secondary reserves according to received offers, it takes into account that each regulation zone should secure the determined relation between upwards and downwards reserves for the whole system. The system operator compares the price of all offers and accepts all the cheapest offers for the required amount of reserve. The marginal cost of the market for each hour sets the market price with which all the assigned capacity is remunerated. Apart from capacity payments, if the assigned service provider is called to give the service then additionally it is paid an energy price component according to the energy price of tertiary reserve market (Energia y Sociedad).

Tertiary reserves in Spain should be fully operational in 15 minutes and the energy provision should be maintained at least for two hours if it is demanded. Tertiary control reserve is also an obligatory service but it is remunerated by market mechanisms. Any agents that can prove its technical and operational capacity to give the service with the authorization from system operator can participate in this service. Minimum necessary tertiary reserve capacity in each period is determined by REE as a sum of the biggest possible generation loss synchronized to the system (biggest nuclear power unit), components related to possible demand forecast errors (2% of the forecasted demand load in each hour), wind power forecast errors and additional reserves for uncertainties (Gil A. et al., 2010). Before the last hour of the day before prior to dispatch, all the available generation units are obliged to bid all their available tertiary reserve capacity in MW, both upwards and downwards, together with the corresponding energy price €/MWh for each of the hourly periods of the following day. In case of that REE detects that existent tertiary reserve will not cover the requirements then it will call more generators that can provide tertiary reserves. In real time, system operator assigns service provisions according to minimum cost criterion; generation units that give upwards service receive lowest price offered and in the case of downwards reserve i.e. pumped storage units receive the highest price offered in the market which are set as market clearing prices. Contrary to the case of secondary reserves, in tertiary reserve market only called generation units are remunerated.

Additionally, there is balancing service in the Spanish electricity system that is named deviation management reserves. During the normal operation, generation units inform system operator the deviation predictions that result from different reasons; unavailability of a generation unit, modification of demand forecast, variations in wind energy forecast etc. If the forecasted imbalance appears to be more than 300 MWh, deviation market is called just after the gate closure of a session of intraday market. The deviation management market asks generators to produce more energy and pumped storage units to reduce the consumption if the system is short with the existing generation program and in the opposite case it is the other way around. Generation and pumping units make their offers in the form of energy (MWh) together with its price €/MWh. The offered value of energy, upwards or downwards, cannot be greater than 300 MWh. Deviation markets provide extra flexibility to the system operator without affecting the secondary or tertiary reserve requirements. Moreover, in real time within 15 minutes before the dispatch, apart from the frequency control reserves mentioned above, REE has emergency mechanisms at its disposal that can oblige determined generation units to change their production levels in case of extreme necessity for the system (Energia y Sociedad).

Finally, with the new reserve mechanism –additional upward reserves- the system operator aims at guaranteeing the security of peninsular Spanish electricity system. Participants of this market consist of units that have not committed any production in the day-ahead market; the thermal power stations under ordinary regime and generation units under the special regime that can control its production. After the closure of day-ahead market, REE determines the requirements for additional upward reserve capacity for each period of the next day according to the available upward reserve capacity in provisional day-ahead market results and frequency reserve requirements. Once the system operator calls the additional upward reserve market, all the possible suppliers should make their offer within a period of 30 minutes. The offers should contain for each generation unit and each dispatch hour, one or various simple block offers, in the form of capacity (MW) and with its corresponding price (MW/h) and the minimum capacity offer for one period can be 10 MW. The offers are assigned according to the marginal market price rule in each period of dispatch by determining the highest accepted offer (REE, The Spanish Electricity System, Preliminary Report, 2012).

3.2. Relationship between Wind Power Penetration and Operating Reserves

As wind power is a variable energy resource and the forecast accuracy of wind power production level is limited, wind power increases system imbalances and the demand for operating reserves[10]. However, the impact of wind power on operating reserves is not same for all power systems. The level of impact can change according to the wind power penetration level, time scale of reserves, geographic spread of wind power, the way the power system is operated and correlation of wind power with load and other source of variable generation units. According to Foley et al., low levels of wind power penetration have insignificant impact on operating reserves to keep the system security in reliable levels. While the increase estimates for operating reserves at 10% and 20% of wind power penetration, respectively, are between 1–15% and 4–18% of installed wind capacity (Helander A. et al., 2009).

The impact of wind power on operating reserves in different time scales also differs. In the literature, it is stated that wind power impact is seen mostly on secondary and tertiary reserves and the impact on primary reserves is negligible. Since the variability of wind power decreases with short time scales (second to minute variability), even at high wind power penetrations fast acting primary reserves are affected insignificantly by the integration of wind power to the electric power system. This is shown by Holttinen H. et al., that the standard deviation of a single large wind power plant variations at one second scale is only 0,1% (2009). Moreover, variations of aggregated several wind parks are smaller due to the smoothing effect[11]. For instance, the smoothing effect of aggregation of wind turbines in one minute scale of standard deviation change; 14 wind turbines have profile of 2.1% standard deviation of nominal capacity whereas this value decreases to 0.6% with 250 wind turbines (Holttinen H. et al., 2009). Additionally, geographic spreading of wind parks also contributes to decreasing the generation variation.

[10] Reserve capacities are determined according to the total system imbalances and the system imbalances are mainly driven by unexpected power plant outages, forecast uncertainty of load demand and variable generation units (Xu M. et al., 2012).

[11] Smoothing effect occurs among spatially spread wind power units as the same air current does not pass through different wind turbines at the same time and a sudden loss of all wind power plants simultaneously because of loss of wind is not probable (Holttinen H. et al., 2009).

The more space there is between the wind farms, the less correlation there is between their generation profiles which leads to less total system variability (Belmans R. et al. (2012).

Moreover, it is concluded that wind power variability increases in intra-hour intervals (10 minutes to one hour). De Vos K. et al. suggests that the imbalances caused by wind power plants are composed of two components; the forecast errors over the settlement period and the short-term fluctuations within the settlement period (see Figure 9). The short-term fluctuations are handled by secondary reserves within the settlement period. Therefore, the secondary reserve requirements increase due to the instantaneous variations of wind power that cannot be predicted with the current forecast techniques.

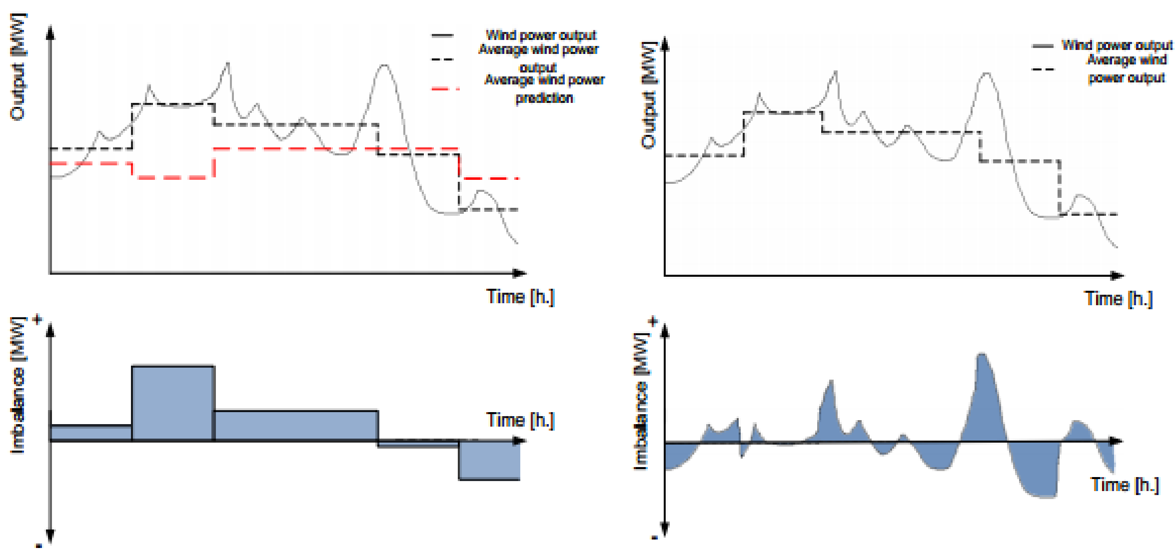

Figure 9: Forecast Errors (left) and Short-term Fluctuations (right) [8]

On the other hand, wind energy can vary much more in longer time scales (4-12 hours). In this time scale, the problem is the forecast error over the settlement period. Yet, the variation of wind power can be forecasted fairly well with the current techniques. However, since the accuracy of forecast techniques improves with closer time scales, the operation of power system is another important factor that affects the increase in slower reserves (tertiary), i.e. the existence of intraday markets that give wind power generators the ability of rearranging their production schedule with consecutive hourly sessions. If a power system enables wind power generators to participate in intraday markets, deviation from the forecasted production in that system can be reduced.

Correlations between load-wind power and different variable generation units, i.e. wind and solar/ocean etc., have also impact on counterbalancing or increasing the system imbalance. However, in this thesis the correlations between variable RES will not be taken into account as if there is no correlation between them.

4. Case Study Description

The Spanish peninsular electricity demand in the last years is on a decreasing trend due to the economic crisis (Figure 10). In 2012, total energy demand was 252.191 GWh being 1.2% lower than in 2011 and the peak demand was 43.527 MW on 13 February. Total installed power capacity was reported to be 102.524 MW at the end of 2012 which is 2.356 MW higher than previous year. The majority of the new installed capacity was from RES; 1.122 MW of wind power, 968 MW of solar and 192 MW of hydroelectric (REFIT, 2012).

Year	GWh	Δ Annual (%)	Δ Adjusted annual (*) (%)
2008	265,206	1.1	0.7
2009	252,660	-4.7	-4.7
2010	260,530	3.1	2.7
2011	255,373	-2.0	-1.1
2012	**252,191**	**-1.2**	**-1.7**

(*) Adjusted as a result of factoring in the effect of seasonal and working patterns.

Figure 10: Demand Evolution in Spain [46]

The Renewable Energy Plan for the period of 2005 and 2010 set the RES targets by stating that at least 12% of total energy consumption should come from RES by 2010 and for the electricity production the share of renewables should be 29.4%. Along with the European Council Directive 28/2009, RES target over the final energy consumption in Spain was set as 20% by 2020. However, the Ministry of Industry in its first estimation reported the support level would be 22,7% which indicates an excess of RES compared to EU objectives. The main development of renewable resources in Spain corresponds to the electricity power sector with a predicted RES contribution of 42,3% to the total electricity production by 2020 (Figure 11).

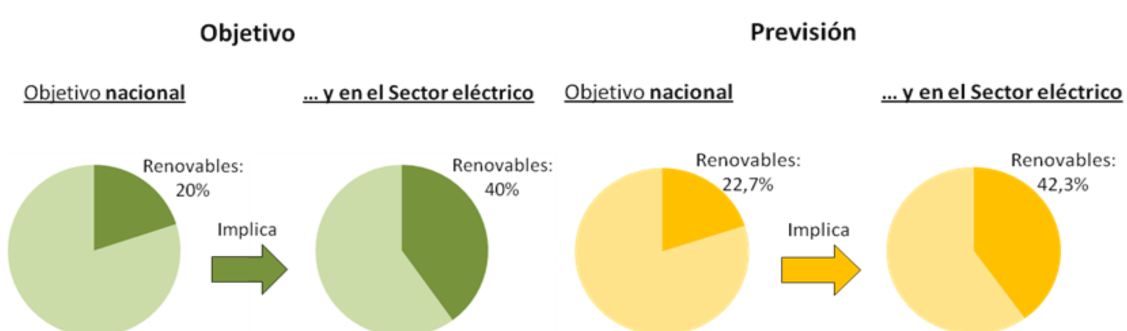

Figure 11: RES Targets for Spain [46]

4.1. Renewable Energy Support Schemes

Renewable energy supports in Spain started in 1980s being triggered by the global oil crisis, to reduce the dependency on imports in energy. The National Energy Plan 1991-2000 aimed at giving incentives to electricity generation from RES. In parallel with this objective, the concept of Special Regime has been created in 1994. The Royal Decree 2366/1994 regulates the generators under this regime, which were defined in the beginning as cogeneration, waste and hydroelectric units. The production of these generators was obliged to be purchased by the nearest distribution company as long as it is technically possible [12].

Three years later, the Electric Power Act 54/1997 was enacted to create a competitive market. Together with this mechanism, generators under special regime that have equal to or less than 50 MW of capacity (this level has been increased later) have been allowed to give their extra energy to the system with the average final price of the market plus a premium. The rest of the generators under special regime (solar, wind, geothermal, mini-hydro and wave energy) can directly participate into the market and receive the marginal hourly market price, a premium, remuneration for capacity payment and additional services, providing that these generators are responsible from their imbalances and charged the corresponding imbalance costs.

With the Royal Decree 436/2004, special regime generation units were given two alternatives to choose for their remuneration scheme; selling the electricity to the distribution company at the regulated tariff (feed-in tariff) or selling directly in the market with the market price plus a premium (feed-in premium) and more than 90% of the wind generators chose feed-in premium scheme (Ragwitz M. et al., 2012). If the generators want to switch their remuneration scheme, they are obliged to stay within the chosen support scheme at least for one year. Tariffs and premiums are differentiated for different technologies and according to the capacity of generation units. Also, tariff, premium levels are revised every four years to incentivize generators to reduce their costs and to improve the technology. Moreover, the Royal Decree 661/2007 adds upper and lower limits to feed-in premiums (cap & floor prices). Renewable energy units have priority to access to the grid in front of other generators. However, the system operator can refuse the access request if there is any justified reason and in this case alternative access points can be offered by the system operator (Energia y Sociedad).

By 2010, proliferation of generation units under special regime (especially wind and solar energy) exceeded the preset RES targets. In order to reduce the burden of RES incentives on the system, some fiscal and financial measures were taken. However, since these measures could not be sufficient, the incentives given for future renewable energy plants have been temporarily suspended by the Royal

Decree 1/2012 to correct the tariff deficit in Spanish electricity power market. The suspension of support schemes does not affect the already installed generators prior to the enactment of law. This urgent measure was justified by the intention of preventing incentives for the additional 550 MW forthcoming PV investments. Lately, on February 2013, a new Royal Decree has been published, Royal Decree-Law 2/2013, which abolishes the premium above the market (WFW, 2012).

4.2. Generation Mix

According to the values of year 2012, nuclear energy covered most of the system demand by 22% (21% in 2011). The second most used generation technology was coal thermal power stations by 20% (15% in 2011), whereas wind energy appears in the third position with a share of 18% (16% in 2011). On the other hand, some technologies reduced their share of demand coverage; hydroelectric from 11% in 2011 to 7% in 2012 and combined cycle gas turbine (CCGT) plants from 19% in 2011 to 14% in 2012. The rest of the generators did not change their production share significantly (Figure 12). As it can be seen from the figure, 32% of the total energy produced comes from RES (REFIT, 2012).

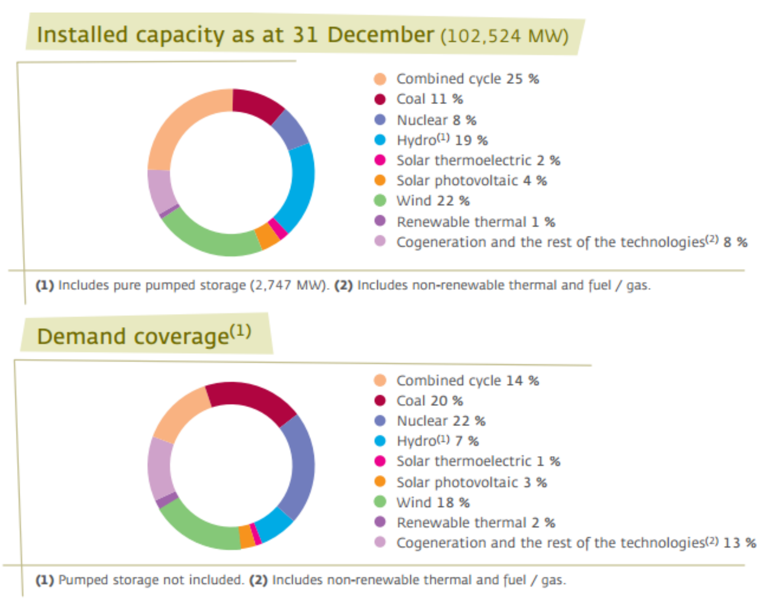

Figure 12: Generation Mix in Spain [46]

Although CCGT plants compose 25% of the total installed capacity in the Spanish power system, their electricity production share stayed only at 14% in 2012 (Figure 13). This phenomenon is due to the low utilization rate of CCGT plants. CCGT plants were introduced to electric power system as base load generation units. However, they have never been used for this purpose but more to compensate the fluctuations in demand and variable generation units. Agosti L. shows that utilization rate of CCGT plants have decreased from 57% in 2004 to 33% in 2010, together with increasing wind energy production levels (Figure 13) (2011). Additionally, note that their share of covering maximum peak power demand increases to 23% among other technologies (Figure 14). With this percentage CCGTs become the most preferred power units at peak load times; this implies that CCGTs are more likely to be used as peak power plants.

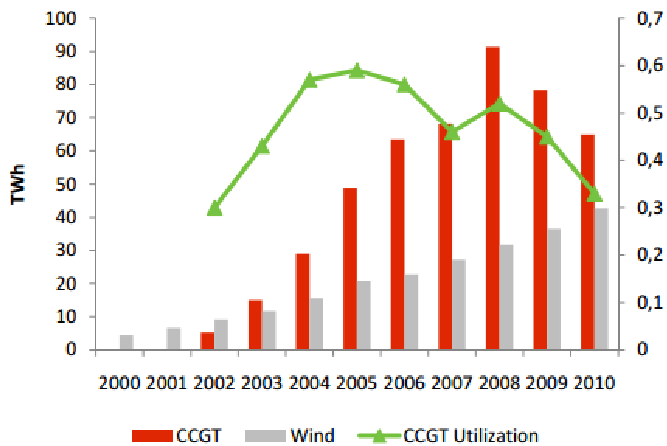

Figure 13: Utilization Rate of CCGT Plants in Spain [2]

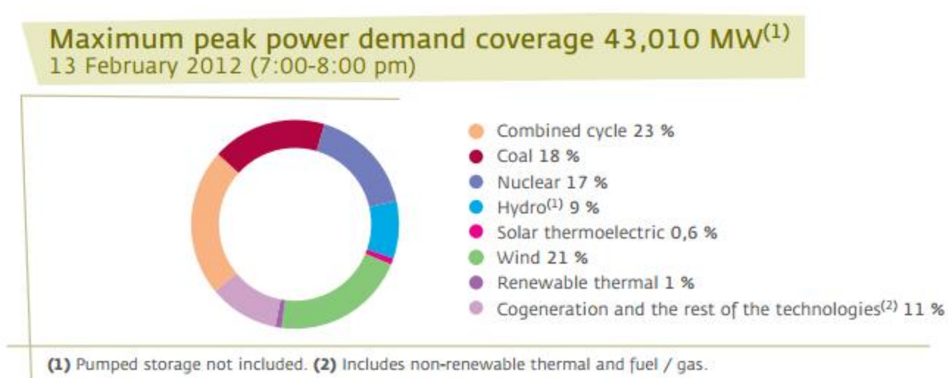

Figure 14: Maximum Peak Power Demand Coverage in 2012, Spain [46]

The second highest share of installed capacity in Spain belongs to wind power by 22% in 2012. The highest demand coverage of wind energy was also in this year on 24 September by 64% and the same day the daily energy production reached to its maximum with 334.850 MWh (REFIT, 2012). In 2011, even though the wind power capacity was increased by 7% compared to previous year, the wind energy generation decreased by 3,3% (Table 2). The reason of this decrease was because of the wind availability which was less during 2011.

	2007	2008	2009	2010	2011	%11/10
Renewables	**34,220**	**41,469**	**52,345**	**60,036**	**59,777**	**-0.4**
Hydroelectric	**4,125**	**4,638**	**5,454**	**6,824**	**5,283**	**-22.6**
Wind	**27,249**	**31,758**	**37,889**	**43,208**	**41,799**	**-3.3**
Other renewables	**2,846**	**5,073**	**9,003**	**10,003**	**12,695**	**26.9**
Biogas	730	713	670	709	767	8.1
Biomass	1,646	1,938	2,375	2,463	3,025	22.8
Solar photovoltaic	463	2,406	5,829	6,140	7,081	15.3
Solar thermoelectric	8	15	130	692	1,823	163.6

Table 2: Evolution of the Energy Acquired from Special Regime (GWh) [43]

Hydroelectric generation units in Spanish peninsula had a total capacity of 17.761 MW in 2012 which has increased by 1,1% compared to 2011. This amount corresponds to 19% of total installed power capacity. However, hydroelectric generation in 2012 was in a record low level with 12.800 GWh which is 54% lower than the average of all years and 43% lower than previous year. The reserve levels were 36% of the full capacity in 2012 whereas this value in 2011 was 52%, which indicates a dry season in 2012 (REFIT, 2012).

Electricity generation from coal thermal units increased significantly (27,9%) in 2012, by producing 55.639 GWh which covered 20% of the total demand. On the other hand, the installed capacity of coal-fired power units, which was 11.620 MW for the same year, composed 11% of the total system capacity. For nuclear power, the change in energy production was limited only by 6,1% increase, producing 61.238 GWh. Although they have less installed capacity (8%) compared to other technologies, since they are operated as base load generation units, their share of covering demand is the highest by 22% (REFIT, 2012).

Fast ramping rates are important for electric power systems to integrate wind power in high penetration rates. Thanks to the existence of hydroelectric and CCGT units, the Spanish power system did not have difficulties to compensate the fluctuations of wind energy. However, at times of low demand and high wind energy, partial load efficiency of thermal units should be taken into account as well. After a certain point, generators cannot lower their production level anymore but should be turned off, which is not economically viable. In this case, the extra wind energy might be curtailed if this allowed by power system. Wind energy curtailments are allowed and have been experienced in the Spanish power system as well. Martin-Martines S. et al. state that main reason of curtailments until 2009 was restrictions in the distribution networks, after that year scheduled energy has been cut on real time. In order to reduce these wind energy curtailments the wind industry has been using energy storage units such as pumped hydro storage (2012).

4.3. Interconnection Capacity

As Belmans R. et al explain that interconnecting power systems strengthens the reliability of each system and reduce the need for required spinning reserves, which also reduces total system operating costs due to the decreased operating reserve costs. For instance, in case of a power plant failure, instead of confronting the problem in only one system, combined spinning reserves of several systems can solve the problem with less reserve capacity held in each system because occurrence of contingency events in different system is not likely to be correlated. As a choice, operating reserves can be maintained in the same level which then leads to an increased reliability in the total system (2012).

With the introduction of wind power into power systems, interconnection capacities have started to be critically important because if the wind energy generates more than expected, this extra electricity can be exported to neighboring country instead of applying wind curtailment or if there is less wind energy than forecasted, then the energy shortage can be covered by receiving energy from interconnected systems (REE, Procedimientos de Operación del sistema: P.O. 3.9). As an example, Denmark is the country with highest wind energy penetration in Europe. Thanks to their extensive interconnection capacity, contingency events are handled by exchanging electricity through electricity interconnections. For instance, when the Gudrun hurricane passed through southern Scandinavia in January 2005, the wind turbines in Western Denmark had to stop due to the extreme wind speed which resulted in a 2100 MW decrease in wind power within 10 hours. In order to compensate the energy loss, operating reserves were activated and the necessary electricity was imported from Norway through HVDC interconnection (ENTSOE, 2010).

Besides the advantage mentioned above, interconnections also increase the efficiency and competitiveness of interconnected systems (REE, Procedimientos de Operación del sistema: P.O. 3.9). When a power system with higher electricity prices is connected to the one with cheaper prices, electricity trade will realize from cheaper to more expensive location, which increases the efficiency of the system. Moreover, market participants with expensive electricity will be prompted to reduce their wholesale price to compete with other electricity providers, which leads to an overall market competition in a larger area.

Taking into account these benefits, EU gives recommendation to member states about how much interconnection capacity should be held. This level has been determined as 10% of the installed generation capacity in each country. However, as it can be seen from the map, interconnection ratio of some countries is even less than 5% (Figure 15). Spain is one of these countries with 3% of interconnection with its neighbors which makes Spain a practically isolated power system. Although, the possibility of strengthening the interconnections is limited because of geographical position of the country, i.e. interconnecting to the rest of Europe can be realized only with France, the objective is to increase this capacity over 5% by 2020 with new investment plans (REE, Procedimientos de Operación del sistema: P.O. 3.9).

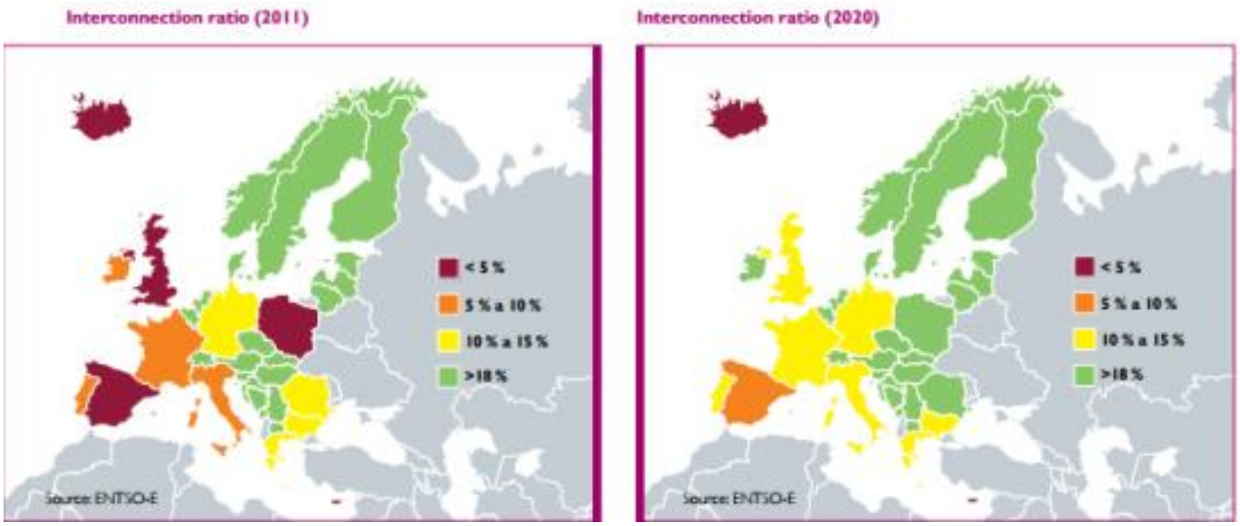

Figure 15: Interconnection Ratio of Power Systems in Europe [44]

According to the information given by the Spanish system operator, the interconnection between Spain and France currently consists of four HV lines, two of which are in the Basque Country (400 and 220 kV), one in Catalonia (400 kV) and another in Aragon (220 kV) (REE, Procedimientos de Operación del sistema: P.O. 3.9). The maximum exchange capacity of these interconnections is approximately 1.400 MW. However, there is a new interconnection project that is being carried out in the eastern Pyrenees. This project is expected to be operational in 2014, which envisages a connection with Continental Europe after a 30-year of stagnation. With this investment the total interconnection capacity with France will reach to 2.800 MW. Yet, the Spanish power system has an objective of increasing this capacity to at least 4.000 MW by 2020 (Figure 16).

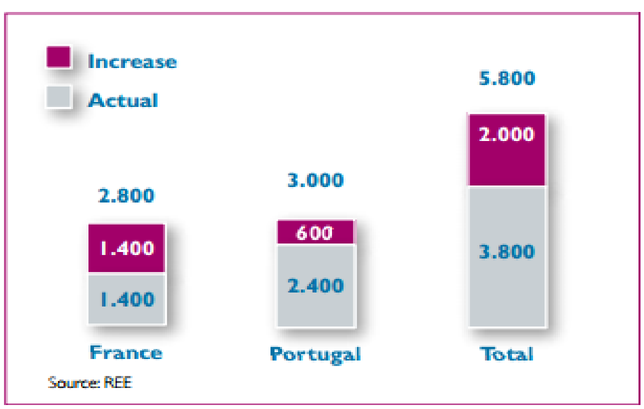

Figure 16: Power Exchange Capacity of Spain in 2012 and 2016 Forecasted [44]

Furthermore, the interconnection within the Iberian Peninsula with Portugal has a maximum capacity of 2.400 MW which includes seven lines; four 400 kV and three 220 kV lines. Also, there are new interconnection constructions going on; one in the northwestern (Galicia) and the other in southeastern region (Andalusia) of Spain, which in total will increase the maximum capacity to 3.000 MW by 2015.

Lastly, Spain has also interconnection outside the Europe, with Morocco through two submarine power cables. The maximum capacity of these lines is 800 MW. This connection point is regarded as the main link with North African countries, as it will connect Europe to Desertec and Medgrid Euro-Mediterranean electricity network projects which aim at providing cheap renewable energy to Europe from North Africa where RES are more abundant (Figure 17).

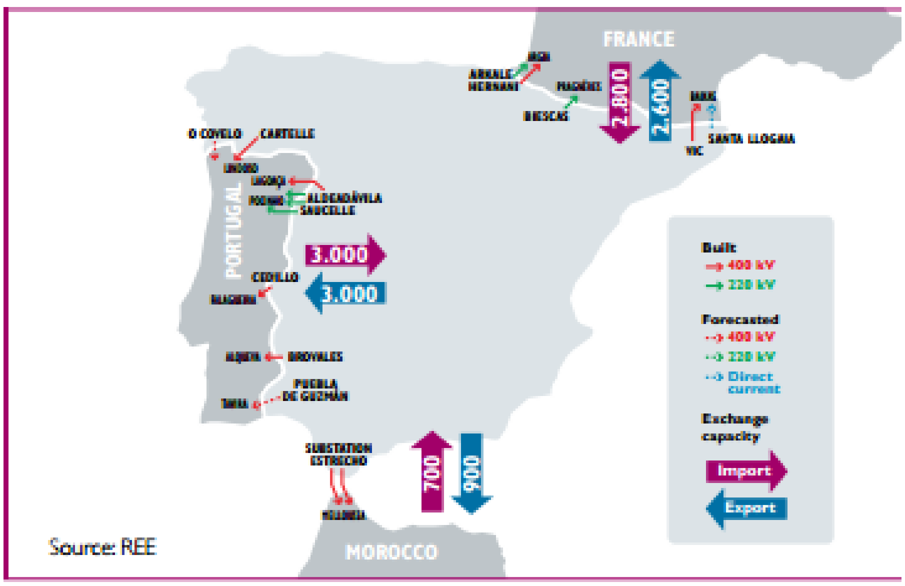

Figure 17: Development of New Interconnections in Spain [44]

4.4. <u>Wind Power Deployment</u>

Variation of wind energy and forecast errors can be reduced by spreading the wind turbines over a larger area as wind fluctuations in different regions are not correlated. In Germany a study was made to show the smoothing effect of dispersed wind power generation (EWEA, 2005). The study compares the occurrence frequency of hourly wind power variations between one single wind farm and aggregated wind power over Germany. It is shown that for a single wind farm hourly wind variations are larger than total wind power, respectively, 60% and 20% of the total capacity. It adds that for larger systems the variation would be lower, such as Nordic regional power system, Nordel.

Additionally, spatial aggregation of wind farms also increases the firmness of wind energy and sharp edges of wind energy profile are smoothed away, i.e. times of peak or no-production are reduced. In order to benefit from these advantages, it is suggested to locate wind farms over locations in which the correlation is minimum possible (EWEA, 2005).

In Spain, wind power installments are deployed over different regions widely. According to the 2011 data taken from (Asociación Empresarial Eólica, 2012), The community of Castile and Leon with 219 wind farms and 5.233 MW of wind power capacity has the highest share of wind power in Spain (24% of total installed capacity). The second biggest share belongs to the Castile-La Mancha with 3.737 MW of installed capacity (17%) and 136 wind farms. The Galician community ranks as third with 3.272 MW of wind power (15%) and 150 wind farms, whereas the Andalusian community just comes after Galicia with 136 wind farms and 3.067 MW of capacity (14%). Among these top four regions, only Castile and Leon has increased its wind power capacity significantly by 9,7% (462 MW) in 2011. On the other hand, three communities that are not among these top four, increased their wind capacity more than 18% of their total installed capacity; the Asturias, the Valencian Community and the Catalonia, respectively, by 20,4%, 18,5% and 18,1%. This indicates a future development of smooth dispersion of wind power among different regions (Table 3 and Figure18).

Comunidad Autónoma	Acumulado a 31/12/2011	Instalado en 2011	Tasa de variación 2011/2010 (%)	% sobre total	Nº de parques
Castilla y León	5.233,01	462,19	9,69%	24,14%	219
Castilla-La Mancha	3.736,79	26,50	0,71%	17,24%	136
Galicia	3.272,17	0,00	0,00%	15,10%	150
Andalucia	3.066,93	92,00	3,09%	14,15%	136
Aragón	1.811,31	50,00	2,84%	8,36%	80
Comunidad Valenciana	1.169,99	183,00	18,54%	5,40%	37
Cataluña	1.003,35	153,71	18,09%	4,63%	39
Navarra	976,92	8,50	0,88%	4,51%	47
La Rioja	446,62	0,00	0,00%	2,06%	14
Asturias	428,45	72,50	20,37%	1,98%	17
Murcia	189,96	0,00	0,00%	0,88%	12
País Vasco	153,25	0,00	0,00%	0,71%	7
Canarias	145,78	1,70	1,18%	0,67%	52
Cantabria	35,30	0,00	0,00%	0,16%	3
Baleares	3,68	0,00	0,00%	0,02%	46
TOTAL	21.673,49	1.050,10	5,1%	100%	995

Table 3: Installed Power Capacity by Autonomous Communities of Spain [3]

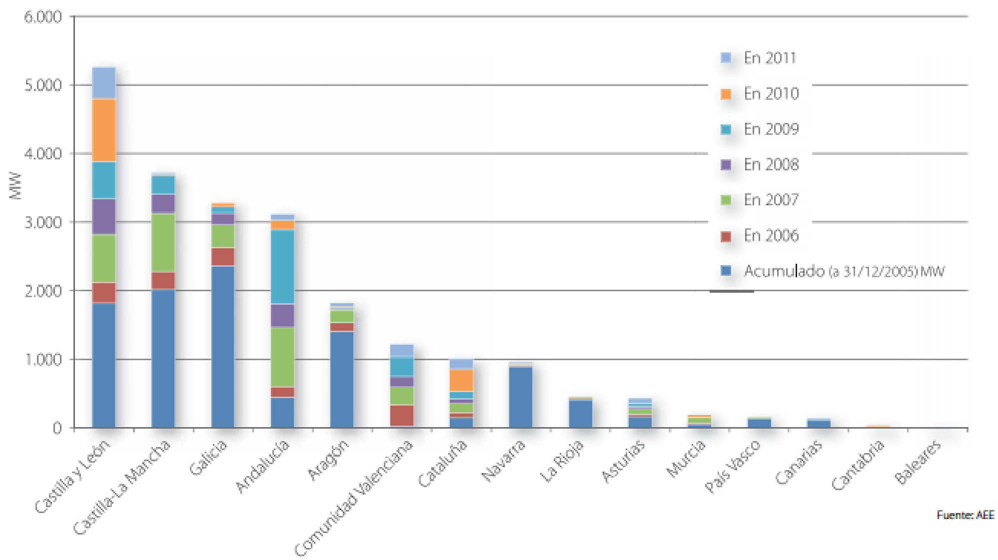

Figure 18: Evolution of Installed Wind Power by Autonomous Communities of Spain [3]

Furthermore, Lorente-Plazas R. et al. analyze the wind variability in Spain by observing 448 different wind power locations that are evenly spread over the peninsula. According to the analysis, they can cluster different regions[12] depending on the season. The regions in common for all seasons are High and Low Ebro Valley, the Mediterranean Basin, the Guadalquivir Valley, the Cantabrian Coast and the Iberian Plateaus. Their findings show that wind variability in these regions are not correlated in some seasons and even sometimes they have been found negatively correlated. This study serves to deduce that since the different regions in Spain are not correlated in terms of wind speed profile, wind power deployment over Spain helps to reduce the variation and forecast errors of wind energy (2012).

5. Case Study Analysis

In this chapter, the data set used in this thesis is presented and then it is explained which methodologies is used to analyze the impact of wind power on operating reserves in Spain.

5.1. Data set

The data set for this study consists of realized hourly load, wind power production, secondary, tertiary, additional upward reserve requirements, allocation (paid capacity in the case of secondary and additional

[12] Locations with similar wind behavior patterns are clustered as a region.

upward reserves; paid energy in the case of tertiary reserve) and actual use of reserves, also forecasts of wind power and demand load data between the years of 2007 and 2013. These data are available to public access through the Spanish system operator, REE, information system website[13]. The mentioned data set belongs to Spanish peninsular system so this study is kept apart from the Balearic, the Canary Islands and the Spanish autonomies cities of Ceuta and Melilla in North Africa. However, downloading each hourly data from the website manually was creating a cumbersome task and was taking a very long time so a macro application in Excel has been created to ease the download process.

5.2. Methodology

Operating reserves are allocated to compensate the possible imbalance that may occur between generation and consumption on real-time. Determination of operating reserves is based on three imbalance drivers; probability of power unit/equipment failure, variations of electricity demand load and intermittent renewable energy units, especially wind energy. It is assumed that the probability of power unit failures will remain at the same level and the effect of interaction between two variables, load and wind power production, on the system operating reserves will be looked for.

First of all, basic statistics of wind power production and electricity demand load data will be analyzed. Seasonal, daily and hourly variations of wind power production in Spain will be examined in detail. The hourly variations of the system load with and without wind power (net load) will be analyzed with a probabilistic method.

The current forecast tools allow to predict the hourly variations to a certain extent so forecast errors will be used instead of hourly variations when determining the increase in reserves. At this point, the correlation value between hourly variation in demand load and wind power production is of importance to calculate the net load variations.

Additionally, in order to distinguish the increase in secondary and tertiary reserves, the secondary reserves are associated with the fluctuations inside the settlement period and the tertiary reserves with the forecast error over the settlement period.

Apart from the methodology explained above, the increase in operating reserves will be presented according to real-time data and the results will be compared with those from the estimation (suggested methodology). The estimation results that are obtained will give us the increase in reserve requirements, in order to obtain the increase in actual use of reserves the security gap between actual usage and

[13] http://www.esios.ree.es/web-publica/

requirement values from the real-time data is used and these ratios are applied to the estimation. Lastly, the cost of increase will be calculated for secondary and tertiary reserves per wind energy produced in Spanish peninsular system as €/MWh.

5.3. Analysis of the data

Under this chapter, first it is started with analyzing the basic statistics and general profiles of wind power production, demand load and operating reserves in Spain. Afterwards the interaction of both imbalance drivers is explained and their impact on the operating reserves is computed with probabilistic methodology.

5.3.1. Wind power production

In order to compare the obtained results with previous studies, wind power production has been converted to wind power production as a percentage of installed wind power capacity. After obtaining hourly installed capacity values, wind power production was analyzed as of capacity. Below in Table 4, some of the main characteristics of generated wind energy in Spain can be observed. Average values are the wind power capacity factors which inform us the ratio of actual wind energy output over its nominated output. Generally, for wind farms this value is between 20-30%. As a form of comparison, Danish and Nordic wind power statistics for years 2000-2002 were placed in the table as well (Holttinen H., 2004). It can be seen that Nordic average is better than both Spain and Denmark.

	Spain	**Denmark**	**Nordic**
Average (%)	23,8	22,2	25,1
Median (%)	21,3	14,9	22,4
Standard deviation (%)	13,8	21,2	14,5
Minimum (%)	0,4	0,0	1,2
Maximum (%)	74,4	92,7	86,5

Table 4: Hourly wind power production statistics as of installed capacity [22]

The median is the value that stays in the middle of a time series when the series is put in an increasing or decreasing order. Since most of the time wind farms operate lower than capacity factor, it is normal to see the median value below average value. However, wind farms produce more alike to normal distribution with geographical smoothing in larger scales and due to this Spain and Nordic region have a closer median value to average value.

Standard deviation shows how much variation occurs in the time series analyzed. As it was explained before, variations increase in longer time scales and reduce in dispersed wind power systems. Spain extends its wind power installments all over the country from Galicia in the northwest to Catalonia in the northeast and in the south to Andalusia. This dispersion helps to reduce the standard variation of wind generation. The standard variation of wind power is 13,8% in Spain, whereas relatively a small country in Denmark this value is 21,2% and 14,5% in all Nordica region. The reason of having of a lower standard variation level in Spain than whole Nordic region can be centralized wind power positioning in the Nordics.

Another sign of spatial smoothing can be observed in the range of hourly wind power production values as of capacity. If wind turbines are placed farther from each other, the possibility of facing the same air current for wind turbines at different locations at the same time decreases. This means that for instance, a wind storm is passing through a specific location will not affect another location and in that location wind farms will continue to produce electricity or high wind production rate in a windy region will be reduced by a less windy region. In parallel to this, production in Spain ranges between 0,4% and 74,4% of capacity, whereas in Denmark it was experienced calm incidents and the maximum production reached a level of 92% (Holttinen H., 2004). It can deduce that a larger spread of wind parks makes the wind power system to produce with less variation and more stability.

5.3.1.1. Variation of wind power production - Seasonal

Holttinen H., states that in Central and Northern Europe there is a general seasonal wind energy generation trend which implies higher production in winter and lower levels in summer (2004). This trend is in force in Spain as well. A clear seasonal variation is observed in Spanish wind power production; in winter time the average wind energy reaches at its maximum power, whereas in summer falls to its minimum. The seasonal variation has been illustrated as frequency distribution chart in Figure 19. The average production as percentage of capacity for each season is also given. Winter months have an average of 28,2% while summer can only achieve 18,7% of installed wind capacity. Frequency distribution chart clearly depicts the high number of low production rates during summer (21% of time), whereas during winter season wind power plants more than 11% of time produced at 40% of production rate which corresponds to less than 5% in summer.

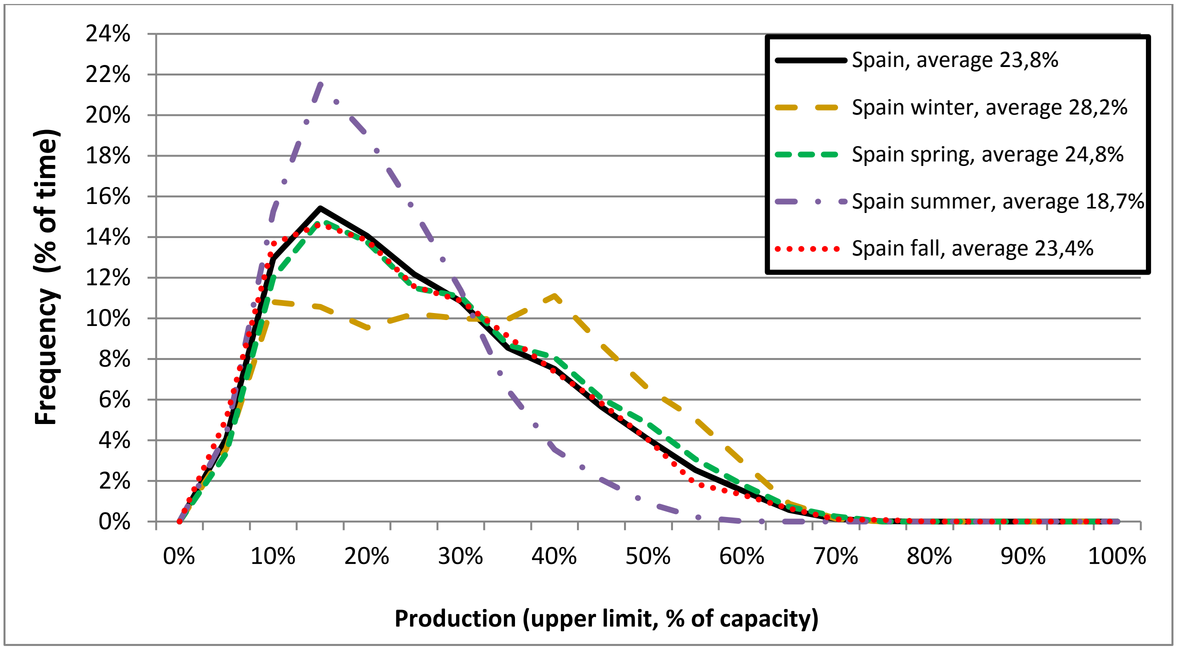

Figure 19: Frequency distribution of wind power production for seasons

5.3.1.2. Variation of wind power production - Daily

Diurnal variation of wind energy in Spain is more significant for summer months, while other seasons and the overall data show a smooth dispersion of wind energy production over the hours of day. For summer months, wind energy tends to produce more around 19:00-20:00 in the evening (23%), whereas the least production is observed around 10:00 in the morning (14%). This can be seen by Figure 20, which shows the average hourly wind power generation of installed capacity according to hours of day. According to the figure, in general, just opposite to the Northern Europe (Holttinen H., 2004), winds tend to blow more in the evening (between 17:00-21:00 with an average of 26%) and less in the morning (between 5:00-11:00 with an average of 22%) in Spain.

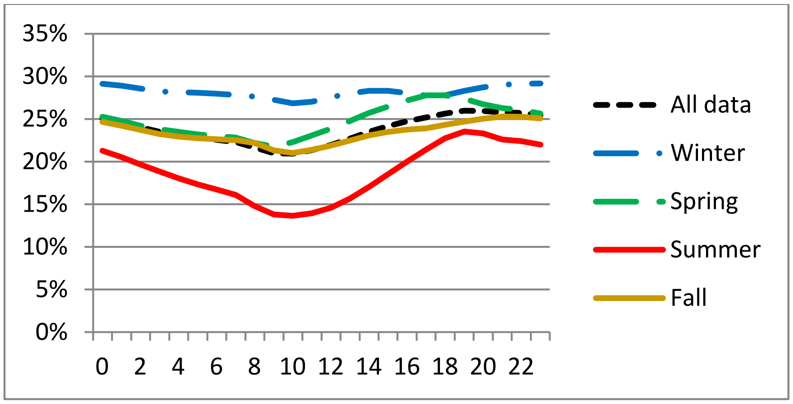

Figure 20: Wind Power Generation for Hours of Day

5.3.1.3. Variation of wind power production - Hourly

Variations of wind power increase in larger time scales. In second to minute time scale variations are largely smoothed out by dispersed wind farms and the inertia of wind turbine rotors. In this time scale primary reserves are held to control unexpected frequency deviations. For the secondary and tertiary reserve determination, concerning time frame is between 15 minutes to one hour. Since the market bids are received in the day-ahead market for hourly periods in Spain, hourly wind power production data is used for the analysis. Hourly values are regarded to be a good estimate for 15-minute variations since there is no significant difference between hourly and 15-minute variances (Holttinen H., 2004).

To analyze hourly wind power variations, wind power generation at time *t-1* is subtracted by that at time *t* to obtain the hourly wind variation at time *t*.

$$\Delta P^{w}{}_{t} = P^{w}{}_{t} - P^{w}{}_{t-1}$$

The largest hourly variations in Spain are -10,1% of capacity for downward variation and 11,7% for upward variation. It is stated that for a country in the size of Germany, expected hourly variations are within ±20% of capacity (Holttinen H., 2004). Spain being a little bit larger than Germany in land size, has the same level of variation level with total Nordic region which has 10% upward and -11% downward hourly variation of capacity. The only explanation to this phenomenon might be that the geographical position of Spain is favorable to diversify wind resources as much as in Nordic region. Not only the area spread over matters but also the characteristics of the area are important. This is touched upon by (Holttinen H., 2004) also saying that if the wind farms are dispersed over regions with different weather patterns such as coastal, mountainous, desert, onshore, offshore etc., smoothing might increase its effect.

One should bear it in mind that most of time the variations remain within ±5% of capacity level (See Figure 21). In the example of Spanish case, hourly upward variations were above 5% of capacity 0,4% of the time and 0,3% of the time downward variations were below -5%. This means that more than 99% of the time variations were within ±5% of installed capacity. On the further limits; above 10% of capacity it has been observed only two cases and below the level of -10% just one case. Consequently 99,99% of the time variations remain within 10% of capacity.

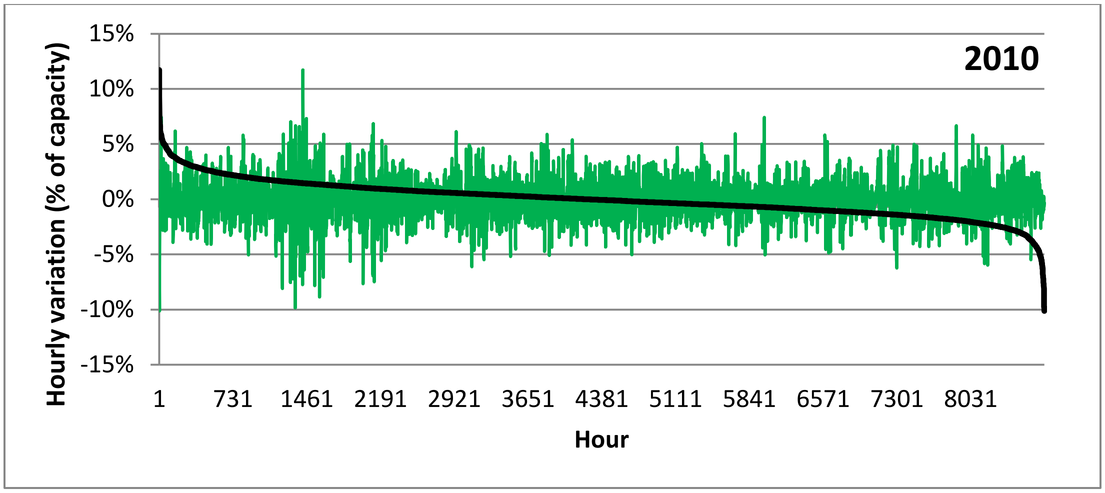

Figure 21: Wind Energy Hourly Variations as of Installed Capacity

On the other hand, at higher wind power production rates, it is more likely to see large variations, i.e. over 10% of installed wind capacity. The explanation of this phenomenon is about working principles of wind turbines. Wind turbines start producing electricity at and above wind speed of 5 m/s. After 15 m/s they reach their maximum potential. As it can be seen from Figure 22, when wind speed exceeds 25 m/s suddenly the wind turbine is shut down to protect the system. This level is the storm threshold value. When a storm passes through a wind farm, wind turbines experience a sharp fall from rated power to zero production. However, this fall will not realize at the same time in all wind turbines. The difference can be distinguished in the figure again where for a single wind turbine and for a wind farm the power shut-down process is shown. Therefore, high wind speeds bear a higher risk for the system operation due to larger variations that they may cause. This can be supported by the statistics in wind power production and variations. At higher wind power production rates, it is more likely to see large variations, i.e. over 10% of installed wind capacity. Hourly variations above 10% were examined for production levels more than 20%, 30% and 40% of capacity. The findings show that large variations above 10%, respectively, occur 1,9; 3,3 and 4,6 times as often as all time data. The increasing probability of large variations at higher production levels verifies the statement.

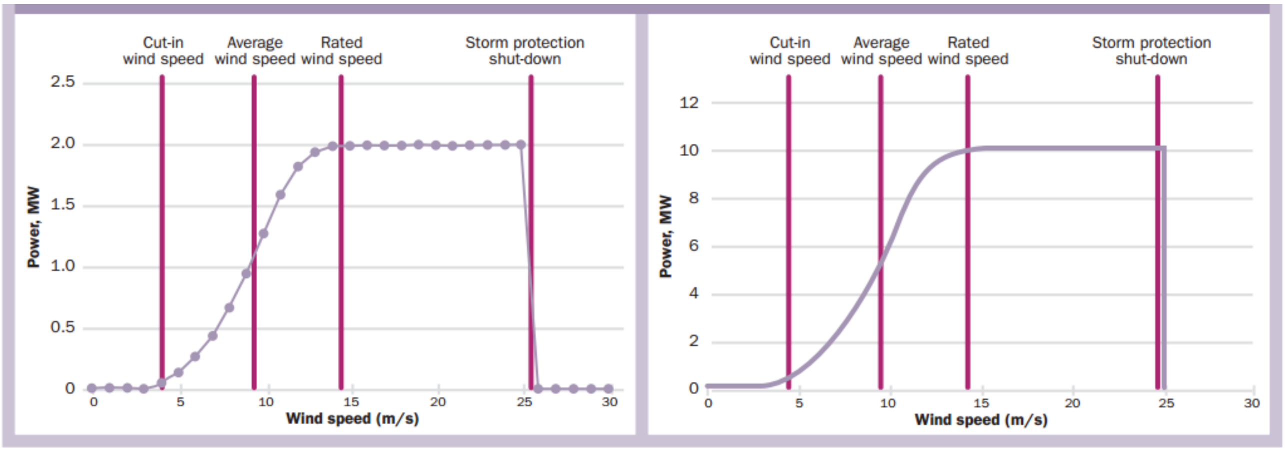

Figure 22: Wind Turbine Power Curve and Aggregated Wind Farm Power Curve [16]

5.3.2. Demand load

Basic statistics of the load time series can be examined in Table 5. Total electric consumption over four years has increased very slightly due to the economic stagnation in the country. Especially in year 2009 the effects of economic crisis became clearer with a 5% of decrease in total demand load. The peak load remained more or less at the same level (around 44.000 MW) with the exception of year 2008 when the peak load reached the maximum level of 42.971 MW. The highest peak load was observed in 2007 and the lowest minimum load in 2009. The highest peak load was, respectively, almost 3 and 1,5 times of the minimum and the average load. The standard deviation has steadily increased from 2007 to 2010; in the first year 2% and in the last two years 4%, which is a sign that variation in load has increased. This can be observed by the increase in standard deviation over peak load as well.

	2007	2008	2009	2010	2007-2010	Unit
Sum of load	256	264	251	259	1031	TWh
Peak load	44.672	42.971	44.235	44.539	44.672	MW
Min load	16.998	18.930	16.006	16.520	16.006	MW
Min / Peak load	38%	44%	36%	37%	36%	%
Average	29.271	30.096	28.610	29.615	29.398	MW
Avrg / Peak load	66%	70%	65%	66%	66%	%
Standard dev.	5.130	5.222	5.451	5.642	5.392	MW
Stdev / Peak load	11%	12%	12%	13%	12%	%
Stdev / Average	18%	17%	19%	19%	18%	%

Table 5: Basic Statistics of Load Time Series in Spain

Like wind power production, demand load also has a variable profile. Nevertheless, the forecast of electric consumption can be made more accurately by taking into account the weather conditions, diurnal variations and historical time series. On the other hand, the unpredictable part of wind power production is larger than load and the accuracy of forecast tools for wind energy is lower. Below in Figure 23, time series of load and wind power production is shown for December 2010 in Spain. In these figure it can be seen clearly that load has a more consistent profile; lower during weekends, has two peaks during weekdays, whereas wind power production does not show any regularity.

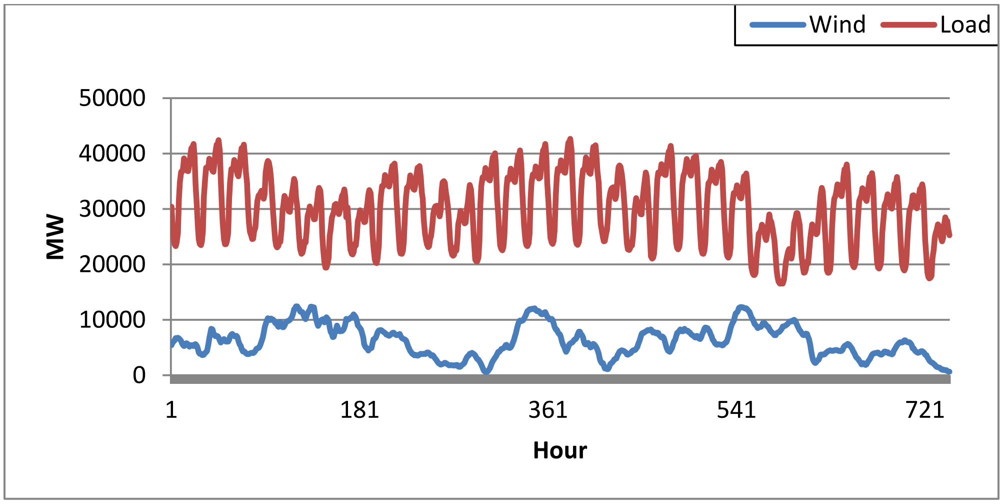

Figure 23: Time Series of Demand Load and Wind Power Production for December 2010

Moreover, as it can be seen from Figure 24, electric consumption in Spain has a seasonal trend; higher consumption during winter and lower in spring months. The use of electricity in winter increases due to the high consumption in household heating, and the load is not low during summer due to the use of air conditioners in hot summer days which also increase electricity consumption. Instead low demand slides back to spring months.

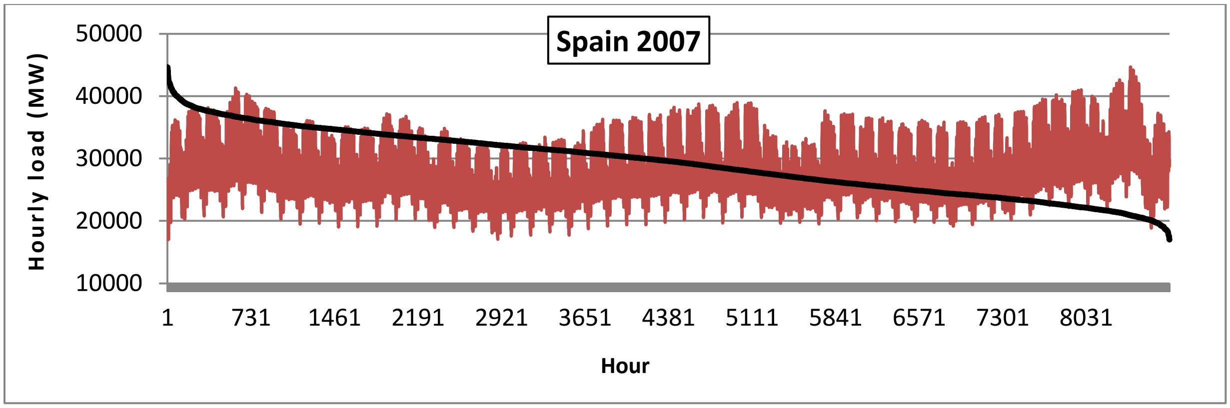

Figure 24: Time Series of Load with Duration Curve

If high generation of wind energy coincides with the increase in load then wind power reduces the variation in load which is good for the power system. In other way around, variances increase and this situation complicates the operation of system in short-time scale and increase the necessity for additional operating reserves which burdens extra costs on the power system.

According to the correlation values that were obtained, it can be said that the correlation between load and wind power is almost nil. For all years between 2007 and 2010 the correlation was found to be 0,07. For the seasons; highest correlation rate was 0,15 during spring months, in summer the correlation was negative with an insignificant value (-0,04) and for winter and autumn even this value was smaller with 0,03. As the values close to ±1 are accepted to have significant correlation (positive or negative) and the values around 0 indicate to no correlation, we can assume that there is no correlation between electricity consumption and wind power production in Spain.

5.3.3. Operating reserves

Operating reserves in Spain show an increasing trend parallel to the development of wind turbines over the country. In Figure 25, we can observe the average operating reserve amount per hour for each year as requirement, allocation and actual use. This figure contains total secondary and tertiary reserves, both upwards and downwards. For actual use since secondary reserve data were available starting 2010, total secondary and tertiary reserve actual use is presented for the years of 2010-2013. It is worthwhile to point out that the only year when the wind energy penetration decreased (2011), operating reserves also experienced a fall. According to this figure, increasing wind energy penetration seems to affect reserve requirement and allocated values. Provided that after the year 2011 we cannot observe any significant increase in total secondary and tertiary reserves, for the very same years additional upward reserves contribute more reserves to the Spanish power system. Besides, the actual use data for the years 2010-2013 fail down to explain the relation for previous years.

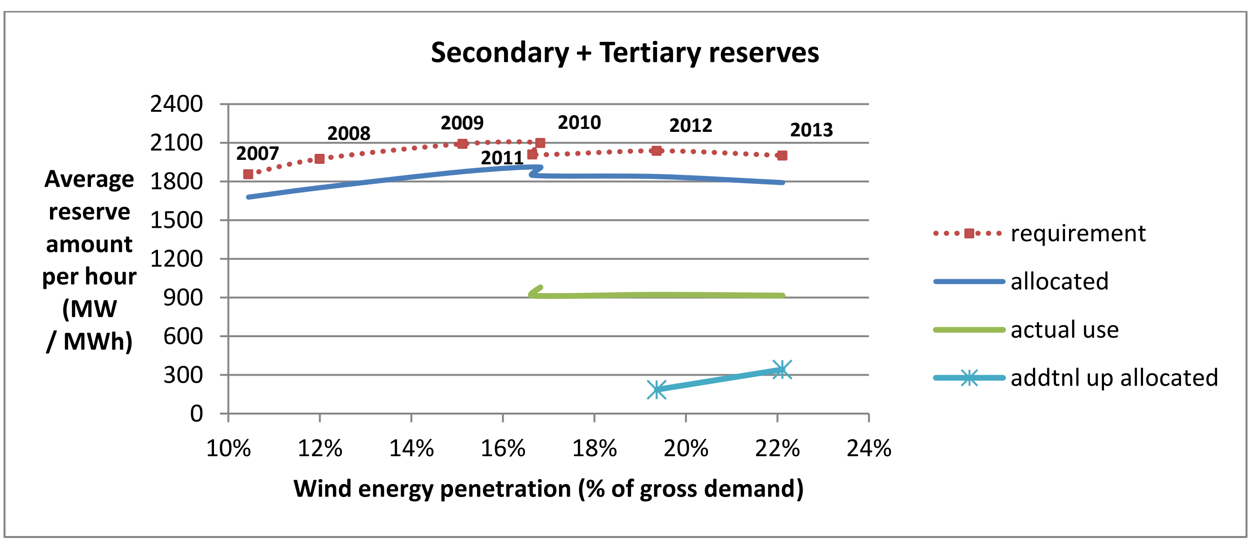

Figure 25: Average Reserve Amount per hour for Secondary and Tertiary Reserves According to Real-time Data

Figure 26 and 27 show secondary and tertiary reserves separated as upward and downward reserves. Upward reserves depict an increasing trend with increasing wind energy penetration. However with the limited actual use data in hand, it is noted that in year 2011 when the wind penetration decreased slightly, oppositely upward reserves show a slight increase. For downward reserves, the course is not coherent with the increase in wind penetration as for the last years a significant decrease in actual use of reserves is experienced.

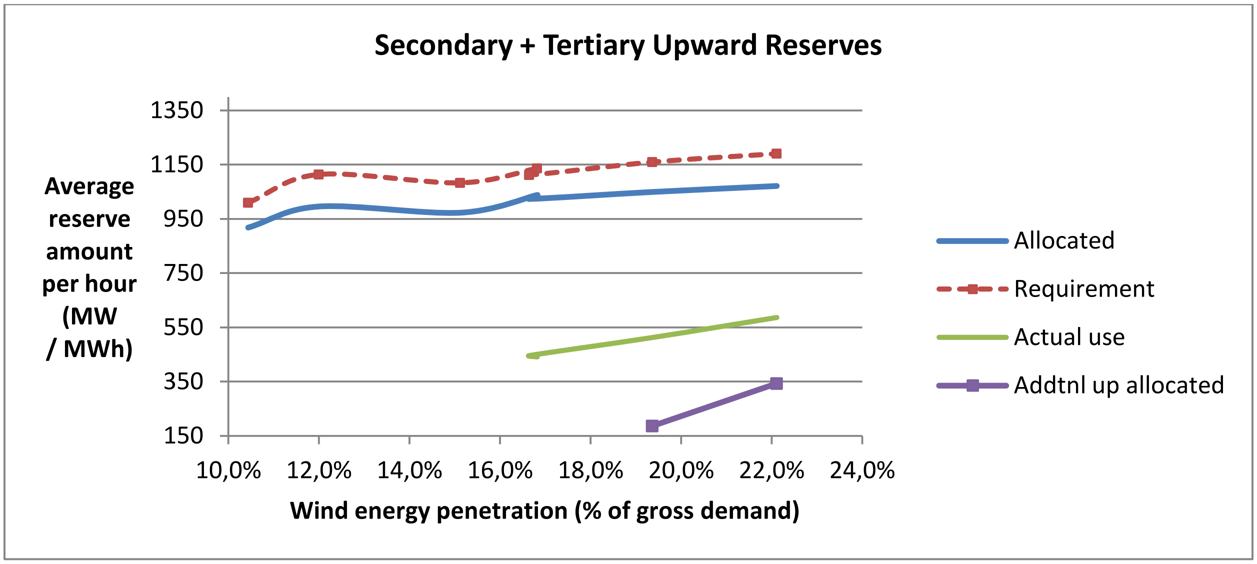

Figure 26: Secondary and Tertiary Upward Reserves According to Real-time Data

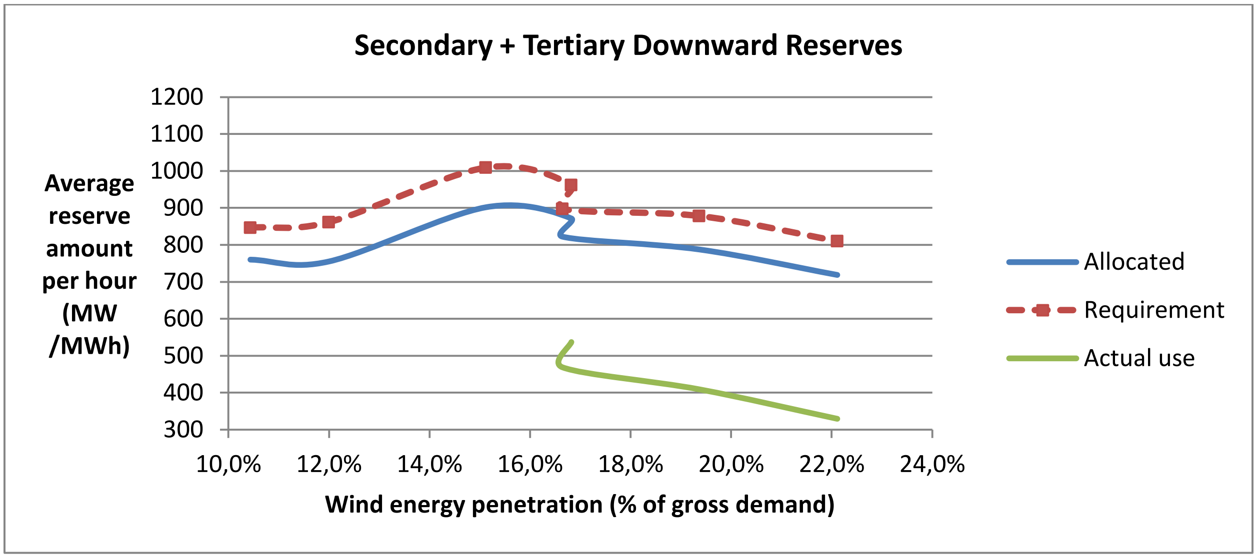

Figure 27: Secondary and Tertiary Downward Reserves According to Real-time Data

Secondary reserves display rather a flat, steady profile over different wind energy penetration levels; the changes are small, negligible and the reserve allocation varies around the level of 1240 MW (Figure 28). However, the reserve amounts between the years 2011 and 2013 fall outside of this tendency. If we have a look at actual use values, it is noted that for the period of 2011-2013 inversely to the allocated reserves, actual use of total secondary reserves increases from 311 MWh in 2011 to 328 MWh in 2013 in parallel with the increase in upward actual use whereas secondary downward actual use values steadily continue to fall down (Figure 29).

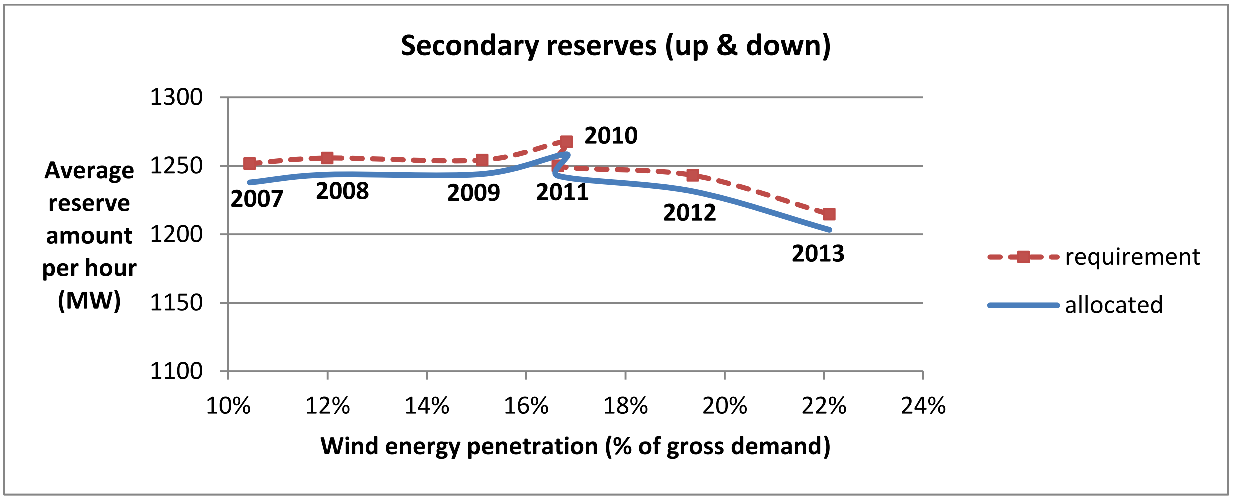

Figure 28: Average Reserve Amount per hour For Secondary Reserves According to Real-time Data

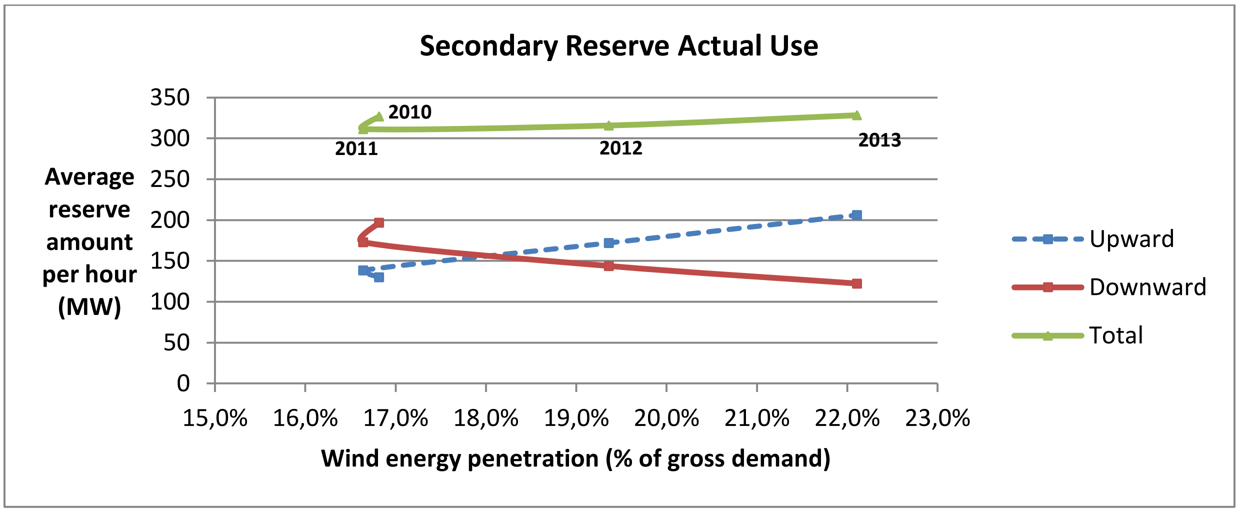

Figure 29: Secondary Reserve Actual Use According to Real-time Data

Average tertiary reserve actual use per hour appears to be more than the one in secondary reserves. Secondary reserves are provided by fast response generators with higher ramping rates and this characteristic makes them more expensive than slow response generators that give tertiary reserve service. By covering more reserves with these less flexible slow response generators the system operator can reduce the total reserve costs. Lastly in Figure 31-32, upward and downward tertiary reserves can be observed. Again, upward reserves have a tendency to increase with more wind energy produced but it is difficult to relate the curve of downward reserves with increasing wind power integration.

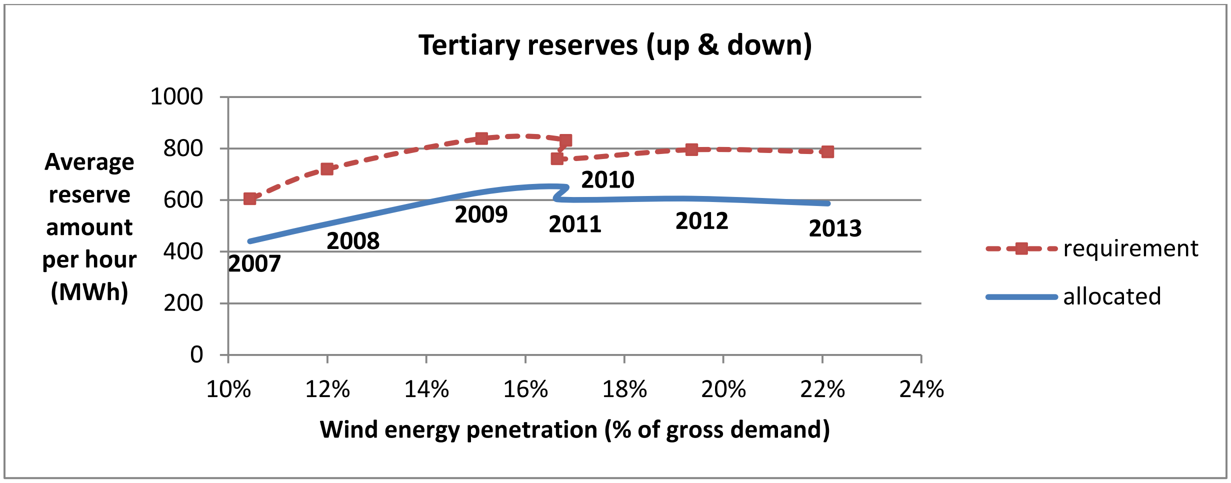

Figure 30: Average Reserve Amount per hour For Tertiary Reserves According to Real-time Data

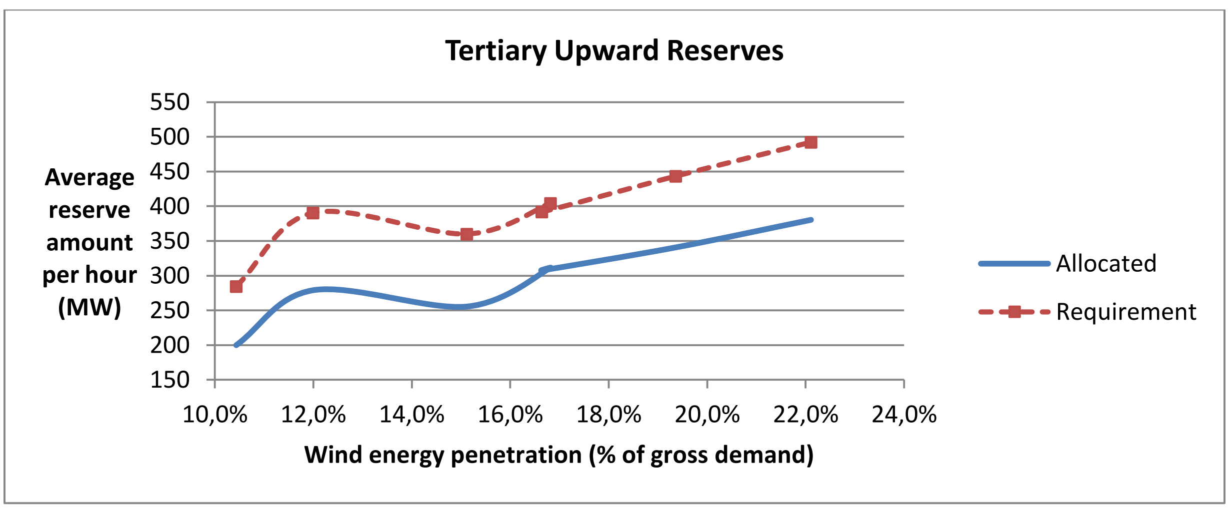

Figure 31: Tertiary Upward Reserves According to Real-time Data

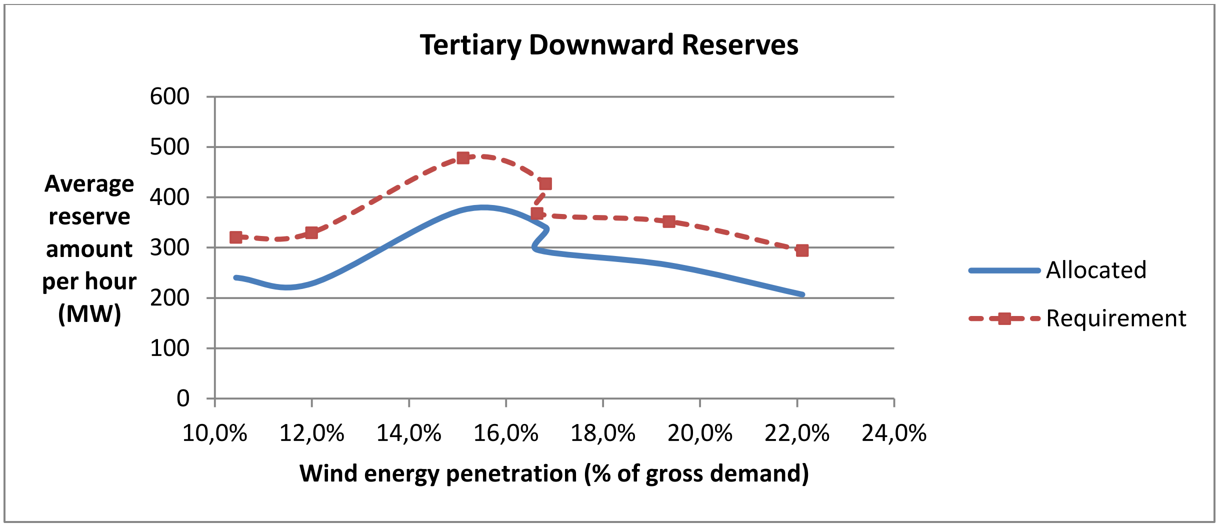

Figure 32: Tertiary Upward Reserves According to Real-time Data

5.3.4. Hourly variations of load and wind power production

As the effect of wind power on secondary and tertiary reserves is seen within hourly timescale, hourly variations of load and wind power production should be analyzed in detail. Load variation in consecutive hours should be followed by the system operator by means of increasing or decreasing generation. Therefore, large variations in load complicate the balancing process and increase the system operation costs.

In Figure 33, hourly variations of load have been illustrated for the year 2010 in Spain. It can be observed that variations increase remarkably during the winter months, whereas in summer less variation is experienced. In March, strangely there is an outlying variation. In total large upward variations are more than large downward variations, this can be easily noticed by looking above the limit of ±6.000 MW.

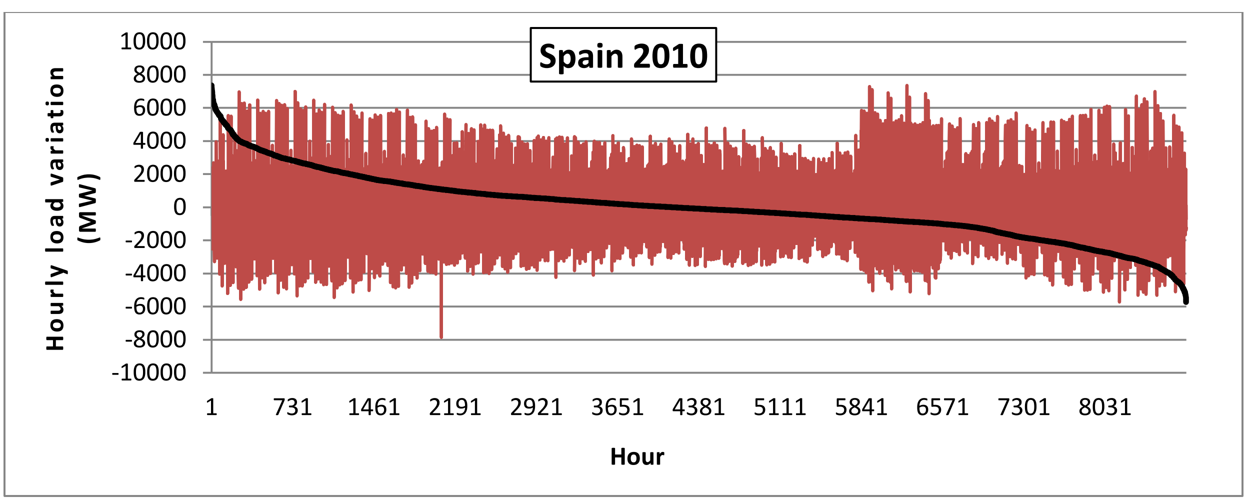

Figure 33: Hourly Demand Load Variations with Duration Curve

Below in Table 6 some features of Spanish hourly load and wind power production variations between 2007 and 2010 are presented. Spain has more hourly variation in load (±17%) than any Nordic country (e.g. Denmark with -14% and 18% of peak load) and almost same variation level in wind power production (±11%) (Holttinen H., 2004). The hourly load variations are 99% of the time between -4.000 and 5.500 MW. The typical daily range of all years load data is around 12.800 MW in Spain, for summer months the value is around 12.400MW and for winter 14.200 MW.

	2007-2010	Unit
Load max up hourly variation	16,5%	% of peak
Load max down hourly variation	17,6%	% of peak
Load stdev of hourly variations	1707	MW
Load stdev of hourly variations	3,8%	% of peak
Wind max up hourly variation	11,7%	% of capacity
Wind max down hourly variation	-10,1%	% of capacity
Wind stdev of hourly variations	271	MW
Wind stdev of hourly variations	1,6%	% of capacity

Table 6: Hourly Load and Wind Power Production Variations in Spain

5.3.4.1. Net load variations

It was stated before that operating reserves depend on three imbalance drivers; probability of power unit failures, variations of demand load and intermittent renewable energy units. By assuming the probability of power unit failures to remain stable, herein the interaction of wind power production and load is analyzed.

As the wind power does not have any significant correlation with demand load, it is difficult to predict the effect of wind power on hourly variations of load which define the need for operating reserves. Interaction between the demand load and wind power production can be seen from Figure 34 and 35. In this figure, load and load after subtraction of wind power generation (net load) is plotted for January 2007 and December 2010. Net load hourly variations were calculated as first creating the net load time series which is the difference between load and wind power production. Later, the difference between consecutive hours was obtained; net load at time *t-1* is subtracted by that at time *t* to obtain the hourly net load variation at time *t*.

$$\Delta P^{nl}_{t} = P^{nl}_{t} - P^{nl}_{t-1}$$

It is seen that when the wind penetration level is higher, the profile of hourly net load values changes more dramatically compared to that with lower penetration level. In Figure 35 from December 2010 we cannot see any weekday-weekend load pattern anymore. Moreover, it is observed that hourly variations in net load are also increasing with the variability added by wind power and this increase requires additional reserves. Hence, the hourly variations in load and net load should be compared to estimate the increase in operating reserves.

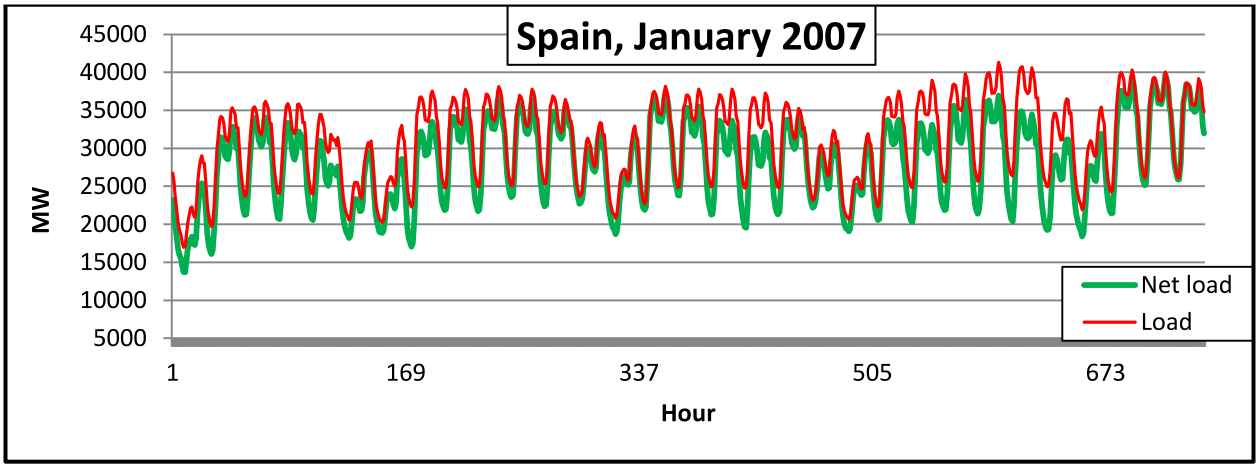

Figure 34: Time Series of Load and Net Load with 9% Wind Penetration on January 2007

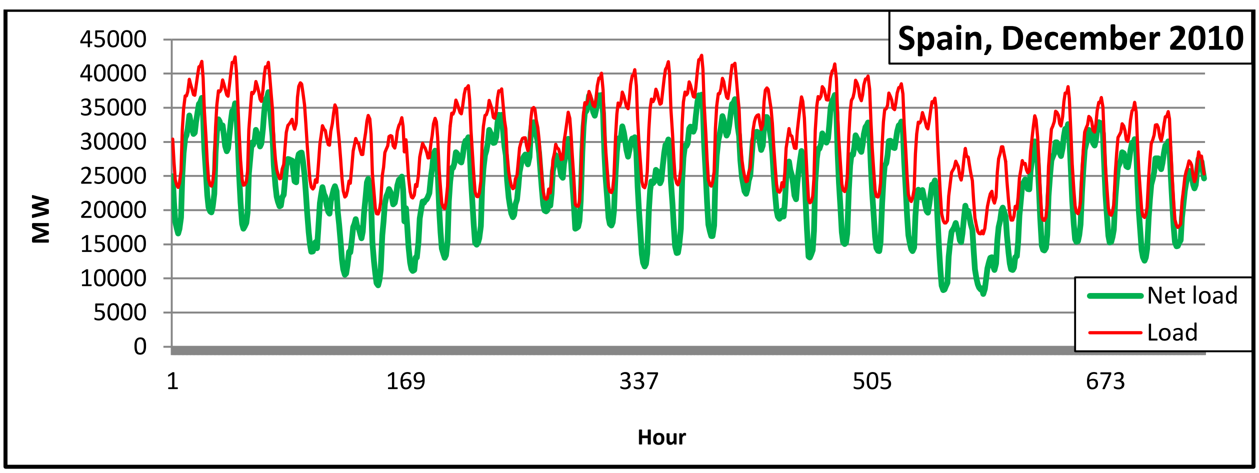

Figure 35: Time Series of Load and Net Load with 21% Wind Penetration on December 2010

Maximum hourly net load variations should be followed by the system operator with ramping up or down generation units and operating reserve capacity contracted by the system operator. Therefore, in some studies they observe the increase in upward and downward largest hourly variations. However, reliability of this methodology is questionable as we determine the increase in hourly variations according to only one point, namely largest hourly variation. This point may appear as a result of an erroneous data. As it was shown before in Figure 33, there were data lying outside the variations of data set in March 2010.

5.3.4.2. Probabilistic method

Another methodology to calculate the increase in the hourly variations is based on probability theory. First of all, standard deviations of load and wind power production hourly time series are calculated. This value shows how much a time series varies from the average value. Standard variation is represented by sigma sign; σ. (Holttinen H.) states that σ indicates that 68% of the variations are within the ±σ of the average value of a normally distributed data set. For ±3σ value the covered area increase to 99% and for ±4σ value to 99,99% of all data set (2004). In this study the hourly variations with a 99% confidence interval are calculated, thus, ±3σ should be used. However, the load and wind power hourly variation data are not exactly normally distributed so more proper σ values which cover 99th percentile of all variations are looked for. The values that are found are approximately 2,6*σ for 2007-2008 and 2,8*σ for 2009-2013.

In order to calculate the standard deviation of net load, it is assumed that there is no correlation between load and wind power variations. According to the data analyzed, calculating net load variations directly from net load time series or from the variations of load and wind power do not show significant difference[14]. The formula that gives the standard deviation of hourly variations of net load as it follows:

$$\sigma_{NL} = \sqrt{{\sigma_L}^2 + {\sigma_W}^2}$$

where σ_{NL}, σ_L and σ_W denotes, respectively, standard variations of net load, load and wind power production hourly variations (Holttinen H., 2004). The increase in variations is illustrated with a frequency distribution chart (Figure 36). $4\sigma_L$ is equal to 6.827 MW of variations, whereas the value for $4\sigma_{NL}$ was found 6.913 MW which covers 99,99% of all data variations around the mean value. Hence, the increase in hourly variations was 84 MW per year on average. On the negative and positive edges of frequency curves the differences are, respectively, 198 MW and -287 MW. Negative value in downward variations means that downward hourly variations decreased 287 MW after the subtraction of wind power production from demand load. As it can be seen, looking at largest variations implies increased need for operating reserves.

In Figure 37, increases in reserve requirements have been depicted for each year according to the standard variations of load and net load time series. These increases indicate how much additional operating reserves the electric power system needs with the integration of wind power at different penetration levels. For instance, at approximately 10% of wind energy penetration level (system with wind power)

[14] 2007-2010 standard deviation of net load hourly variation is found 1.728 MW by the formula given above, whereas directly calculating standard deviation from hourly variations of net load the value is 1731 MW so the formula gives accurate result.

Spanish power system purchases 210 MW of additional operating reserves compared to no wind power situation (system without wind power). This is due to the variation and unpredictability characteristics of wind power. When the penetration rises up to 20%, the amount of additional reserves also increase linearly.

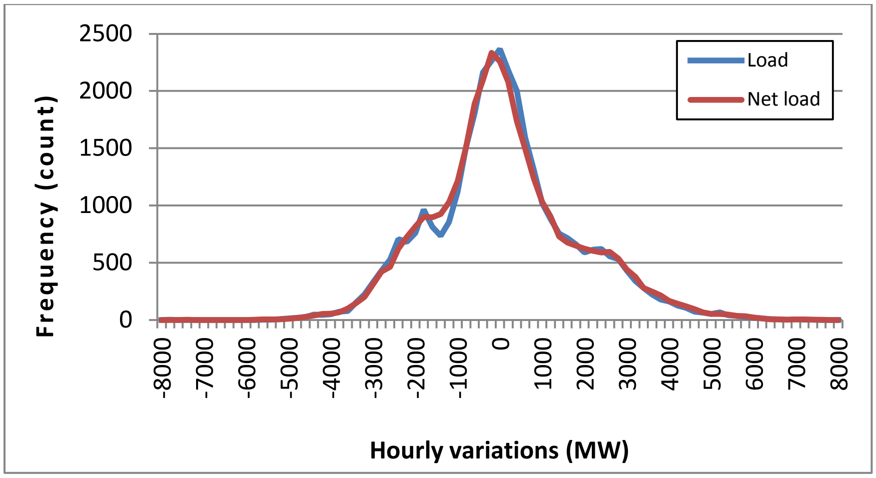

Figure 36: Occurrence Number of Hourly Variations for Load and Net Load Time Series

There are differences in slope as it can be noted; for instance the increase in reserve requirements between the years 2007-2008 is steeper than other periods, even though the increase in penetration level is relatively smaller. The explanation to this phenomenon is that wind power production can have a more variable and less predictable profile during one year compared to another year. In other words, wind energy penetration level is just an indicator of variations; normally we expect more variations with higher penetration level. However, it does not reflect necessarily all the time the rate of variations. For example, it is possible that a year with 18% of wind energy penetration can have more variations in wind power production than that with 19% of penetration level.

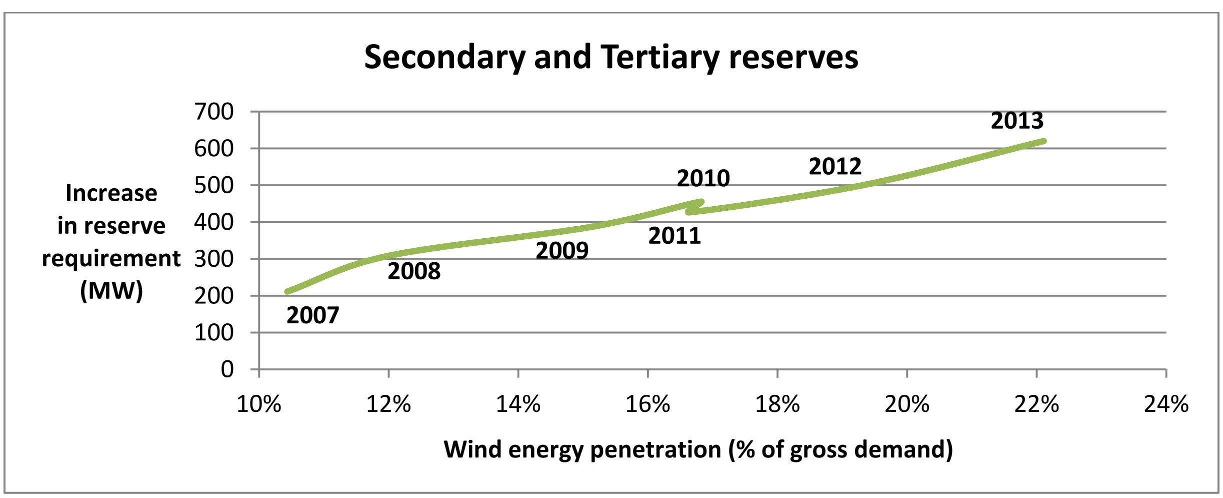

Figure 37: Increase in Reserve Requirements for Secondary and Tertiary Reserves

If we analyze only the interaction of hourly variations, we assume that the hourly variations of load and wind power generation are unexpected. Yet, with the current forecast tools, hourly variations can be predicted to a certain extent so forecast errors should be used instead of hourly variations when determining the increase in reserves.

Another approach suggests decomposing total system imbalances into two main components, namely the forecast error over the settlement period which is the difference between the forecast and the averaged output over the same period and the fluctuations inside the settlement period (De Vos K. et al., 2011).

In this approach, secondary reserves are associated to short-term fluctuations and tertiary reserves to forecast errors over the settlement period. Secondary reserves consist of more flexible generators so the costs of secondary reserves are much higher than tertiary reserves. By dimensioning the reserves in this way, secondary reserves are minimized in terms of capacity and activation so they are used when only absolutely necessary.

Tertiary Reserves: Forecast Error = *Real Time 1 hour – Prediction 1 hour*

Secondary Reserves: Fluctuations = *Real Time 10' – Real Time 1 hour*

Above we can find the formula to estimate roughly the impact of wind penetration on tertiary and secondary reserves. For tertiary reserves, hourly forecast error and for secondary reserves the difference between 10-minute real time data and real time average hourly value. Since we do not have 10-minute data, the hourly variations in consecutive hours are used as estimation. Increase in reserve requirement for secondary reserves is plotted in Figure 38. According to the actual secondary reserve use by the Spanish system operator, the increase was flatter and in this estimation the increase appears a bit steeper. Keeping in mind that hourly variations were used instead of 10-minute data so there is an error margin in this estimation but generally speaking it can be deduced that wind power production increases the use of secondary reserve slightly (See Annex I).

Since secondary reserves cost more than tertiary reserves, we would expect higher increase in tertiary reserves. Figure 39 demonstrates us the increase curve of tertiary reserve requirements with the integration of wind power. This figure shows us pretty much the same trajectory of the actual use of tertiary reserves according to real time data. The only difference is in the years of 2012-2013; the increase in estimation continues to rise whereas the real data reveals a cease in increase. This figure indicates that at 10% of wind energy penetration the increase in tertiary reserve requirements is around 175 MW with 13.500 MW of installed wind capacity and at 20% of penetration level is around 400 MW with 22.500 MW of installed wind capacity. Thus, we can deduce that increasing wind power production in Spanish electricity system leads to an increase in tertiary reserve requirements (See Annex II).

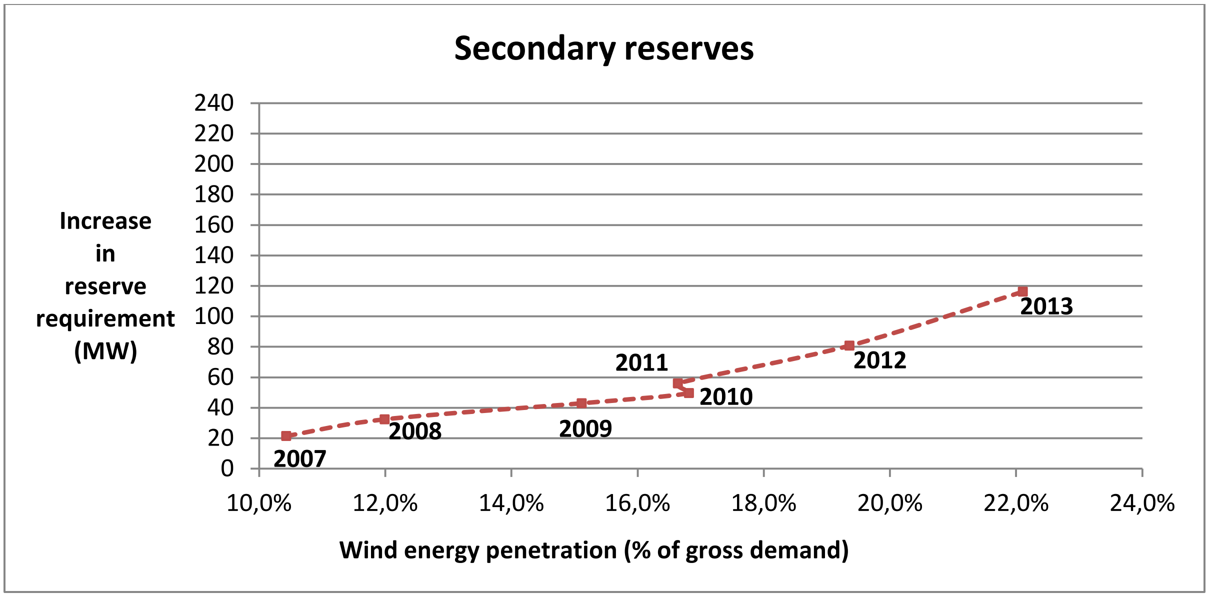

Figure 38: Increase in Reserve Requirements for Secondary Reserves

When the actual use of secondary, tertiary reserve values were being analyzed, it was noted that tertiary reserve requirement-allocation interval was larger than that in secondary reserves. Numerically speaking tertiary reserve requirement values are 1,33 times of the allocated values in average for the years between 2007-2013, whereas this ratio for secondary reserves is only 3,88. These ratios will be used later to estimate the actual use of tertiary and secondary reserves.

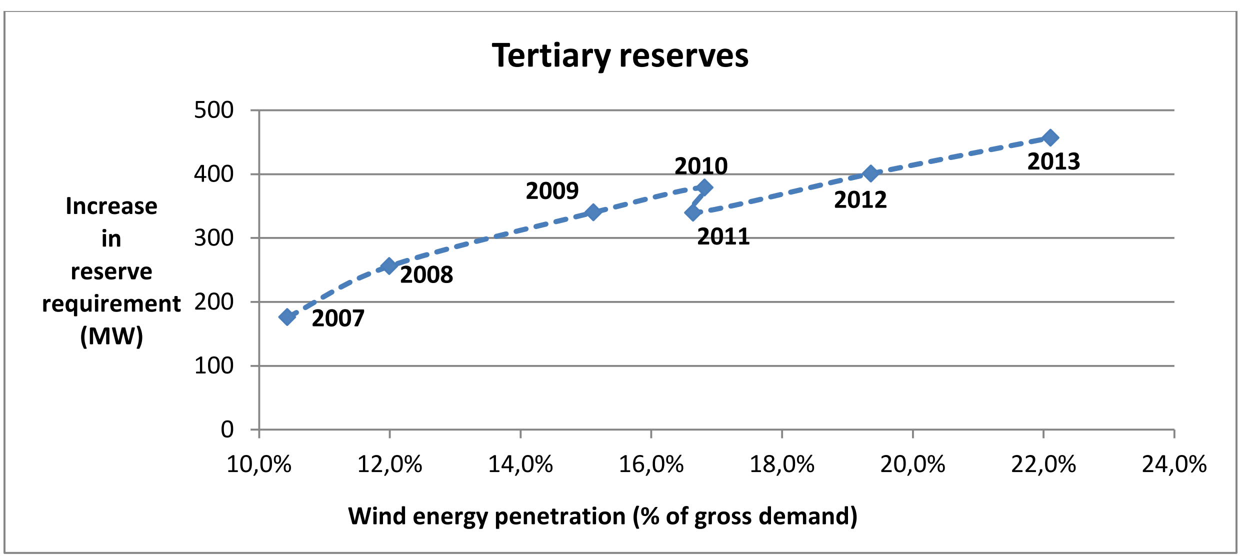

Figure 39: Increase in Reserve Requirements for Tertiary Reserves

Lastly we can observe the increase in total load following, tertiary and secondary reserves in a bar chart (Figure 40). As it is stated before most of the increase in total load following reserves comes from the increase in tertiary reserves, approximately 75%. The first reason is that secondary reserve increases do not vary as much as tertiary reserves since they are contracted for smaller time-scale and secondly, tertiary reserves provide cheaper energy than the former. In the next step, we will see whether these increases cause a significant cost on the system.

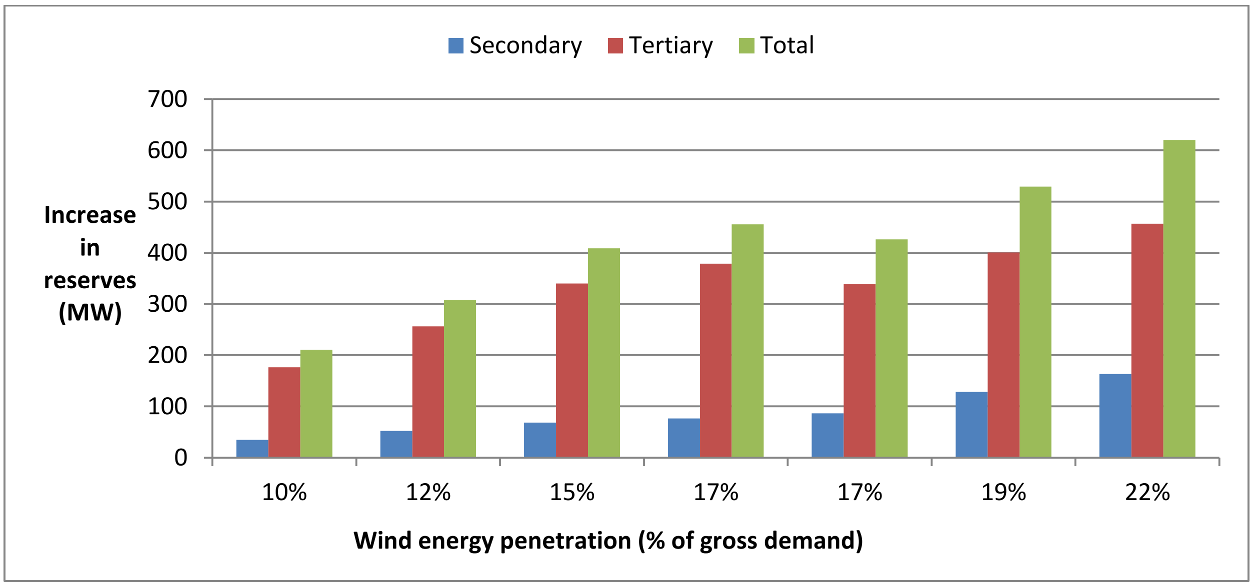

Figure 40: Bar Chart of Increase in Reserve Requirements of Operating Reserves

5.3.5. Cost of Increase in Operating Reserves

Up to now the amount of system reserves that increase with the introduction of wind power to the system has been found. In other words, the amount of system reserves with wind power and without wind power was found and the amount of increase in the system reserves was obtained. In order to calculate the cost of increase in operating reserves, the remuneration method of the reserves in Spain should be recalled. First of all, for secondary reserves the system operator pays the secondary reserve market price for all the assigned capacity and apart from capacity payments, if the assigned units are called to give the service then additionally they are paid an energy price component according to the energy price of tertiary reserve market. Secondly, for tertiary reserves only called generation/consumption units are remunerated (energy price). Lastly, for additional upward reserves assigned units will receive the marginal price of the related market.

Regarding the increase in reserve costs there are two components; capacity and energy payments. Capacity payments will be calculated (for secondary and additional upward reserves) by multiplying reserve market marginal price with the increase in reserves that was found in previous chapter. Although in the reserve market each hour has a different marginal price, yearly average marginal prices will be used. For the energy payments (for secondary and tertiary reserves) the difference between the spot price and reserve market price will be taken (Holttinen H., 2004).The logic behind this calculation is that we pay additional capacity payments and also as we buy the electricity with a higher price in the Reserves Market (RM) compared to Day Ahead Market (DAM), we bear additional energy costs; which is the difference of prices in DAM and RM. As an example, let's say without wind power the system operator purchases *X MWh* of electricity in RM. However, if we integrate wind power to the system, with the increase in system reserves, e.g. *100 MWh* of increase, the system operator contracts *X+100 MWh* of electricity in RM. So if we had used a conventional technology instead of wind power, that additional *100 MWh* of electricity would have been purchased in the DAM, not in RM. Therefore, we take the difference of prices of the same product (*100 MWh* of electricity) in DAM and RM; it is the same product in two different cases: the system without wind power (*100 MWh* purchased in DAM) and with wind power (*100 MWh* purchased in RM). Lastly, to calculate capacity payments increase in reserve requirements will be used and for energy payments the actual use of energy will be taken.

Below the formula to calculate the cost of increase in secondary reserve is given. Tertiary and additional upward reserves are calculated likewise with the corresponding cost component. In the next chapter results for the cost of increase in operating reserves together with the general analysis of wind power on operating reserves are presented.

Increase in secondary reserve costs = **Capacity payment + Energy payment**

Capacity payment = Secondary RM marginal price * Increase in secondary reserve requirement

Energy payment = (Tertiary RM Up marginal price – DAM marginal price) * Increase in secondary reserves (upwards) **+**

(DAM marginal price – Tertiary RM Down marginal price) * Increase in secondary reserves (downwards)

6. FINAL RESULTS & CONCLUSIONS

In my analysis first the change of Spanish reserve requirements, allocation and actual use according to real-time data has been depicted with increasing with energy penetration. It has been observed that with the increase in wind power production the need for additional operating reserves increase for all types of reserves with varying increase rate. The impact on tertiary reserves is more evident than secondary reserves and the increase mainly driven by tertiary reserves leads total reserves to rise. Moreover, it was noticed that the increasing course of reserves, both for secondary and tertiary reserves, reveals a flatter profile in 2012-2013. Spanish power system has inaugurated a new operating reserve to strengthen the system reliability in the beginning of same period (2012) which is called additional upward reserves. This new operating reserve started with an increasing trend while for the same period the secondary and tertiary upward reserves continued to rise as well.

In the next step, probabilistic methodology has been applied to estimate the impact of wind power on the system reserves by bearing in mind the interaction with variation of load and assuming the probability of power unit failures to keep in the same level. The amount of increase in reserve requirements in the power system has been obtained. This increase is calculated by comparing the system with wind power and without wind power. The results are consistent with the ones from real-time data; an increasing profile for both secondary and tertiary reserves. Yet, secondary reserves in the estimation appear with a higher increase which might result from the use of lower resolution data (hourly data instead of 10’ data).

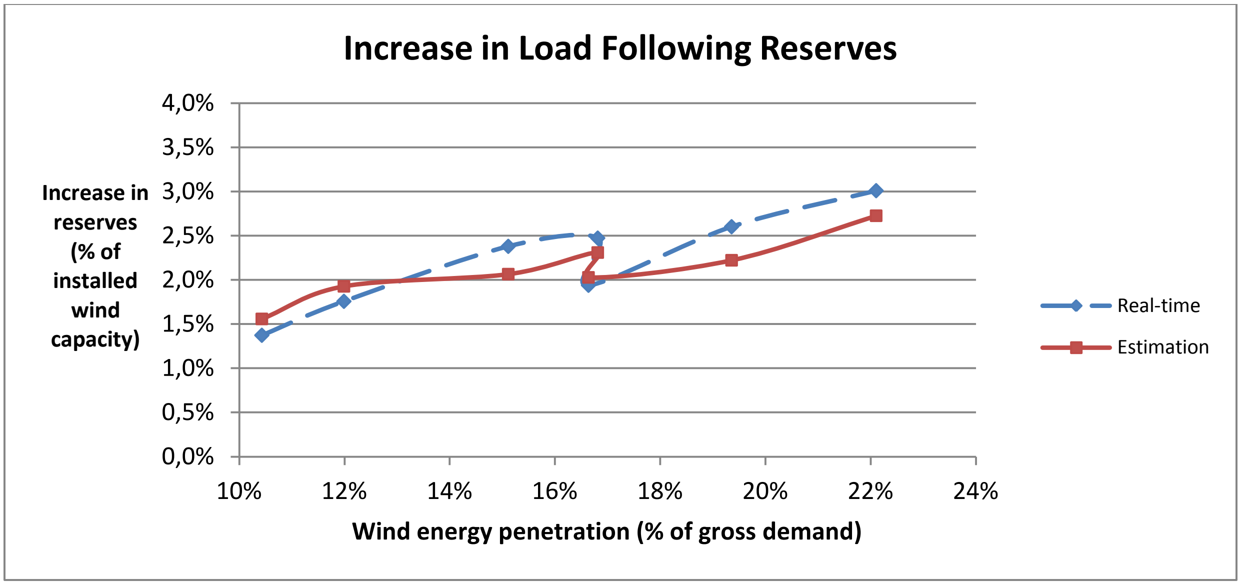

Figure 41: Increase in Secondary and Tertiary Reserves According to Real-time Data and Probabilistic Method

Increase in secondary reserve requirements at 10% of wind energy penetration is around 20 MW and at 20% of penetration level is approximately 80 MW, whereas increase in tertiary reserves at 10% and 20% of penetration level, respectively, is 176 and 401 MW. These increases still remain low compared to previous studies held in different countries; at 10% penetration level between 1,5-4% of installed wind capacity and at 20% penetration level between 4-7% of wind capacity (Holttinen H., 2004). Above the increase in load following reserves in Spain as percentage of installed wind capacity can be observed according to the probabilistic methodology estimation and the real-time data (Figure 41). At 10% of penetration level both of them display an increase of approximately 1,5% of wind capacity whereas at 20% of wind energy penetration the real-time data indicates 2,6% increase of installed wind capacity and for the estimation this value is only 2,2%. In any case, these values are much lower than those in other studies (4-7%). Thus, we can deduce that the impact of wind power on operating reserves in Spain is relatively insignificant.

As for costs of increase, in Table 7 and Figure 42 we can see the costs of secondary, tertiary and total reserve increases per wind energy produced in the country according to the probabilistic estimation. It is noted that the costs are increasing with each MWh of wind energy generated and added to the system. However, another important component of the costs is the price of reserve and day-ahead market prices. For instance, in year 2009 the system witnesses a decrease in the costs of increase for all reserve types while in the very same year the penetration rate increases significantly, more than 3%. The reason as it was mentioned is because of low prices of electricity in RM and DAM, actually the lowest prices of the 2007-2012 period.

	2007	2008	2009	2010	2011	2012	2013	Units
Secondary reserve costs	0,26	0,33	0,24	0,29	0,36	0,76	0,93	**€/ MWh**
Tertiary reserve costs	0,70	0,81	0,81	0,94	0,94	0,98	1,20	**€/ MWh**
Total reserve costs	0,96	1,14	1,05	1,23	1,30	1,74	2,13	**€/ MWh**
Penetration rates	10,4	12,0	15,1	16,8	16,6	19,4	22,1	**%**

Table 7: The Costs of Operating Reserve Increases per Wind Energy Produced

Secondary reserve costs vary around 0,3€ and are lower than tertiary reserve costs in all years. However, in 2012 and 2013 the secondary reserve market marginal price peaked and the cost of secondary reserve increase, respectively, reaches to 0,76€ and 0,93€. At 10% wind energy penetration rate the cost of total reserve increase is 0,96€ and at 20% level the cost increases to 1,74€ per (MWh) wind energy produced.

This figure clearly shows that generating electricity more with wind power causes extra operating cost to the Spanish electricity system. However, these costs cannot be considered as significant if we compare with the results from other studies and take into account the advantages of wind energy. For instance, the studies in UK, US and Nordic countries estimate 1-3€/MWh cost of increase in operating reserves for 10% penetration rate and 2-4€/MWh for a penetration of 20% (Holttinen H., 2004).

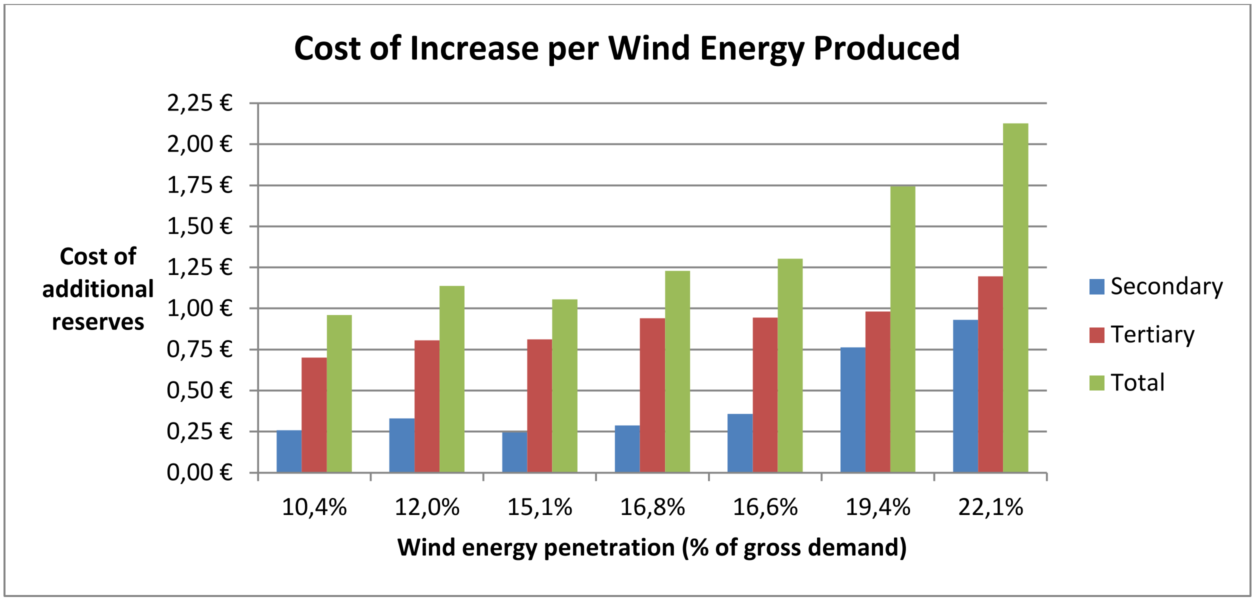

Figure 42: Costs of Operating Reserve Increases as of Bar Chart

CONCLUSIONS

Increasing wind turbine installations in electric power systems and in parallel with this, the increasing share of wind energy over total electricity production have triggered the concerns about the integration of this renewable energy resource. The concerns result from the two important characteristics of wind power; variation of wind power production, in other words uncontrollability of the energy resource; wind, and the difficulty to predict the production level; accuracy of the forecasts.

These characteristics lead to some negative impacts on different timescales; on the short-term, regarding the operation of the system; the need of voltage management, cycling losses, transmission or distribution losses, increase in operating reserves and discarded wind energy, whereas on the long-term the impacts relates to the system reliability. In this thesis, the impact of wind power integration on operating reserves in Spain was analyzed. The operating reserves in Spain are classified according to the time frame in which they are activated, namely; primary, secondary and tertiary reserves. Additionally, starting from the year 2012 a new operating reserve was inaugurated; additional upward reserves.

Literature review and all the previous studies show that the impact on primary reserves is very small since the variability of wind power decreases with short time scales (second to minute variability) and aggregating several wind parks over a geographically spread area smoothes out the second to minute variations. Thus, the analysis has been focused on the secondary and tertiary reserves.

First, the trajectory of reserves according to real-time data that was obtained from the Spanish system operator (REE) was depicted together with the increase in wind energy penetration in the country. The data and the figures show that there is a relationship between wind energy penetration and operating reserves; increasing wind power production causes the operating reserves rise as well. This is especially more evident for tertiary reserves, whereas secondary reserves reveal a slight increase.

The change in operating reserve amounts results from three imbalance drivers; probability of power unit failures, variations of electricity demand load and intermittent renewable energy units. In order to estimate the impact of wind power, it has been assumed that the probability of power unit failures remain in the same level and then the interaction of demand load and wind power production based on probabilistic methodology has been analyzed. This methodology compares the power system without wind power with the system at different wind energy penetration levels for each analyzed year (2007-2013) by analyzing the change in standard variation values of forecast errors of demand load and wind power production (Holttinen H., 2004). The results give us the increase in operating reserves with the integration of wind power to the system. Furthermore, the increase in secondary and tertiary reserves has been decomposed and estimated by associating the short-term fluctuations within the settlement period to secondary reserves and the forecast errors over the settlement period to tertiary reserves (De Vos K., et al., 2011). The estimation results are consistent with the increase that we observe in real-time data and both demonstrates that large scale wind power integration in Spain has increased the amount of operating reserves purchased.

Lastly, the costs of increase in operating reserves have been calculated according to the remuneration scheme in Spain. The results show that at 10% wind energy penetration rate the cost of total reserve increase is 0,96€ and at 20% level the cost is 1,74€ per wind energy produced, whereas the studies in other countries estimate a variation between 1-3€/MWh for 10% penetration rate and 2-4€/MWh for a penetration of 20%. Note that not only the increase in operating reserves is determinant for the calculation of costs but also the prices of reserve markets and day-ahead market. For instance, in year 2009 when the reserve and day-ahead market prices were at their lowest for the period of 2007-2013, despite a remarkable increase in wind energy penetration, the cost of increase in operating reserves decreased due to the low market prices.

Although the costs that are found in this work appear in the lower limit of the calculated costs in other studies and also given the reserves and day-ahead market prices, it would not be enough to deduce whether these costs of increase in reserves become a significant burden for Spanish electric power system. Instead, in order to better understand, a further study that compares the costs with the benefits of wind power is needed. For instance, it is possible that large scale wind power integration might reduce electricity market prices so maybe the cost of increase in reserves would be offset by this kind of gain. Additionally, the estimation of increase in secondary reserves might be improved if higher resolution data can be used in the analysis.

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8. ANNEXES

I. Increase in secondary reserves with probabilistic methodology.

	2007	2008	2009	2010	2011	2012	2013	Unit
Peak load	44.672	42.971	44.235	44.539	42.940	42.456	39.502	MW
Installed wind capacity	13529	15977	18712	19710	21011	22573	22746	MW
Load stdev of hourly variations	968	1044	1121	1285	1097	1063	954	MW
Wind stdev of hourly variations	126	160	184	214	210	249	284	MW
Netload stdev of hourly variations	976	1056	1136	1303	1117	1092	995	MW
Increase in the variations (MW)	21	32	43	50	56	81	116	MW
Penetration rates	10,4%	12,0%	15,1%	16,8%	16,6%	19,4%	22,1%	%

II. Increase in tertiary reserves with probabilistic methodology.

	2007	2008	2009	2010	2011	2012	2013	Unit
Peak load	44.672	42.971	44.235	44.539	42.940	42.456	39.502	MW
Installed wind capacity	13529	15977	18712	19710	21011	22573	22746	MW
Stdev of Load forecast error	728	750	785	760	818	947	747	MW
Stdev of Wind forecast error	320	393	449	473	461	540	520	MW
Netload stdev of hourly variations	795	847	904	895	939	1090	910	MW
Increase in the variations (MW)	176	256	340	379	340	401	457	MW
Penetration rates	10,4%	12,0%	15,1%	16,8%	16,6%	19,4%	22,1%	%