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OFFICIAL MASTER'S DEGREE IN THE
ELECTRIC POWER INDUSTRY

Master's Thesis

FOR THE PERMITTANCE OF RENEWABLES IN THE SPANISH SECONDARY RESERVES MARKET

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Terms and Acronyms

AGC: Automatic Generation Control

CAPEX: CAPital EXpenditure

CCHP: Combined Cooling, Heating and Power

CECI: Cumulative Estimated Capturable Income

CECOEL: *Centro de Control Eléctrico*, National Control Center

CECORE: *Centro de Control de Respaldo,* Backup National Control Center

CHP: Combined Heat and Power

CNMC: *Comisión Nacional de los Mercados y la Competencia*, Spanish National Commission of Markets and Competence (includes the former CNE: *Comisión Nacional de Energía)*

CPI: Consumer Price Index

D+1: Day Ahead

DER: Distributed Energy Resources

DM: Daily Market

ECI: Estimated Capturable Income

EFHB: Effective Hourly Benefit

ENTSO-E: European Network for Transmission System Operators for Electricity

FIT: Feed-In Tariff

IBC: Intraday Barter Cost

IRR: Internal Rate of Return

IIT: Instituto Investigación Tecnología (Pontificia Universidad Comillas)

MIBEL: *Mercado Ibérico de la Electricidad,* Spanish and Portuguese Wholesale Electricity Market (Iberian Peninsula Market)

MO: Market Operator

MY: Market Year

NPV: Net Present Value

NREL: National Renewable Energy Laboratory

OMIE: *Operador Mercado Ibérico, polo español,* Daily and Intraday Market Operator of MIBEL

OMIP: *Operador Mercado Ibérico, polo portugués,* Derivatives Market Operator of MIBEL

OPEX: OPerational EXpenditure

PHB: Potential Hourly Benefit

PO: *Procedimientos de Operación*, Operation Procedures

RAIPEE: *Registro Administrativo de Instalaciones de Producción de Energía Eléctrica*, Administrative Registry of Electrical Energy Production Facilities

RBO: Reasonable Band Offer

RCP: *Regulación Compartida Peninsular*, Shared Pennisular Regulation Control System

RDL: *Real Decreto Ley*, Royal Decree-Law

REE: *Red Eléctrica de España*, Transmission System Operator of Spain

RT: Real-time

SO: System Operator

SR: Secondary Reserves/Regulation

SRM: Secondary Reserves/Regulation Market

TD: Tariff Deficit

TR: Tertiary Reserves/Regulation

VPP: Virtual Power Plant

WACC: Weighted Average Cost of Capital

Note: All citing of Spanish documents are given as translations by the author and thus are not official translations unless otherwise mentioned

Abstract

Recent Spanish legislation has enacted a complete reform of the energy sector in efforts to balance system costs with revenues and reign in the accumulating tariff deficit. Under the new legislation, wind energy and other renewables must compete against traditional thermal and hydro plants, yet are not allowed in the ancillary services market for grid stability. As Wind was the number one source of energy for Spain in 2013, and as any practical future which is dependent on renewables will necessitate them to provide ancillary services, there has been a growing interest to determine the consequences of allowing wind generation into the Secondary Reserves Market (SRM).

This research is conducted from a single agent perspective with the intention of answering **if the investment costs necessary to participate in the Secondary Reserves Market will be outweighed by the revenue a wind producer is likely to receive.** Additionally, if true, this thesis aims to parameterize under what conditions it will be beneficial for a wind producer to participate in the SRM and investigates possible strategies a wind agent could pursue.

As provision of Secondary Reserves would likely require a wind agent to change from a market-clearing schedule to that which would allow for the maximum amount of band offer, this change must be managed by participation in the Intraday Market and may constitute an additional cost. Thus the final calculation of revenue considers Primary Effects or the direct revenues from participation in the SRM, and Secondary Effects or the costs/benefit from bartering power in the Intraday Market.

Revenue calculation, denoted as the Estimated Capturable Income (ECI), is subject to some uncertainty. Thus to give different perspectives on possible revenues, three methods of ECI calculation have been developed: a conservative estimate, a probable estimate, and an optimistic estimate. The investment costs assumed in this research are taken from previously conducted technical studies which proved that wind farms acting in clusters can provide Secondary Regulation within reliability criteria. These costs were socialized across a test-bed of 488 MW of installed wind capacity and constitute a unitary investment cost of €3,053 per MW.

Therefore the principle conclusions from the analyses performed throughout this thesis is that a wind producer could expect to earn between € 762 to € 1,238 per MW of Installed Wind Capacity through participation in the Secondary Reserves Market. When applying this to an existing case, the Huéneja cluster of 254 MW of wind capacity, wind operators/owners could expect to gain between € 193,753 to € 314,712 annually and could recoup investments within three years. The thesis results indicate that maximum benefit can be derived by participating in the SRM in those hours which experience a Capacity Factor of 41% or greater.

Further investment analysis based upon ten years of simulated inflows imply that the necessary investment for such a cluster would experience an IRR between 35%-56% and constitute an NPV between € 1.1 – € 2 Million for an initial investment of € 523,174.

In an industry with economic scopes of 20 years or more with the expected regulated rate of return for wind installations at 7.5% according to ***The 2013 Energy Reform Details***, the results indicate that participation in the Secondary Reserves Market for wind producers would be both attractive and economically feasible.

Chapter 1: Introduction

Motivation

Prologue

In June of 2013, the Spanish government enacted what has been opined by energy firms as a legislative overhaul of grandiose proportions, affecting all parts of the energy sector and as a result, greatly impacting the national economy as a whole. In response to a multiplicity of factors, the aforementioned Royal Decree-Law 9/2013 has several provisions and retroactive changes which directly impact renewables as well as traditional thermal generation. Several private sector actors have actively expressed their concern declaring the RDL9 as “a threat to Spain´s energy future” (AEE, Asociación Empresarial Eólica, 2014); (Iberdrola), 2013). The most notable change being the disbandment of the Special Regime nomenclature, which was originally implemented to provide economic incentives and benefits to renewables, co-generation, and distributed generation (less than 50 MW) in efforts to meet the European Union 20/20/20 goals.

The RDL 9 is one of several (at least seven) alterations which have been made to the Spanish energy sector in a span of a year; the results of which have caused investor circumspection if not outright consternation, political risk premiums to increase, and national securitization ratings to decrease. Furthermore, affected persons and enterprises have actively expressed their indignation towards the recent governmental actions due to the perceived lack of transparency and failure to consult expert advice before enacting such expansive changes. (T. Couture(IFOK GmbH), Dr. M. Bechberger(APPA), 2013); (Fitch, Fitch Wire, 2013); (Fitch, Yahoo Finance, 2014); (AEE, Asociación Empresarial Eólica, 2014); (UNESA), 2014); (Iberdrola), 2013); (Herbert Smith Freehills LLP; "Regulatory Evolution", 2013).

> ***“This reform is leading the Spanish electrical system to an untenable situation, in which almost half of what consumers pay through their bills serves to pay for the political mistakes of the government and not to cover the costs of electricity supply” (Energy News, 2014)***

The Special Regime

Justification

The Special Regime nomenclature was originally established in 1994 with the Royal Decree 2366, however with subsequent revisions and updates, the most recent legislation governing the Special Regime was the Royal Decree 661 (*Real Decreto 661*) from May 2007. The original justification of the Special Regime was driven by political and social values to promote green technologies, reduce dependency on foreign sources of energy, and to better take advantage of domestic sources. After the 1997 Kyoto Protocol agreement to comply with reduction of Greenhouse gases, the European Union published aggressive energy targets known as the 20/20/20 initiative. The Initiative states that 20% of energy in the EU will be produced by renewable energy with a 20% reduction in greenhouse gasses from 1990 levels by the year 2020. From 1997 onwards, Spain wholeheartedly adopted a strategy for supporting renewables as described in the E4 plan (Estrategia de Ahorro y Eficiencia Energética en España, Strategy for Energy Savings and Efficiency in Spain) in efforts to achieve these shared goals.

Definition

The Special Regime nomenclature included the following technologies enumerated in the table below. For a complete list of all included technologies and their definitions please refer to ***Capítulo 1, Artículo 2, Real Decreto 661***.

Table 1: Special Regime Definition

Category A	Category B
Cogeneration and other forms of production using waste fuel	Solar energy • Photovoltaic • Thermal Solar
	Wind Energy • Onshore Wind • Offshore Wind
	Hydro Plants with less than 10MW Installed Capacity (excluding plants which were previously built during centralized planning, i.e. before the market was created)
	Hydro Plants between 10-50MW Installed Capacity (excluding plants which were previously built during centralized planning, i.e. before the market was created)
	Any form of production using the earth as primary energy such as: Geothermal, Wave, Tidal, Ocean Thermal, Hot and Dry Rock, and Ocean Currents

Furthermore, all Special Regime generation was required to comply with certain obligations such as:

- To deliver and receive energy without disturbing the regular functioning of the electric system
- Any installation above 10 MW or any group of installations whose total was equal or greater to 10 MW was required to be assigned to a central generation controller which was to act as an interlocutor to the System Operator.
- Any installation or group of installations greater than 2 MW of either wind or photovoltaic generation was required to comply with regulations relating to maintenance of grid voltage levels as enumerated in ***Resolución de 4 de octubre de 2006*** (RCL 1924/2006, 2006).

The previous requirements were applied to island and mainland installations, however were deferent to any and all prevailing technical constraints *"that may be required in each case"* (Real Decreto 661, 2007).

Remuneration

The Special Regime legislation called for a "reasonable" means of remuneration which would cover the initial investment and all relevant costs to renewable generators. It also aimed to eliminate irrationalities in the previous remuneration scheme for generators whose costs did not depend on the price of petroleum or other fuels in international markets. (Real Decreto 661, 2007).

Specifically, most generation under the Special Regime was able to choose between remuneration under a regulated feed-in tariff (FIT) or by selling electricity in the market and receiving a complementary premium in euro cents per kilowatt-hour (€/kWh); however, some technologies such as photovoltaics and thermal solar were required to be remunerated through the FIT method. The premium scheme was implemented such to guarantee a minimum level of remuneration when market prices were low and was set to zero above a chosen point when the market price was sufficiently high to guarantee a full cost recovery (Real Decreto 661, 2007); (CNE, CNE, 2013).

> ***"In the case of wind, the remuneration cannot fall below 73 EUR/MWh (which includes both the market price plus the premium); the premium is set to zero when the market price is above 87 EUR/MWh". (C. Batlle, I.J. Pérez-Arriaga, & P. Zambrano-Barragán, 2011)***

Figure 1 below graphically explains the premium scheme and tariff options put into place by the RD 661.

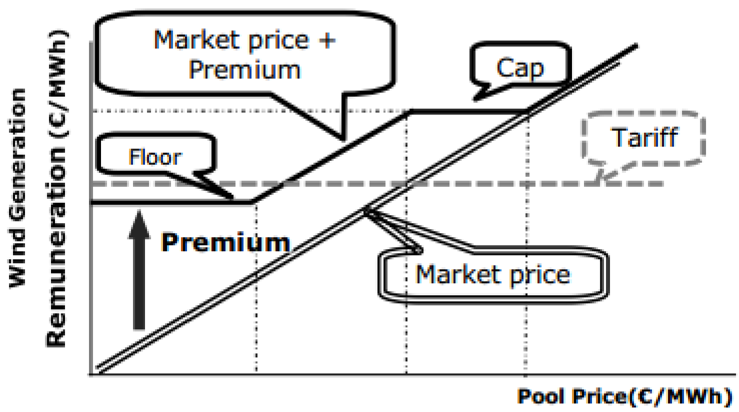


Figure 1: Special Regime Remuneration Schemes

Source: (TWENTIES PROJECT 15.1, 2014)

Some larger installations which would otherwise be included in the Special Regime were considered separately (given another premium) due to their Installed Capacity (more than

50MW), or due to their use of thermal methods of generation such as cogeneration, biogas, or other plants using waste fuel. Another separate premium was created as well for biomass and/or biogas, independent of their Installed Capacity and apart from the remuneration scheme defined in the ordinary regime.

The Tariff Deficit

The ambitious energy sector reforms were a response in large part to the Tariff Deficit (TD), an appreciating problem over the past fourteen years which has been attributed to different reasons depending on the point of view taken. Governmental sources have claimed the TD arose from incorrect demand and economic growth predictions and significant over-investment in renewable technology at early stages. Wind producers blame faulty energy remuneration schemes and a general mismanagement of economic reality by several interim governments. While the actual reasons are subjective and indeed may be due to a combination of some or all of the previously mentioned, it is unanimously agreed that the TD must be counteracted (Spanish Ministry of Economy and Competitiveness, 2013); (Iberdrola, Outlook 2014-2016, 2014).

Since 2000 the revenues in the Spanish electricity system have not covered the costs of the system to varying degrees (CNE, CNE, 2013). As such the resultant cumulative deficit in 2013 was predicted rise to reach €30 Billion by year end (Fitch, Fitch Wire, 2013); (CNE, Nota Resumen del Saldo de la Deuda del Sistema, 2013). The majority of extraneous system costs, and thus the sources of the TD, have been driven by an overly-generous subsidization to renewable generation, particularly to non-mature technologies such as solar thermal and photovoltaics. Other key attributed factors include the subsidization of the Canary and Balearic extra-peninsular systems of Spain and the general unwillingness of incumbent governments to pass actual costs onto consumers (CNE, CNE, 2013).

As of 2007 the problem was handled through ex-ante deficit auctions: access tariffs are set up lower than access costs and the difference is financed through future receivables. This effectively means that the price for electricity today not only is the actual cost of production, but also includes the cost recovery of past production plus interest.

> ***[The] Tariff Deficit has been financed primarily by incumbent electricity companies, which have subsequently been granted a credit right to receive such amount with interests over 8 to 15 years ("Tariff Deficit Receivables"). The annual payment of the tariff deficit is included in the tariff as an access cost. (CNE, CNE, 2013)***

In 2009 in response to the rapidly growing cumulative deficit and the large financial burden placed on Spanish electricity companies during the Euro Financial Crisis, the Spanish government created a securitization vehicle backed by the national sovereign debt to begin accepting Tariff Deficit Receivables to pay down the TD owned by utilities. The fund known as FADE (Fondo de Amortización del Déficit Eléctrico) or the Spanish Electricity Deficit Amortization Fund, works "by turning the utilities' rights to collect the deficit through electricity tariff hikes into government-backed fixed-income securities" in attempts to maintain low prices for consumers (Reuters, 2010); (FADE, 2012).

In addition to FADE, measures to combat the growing tariff deficit included dedicating portions of the state budget to directly pay down the TD (which were eventually retracted), a disbandment of the quarterly CESUR auctions for determining the last resort tariff, and revisions to grid access tariffs. Changes in pricing methodology for Transmission and Distribution were also enacted as well as a 7% retroactive tax hike on all Generation. Further actions included a reduction of capacity payments and other investment incentives as well as a complete moratorium on new Special Regime projects (Herbert Smith Freehills LLP; "Regulatory Evolution", 2013); (T. Couture(IFOK GmbH), Dr. M. Bechberger(APPA), 2013).

The 2013 Energy Reform Details

The RDL 9/2013 was enacted as "urgent measures for guaranteeing the financial stability of the electricity system" (Herbert Smith Freehills LLP; "Royal Decree-Law 9/2013", 2013). This goal was set to be accomplished through a thorough reform of the economic system of the energy sector, the purpose of which was three-fold, namely:

- To establish a regulatory framework to guarantee financial stability in the electricity sector.
- To remove the electricity sector deficit once and for all, preventing future deficit and guaranteeing supply to consumers at the lowest possible cost and with increased transparency.
- To simplify and clarify electricity bills and encourage competition in domestic electricity tariffs to foster competition towards consumers, while maintaining the "social bonus" (Herbert Smith Freehills LLP; "Main Measures", 2013).

Important measures are as follows:

1. RD 661/2007, the regulation which created the current tariffs, and article 4 of Royal Decree-Law 6/2009 **are revoked**. With respect to this, a new economic system is announced, to be developed and approved in the coming months.

2. The new remuneration will consist of the **sum obtained through the sale of the energy generated valued at market price** (through the pool), plus specific remuneration consisting of:
    a. a cost per unit of power installed covering, where applicable, any investment costs of **standard** installations which cannot be recovered by the sale of the energy, and
    b. an operation cost covering, where applicable, the difference between the operating costs and revenue through participation on the market of such **standard** installations.

3. For the calculation of such specific remuneration, standard installations for each technology will be taken into account, bearing in mind, throughout their regulatory useful life:

a. **Standard income** from the sale of the energy generated valued at production market price.
b. **Standard operating costs**.
c. The **standard value** of the initial investment

4. Among the costs, **any costs or investments determined by administrative rules or acts not applicable throughout Spanish territory will not be included**. In the absence of any further specifications, it seems to intend to exclude from the calculation any local or regional levies, fees and charges encumbering the generating of electricity through renewable sources and co-generation.

5. Reasonable profitability will be calculated before tax and in reference to the **average yield on the secondary market of Government Bonds at ten years** applying the "appropriate" margin as indicated in the following point.

6. This margin has not been defined for new installations. For those installations already in operation (or allocated in advance, provided they have been recorded in the RAIPRE), the margin will be 300 basis points**, which would currently produce a remuneration of around 7.5%**, calculated as profitability of the project.

7. Payments for capacity include two types of services: the incentive for long-term investment in capacity and the service of mid-term availability.
   a. RDL 9/2013 reduces the incentive for long-term investment established under Order ITC/2794/2007, of December 27, establishing it at 10,000 €/MW/year. The installations which already had a collection right on the coming into force of RDL 9/2013 will have this reduction compensated by an increase in the period of the same.
   b. Moreover, the application of the said incentive for new production installations **is removed**, except for those which obtained a definitive start-up record prior to January 1, 2016.

Sources:
(Herbert Smith Freehills LLP; "Royal Decree-Law 9/2013", 2013); (Herbert Smith Freehills LLP; "Main Measures", 2013); (Boletín Oficial Del Estado; Jefatura Del Estado, 2013)

Furthermore, the RDL 9/2013 changes the indexation formulae for calculating remuneration of regulated activities from the Consumer Price Index (CPI) to the ***core*** CPI "excluding from it price variations in energy and food products and any impact due to tax changes" (CNE, CNE, 2013) and in effect, "the end result is that FIT prices will be decoupled from food and fuel prices, and annual adjustments will therefore be significantly less than investors had previously been promised" (T. Couture(IFOK GmbH), Dr. M. Bechberger(APPA), 2013).

As noted by Iberdrola, it is a problem that "reasonable" or "standard" remuneration for regulated activities are to be based upon government bonds and not the Weighted Average Cost of Capital (WACC), the typical benchmark used internationally in incentive based regulation. Iberdrola claimed that the new remuneration scheme will lead to "insufficient after-tax returns that are nearly 300 points below the cost of capital" for distribution and other regulated activities and, "as a result of the energy reform, will be channeling investment outside of Spain for the near future." (Iberdrola), 2013) (Iberdrola, Press Release, 2014).

Price Coupling of Regions

Apart from the regulatory changes generated within Spain, due to the greater European goal of developing an internal market, the electricity market is susceptible to changes from international influence as well. In February of 2014, in realization of the first phase of the Price Coupling of Regions (PCR) initiative which began in 2009, seven European power exchanges covering seventeen nations (listed in ***Annex I: List of Countries in PCR Initiative***) implemented a single market clearing algorithm for the day-ahead market (***Daily Market***).This agreement enacted changes in the scheduling of market activities, the market mechanisms in place previously, and will likely further affect capacity allocations, ***Intraday Markets***, and ***Ancillary Services Markets*** in subsequent phases (Noordpool, 2014) ; (OMIE, Price Coupling of Regions, 2014). As several nations in PCR have large shares of renewables, most notably Spain, Germany and the Nordic countries, future market structure will certainly impact how these technologies participate in the market, further contributing to the regulatory uncertainty.

Implications for Renewables

The recent legislation, both from within and outside of Spain, is of enormous impact due to the expansiveness of changes to market rules and scheduling, remuneration schemes for renewables, as well as the disbandment of the Special Regime nomenclature and the moratorium on new renewable energy projects. Furthermore, a wind-specific regulation is being proposed in Spain as of April 1, 2014 in which wind farms installed before 2005 would no longer be eligible for subsidies under the new system, breaking promises to investors to support wind installations over their 20 year economic life (Wind Power Monthly, 2014).

With renewable generation frequently accounting for over 50% of the Spanish energy mix on a monthly basis and with Wind overtaking Nuclear in 2013 for the number one source of energy for the entire year (an unprecedented achievement) it is clear that changes affecting renewables are no small matter (REE, 2013); (AEE, Nota de Prensa, 2014). Renewables are now forced to accept market prices without premiums, without clear reasoning as to what additional costs will be remunerated as being susceptible to Spanish law, and without indication of what “standard” installations entail.

The general uncertainty and regulatory risk has begun to enact behavioral change in wind generator participation in the market and is a driving force behind exploring alternate methods of cost recovery. One such method being the possibility of **permitting renewables in the ancillary services markets** for grid stability. This concept is not new and has been studied previously since any practical future which is dependent on renewables will necessitate them to provide such ancillary services. However, the current regulatory environment is providing a renewed vigor for such considerations.

Objectives of Thesis Research

Statement of Purpose

The aim of this thesis research is to conduct a quantitative assessment of the economic feasibility for permitting wind generation into the Secondary Reserves Market (SRM) in Spain. This analysis has been conducted using the most current market design and regulation to provide a relevant assessment of such measures if applied today (2014). This research has been undertaken from a single agent perspective, that is, from the point of view of a private wind producer, as much of the literature in this area has been focused at the system level.

Instead of asking if the Net Social Welfare will be positive, **this research asks if the investment cost necessary to participate in the Secondary Reserves Market will be outweighed by the revenues for individual wind producers**. Furthermore, this research aims to determine under what circumstances participation in the SRM will be profitable for wind producers, if at all, to contribute to a body of work which may be referenced to change the current law and to allow for more market liquidity within MIBEL.

Main Assumptions

The main assumptions taken while conducting this research are: the definition of generator band offer, the necessary investment costs, and the Estimated Capturable Income (ECI). A brief definition of these assumptions follows, as is further elaborated in the ***Methodology*** section of ***Chapter 4: Economic Analysis***.

- The Generator Band Offer
  - Defined as from the minimum technically feasible operation (25% of Installed Capacity) to maximum reliable operation (minimum point of real-time production over one hour, 87% of PDBF)
  - Only downward regulation band is offered

- The Investment Costs
  - Take into account Capital Expenditure (CAPEX) impact at all levels and are assumed from the conclusions of the TWENTIES Project research.
  - Defined as:
    - Socialized costs
    - Per MW costs
    - Per Cluster costs

- The Estimated Capturable Income
  - The difference between participating only in the Daily Market versus participating in Secondary Reserves taking into account:
    - Secondary Band Price (2BP)
    - Daily Market Price (DMP)
    - Capacity Factor(CF)
    - Realistic Band Offer (RBO)
    - Intraday Barter Cost (IBC)

Effective Hourly Benefit (EFHB)

  - Production Factor: amount of production offered as Band (B)
  - Production Factor: amount of production change managed in Intraday market (C)

- All revenues are calculated conservatively, thus no penalties for deviation are expected (with a 95% confidence resulting from the band definition).

Thesis Outline

This thesis progresses with ***Chapter 2: Literature Review*** where the technical feasibility of wind generation in Secondary Reserves is addressed as well as a review of previous research which forms the context for this work. Those readers familiar with concepts such as: Primary, Secondary, and Tertiary Reserves; Daily, Intraday, and Ancillary Services market mechanisms; Market Operator and System Operator; as well as Spanish electricity market operations, may skip ***Chapter 3: Spanish Electricity Market Overview*** without loss in clarity. Those readers looking for a quick explanation of the essential concepts can refer to the ***Introduction and Structure*** and ***Ancillary Services Market Summary*** sections of Chapter 3 before continuing onward while readers interested in a thorough description of the Spanish electricity market may continue chronologically. Finally, ***Chapter 4: Economic Analysis***, ***Chapter 5: Results*** and especially ***Chapter 6: Conclusions and Deliberation*** are beneficial for all readers.

Chapter 2: Literature Review

This chapter largely consists of an explanation of a multi-year research project under the 7th Framework Program of the European Commission known as the TWENTIES Project due to its acute relevance in this topic. Other research considered in the literature review consists of previous work conducted within The FENIX Project, at the Instituto Investigación Tecnología (IIT) at Comillas University in Spain, and various other journal publications.

The TWENTIES Project

Starting in April of 2010, several concurrent projects were undertaken across Europe with the intent to "demonstrate by early 2014 through real life, large scale demonstrations, the benefits and impacts of several critical technologies required to improve the pan-European transmission network, thus giving Europe a capability of responding to the increasing share of renewable in its energy mix by 2020 and beyond while keeping its present level of reliability performance" (TWENTIES, 2010).

As such, there was a specific focus on the controllability of wind power and its application to providing Secondary Reserves undertaken in DEMO 1. As DEMO 1 was largely conducted using the Spanish electricity system, its applicability to this thesis research is quite clear and thus has been utilized fully with the most relevant deliverables as follows:

- 9.1: Technical Feasibility
- 9.2: Investment Cost Estimation
- 15.1: Economic Impact
- 15.2: Proposed Regulatory Solutions

9.1: Technical Feasibility

This deliverable aimed to prove the ability of wind producers to effectively regulate their output in order to comply with the technical requirements of Secondary Regulation. This test formed the foundation on which the other deliverables were based and was conducted using three clusters consisting of fifteen wind farms in the southern region of Spain with the specifications seen in ***Table 2: Wind Farm Specifications*** below.

Table 2: Wind Farm Specifications

TWENTIES WIND FARMS			
Huéneja Cluster	Region	# Wind Turbines	Turbine Rated Power (MW)
WF 1: Dólar I	Granada	27	2
WF 2: Dólar II	Granada	25	2
WF 3: Huéneja III	Granada	25	2
WF 4: Ferreira II	Granada	25	2
WF 5: Tacica de Plata	Almería	13	2
WF 6: Nacimiento	Almería	12	2
	Total Turbines	127	
	Smallest WF Capacity	24	MW
	Largest WF Capacity	49.5	MW
	Total Cluster Capacity	254	MW
Tajo de la Encantada Cluster	Region	# Wind Turbines	Turbine Rated Power (MW)
WF 7: Altamira	Málaga	25	2
WF 8: Cerro de la Higuera	Málaga	22	2
WF 9: Cortijo Linera	Málaga	14	2
	Total Turbines	61	
	Smallest WF Capacity	28	MW
	Largest WF Capacity	50	MW
	Total Cluster Capacity	122	MW
Arcos de la Frontera Cluster	Region	# Wind Turbines	Turbine Rated Power (MW)
WF 10: Alburejos	Cádiz	5	2
WF 11: Chorreaderos Altos	Cádiz	11	2
WF 12: Chorreaderos Bajos	Cádiz	15	2
WF 13: Isletes	Cádiz	5	2
WF 14: Venzo	Cádiz	4	2
WF 15: Zorreras	Cádiz	16	2
	Total Turbines	56	
	Smallest WF Capacity	8	MW
	Largest WF Capacity	32	MW
	Total Cluster Capacity	112	MW
	Total Overall Capacity	**488**	**MW**

Although only half of the wind farms effectively took part in the test regulation due to low observed wind velocity in some clusters, the test proved that wind producers can indeed regulate their output in compliance to Secondary Reserves technical requirements (TWENTIES PROJECT 9.1, 2013). Furthermore it was determined that a **minimum Capacity Factor of at least 25% of Installed Capacity** was required to adequately control voltages and to minimize stoppages of wind turbines; the latter point being a key assumption in this thesis research.

9.2: Economic Analysis

This study was a quantitative assessment of the technical/economic impact in terms of CAPEX, OPEX, and Production Impact of the previous technical tests. Both secondary frequency control (Secondary Reserves) as well as voltage control (another ancillary service) were tested, however only the first test results have been used as assumptions for this thesis.

The analysis was partitioned into three levels of impact: wind turbine scope (WTG), wind farm scope (WF), and the cluster scope along with the relevant costs associated in Euros to each level which resulted in the following table (TWENTIES PROJECT 9.2, 2013).

Table 3: Investment Cost Assumptions

(Highlighted portion is the Secondary Reserves Test)

Source: (TWENTIES PROJECT 9.2, 2013)

		CAPEX			OPEX (€)	Production loss(MWh) Installation/Validation	Annual production loss(MWh/WTG) Continous Operation
		Development (€)	Equipment & Installation (€)	Total Capex(€)			
Scenario#1 independent services	Secondary Frequency Control	105900	1306890	1412790	0	149,96	1756
	WTG	24000	8100	32100	0		
	WF	11400	427090	438490	0		
	Cluster	70500	871700	942200	0		
Scenario#2 independent services	Voltage control	110300	1440435	1550735	15000	152,86	0
	WTG	22400	41280	63680	0		
	WF	17400	527455	544855	15000		
	Cluster	70500	871700	942200	0		
Scenario#3 simultaneous services	Simoultaneous Secondary f/V Control	216200	1448535	1664735	15000	219,55	1756
	WTG	46400	49380	95780	0		
	WF	28800	527455	556255	15000		
	Cluster	141000	871700	1012700	0		

Looking only at the secondary frequency control test, it was concluded that €32,100 was due to wind turbine costs, €438,490 due to wind farm costs, and €942,200 due to cluster costs. These costs for all levels consist of new telemetry/communication equipment and studies needed to optimize measurement and control algorithms, thus only CAPEX is affected. OPEX was deemed in all instances to be unaffected as the maintenance and operational schedules would not need to be changed. Additionally, there were estimates for the Production Impact (loss in production per year measured in MWh) due to installations of installed equipment, which can be expressed in terms of Euros as well when applying an average yearly market price.

These findings are key assumptions for this thesis research which assumes the costs incurred when implementing only Secondary Control. Another important point which is touched upon later in ***Chapter 6: Conclusions and Deliberation***, is that a significant portion of these costs are subject to reduction as they are due to studies which only need to be conducted once.

15.1: Economic Impact Assessment from System Perspective

Using the cost estimates from the previous test in ***9.2: Economic Analysis***, this deliverable aimed to explain from a system perspective the economic benefit derived from investing in wind power controllability and to what extent it would be economically efficient to scale-up this technology. A centrally-planned Reliability and Operation Model for Renewable Energy Sources (ROM) was used to assess system costs both with and without wind providing Secondary Regulation. The ROM consisted of a daily operation model that could simulate the optimal hourly scheduling of all generating units in the system and was employed in a limited experiment consisting of one nuclear plant, one hydro plant, and three other generation units (TWENTIES PROJECT 15.1, 2014).

The findings of this model suggested that "in particular, the provision of wind downwards reserve is expected to gain importance during off-peak hours, where hydro plants and thermal units are operated close to their minimum output values and therefore, have very low down reserve capabilities. The provision of wind downwards reserve is also expected to reduce wind spillage since it prevents the system from increasing hydrothermal generation and spill wind generation in order to meet system down reserve needs. However, the provision of wind upwards reserve may also entail a decrease of wind output and increase of thermal generation due to the scheduling of a new unit commitment that entails lower operating costs. Consequently, the provision of active power control by wind farms may lead to lower operating costs but also higher CO_2 emissions" (TWENTIES PROJECT 15.1, 2014).

This study also extrapolated its results for a year 2020 scenario:

> ***"The impact on CAPEX for making it possible to provide active-power control was assessed as 1,412,790 €, with no relevant impact on OPEX. Therefore, the unitary cost per MW of wind power installed would be 1,412,790 €/488MW = 2,943.31 €/MW. Assuming an Installed Capacity of wind generation of 34,820 MW in 2020, the scaling-up cost would be 102.5 M€, that assuming a 20 year life span and neglecting the discount rate, it could be annualized as 5.1 M€/year. As in the installed case the cost savings per year were estimated as 83 M€, this results in a positive cost-benefit analysis." (TWENTIES PROJECT 15.1, 2014)***

It was generally agreed that both the costs assumed in ***9.2: Economic Analysis*** as well as the scaling up costs used in this economic analysis were overestimated. "Moreover, in the previous analysis the up-scaling costs have been notably overestimated, given that the presented figures correspond to the cost incurred during the demo (***9.1: Technical Feasibility***), and it is likely that the effect of economies of scale would diminish such costs" (TWENTIES PROJECT 15.1, 2014).

In particular, the impact study had been carried out in three complementary scopes: Wind Generator (WTG) scope, Wind Farm (WF) scope, and Cluster scope in such a way that the total cost could be distributed as follows:

- Low impact (23% of total cost) at the WTG level (spending only on adaptation and control software update).
- Very low impact (11%) at the WF level (Parameterization of control and communications with the superior regulator).
- The greatest impact (66%) corresponds to the Cluster level (equipment and superior control software and weather forecasting system).

While this study is certainly relevant and useful for long-term decision making, it does not take current regulation into account. Instead this study assumes that the system will be optimally dispatched which, due to market imperfections, is not always the case. Market rules such as bid structure, scheduling, and preferences to certain technologies (e.g. renewables), can also greatly affect both the system dispatch and the corresponding hourly price, thus it is imperative for economic impact studies to reflect the market reality. Furthermore, due to the computationally intense nature of such an analysis, the economic impact was assessed in a limited manner, only using a system comprised of five generation units, which does not take into account the complexities and added costs due to transmission network characteristics.

15.2 Proposed Regulatory Solutions

This deliverable explained current regulation for Secondary Reserves in the Spanish system and made a number of recommendations on how to adapt market rules better to include wind production. It claimed that,

> ***"Under the current market rules, it would not be economical for wind generators to provide Secondary Reserves in Spain. Under the Spanish market design, the provision of upward regulation by wind generators would only take place in situations of high wind production, when the TSO has to curtail renewable production to guarantee the generation/demand balance or enough online reserves. The provision of downward reserves would also be limited to those hours inasmuch as, according to the current market design, generators must provide both upward and downward reserve within the same hour." (TWENTIES PROJECT 15.2, 2013)***

However this statement was made assuming the conclusions from ***15.1: Economic Impact Assessment from System Perspective*** which as previously mentioned, do not take several market realities into account. The largest barriers for wind production entry to the Secondary Reserves Market were determined to be:

1. The current ban in place for intermittent generation (e.g. wind and solar).

2. The requirement of providing both upwards and downwards reserves in the same hour, thus constituting a primary energy loss (spilling of wind energy) to wind generators due to providing upwards reserves.

3. Aggregation of units for service provision only being permitted for units within the same regulation area, which does not allow for clustering of wind generation units according to ownership and technical operation.

4. An early gate closure time for the Secondary Reserves Market, which does not lend itself well to participation of wind generation due to forecast errors which significantly rise after fifteen minutes.

Since changing market designs can be a very complex task, some essential recommendations that would not require significant changes in the current market design were proposed:

1. Wind generators, at least, should be allowed to participate in reserve markets.

2. Service provision capability should be tested at an aggregated level, meaning that units that could not provide service individually should be allowed to participate if aggregated with other units in portfolio bids[1], regardless of their regulation areas. If regulation areas are to be maintained, an area composed of as many wind generators as possible should be created.

3. Upward and Downward reserves should be procured separately as independent products, better allowing for wind to participate in the downward reserves provision (TWENTIES PROJECT 15.2, 2013).

All suggestions made above were assumed in the thesis research, with the most pertinent conclusion being that wind producers would only provide downward reserves, thus eliminating the production loss variable for analysis.

[1] This idea of ancillary services as a portfolio is reinstated with the Virtual Power Plant (VPP) concept developed by the FENIX project as well, which calls for a portfolio of distributed (renewable) generation to be treated similarly as a conventional power plant.

The FENIX Project

The FENIX Project was another multi-year research project conducted before ***The TWENTIES Project*** under the 6th Framework Program of the European Commission which focused research on new methods of integrating Distributed Energy Resources (DER). This research defined DER as any generation method which was not centrally planned, not centrally dispatched, usually connected to the distribution network, and was smaller than 50-100 MW. With this definition, the FENIX Project investigated methods of deploying Wind, Photovoltaic, Hydro, and Combined Cooling, Heating and Power (CCHP) generation as well as developing new concepts of how DER could participate in the future electricity grid.

Virtual Power Plant

One key concept was the idea of the Virtual Power Plant (VPP) which aggregates the capacity of many diverse Distributed Energy Resources to create a single operating profile. A graphical description of a VPP can be seen below in ***Figure 2***.

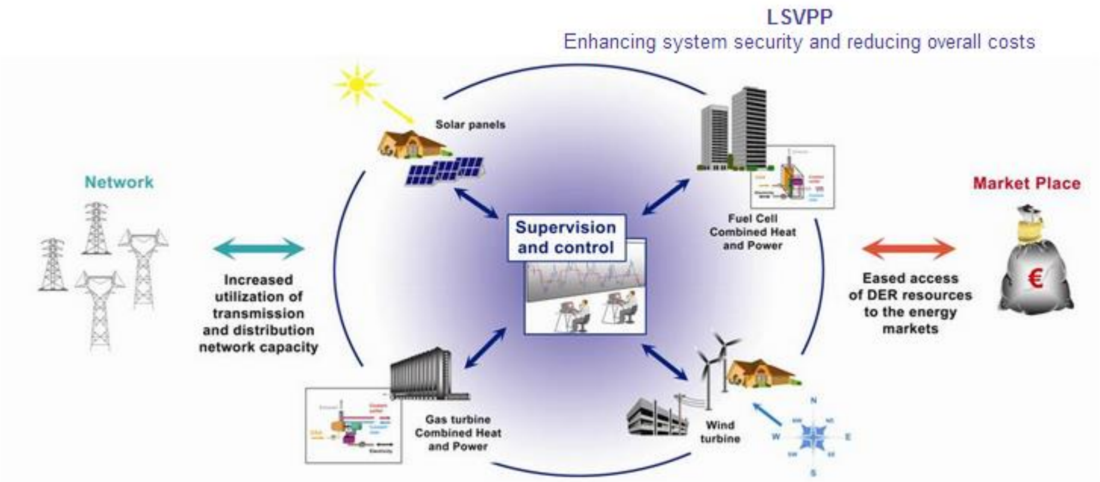


Figure 2: Virtual Power Plant Description

Source: (FENIX Project)

> ***"A VPP is a flexible representation of a portfolio of DER that can be used to make contracts in the wholesale market and to offer services to the system operator"…. "In principle, a VPP consisting of a portfolio of aggregated distributed energy resources can be remotely monitored and operationally controlled just like a conventional large-scale power plant, owing to the application of advanced information and communication technology." (FENIX Project); (Adriaan van der Welle, Carlos Madina, Cristos Kolokathis, Angel Diaz, Jaap Jansen, 2009)***

The FENIX Project went further to refine the virtual power plant concept into proposed methods of operation, technical protocol, and communication methods to enable the creation of LSVPPs (Large Scale Virtual Power Plants). Validation was conducted through two large field deployments, one focused on domestic CHP (Combined Heat and Power) aggregation, and the second aggregating large DER in LSVPPs (wind farms, industrial cogeneration); with intentions to better integrate DER in electricity markets (FENIX Project). The findings of the final report suggested that adopting FENIX measures would result in a more efficient deployment of DER, with the greatest benefit manifested in gas savings from more efficient CHP and CCHP operation.

> ***"Overall, more efficient CHP units tend to replace less efficient production technologies and vice versa for instance during periods when heat demand is lacking. This tends to result both in lower gas consumption and lower CO2 emissions. Besides, the entry of flexibly operated CHP units in several markets contributes to competitive markets." (Adriaan van der Welle, Carlos Madina, Cristos Kolokathis, Angel Diaz, Jaap Jansen, 2009)***

Technological Control Capabilities of DER to Provide Future Ancillary Services

As another branch of the FENIX Project, this research investigated the possibility of DER specifically in the context of providing Ancillary Services. It was reasoned that the grid coupling technology of a distributed resource, as it is the final point of control in an electrical energy conversion chain, would best indicate what possible ancillary services such a DER theoretically could provide. The coupling technologies considered included:

- Directly-coupled induction generators (IGs)
- Directly-coupled synchronous generators (SGs)
- Double-fed induction generators (DFIGs) and
- Inverters

And were examined for the ancillary services of: Reactive Power Control, Direct Voltage Control, Voltage Quality, and Fault-Ride-Through capabilities. A qualitative assessment of such control capabilities concluded that frequency control (Secondary Reserves) could be provided by all DER as all four types of grid coupling technologies considered were well suited to active power control (Braun, 2007).

IIT Research

Economic Assessment of the Participation of Wind Generation in the Secondary Regulation Market

Summary

The aim of this paper was to analyze the profitability of wind technology as a potential participant in the Secondary Reserves Market in Spain. This paper along with other work within the IIT of Comillas University are particularly relevant such that this thesis research may be viewed as a continuation of those works, yet from a different set of premises and in a new regulatory environment.

Using market data from the years 2004-2008, this study conducted a profitability analysis based on agent behavioral modeling, which comprised of three main steps:

1. A computation of perfect information bounds
2. A definition of a bidding strategy
3. The validation of an offering strategy

It assumed that wind producers would offer all forecasted wind production in the Daily Market (DM) and, if participation in the Secondary Reserves Market (SRM) was determined profitable, adapt production schedules in the first Intraday market session. Profitability was determined from an additional income equation which represented the revenues an agent was likely to receive over the DM incomes by participating in the SRM. The equation can be seen below:

$$\Delta Incomes = +B_{Total}P_{Band} - B_{Up}P_{Wind} - B_{Up}(P_{IDM} - P_{DM})$$
$$+B_{Up}U_{Up}P_{Up} - B_{Down}U_{Down}P_{Down}$$

Equation 1

Where:

- $B_{Total}P_{Band}$: The income from the band capacity offered in Secondary Regulation, it was assumed that only 10% of the total wind forecast could be used in the band offer, a number which was taken from a review of existing literature.

- $B_{Up}P_{Wind}$: The loss in production due to adjusting production schedules to offer Secondary Regulation Band

- $B_{Up}(P_{IDM} - P_{DM})$: The extra cost due to adjustment in the first Intraday market session.

- $B_{Up}U_{Up}P_{Up} - B_{Down}U_{Down}P_{Down}$: Income from the net energy usage of Secondary Reserves.

The sum of the first three terms were collectively known as the "band component" while the last term was the "energy component". A wind generator was modeled as a rational actor such that it would only participate if there was a possibility to achieve a greater income from the Secondary Reserves Market over the Daily Market. The decision to participate in the SRM was hinged on whether the band component was positive since at the time a decision must be made the energy component is unknown. Furthermore, statistical distributions of the relation between the Intraday price and the Daily Market price, as well as the relation between the Daily Market price to both the upwards and downwards energy price, were used in the analysis in lieu of market data.

This study compared the estimated incomes in both the regulatory environment under the RD 661 premium scheme and (with much foresight) a scenario without a premium in which only market revenues could be received. Interestingly enough, it found that wind producers would derive the most benefit from participation in the SRM when no premiums to wind production were granted; the reason being that as wind premiums were generous for produced energy, it would be difficult to gain more in the SRM by reducing output.

> ***"However, if wind power producers were remunerated in the same way as any other conventional technology (no premiums), the revenues coming from participating in the Secondary Regulation Market could represent a substantial percentage of their income " (Elena Sáiz Marín, Javier García-González, Julian Barquin, Enrique Lobato, 2012)***

It was concluded that between €1,000-€100,000 per unitary megawatt of production offered as Secondary Regulation band in yearly earnings could be realized using the economic model based on market years 2004-2008. This unitary estimation was translated into more practical terms by using wind production data from twenty-nine wind farms to better represent what a wind portfolio of 730MW could expect to earn. The estimated yearly earnings were calculated to be between €2,000 – €2,000,000 per MW of Secondary Band offered. The study went on to calculate what percentage the additional incomes from Secondary Reserves constituted when compared to all other market incomes and concluded that:

> ***"Although the percentages are quite small, they represent substantial value in financial terms, and therefore, the investment cost required to adapt the wind farms to provide AGC regulation could be economically justifiable." (Elena Sáiz Marín, Javier García-González, Julian Barquin, Enrique Lobato, 2012)***

Evaluation

This study was methodical, well-communicated, and still maintains relevance as a resource in the new regulatory scheme in Spain due to its foresights, however there are a few limitations which this thesis research aims to address.

First:

- The Estimated Capturable Income (ECI) equation contains some superfluities. Namely that the loss in wind production should not be considered as a penalty if indeed this energy can be sold for a higher price in the Secondary Reserves Market (which is an initial requirement for participation). Furthermore, the energy component induces a relatively large uncertainty into the analysis without constituting a significantly high monetary value to the final revenue calculation. This thesis simplifies the ECI by omitting both the production penalty and the energy components due to these observations which also have been confirmed by expert advice.

Second:

- The IIT work, instead of relying on the hourly Capacity Factor, instead compared the forecasted wind production to the actual wind production for market income calculations. The hourly Capacity Factor is a more concise metric however as it takes into account both the Installed Capacity and the actual wind production and is denoted as a percentage. The Capacity Factor metric allows for a succinct representation of economic benefit in terms of unitary megawatt of Installed Capacity, the widely accepted benchmark for cost-benefit analyses in the energy sector.

Third:

- There is no determination of a reliable band offer, instead a constant 10% of the forecasted wind production (which is always less than the Installed Capacity) was used when this number was above the 5 MW floor. Due to studies conducted throughout this thesis research however, it is known that a band offer of above 35% of the *Installed Capacity* is feasible at high Capacity Factors. It was noted in the IIT study however that the 10% metric was taken from a review of literature and was admittedly conservative. This thesis aims to better quantify the band offer strategy keeping in mind both system reliability (not allowing for deviations with 95% confidence), while stressing the dynamic relationship of a reliable band offer to the hourly Capacity Factor.

Fourth:

- The Intraday costs were calculated by only considering the first session price which may not be the best strategy. While the claim of greater market liquidity is true, from analysis conducted during this thesis, Intraday prices are generally not equal to Daily Market prices in the first session which can result in large losses. Furthermore, the Intraday prices in the IIT research were estimated based on statistical methods while this thesis research uses actual market data for all Intraday market sessions.

Fifth:

- The IIT study assumed that a wind producer will sell all forecasted generation in the Daily Market and then attempt to adjust the schedule in the first Intraday session in order to participate in Secondary Regulation. A different strategy of withholding generation from the DM to sell in the SRM, thus eliminating the Intraday Barter Cost, is proposed and examined additionally in this thesis.

Chapter Summary

The TWENTIES Project, FENIX Project, as well as the IIT and other research all demonstrate that not only are wind power producers able to participate in ancillary services based on technical criteria, but that it may also be economically efficient to allow them to do so. The large majority of these studies however tend to focus on the economic benefits derived from a system perspective, essentially ignoring market realities and assuming that investment costs would be substantial enough to necessitate governmental/centralized planning for the realization of such benefits.

Yet, according to the TWENTIES Project research, investment costs may be both significantly less than anticipated and more importantly, depreciable, therefore well within the realm of the private sector. Furthermore, to adequately assess the economic efficiency of such service provision for a private actor, it is necessary to conduct analysis within the market framework in which they operate as market realities are non-negligible. Therefore this thesis will continue with an overview of the Spanish Electricity Market to inform the reader of the rules and procedures in which the analysis has been conducted and to provide the context for further deliberation.

Chapter 3: Spanish Electricity Market Overview

This chapter begins with a ***Brief Historical Background*** of the electricity market in Spain, followed by an ***Introduction and Structure*** where the fundamental structure and key terms will be introduced. Finally, a description of the ***Market Operation*** will be given to explain timetables and better inform when market decisions must be made.

Brief Historical Background

The Spanish market for electric power was initiated following the European Union Council Directive 90/547/EEC on the "Transit of Electricity through Transmission Grids" in October of 1990 during the wave of liberalization seen throughout the 90´s across Europe, the Americas, and Asia. This directive introduced provisions for power transmission through the high voltage network between member states and envisaged the creation of individual electricity markets with an eventual aim of a unified European energy market to better manage resources and planning. The 1996 EU Directive furthered this goal by setting out common rules by which individual markets should be conducted to facilitate a single internal energy market for the EU (Council Directive 90/547/EEC, 1990) (Directive 96/92/EC, 1996) (D.Arlt & R.Zeise, Accessed March 2014).

In the same year, the forenamed Spanish Ministry of Industry and Energy (*Ministerio de Industria y Energía)* along with the incumbent electricity companies, together established new protocols for the operation of the electricity grid to allow for competition in the new liberalized framework. Although it was not until 1997, with the approval of Law 54/1997, that the electricity sector was transformed from a centrally planned environment supported by vertically integrated electric utilities, into a market context supported by competitive Generation and regulated natural monopolies in the Transmission and Distribution sectors; however, this liberalization was not fully realized until January 2003 (Directorate General de Política Energética y Minas, 2014).

Meanwhile, as early as November 2001, bilateral discussions were underway to harmonize the Portuguese and Spanish electrical systems to create a regional market for the Iberian Peninsula which would later come to be named MIBEL (Mercado Ibérico de la Electricidad). Following several years of market design revisions, legal and political setbacks, uncertainties in the MIBEL regulatory framework, as well as financial restructuring and creation of new business entities, an international treaty was signed in Santiago de Compostela on October 1st 2004, officially creating the MIBEL spot market. A later updated treaty was signed in Braga and published in Portugal on March 23rd 2009 and in Spain on December 11th 2009 (OMIP, 2014).

MIBEL currently consists of two main entities: OMIE (Operador Mercado Iberico España), the operator of the Daily spot and Intraday markets, and OMIP (Operador Mercado Iberico Portugal) which operates the Futures/Derivatives market. As taken from the OMIP website, "with the materialization of MIBEL, it becomes possible for any consumer in the Iberian zone to acquire electrical energy under a free competition regime, from any producer or retailer that acts in Portugal or Spain."

MIBEL's main goals are:

- To benefit the electricity consumers of both countries, through the integration of the respective electric systems;
- To structure the market organization based on the principles of transparency, free competition, objectivity, liquidity, self-financing and self-organization;
- To support the development of the electricity market of both countries, with the existence of a single reference price for the whole of the Iberian Peninsula.
- To allow all the participants free access to the market, under equal conditions of rights and obligations, transparency and objectivity;
- To promote economic efficiency of electrical sector companies, encouraging free competition amongst them (OMIP, 2014).

Introduction and Structure

The Spanish power market consists of four elements: a ***Daily Market***, an ***Intraday Market***, a ***Services Adjustment Market*** which includes the ***Ancillary Services Market***, and a Futures/Derivatives market. Bilateral contracts are also allowed and are incorporated into these markets, which are known collectively as the Production Market. The Production Market for Spain is operated by two main entities, the Market Operator (MO), OMIE and the System Operator (SO), Red Eléctrica de España (REE). OMIE is responsible for the financial and economic management of the Daily and Intraday markets while REE is responsible for the technical operation of the transmission grid (OMEL, 2012).

However, as the focus of this research is related to Ancillary Services, the Futures/Derivatives market will be omitted and the remaining markets will only be covered briefly so as to explain their relation to the Ancillary Services Market, which is covered in greater detail.

Daily Market

Next-day sale and electricity purchase transactions are carried out on the Daily Market (*Mercado Diario*). The DM incorporates both bilateral contracts as well as simple generation bids with optional complex conditions. Complex conditions are usually related to technical limits generators face such as the ramp rates, startup times at varying temperatures, the need to produce for a minimum number of hours to remain economically viable, and the minimum thermal limit. For a more in-depth description of these complex conditions, refer to (Daily Market Description OMIE, 2014).

Market bids and bilateral contracts with physical delivery are matched with hourly demand using a simple matching algorithm and the single marginal reference price for Spain is found for each hour of the following day by matching demand and supply bids. Sessions on the Daily Market are structured in scheduling periods equivalent to a calendar hour, with a scheduling horizon divided into 24 consecutive schedule periods of Spanish official time (23 or 25 on days of light-saving clock changes) (OMEL, 2012).

Spain, as part of the MIBEL wholesale market, operates a physical power exchange meaning that all generation facilities must participate in the Daily Market in some form up to the limit of their capacity of production. This participation is marked either through declarations of unavailability (which are subject to regulation), bid offers on the Daily Market, or through bilateral contracts with physical delivery. A physical market requires that all information of available supply resources and actual demand is available on the Daily Market which results in a reference price for all contracting mechanisms (González, 2014). Physical delivery of energy negotiated on the futures organized markets can also take place on the Daily Market (OMEL, 2012). The Daily Market functioning will be further explained in the ***Market Operation*** section.

Intraday Market

The purpose of the Intraday Market (*Mercado Intradiario*) is to allow for modification to the schedule previously matched in the DM or declared in a bilateral contract. It is an auction based adjustment market with non-mandatory participation which results in the final hourly schedule given to the SO for final technical limits adjustment. Essentially, it is the last chance for market agents to modify unwanted situations arising from the adapted daily schedule (taking into account grid constraints) or due to unexpected unavailability. It allows the agents to rely on more precise predictions closer to operation time to buy or sell electricity accordingly to cover their production or consumption obligations (Cuéllar, 2014) (P. Bennerstedt & J. Grelsson, 2012).

There are six sessions (where Session 7 = Hours 21-24 of Session 1 of the day before) in which purchase and sale bids are accepted in firm time periods leading up to the daily operation. Only market agents who have participated in the immediately preceding Daily Market matching may submit bids for the Intraday Market. Each generator or supply agent is allowed one valid purchase or sale bid per session and must also provide reasoning for deviating from the matched schedule in the DM. Bids may be simple or contain complex conditions although there is no fixed requirement for the presentation of a bid. Purchase and sale bids are matched using a simple matching algorithm and the final results are published in regular intervals as will be further elaborated in the ***Market Operation*** section.

Services Adjustment Market

The Services Adjustment Market (*Mercado de Ajustes*) includes all those services of an optional participatory nature which the Market Operator deems necessary to ensure the system's operation, including Technical Resolution, Voltage Control, and Ancillary Services (which includes frequency control) (Casado, 2014) (OMEL, 2012).

Technical Resolution refers to the adjustments of system-wide generation scheduling or even re-dispatch of generation to meet technical criteria of feasibility and security. This service is manifested in modifications to scheduled generation programs (modification or complete re-dispatch) and/or the application of limits to previously scheduled programs. This service can be provided by production units, pumping units, or through use of the interconnections with neighboring countries by either importing or exporting electric power (Casado, 2014).

Voltage Control refers to actions taken to ensure the proper profile of voltage throughout the transport grid, according to predefined criteria, to guarantee the security and quality of supply.

Among the relevant factors are the maintenance of voltage amplitude and waveform, control of voltage dips and other deviations, and minimization of losses of active power (Casado, 2014) (OMEL, 2012).

The time periods in which system balancing services are applied are: the day-ahead horizon (resolution of technical restrictions in daily production schedules, daily voltage control set points, and allocation of Secondary Regulation band) and the time horizon after Intraday sessions (regulation and balancing services, resolution of restrictions and voltage control in real time, and restoration of service) (MIBEL Regulatory Council, 2009).

Ancillary Services Market

Ancillary Services consist of four products: ***Deviation Management***, ***Primary Reserves***, ***Secondary Reserves*** and ***Tertiary Reserves*** which together are used to manage real-time variation in demand/generation from system-wide scheduled production (OMEL, 2012). Utilization of ancillary services and operation of their markets or other mechanisms of acquisition are conducted exclusively by the System Operator as they relate to technical operation of the grid. First, Deviation Reserves and Primary Reserves will be introduced briefly while Secondary and Tertiary Reserves will be given a more in-depth description due to their central importance in this thesis research.

Deviation Management

Deviation Management helps to balance large differences (> 300 MWh) between scheduled generation and forecasted demand and is provided by generation and pumped storage power units. Possible causes for these deviations include generator unit unavailability or justified changes to schedules communicated from generators. Deviation management provides the SO with a flexible mechanism to solve the imbalances between generation and demand without compromising or risking the availability of Secondary and Tertiary Reserves (NREL, 2010).

Primary Reserves

Primary Reserves are an obligatory service which is non-remunerated and requires that generators allow for a real time variation at any given moment of 1.5% of their installed rated power (OMEL, 2012). The objective of Primary Reserves is to automatically correct instantaneous imbalances between production and consumption and the response times are as follows:

- Deviations below 100 mHz must be corrected within 15 seconds,
- Deviations above 100 mHz up to 200 mHz will have a response which varies linearly between 15-30 seconds (BOE 173, P.O. 1.5, 2006)

Primary Reserves are provided by automatically varying the generator output power by means of the speed regulators in turbines to respond to variations in system frequency. Each year the

System Operator will determine the requirements for primary regulation (BOE 190, PO 3.1, 2013).

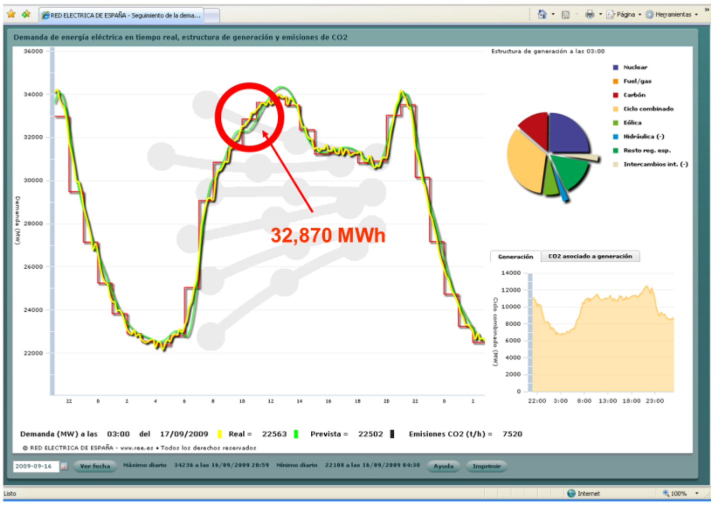
Secondary Reserves

Definition and Objective

The purposes of Secondary Reserves (SR, also known as Secondary Regulation) are to nullify deviations in each instant in the international interchanges and to maintain system frequency within prescribed limits. Secondary Reserves are essentially the **capacity to either increase or decrease production in a generating unit according to Automatic Generation Control (AGC) signals** and are provided and remunerated according to a market mechanism. Secondary Reserves are organized into control zones consisting of groups of AGC enabled generating units and their dispatch are controlled by the Shared Peninsular Regulation (RCP), the Control Center (CECOEL), and the Backup Control Center (CECORE) when necessary (OMEL, 2012).

The secondary reserve of an individual unit is **the maximum value of variation of power within which it is possible to modify generation according to the prescribed response signal** indicated by the technical requirements of the SO. Secondary Reserves thus are offered as a **band of potential variation** and are remunerated based upon these bands. The reserve band is distinguished between reserves to increase and reserves to decrease, each provider participating in SR currently (as of September 2014) must offer both products, and there is a fixed relationship (ratio of upwards to downwards reserves) established by the SO every hour.

Furthermore, Secondary Reserves are remunerated based upon their **Net Effective Energy (NEE)** as well**,** which is the amount of energy realized in providing SR above the amount which the SO previously requested in an operating period or, in other words, **the deviation in energy in an operating period from previous operating schedules of the involved units of production** within a control zone (OMEL, 2012). The SR bands and NEE are best explained with the following graphical example.



Source REE

Figure 3: Real-time Daily Demand Curve Example

Source: (Red Electrica España (REE))

Figure 3 shows the real-time demand curve (yellow) along with the predicted demand (green) and the scheduled level of generation in hourly blocks (red) for September 17th, 2009. The intention of a scheduled level is to accurately represent the average energy within an hourly block so that Secondary and Tertiary Reserves are utilized most economically. Visually, this means that the ideal red scheduling blocks are those which separate real-time demand so that the area above and below is equal when comparing the difference of real-time demand to scheduled generation. To further illustrate, a point is taken where the total scheduled level of generation was 32,870 MWh. When looking closer in ***Figure 4***, it can be seen that the scheduled level was fairly accurate despite the clear error in predicted demand as seen in the discrepancy between the yellow real-time demand curve and the green predicted demand curve.

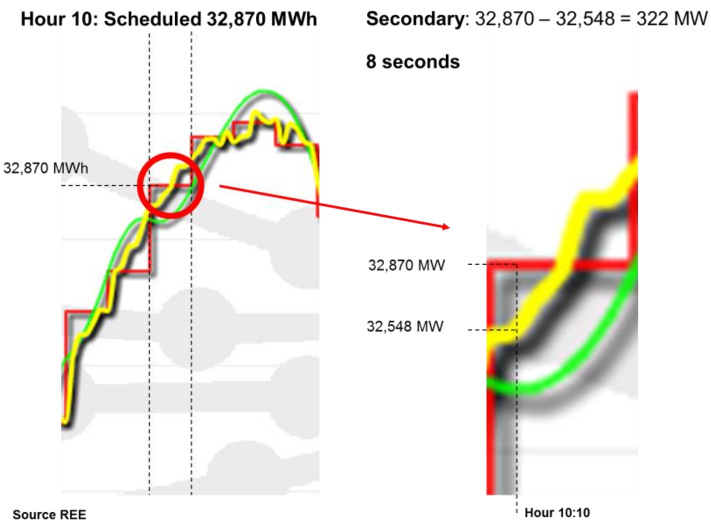


Figure 4: Close up of Real-time System Demand

Source: (Red Electrica España (REE))

In this hourly block, the real-time demand (32,548 MW) began below the scheduled generation (32,870 MW) at the beginning of the hour and terminated above the scheduled generation at the end of the hour. This discrepancy in real-time is corrected for using Secondary and Tertiary Reserves and shows the reality of grid operating conditions. ***Figure 5*** below is the same hourly block along with the Secondary Reserve band as required by the SO.

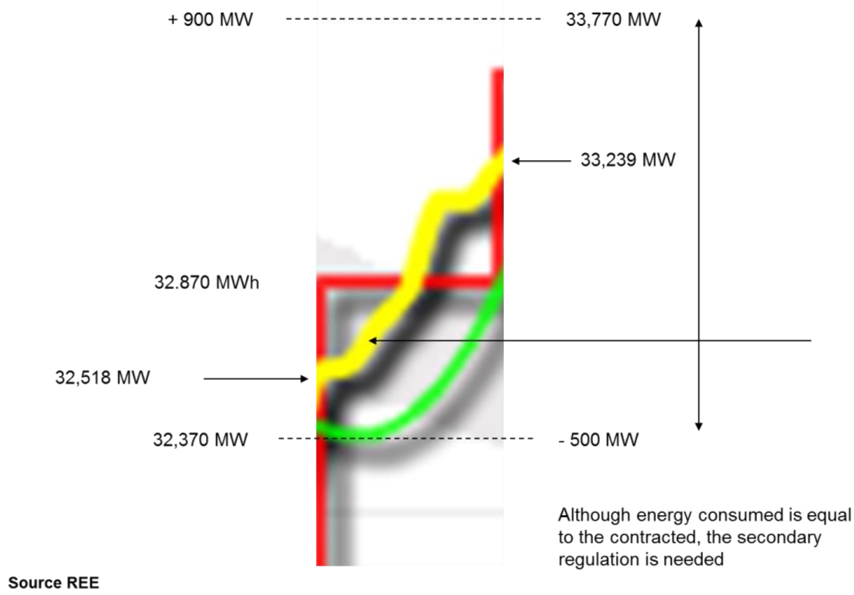


Figure 5: Secondary Reserve Margin

Source: (Red Electrica España (REE))

It can be seen that the Secondary Reserve requirement was 352 MW to decrease in the beginning of the hour and 369 MW to increase by the end of the hour. In this hourly period the reserve band (the amount of generation required to be made available to the SO) to increase was 900 MW while the reserves band to decrease was 500 MW. Thus in this case, the SO will remunerate all control zones which participate in providing the total reserve band according to their contribution to the overall Secondary Reserves requirement. Since the amount of production upwards and downwards was the same (for this example it will be taken to be so), the NEE of this hourly period was zero as no extra energy was necessary above the scheduled amount; thus generators providing SR will only be remunerated for their bands.

Now if another point is taken in which the hourly demand increases much faster than the scheduled demand as seen in ***Figure 6*** below, the upward and downward movements of power over the course of the hour are not equal. Thus the SO will require more SR than contracted and the Net Effective Energy as well as the regulation bands will be remunerated.

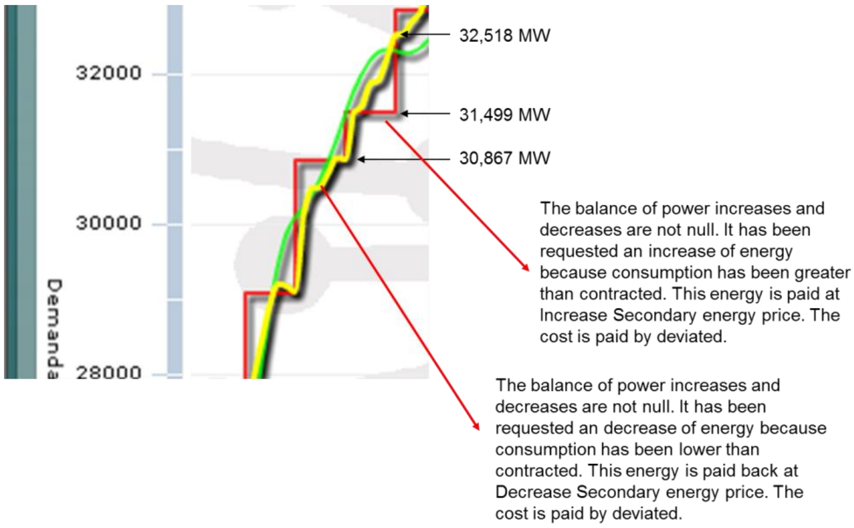


Figure 6: Net Effective Energy Example

Source: (Red Electrica España (REE))

Note that the upward reserves are always greater than downward reserves to take into account the possibility of generation unit failure and this ratio of upward/downward reserves is kept constant to serve as the general requirement that each control zone must provide in SR across each program hour. The secondary reserve margin is determined by the SO for every operation period and reserves are dispatched according to real-time demand. Regarding Secondary Regulation, the ENTSO-E system proposes the following minimum up-reserve level (BOE 173, P.O. 1.5 Annexo, 2006):

$$USR = \sqrt{(a \cdot L_{max} + b^2)} - b$$

Equation 2

Where USR is the level of secondary up reserve demanded by the ENSTO-E system, L_{max} is the forecasted demand for a certain period and a and b have been empirically determined as 10 MW and 150 MW, respectively. On the other hand, the ENTSO-E system establishes that down reserve level represents between 40% and 100% of the up reserve one. Additionally, ENTSO-E imposes 500 MW and 400 MW as the minimum values for up and down reserve levels respectively (TWENTIES PROJECT 15.1, 2014); (BOE 173, P.O. 1.5 Annexo, 2006).

Thus it is clear that generating units must have strict technical requirements to be allowed to provide Secondary Reserves.

Technical Requirements

Providers of Service

The providers of Secondary Regulation services are the owners of production units within a control regulation zone. These control zones may only incorporate production units which are manageable (equipped for AGC and with proper response characteristics). The enable condition of a control zone is rendered void in the event that none of the production units in the area have recognized technical capacity for active provision of Secondary Regulation (BOE 129, PO 7.2, 2009).

To provide SR a generating unit must comply with the following requirements:

- Must provide all available technical information about their system of frequency/voltage regulation: Control loops, AGC connection, turbines, protection systems, etc.
- Must belong to a single area of control
- Must verify and test communication between the production unit, the AGC of the regulation zone, as well as the principal and backup systems of the RCP
- Must comply with the technical requirements for providing service
- Must comply with the technical requirements for real-time response

According to the PO,

> ***The information provided should be detailed enough to reproduce by simulation, with reasonable accuracy, the actual operation using a system model of regulation capabilities. (BOE 129, PO 7.2, 2009)*** [Translated]

Furthermore the definition of what constitutes as a "manageable" power plant is subject to interpretation. With the new law (Real Decreto 413/2014, 2014) the (newly named) Ministry of Industry, Energy, and Tourism will be providing the overarching requirements to be considered "manageable" although the more technical requirements will be provided by the SO. In the previous legislation set out by the RD 661, as explained in ***The Special Regime*** section of Chapter 1, technologies within the Special Regime were permitted however renewables were strictly banned.

> ***In the case of facilities belonging to the Special Regime which are manageable, they must present the corresponding resolution from the Directorate General of Energy Policy and Mines authorizing the participation of said units in ancillary services. (BOE 129, PO 7.2, 2009)*** [Translated]

Response Requirements

To provide Secondary Reserves a generating unit must be able to respond to AGC signals within **100 seconds with a linear, fixed time constant** and remain within a 10% margin of error of their trajectory. AGC signals are sent out **every 8 seconds**, thus providers of SR must continually update their production according to the new requirements of the system (BOE 129, PO 7.2, 2009). ***Figure 7: Secondary Reserves Response Example*** below demonstrates how a generating unit providing Secondary Reserves must respond to AGC signals.

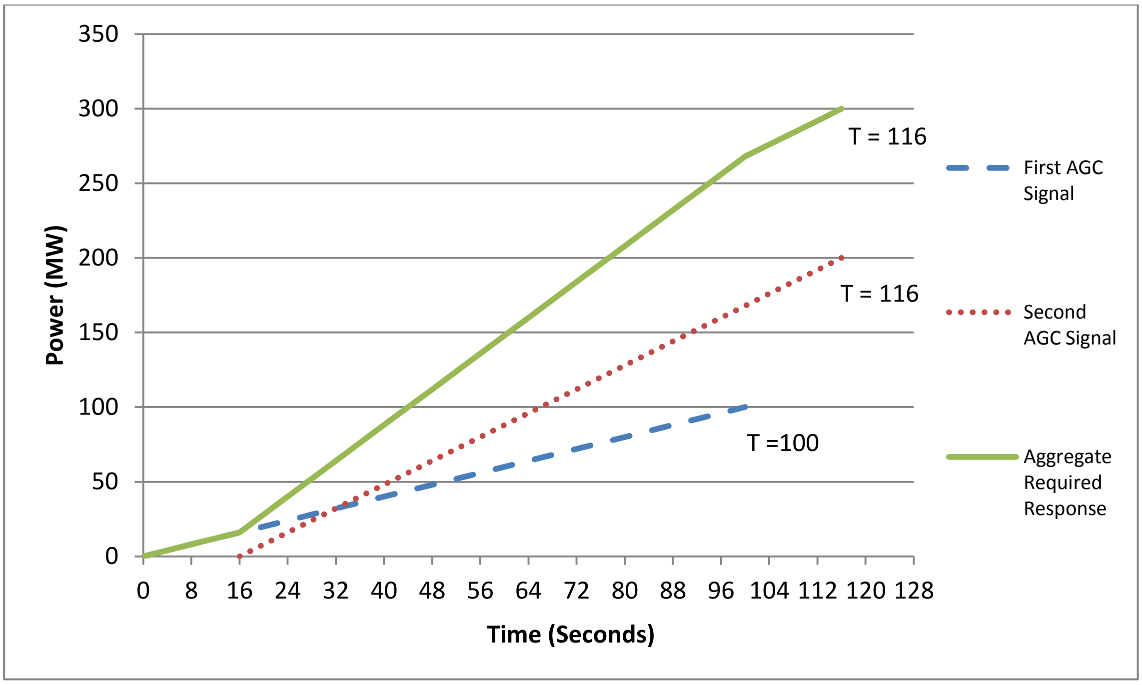


Figure 7: Secondary Reserves Response Example

At T=0 seconds an AGC signal is sent which requires the plant to increase production to 100 MW which must be met according to a linear response, thus at time T=100 seconds; this is seen in the blue (dashed) line. Then at time T=16 seconds another signal is sent which requires production to increase to 200 MW which must be met within 100 seconds as well, thus at time T=116 seconds; this is seen in the red (dotted) line. As both requirements must be met within their required time limits, the overall response of the generator will be the aggregate response of all AGC signals over time, thus met by T = 116 seconds for this example as can be seen in the green (solid) line. This situation remains the same for signals to increase as well as to decrease.

Operation Modes

There are two modes that a control zone can operate in, either **integral or proportional**. The proportional operation mode entails that the control zone will respond to all AGC signals exactly at the numerical values given, regardless of the overall system discrepancy. Integral mode entails that the control zone will only respond to AGC signals which further contribute to the system discrepancy and will ignore all signals which are in opposition to system discrepancy.

For example, if there is a discrepancy in the interconnection with France which results in a positive 100 MW unbalanced system load in the first 8 seconds, and this discrepancy is exacerbated to 150 MW in the next 8 seconds, two corresponding AGC signals will be sent out to the control zones to collectively decrease 100 MW and then to decrease an additional 50 MW; these signals will be followed by both types of control zones. If in the next 8 seconds a negative discrepancy with France for 20 MW is detected, the AGC will send out a signal to increase 20 MW system-wide. In this instance, the integral control zones will ignore the AGC as the negative mismatch is compensating for the earlier positive mismatch; however proportional control zones will respond accordingly. Both operation modes are essential and serve to dampen SR responses and provide regulation which is not constantly fluctuating. In the Spanish electrical system a mix of both modes is used. All control zones operate in proportional mode when the system deviation is greater than 100 MW and are operated in integral mode when the deviation is at or below 100 MW.

Market Mechanism

Bid Structure

As mentioned previously, SR is procured by the Spanish SO using a bid-based market mechanism. Secondary Regulation is offered in **each regulation zone** in the form of power bands, which indicate the amount of variance in production possible for a given control zone in MW, along with the corresponding price in €/MWh, for each operation period in the following day. This means that while the control zone as a whole must offer the required upward/downward reserves ratio required by the SO, individual plants within a control zone may only be offering one product (only upwards or only downwards reserves), or both but in a different proportion than the overall system ratio. Furthermore, a bid must contain the following:

- Offer Number
- Offer to increase (MW)
- Offer to decrease (MW)
- Bid price of the regulation band (€/MW), subject to maximum prices set by the National Regulatory Commission (In Spanish, *CNE*)
- Variation of energy necessary in respect to the daily variable provisional program (***Provisional Viable Daily Market Schedule (PDVP):***)
- Code of indivisibility of the bid (which type of indivisibility the offer is requesting)
- The sum of the amount to decrease and increase must be less than the amount of reserves required systemically (BOE 129, PO 7.2, 2009).

In previous legislation, renewables were banned from participating in the Secondary Reserves Market although other Special Regime technologies were allowed with the following stipulation.

> ***In the case of production units considered within the Special Regime, in each of the hourly periods in which the production unit has presented a bid, the sum of all blocks, to increase or decrease production, must be equal or greater than 5 MW. (BOE 129, PO 7.2, 2009)*** [Translated]

Note that there is only one price component for both upward and downward reserves, thus they are treated as the same product which has clear market implications and creates barriers to renewables which have an opportunity cost associated with spilling production. Thermal or (non-Run of River) hydro generation on the other hand, can forego production and save production capacity for later, thus the provision of upwards reserves is less costly. Furthermore, as reserves to increase will always be more in demand by the SO due to security reasons, microeconomic theory would imply that a price difference should be present between the two products. Indeed, this point is reiterated by findings of the TWENTIES Project in ***15.2 Proposed Regulatory Solutions*** in the previous ***Chapter 2: Literature Review***.

Price Setting

The Secondary Reserves Market is a marginal market with the marginal price determined by the last aggregated bid (highest priced) deemed necessary in all or part of each operation period to cover the systemic reserve requirements for SR (BOE 129, PO 7.2, 2009). As both upward and downward reserves are provided in the same bid, price-quantity pairs reflect the SR band offers for every hour of the next operational day and thus are only positive. Generator bids for the entire day are aggregated, hour by hour, and the market is cleared using a simple matching algorithm similar to the ***Daily Market*** as explained later in the ***Market Run Through*** section.

For example, an AGC enabled production unit bids and is accepted to produce 150 MW in a given hourly period in its regular ***Baseline Schedule of Daily Market (PDBF)***: yet also is participating in the Secondary Reserves Market with a 100 MW band. Hence the effective production schedule could be anywhere between 50-250 MW for the programmed hour depending on what the SR requirements are. The production unit therefore would be paid the Daily Market price in that hour for the scheduled 150 MW and the Secondary Market price for the 100 MW band for the hour, regardless of whether that band is used.

Net Effective Energy, however is remunerated at a price calculated by incorporating the assigned ***Tertiary Reserves*** plus the Tertiary Reserves that would have been necessary to assign in order to have null a Net Effective Energy. The economic reasoning behind this price scheme will become more apparent after reading the following ***Tertiary Reserves*** section.

Tertiary Reserves

Definition and Objective

Tertiary Reserves (TR, also revered to as Tertiary Regulation) is an ancillary service of optional nature with obligatory offer which is managed and remunerated through market mechanisms. Its purpose is the restitution (the recovery) of Secondary Reserves as they are used by adapting the corresponding operating program of production facilities and pumping facilities (BOE 190, PO 7.3, 2009).

Tertiary Reserves is defined as the **maximum variation of power upwards or downwards** a given generation or pumping unit can achieve **within a 15 minute time frame,** which must be capable of being **maintained at least for a duration of two consecutive hours**. Tertiary Reserves are defined on a per unit basis throughout the system, corresponding to any/all available production or pumping facilities (BOE 190, PO 7.3, 2009).

Figure 8 below is a zoomed view of ***Figure 6*** at the 31,499 MW point. As noted before, the actual demand has increased more rapidly than the scheduled generation, thus to avoid using the more costly Secondary Reserves band to meet the discrepancy, Tertiary Reserves is instead used to shift the operating point of the scheduled generation (shift in the red line, the hourly block) and to maintain the available SR band within acceptable limits.

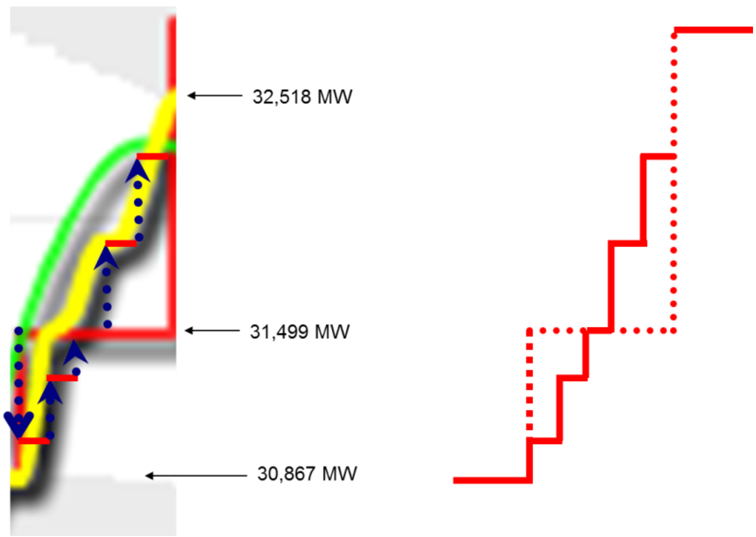


Figure 8: Tertiary Regulation Example

Source: (Red Electrica España (REE))

In the beginning of the hour, actual demand was far below scheduled generation and increased quickly above even the predicted (green line) schedule, thus using only SR to cover the discrepancy would result in a large amount of NEE as well as greatly deplete available SR resources, thus Tertiary Reserves is employed to shift the scheduled generation operating point. The effective shift in schedule can be seen on the right-hand side of Figure 8 where each step signifies how the original middle dotted line has been altered. As TR is used to shift the overall production schedule, they are slower acting reserves and are not held to the same technically stringent requirements as SR. The Spanish SO determines the minimum amount of Tertiary Regulation computed as the rated power of the largest unit within the system plus 2% of the forecasted load for each hour (BOE 190, PO 7.3, 2009); (TWENTIES PROJECT 15.1, 2014).

Technical Requirements

Providers of Service

The SO will determine, on an individual basis, whether each unit (in the case of thermal) or combination of units (in the case of hydro) have the necessary technical operations to be allowed to participate in Tertiary Reserves and the SO has the authority to disallow any unit if their technical capabilities are found in fault. Providers of TR must fulfill at least the following requirements:

- Must register in the corresponding RAIPEE (Registro Administrativo de Instalaciones de Producción de Energía Eléctrica)
- Must officially request for participation in Tertiary Reserves
- Must integrate production facilities in a control center
- Must communicate to the SO additional required information as outlined in the Operating Procedures for suppliers of Tertiary Reserves, and to update this information periodically.

Response Requirements

As mentioned previously, Tertiary Regulation is used to recover the Secondary Reserve band by shifting the generation schedule, thus it is a less strict and slower acting ancillary service. The only requirements are that TR **must respond within 15 minutes** to requests from the SO and maintain required generation levels for a two hour period. These requests are conducted by individually calling upon TR providers when needed and there is no required response profile, only that units must reach the required set points by the 15 minute mark. However, once a production unit is registered and accepted as a TR providing entity, it must always offer its services; hence the designation of TR as having an "optional nature with obligatory offer."

Market Mechanism

Bid Structure

Tertiary Regulation is remunerated using a market mechanism and is **offered on an individual (per unit) basis** by only those production units which have been approved for providing service. If the SO detects that Tertiary Reserves are not sufficient at any moment, it may however allow startup of additional thermal units to solve technical constraints and to maintain a sufficient margin of Tertiary Reserves outside of the preapproved units (BOE 190, PO 7.3, 2009). Bids from each unit providing TR must offer total capacity in MW along with the corresponding energy price (MWh). This bid structure is known as the "staircase" and is best explained graphically.

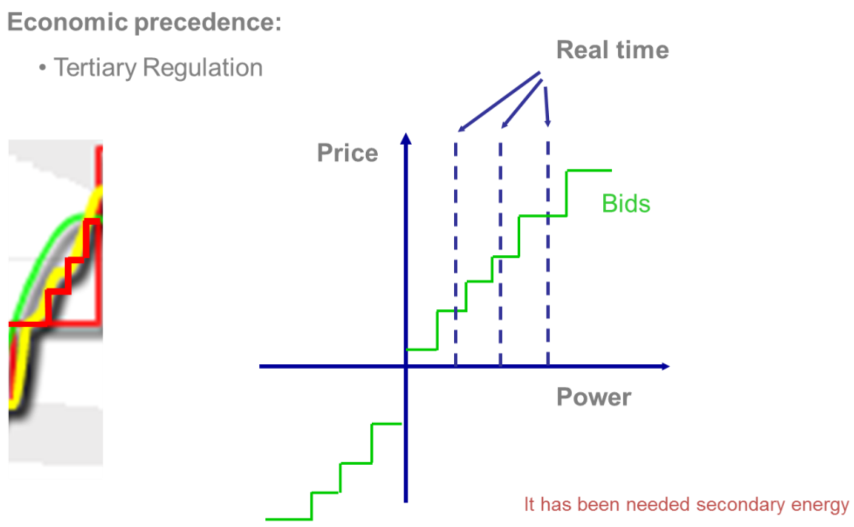


Figure 9: Staircase of Tertiary Reserves

Source: (Red Electrica España (REE))

As in Secondary Reserves, TR is procured through an aggregated bid-based system with price-quantity pairs. Since TR is used to modify the existing scheduled generation, the foundation on which bids are referenced is the Daily Market price; this corresponds to the Y=0 mark on the y axis and in this example is given to be 60 €/MWh. As seen in ***Figure 9***, upward bids are given as the amount of power available to increase (positive x axis) along with the corresponding price (positive y axis) a generator is willing to offer its capacity to increase production. Downward bids however, represent a production cost savings to TR offering entities as downward reserves are offered by decreasing production or not producing at all. Thus downward bids are structured as the amount of energy available to decrease (negative x axis) as well as the price below the market price (negative y axis) which TR units are willing to modify their previous production schedules and effectively sell back their power to the SO.

For example, if a regular production unit was scheduled to produce 300 MW in a given hourly period at the Daily Market price of 50 €/MWh, it would receive €15,000 for that hour. If however this unit is also a TR providing unit and is called to provide downward reserves, it will be willing to provide this service for -100 MW at a price of 40 €/MWh. The new altered schedule would call for the unit to produce 200 MW for one hourly period at the market price of 50 €/MWh and receive € 10,000, however as this schedule has been altered due to offering Tertiary Reserves, the unit actually receives:

$$300\ MW * 50\,€/MWh - 100\ MW * 40\ \ €/MWh = 11{,}000\ €$$

The extra €1,000 is essentially what the unit is paid for not producing, hence what the unit has sold back to the SO. Similar to the Secondary Reserves, in previous legislation renewables were historically banned from participating in the Tertiary Reserves market as well, although other Special Regime technologies were allowed with the following stipulation.

In the case of facilities belonging to the Special Regime which are manageable, they must present the corresponding resolution from the General Director of Energy Policy and Mines authorizing the participation of said units in ancillary services The offers of said units must also amount to greater than 10MW (BOE 190, PO 7.3, 2009) [Translated]

Price Setting

Tertiary Reserves is also a marginal market thus the TR market price is determined by the last aggregated bid deemed necessary in all or part of each operation period to fulfill the upward or downward requirement. Furthermore, each production unit or group which is called upon to offer service is remunerated at the highest TR offer price within the same hourly period (or the minimum for purchases/downward reserves).

Looking again at ***Figure 9***, the vertical dotted blue lines correspond to the TR requirement to increase (shift the red generation schedule upwards) throughout the hourly period seen on the left-hand side of the figure. In the first call, only up to the second "step" in TR is needed, thus units providing service in the first call are remunerated at the marginal bid price of 75 €/MWh. In the second call, approximately twenty minutes later, up to the fourth step is needed to cover TR requirements, thus all generating groups in this call receive the new marginal price of 85 €/MWh, ***and additionally,*** all units in the first group now receive the new marginal price for whole period in which they were assigned. ***Figure 10*** below is a graphical explanation of the Tertiary Reserves remuneration scheme which corresponds to the situation seen in ***Figure 9***.

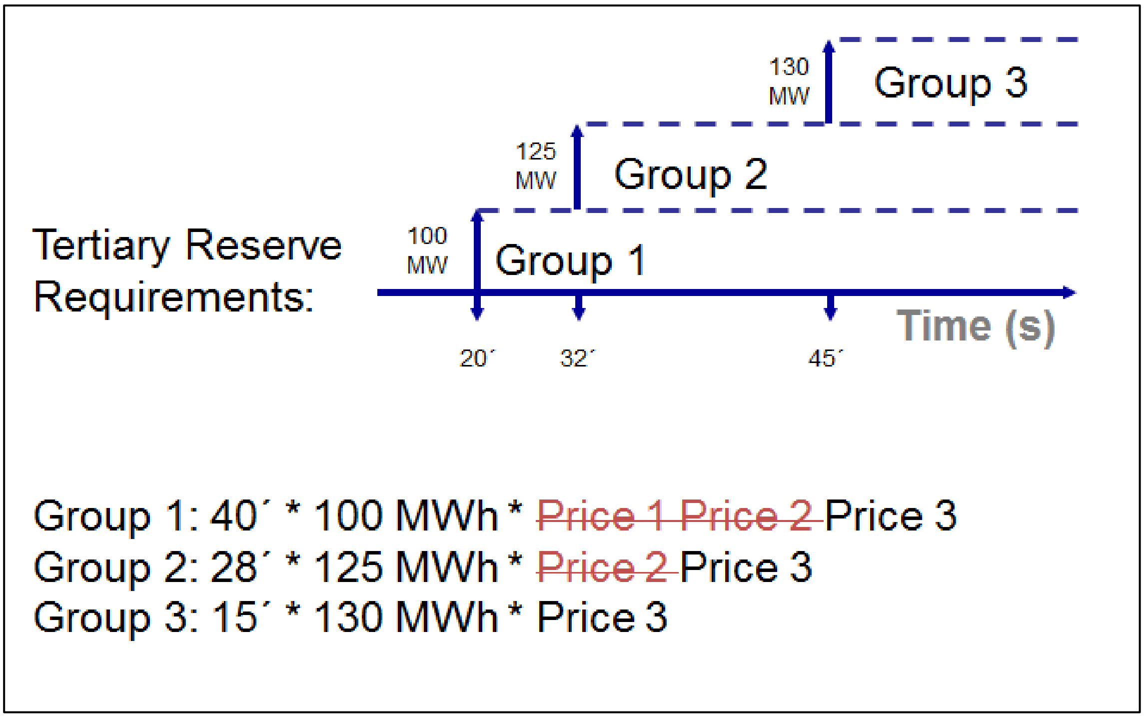


Figure 10: Tertiary Reserves Remuneration Example

If the supply/demand deviation had continued as in the first call (made at the 20 minute mark), Group 1 would have received the marginal bid price of 75 €/MWh (Price 1) for the 40 remaining minutes in the hourly period. Since an extra 125 MW of reserves was necessary at the 32 minute mark, a second call for Group 2 was made, thus both groups involved received the new marginal bid price of 85 €/MWh (Price 2) but for 40 minutes for Group 1 and 28 minutes for Group 2 respectively.

If a third call had been necessary, for example at the 45 minute mark, a Group 3 would have been required and a final marginal price (Price 3) would have been applied to all groups involved for: 40 minutes for Group 1, 28 minutes for Group 2, and 15 minutes for Group 3. Thus at the close of an hourly period, all groups will receive the highest marginal price seen within the hour for the entire duration of their respective contribution regardless of their initial marginal price.

Furthermore, referring back to ***Figure 9***, at the end of the hour there still exists a deviation between the real-time demand and the scheduled generation, thus Secondary Reserves is still required and will result in a positive Net Effective Energy. As this amount of energy could have been provided by Tertiary Regulation (Group 3) if the SO had perfect information, **thus the price for the Net Effective Energy is the Tertiary Reserves marginal price plus the price for the Tertiary Reserves that would have been necessary to assign in order to have null a Net Effective Energy.**

Ancillary Services Market Summary

To summarize, as can be seen in ***Figure 11,*** Deviation Management helps to balance large differences (> 300 MWh) between scheduled generation and forecasted demand and are provided by generation and pumped storage power units. Primary Reserves is an obligatory non-remunerated service and requires that generators allow for a real time variation at any given moment of 1.5% of their installed rated power.

Secondary Reserves consists of two components: **the band offered** (variability, remunerated at the marginal Secondary Reserves Market price) **and the Net Effective Energy** (the energy difference across the hourly period, remunerated at a marginal price equal to the Tertiary Reserves marginal price that would have been required to have a null Net Effective Energy). Units providing SR must be able to respond within **100 seconds with a linear, fixed time constant,** this service is autonomously controlled by AGC, and is provided at the control zone level.

Tertiary Reserves is the **maximum variation of power upwards or downwards** a given generation or pumping unit can achieve **within a 15 minute time frame** and can maintain for a period of two hours**.** TR is controlled by individually calling TR generators and is provided at the individual unit level**.** Once a unit has been approved for providing TR they must always offer their service, hence it is an “optional nature with obligatory offer.”

Thus Secondary Reserves is more costly than Tertiary Reserves as the Net Effective Energy already incorporates the price of TR in addition to the Secondary Reserves band. This conclusion also follows economic theory as only generation units which have incurred additional investment costs to be both equipped for AGC and flexible enough to respond within limited time frames with specific response patterns can participate in SR; thus their required remuneration to recoup these additional costs will necessarily be greater as well.

Service	Definition	Nature	Providers	Requirements
Primary Regulation	Generation units facing frequency variations (<30 sec)	Mandatory and non- paid service	All generation units	UCTE Requirements P.O.1.5
Secondary Regulation	Activation of Master Regulator and AGC on units regulators facing frequency variations and imbalances respect scheduled program in France interconnection (<=100 sec)	Optional, Market Driven (both reserve and energy payments)	Licensed generation included in Regulation Areas	P.O. 1.5
Tertiary Regulation	Manual operation of units to face unexpected deviations (and short duration expected dev. as well) and recover secondary reserves (15 min and maintaining 2 hours)	Mandatory bid, Market Driven (energy payment)	Licensed generation and pumping units	P.O.1.5 (regarding tertiary reserve required)
Deviation Management	Manual operation of units to face expected deviations above 300 MWh that may last [1 to several hours], and recover tertiarty reserves	Market Driven (energy payment)	Licensed generation and pumping units	P.O.1.5
Voltage Control	Maintaining Voltage Control in Transmission Grid: Generation: Voltage set point at the connecting node Transformers 400/220 kV: Voltage set point at the controlled node Consumption: Power factors in border points Management of reactors	Partly mandatory, partly optional (pending development)	G: P>30 MW C: s P>15 MW Distribution Transmission Companies	G: +/- 15% reactive for nominal voltage C: depending hour
Additional upwards power reserve	Allocation and management of additional slow reserve carried out just after D-1 contraint solving process (additionally required with respect to the slow reserve available at PDVP)	Mandatory bid	Thermal units previously licenced by OS	P.O.3.9

Figure 11: Ancillary Services Definitions

Source: (Casado, 2014)

Market Operation

The following section explains the Daily Market operation, terminology, timetables and scheduling to better inform when market decisions must be made. First the ***Objective and Overview*** of market operations will be introduced, followed by ***Definitions*** of key phrases and terminology, and concluded with a complete ***Market Run Through*** of a daily operation from both the economic (Market Operator) and technical (System Operator) perspectives working in their designated capacities.

Objective and Overview

As taken from official Operating Procedures (OP) of Generation Scheduling, the intended objectives are:

> ***"To establish the daily operation process for generation scheduling from programs derived from bilateral contracts (with physical delivery), the matching of sale bids, and the acquisition of energy in the Daily and Intra-Daily Market, in the manner which guarantees demand coverage and system security." (BOE 190, PO 3.1, 2013)[Translated]***

This OP defines the daily scheduling and overall market operation of both the MO, for the economic provision of scheduling, as well as the SO for the final, technically feasible scheduling and operation. Market scheduling consists of seven elements from baseline to final dispatch, including:

- Baseline Schedule of Daily Market (*Programa Diario Base de Funcionamiento, PDBF*)
- Provisional Viable Daily Market Schedule (*Programa Diario Viable Provisional, PDVP*)
- Secondary Reserves Market (*Mercado Secundaría*)
- Dispatch after Intraday Market *(Programa Horarios Finales, PHF*)
- Management of Deviations (*Gestión de desvíos)*
- Hourly Operating Dispatch after horizon programming (*P48*)
- Final Dispatch (*P48CIERRE*)

Dispatch (generator scheduling) is expressed in energy format (MWh) and all temporal values are in reference to Central European Time (CET) (BOE 190, PO 3.1, 2013).

Note, all acronyms referring to scheduling will be presented in their Spanish nomenclature, thus Baseline Schedule will be referred to as PDBF, Provisional Schedule as PDVP, etcetera.

Definitions

Bilateral Contracts:

Must be communicated to the SO which forwards this information to the MO before 11 AM (yet this is perceived to change in the future to 10 AM) through either direct or indirect nomination. Direct nomination is when each one of the market participants taking part in a bilateral contract (with physical delivery) proposes to the SO the production schedule of the units which they own or represent along with the intended recipients. Indirect Nomination is when one of the market participants taking part in a bilateral contract, designated as the Subject Nominator, is responsible for the scheduling of all units involved in the bilateral contract, subject to authorization given by the SO.

Baseline Schedule of Daily Market (PDBF):

This is the daily energy dispatch with hourly breakdown as the result of economic conditions. The PDBF is the market-clearing result, including matching of demand with supply bids from the MO as well as physical bilateral contracts. It is the schedule for the following day although it may not be technically feasible.

Provisional Viable Daily Market Schedule (PDVP):

The PDVP is the daily baseline hourly dispatch (PDBF) along with modifications from the SO due to technical limitations, system security criteria, or the rebalancing of generation and demand.

Secondary Reserves Market:

This is the process through which the SO (REE) obtains Secondary Reserves through a bid-based market mechanism in the day before (D-1). See full definition of Secondary Reserves in the ***Ancillary Services Market*** section.

Dispatch after Intraday Market (PHF):

The technically viable hourly dispatch, established by the SO, after the results of the successive sessions of the Intraday Market carried out by the MO and the Intraday Market technical corrections by the SO. Refer to the previous ***Intraday Market*** section for the definition of the Intraday Market.

Management of Deviations:

This procedure refers to the management of deviations which arise from the difference between real-time production and predicted/scheduled production due to variations in system demand and/or modifications to generation obligation. Due to the reality of real-time operation of the electric grid, deviations occur and create differences in the scheduled and actual system demand, even after the Intraday market results, and thus require mitigation.

Management of grid deviations is enacted through the procedures relating to Ancillary Services such as frequency/voltage regulation and, when applicable, deviation management (a separate ancillary service, not to be confused with the procedure). For a more complete description of these Ancillary Services please refer to the ***Ancillary Services Market*** section of this thesis or view ***Figure 11: Ancillary Services Definitions***.

Hourly Operating Dispatch after horizon programming (P48):

The Hourly Operating Dispatch which incorporates all applicable generation assignments and re-dispatches as designated by the SO, given every 15 minutes before the programmed hour.

Final Dispatch (P48CIERRE):

Final Hourly Dispatch after results of all markets, deviation management, frequency regulation, re-dispatches, as well as technical and system security corrections in real-time made by the SO.

For a more complete description of scheduling and all definitions please refer to ***B.O.E 190, P.O. Sections 3.1-3.3,*** *and for technical measures and system security definitions,* ***P.O. Sections 4.6-4.8.***

Market Run Through

What follows is a description of the market operations from start to finish along with pictorial examples taken from real operational data at hour 20:00(Peak Hour) on the 7th of January 2014. All slides are courtesy of OMIE and Red Eléctrica España unless otherwise noted.

Overview

Figure 12 shows an overview of the market processes timeline from the auctions of interconnection capacity up until real-time operation from both the MO and SO perspectives, while ***Figure 13*** is a visual of the Intraday Market and the six sessions of which it comprises. It should be noted however, that as forward contracts are settled well in advance by another market entity (OMIP) they are not included in the Daily Market timeline.

In ***Figure 12***, the blue (dark) blocks indicate the duration of a process by either the MO or SO while the light blue (light) blocks represent the horizon of application of the related process. Taking the first Intraday session (*Intradiario 1)* as an example, the period of execution (thus the dark blue box) is from 18:00-21:30 of the Day before (D-1) meaning that buyers and sellers submit bids throughout this period. Thirty minutes later, from 22:00 D-1 onwards, the results of this bid session are processed and are relevant throughout the remaining Intraday sessions, thus the horizon of application (light blue box) extends from 22:00 D-1 until 24:00 D. The second Intraday session is executed from 22:00 D-1 until 23:30 D-1 and the results are relevant throughout the entire D day. The time horizons of the Intraday sessions are also more clearly represented in ***Figure 13***.

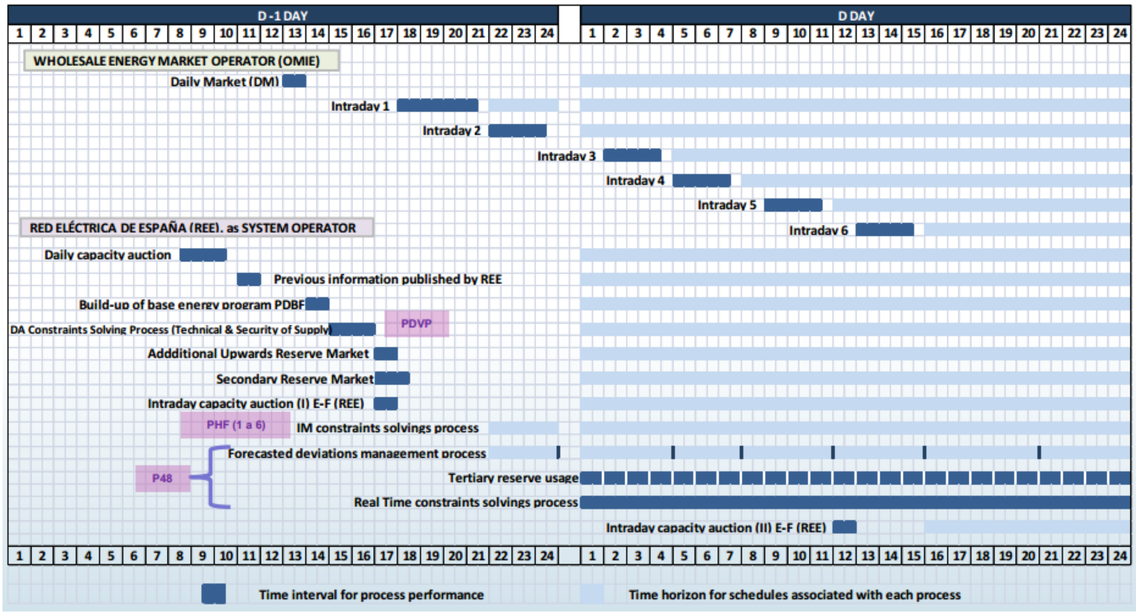


Figure 12: Daily Market Processes Timeline

Source: (Casado, 2014)

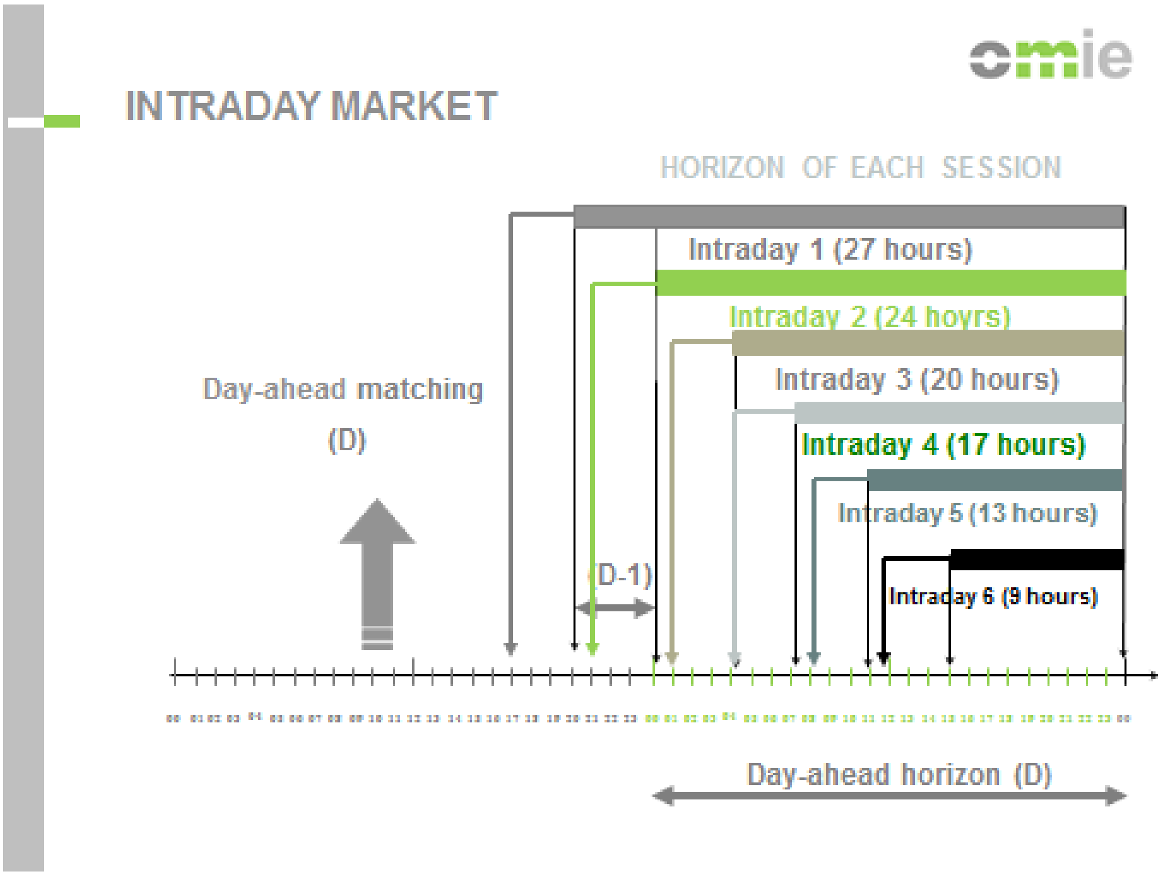


Figure 13: Intraday Market Sessions

Source: (Bogas, 2014)

Baseline Schedule of Daily Market (Programa Diario Base de Funcionamiento, PDBF)

As can be seen in ***Figure 12***, forward contracts are settled well in advance of daily operation (hence are omitted from the figure) and are only relevant for daily operation if their owners opt for physical delivery. For the hour of 13:00 D-1, qualified producers and consumers can place hourly bids for the subsequent 24 hour day and bids are structured in 25 blocks per hour with each block corresponding to a price-quantity pair. For example, a producer could bid for the first hour to sell 100MW at 10 €/MWh, from greater than 100MW until 210MW at 30 €/MWh, and from greater than 210 MW until 340 MW at 80€/MWh. This bid would constitute a simple bid consisting of three blocks for the first hour and is shown graphically below in ***Figure 14***.

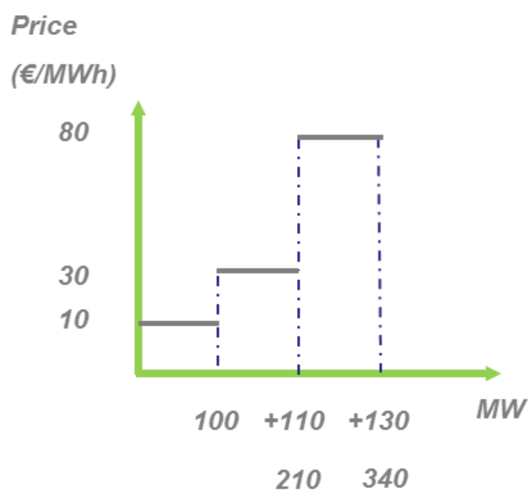


Figure 14: Example of Hourly Block Bid for Daily Market

Source: (Bogas, 2014)

Likewise, the demand bids are provided in decreasing price-quantity pairs. The supply and demand bids are then aggregated for all generation and consumption bids to find the marginal price, the result of matching, which is the cross point and can be seen in ***Figure 15*** below.

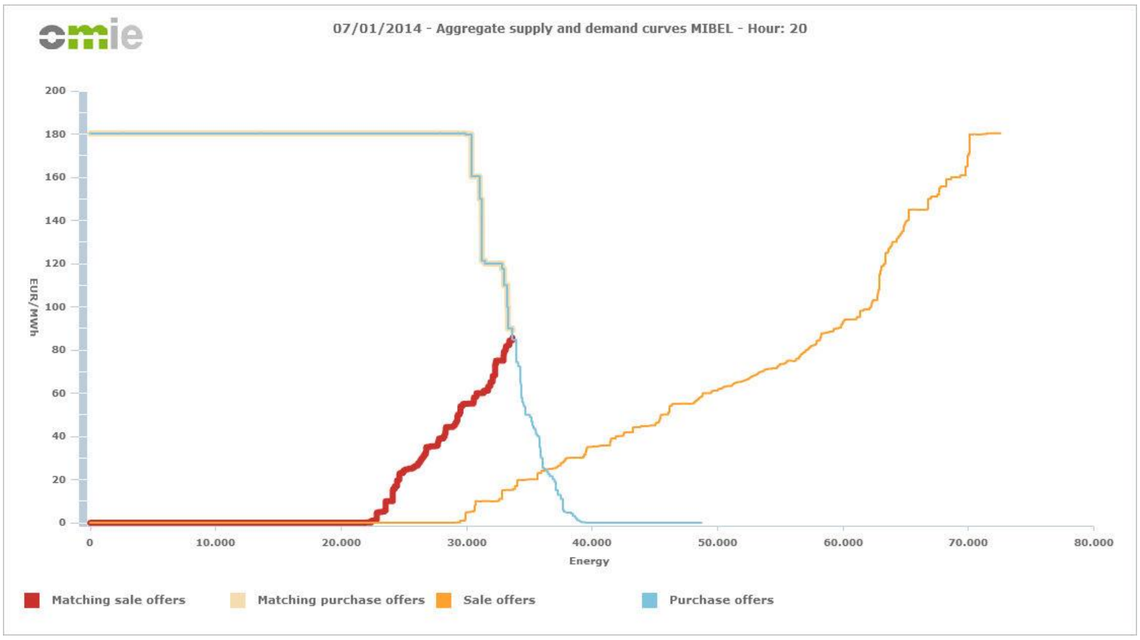


Figure 15: Peak Hour Matching for January 7th 2014

Source: (Resultados del Mercado OMIE, 2014)

The marginal hourly price is the point where the green aggregate demand (downward sloping curve) meets the red matching sales offers (highest upward sloping curve). Note however that the yellow sales offers (the less steep upward sloping curve) represent the actual generation bids in simple form; the final marginal price is higher in this case due to the complex conditions generators impose in their bids relating to technical or economic limitations (ramp rates, minimum income conditions, etc.). While the blue portion (or the remainder of the downward sloping curve past the intersection point) of the demand curve is the aggregated profile of unmatched demand bids. This process is executed simultaneously for all hours of the following day and the daily price curve corresponding to the ***Baseline Schedule of Daily Market (PDBF):*** schedule is published at 15:00 of D-1 as seen in ***Figure 16*** below.

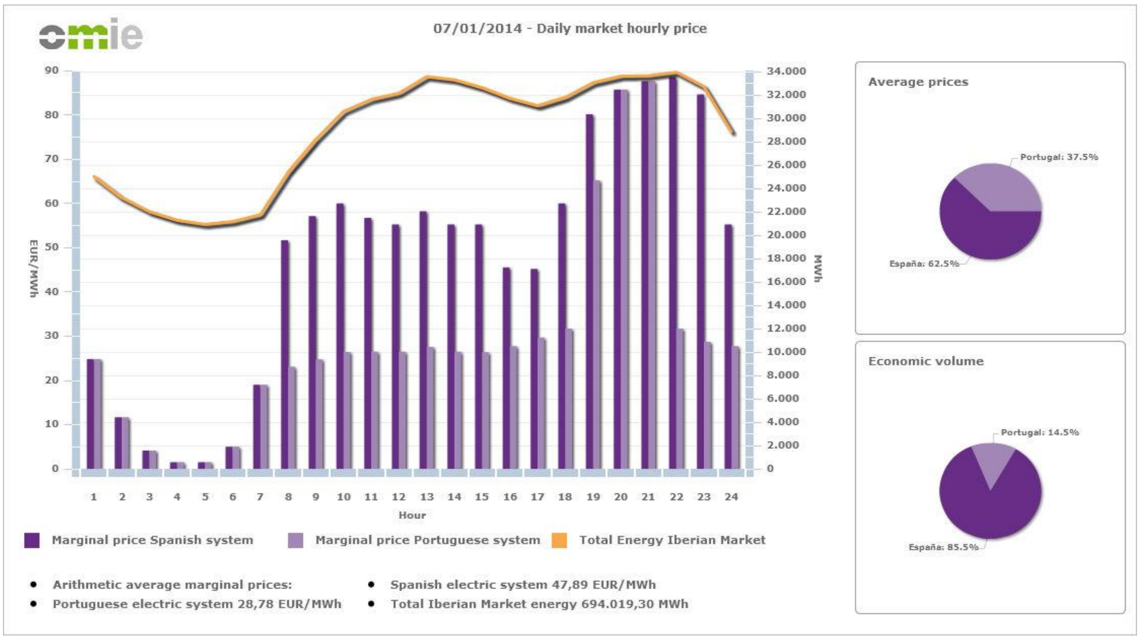


Figure 16: Daily Price Curve Corresponding to Provisional Daily Base Schedule (PDBF)

Provisional Viable Daily Market Schedule (Programa Diario Viable Provisional, PDVP) and Ancillary Services

Next, the ***Provisional Viable Daily Market Schedule (PDVP):*** is calculated between 15:00-17:00 D-1 by the SO and the predicted necessary Ancillary Services are acquired between 17:00-18:30 D-1, slightly overlapping the first Intraday Market Session. The Ancillary Services acquisition is seen through "Additional Upwards Reserve Market", "Secondary Reserve Market", and "Intraday capacity auction" (dark) blue blocks. These Ancillary Services include: ***Secondary Reserves***, ***Deviation Management***, Voltage Regulation, ***Tertiary Reserves***, and are used throughout the operating day (D) to control various grid discrepancies.

Dispatch after Intraday Market (Programa Horarios Finales, PHF)

Final hourly schedule resulting from each Intraday Market session (PHF 1-6) is published after the end of the each corresponding Intraday Market session and the corresponding IM technical constraints solving processes. The final PHF schedule thus consists of the sum of the ***Provisional Viable Daily Market Schedule (PDVP):*** plus the re-dispatches representing the technical constraints solutions of the IM (sum of PHF 1-6) (OMEL, 2012).

Management of Deviations (Gestión de desvíos)

Management of Deviations: is enacted for any deviation greater than 300 MWh which persists within any two consecutive Intraday market sessions and thus the horizon of application corresponds to the IM timing as represented by the vertical dark blue bars in day D.

Hourly Operating Dispatch after horizon programming (P48)

The Hourly Operating Dispatch which incorporates all applicable generation assignments and re-dispatches as designated by the SO including ***Tertiary Reserves*** and real-time constraints solving, given every 15 minutes before the hour throughout the day D.

Final Dispatch (P48CIERRE)

The Final Hourly dispatch after results of all markets, Management of Deviations, Ancillary Services re-dispatches, as well as technical and system security corrections made by the SO.

Chapter 4: Economic Analysis

Introduction

The analysis which follows has been conducted with the research philosophy that, as the energy market is a highly complex entity dependent on volatile factors such as the weather, consumer demand, and exogenous political decisions, analysis should be conducted by observation rather than postulation of mathematical principles. Therefore whenever possible, market data is used in place of statistical methods, recent data preferred over past data, and the current regulatory environment is considered extensively to allow for conclusions which are founded in contemporary market phenomena.

Due to the nature of this investigation as primarily an investment analysis in a well understood environment, no behavioral aspects are considered. Furthermore, all production data is aggregated for the Spanish peninsular system; thus any numeration of Capacity Factors, real-time production, PDBF scheduling, etc. are understood to be from the peninsular system level due to the proprietary nature of production data from individual wind generators.

As mentioned previously, the intention of this research is to answer the question of: **if the investment costs necessary to participate in the Secondary Reserves Market will be outweighed by the revenue wind producers are likely to receive.** Additionally, if true, this thesis aims to parameterize under what conditions it will be beneficial for wind producers to participate in the SRM and investigates possible strategies a wind agent could pursue.

Methodology

This work is founded on three main assumptions, enumerated below, which are elaborated in the following sections of this thesis. They are the:

- The Generator Band Offer
  - Defined as from the minimum technically feasible operation (25% Installed Capacity) to maximum reliable operation (minimum point of real-time production over one hour, 13% below PDBF schedule)
  - Only downward regulation band is offered

- The Investment Costs
  - Take into account CAPEX and OPEX impact at all levels and are assumed from the conclusions of the TWENTIES Project research.
  - Defined as:
    - Socialized costs
    - Per MW costs
    - Per Cluster costs

- The Estimated Capturable Income
  - The difference between participating only in the Daily Market versus participating in Secondary Reserves taking into account:
    - Secondary Band Price (2BP)
    - Daily Market Price (DMP)
    - Capacity Factor(CF)
    - Realistic Band Offer (RBO)
    - Intraday Barter Cost (IBC)
    - Production Factor: amount of production offered as Band (B)
    - Production Factor: amount of production change managed in Intraday market (C)

Effective Hourly Benefit (EFHB)

  - All revenues are calculated conservatively, thus no cost increase for deviation is expected (with 95% confidence resulting from the band definition).

The majority of this section is concerned with the crucial assumptions surrounding the calculation of revenues a wind generator is likely to receive. The Secondary Regulation Band can be defined by technical criteria, investment costs are relatively easy to estimate, but the possible revenue is more speculative, thus a large portion of this chapter is dedicated to explaining assumptions for the ***Estimated Capturable Income (ECI)*** equation and calculation.

As explained in the ***Secondary Reserves*** section, the SRM primarily consists of generators offering a band of production with the Net Effective Energy only being remunerated when it arises; thus the term "band" in all instances, is understood to be the regulation band of variability a wind generator offers in the SRM. Also, as the regulation band is the fundamental market commodity, it is necessary to clearly define it for the case wind.

Band Definition

The Secondary Band is defined as **from the minimum technically feasible operation to the maximum reliable operation.** The rational for this is partially taken from ***The TWENTIES Project*** which had concluded in the technical tests that to ensure the least number of stoppages while providing regulation services, wind turbines must to be operated at between 25-50% of their Installed Capacity. A key assumption in this research therefore is that the technical minimum is 25% of Installed Capacity for a wind turbine, thus the lower boundary of the band definition.

The maximum boundary of the band is the minimum point of available power throughout an hour to ensure that regulation set points will reliably be met. The band definition is best explained graphically as seen in ***Figure 17*** below.

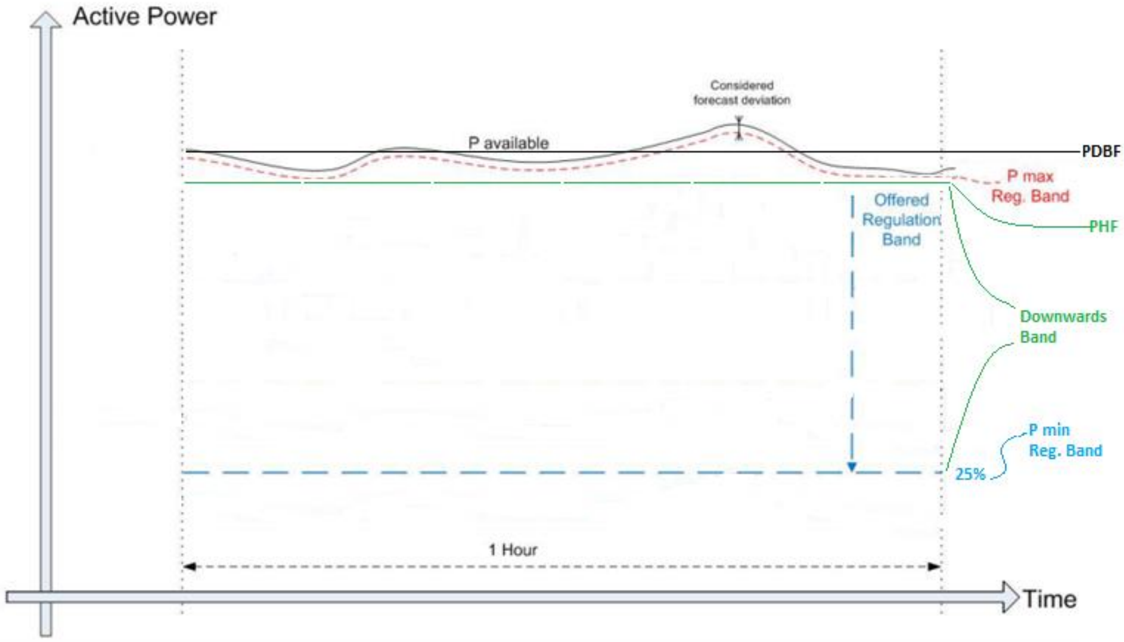


Figure 17: Secondary Band Definition

Adapted from source: (TWENTIES PROJECT 9.1, 2013)

The black curved solid line represents the available power throughout one hourly period however, as the technical test assumed a forecast error, the red dotted line is the reliably available power. Thus the regulation band is defined from the minimum point of the reliably available power throughout one hour down to the 25% mark of Installed Capacity as seen in the blue dashed line. As the data in this thesis is based upon final wind production it is assumed that this forecast error is already included in the analysis. Another key assumption of this thesis is that only downward regulation is offered by wind turbines, hence the downward arrow of the band definition.

The straight black solid line is the PDBF schedule as defined in the ***Market Operation*** section, while the straight green dashed line is the PHF schedule; these two markings are unrelated to the band definition, nevertheless they are useful for showing the reality between actual production and economic production, the latter which is assumed to be the average for an hour and is constant.

The PDBF is the contracted amount of power which is sold in the Daily Market (or declared through a bilateral contract) while the PHF is the final production level after the Intraday Market sessions which ideally would correspond to the level at which a wind producer could offer the largest possible Secondary Band. This difference between the PDBF and the PHF is very relevant as real-time wind production obviously cannot be known with certainty at the time the Daily Market closes. Likewise, the relationship between the real-time production and the PDBF schedule will also be an important point when taking into account a ***Realistic Band Offer*** and the ***Intraday Barter Cost (IBC)***, as explained in the ***Estimated Capturable Income (ECI)*** section.

Investment Cost Assumptions

The investment costs used for analysis have been taken directly from the findings of ***9.2: Economic Analysis*** of The TWENTIES Project. These findings take into account CAPEX and OPEX impact of necessary investments to allow wind generators acting in clusters to provide Secondary Regulation services. These costs have been apportioned to three scopes of impact: Wind Turbine Scope (WTG), Wind Farm Scope (WF), and Cluster Scope which can be seen in ***Table 4*** reproduced below.

Table 4: Investment Cost Assumptions Reproduced

(Highlighted portion is the Secondary Reserves Test)

Source: (TWENTIES PROJECT 9.2, 2013)

		CAPEX			OPEX (€)	Production loss(MWh) Installation/Validation	Annual production loss(MWh/WTG) Continous Operation
		Development (€)	Equipment & Installation (€)	Total Capex(€)			
Scenario#1 independent services	Secondary Frequency Control	105900	1306890	1412790	0	149,96	1756
	WTG	24000	8100	32100	0		
	WF	11400	427090	438490	0		
	Cluster	70500	871700	942200	0		
Scenario#2 independent services	Voltage control	110300	1440435	1550735	15000	152,86	0
	WTG	22400	41280	63680	0		
	WF	17400	527455	544855	15000		
	Cluster	70500	871700	942200	0		
Scenario#3 simultaneous services	Simoultaneous Secondary f/V Control	216200	1448535	1664735	15000	219,55	1756
	WTG	46400	49380	95780	0		
	WF	28800	527455	556255	15000		
	Cluster	141000	871700	1012700	0		

Looking only at the Secondary Frequency Control test, the assumed investment costs used in this thesis research are: €32,100 due to wind turbine costs, €438,490 due to wind farm costs, and €1,012,700 due to cluster costs. Note, the small discrepancy in the cluster cost stated here and that seen in ***Table 4*** is due to the fact that only the Secondary Frequency Control test is considered in this thesis research while in The TWENTIES Project costs at the cluster level were shared across both tests. Thus if only one test were to be implemented, the relative cost at the cluster level would be slightly larger.

As these costs were calculated across the entire technical test bed (as explained in ***9.1: Technical Feasibility***) which consisted of 488 MW of wind farms, they are denoted as Socialized Costs. To find the Per MW Costs, each Socialized Cost item was divided by 488 MW. The Cluster Costs however were taken directly from the actual costs which were attributed to each cluster throughout the technical testing and can be found in ***Annex II: Calculation of Cluster Costs***. The Production Costs are associated with the loss of wind production a wind farm would experience due to the installation of required equipment and were found by multiplying the number of MW of foregone production throughout one year by the average market price for 2013 of 44.26 €/MW. Thus the final cost items can be seen below in ***Table 5***.

Table 5: Investment Cost Assumptions

Investment Costs			Cluster		
	Socialized	Per MW	Huéneja	Tajo de la Encantada	Arcos de la Frontera
Turbine Impact	€ 32,100.00	€ 65.78	€ 12,840.00	€ 6,420.00	€ 12,840.00
Wind Farm Impact	€ 438,490.00	€ 898.55	€ 169,246.00	€ 98,544.00	€ 170,700.00
Cluster Impact	€ 1,012,700.00	€ 2,075.20	€ 337,566.67	€ 337,566.67	€ 337,566.67
Production Impact	€ 6,765.85	€ 13.86	€ 3,521.57	€ 1,691.46	€ 1,552.82
Total	**€ 1,490,055.85**	**€ 3,053.39**	**€ 523,174.24**	**€ 444,222.13**	**€ 522,659.49**

Estimated Capturable Income (ECI)

As noted previously, the most influential assumptions of this thesis pertain to the expected revenues from participation in the SRM; therefore careful consideration is taken in explaining the rationale behind these decisions. The Estimated Capturable Income (ECI) equation developed in this thesis research is essentially the difference between participating only in the Daily Market versus participating in the Secondary Reserves Market taking into account the following factors:

- Secondary Band Price (2BP)
- Daily Market Price (DMP)
- Capacity Factor(CF)
- Realistic Band Offer (RBO)

Effective Hourly Benefit (EFHB)

- Intraday Barter Cost (IBC)
- Production Factor: amount of production offered as Band (B)
- Production Factor: amount of production change managed in Intraday market (C)

Using these factors, the ECI equation has been created as follows:

$$(2BP_h - DMP_h) \times CF_h \times RBO_h => EFHB_h$$

$$(DMP_h - IMP_h) => IBC_h$$

$$Hourly\ Band\ Factor => B_h$$

$$Hourly\ Cost\ Factor => C_h$$

$$ECI = \sum_h (\underbrace{B_h * EFHB_h}_{\text{Primary Effects}} + \underbrace{C_h * IBC_h}_{\text{Secondary Effects}})$$

Equation 3

The rationale and definition for each element of the ECI equation is explained in the following sections. Hourly market data for the year 2013 forms the baseline dataset for this research and includes: the Secondary Band price (2BP), Daily Market Price (DMP), and Intraday Market prices for sessions 1-6 (IMP). Non-price related data consists of: real-time wind production for peninsular Spain (RT), baseline scheduled wind production for peninsular Spain (PDBF), and installed wind capacity for peninsular Spain (IC). Another important point is that although wind production is understood to be energy, the data used in this research is hourly thus production can be expressed using either MW (with the duration of one hour understood) or in MWh (to alleviate unit confusion).

Effective Hourly Benefit (EFHB)

The Effective Hourly Benefit (EFHB) is a key concept and is defined as the hourly Secondary Band Price (2BP) markup over the hourly Daily Market Price (DMP) factored by the hourly Capacity Factor (CF) and a Realistic Band Offer (RBO) as can be more easily seen in the first part of ***Equation 3***. The EFHB is essentially the amount of money a wind producer would receive *per unitary megawatt per hour* from participating in the Secondary Reserves Market. The rational for the Effective Hourly Benefit concept is as follows.

Secondary Band Markup

To elaborate, the Secondary Band markup is the difference between the hourly Band Price and the hourly Daily Marginal Price expressed in €/MWh; thus it represents the theoretical maximum added benefit per MW a wind producer could gain by participating in the SRM. ***Figure 18*** is the Daily Market Price along with the Secondary Band Price for 2013.

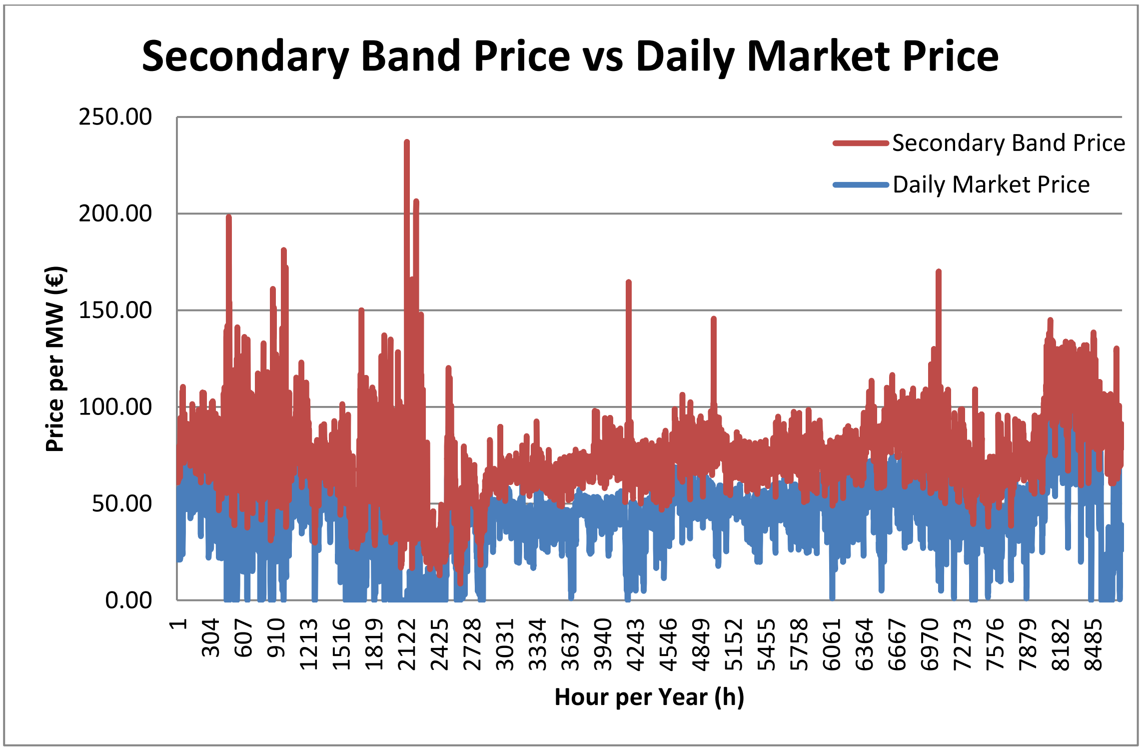


Figure 18: Secondary Band Price vs. Daily Market Price

As can be seen in ***Figure 18***, throughout the majority of the year the Secondary Band price exceeds that of the Daily Market price. By subtracting the 2BP from the DMP and converting the data into only positive differences, converting those which are negative into 0 as they constitute a situation where no benefit is derived, the Secondary Band Markup is shown below in ***Figure 19***.

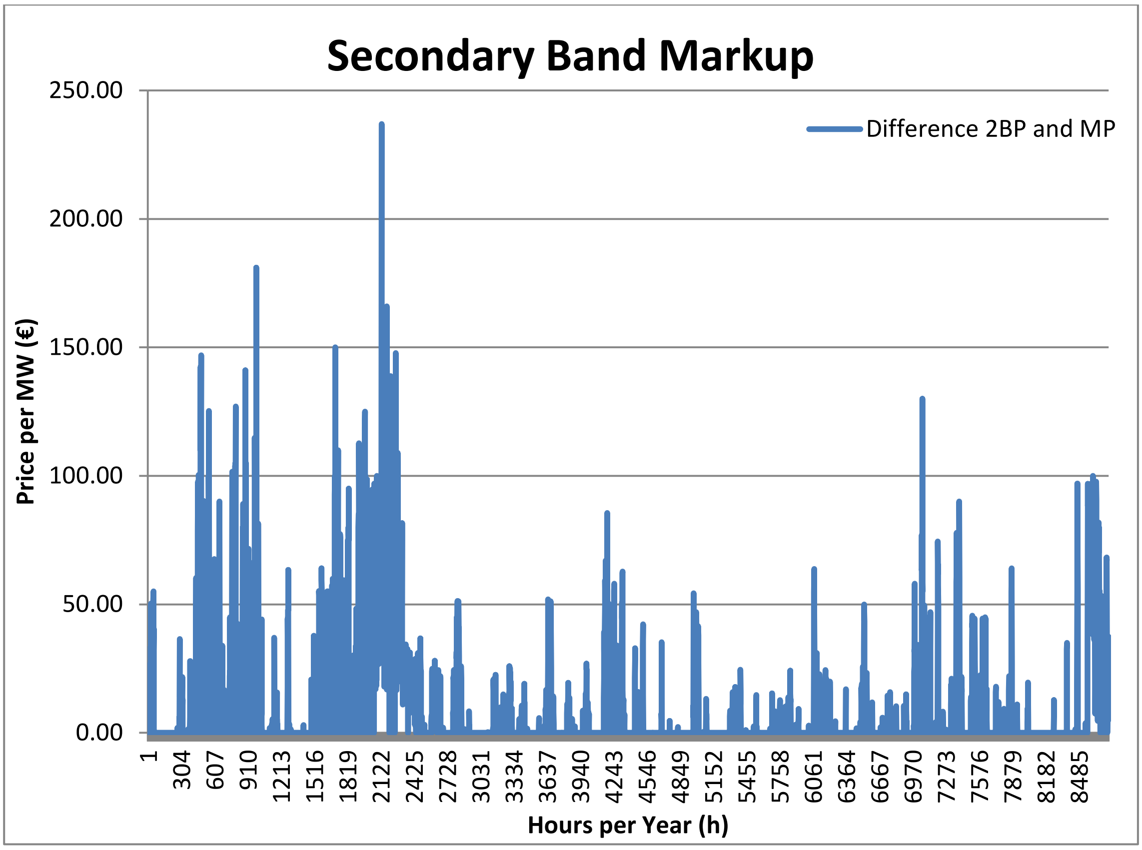


Figure 19: Secondary Band Markup

Also, this markup is an important point in the analysis such that only when the 2BP is greater than the DMP will a wind producer be interested in participating in the SRM thus negative values are irrelevant and can be represented as a markup of zero value. This criterion has been used to filter the data into the hours throughout the year which constitute a positive benefit; for the Market Year (MY) 2013 this number of hours was 2,111. While the markup constitutes the theoretical maximum benefit, only a portion of this benefit can be realized since wind producers have a limited amount of power to offer. Thus the concept of Effective Hourly Benefit must take into account the availability of wind power.

Hourly Capacity Factor

The Capacity Factor (CF) is a convenient metric as it takes into account both the Installed Capacity (MW) and the (programmed PDBF schedule) wind production and is denoted as a percentage. This allows for succinct representation of economic benefit in terms of unitary megawatt of Installed Capacity, the widely accepted benchmark for cost-benefit analyses in the energy sector. While other studies have applied the average yearly Capacity Factor in economic benefit analysis in the energy sector (Usaola, 2012); (TWENTIES PROJECT 9.2, 2013), this results in a relatively large undervaluation of actual benefit as evidenced by the comparison of the hourly CF and the year average CF seen in ***Figure 20*** below.

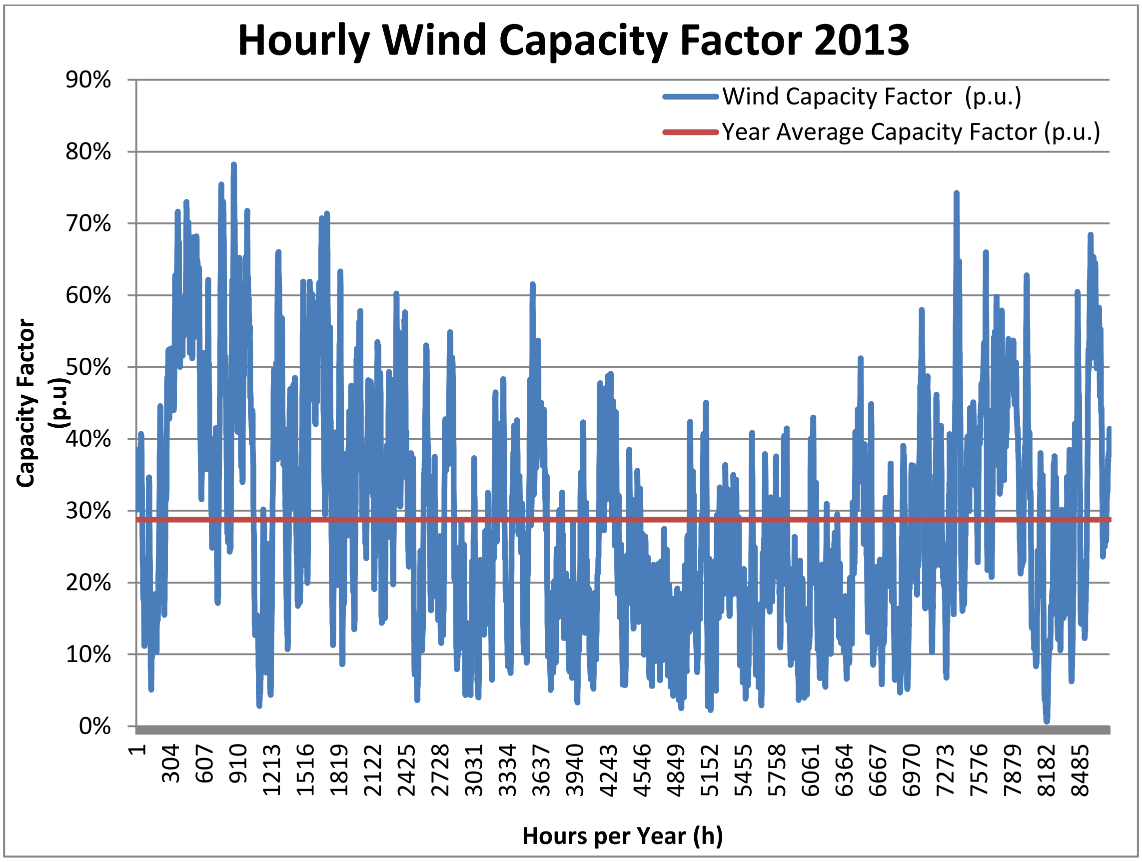


Figure 20: Hourly Wind Capacity Factor vs. Year Average Capacity Factor for MY2013

The hourly Capacity Factor was found by dividing the PDBF scheduled production at each hour by the total Installed Capacity for the Spanish peninsular system, thus:

$$CF = \frac{PDBF}{Installed\ Capacity}$$

Equation 4

with an Installed Capacity of 22,746 MW for the Market Year (MY) 2013. As can be seen in ***Figure 20***, there are a large number of hours in which the CF is greater than the year average of 29%. The 2013 year average of 29% is a realistic number as it falls within the long-term monthly averages (which fluctuate between 20-29%) when looking at Capacity Factor data compiled from 1998-2012 seen in ***Figure 21*** below.

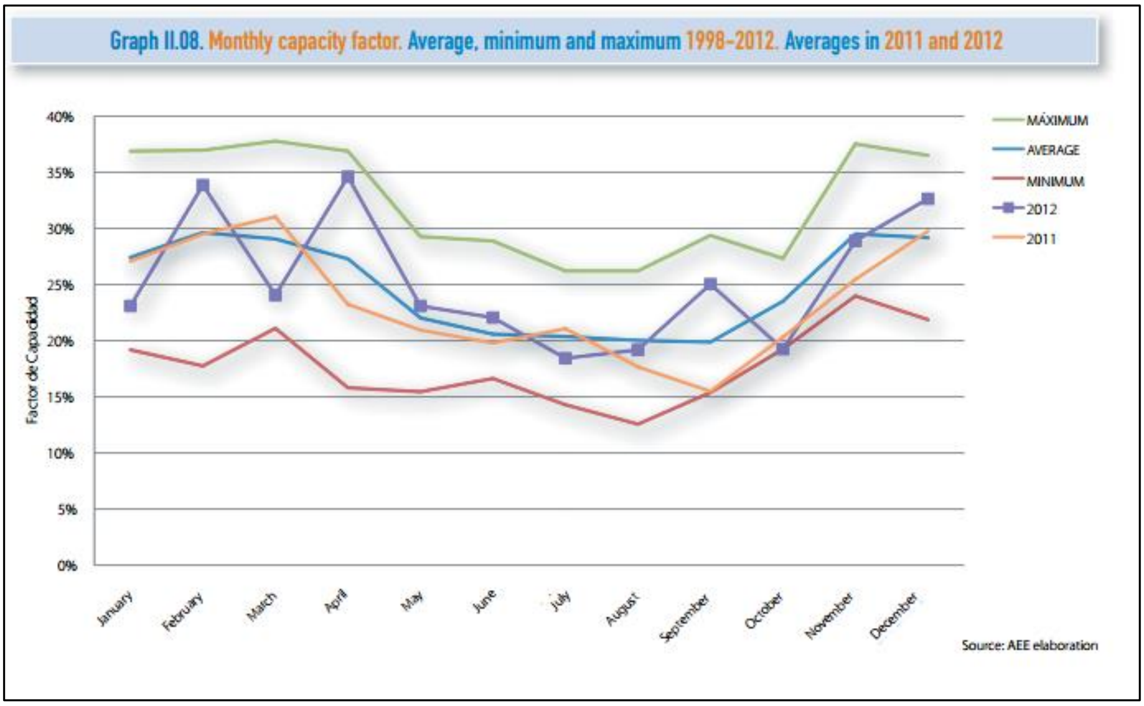


Figure 21: Monthly Wind Capacity Factors in Spain (1998-2012)

Source: (The Spanish Wind Energy Association (AEE), 2013)

When abundant wind production is present, Daily Market prices tend to be low and as a consequence, there is likely to be a large difference between the 2BP thus a large potential benefit. To illustrate this point, ***Figure 22*** below is the correlation plot of the Secondary Band Markup (potential benefit) compared with hourly Capacity Factor of wind for the entire MY 2013.

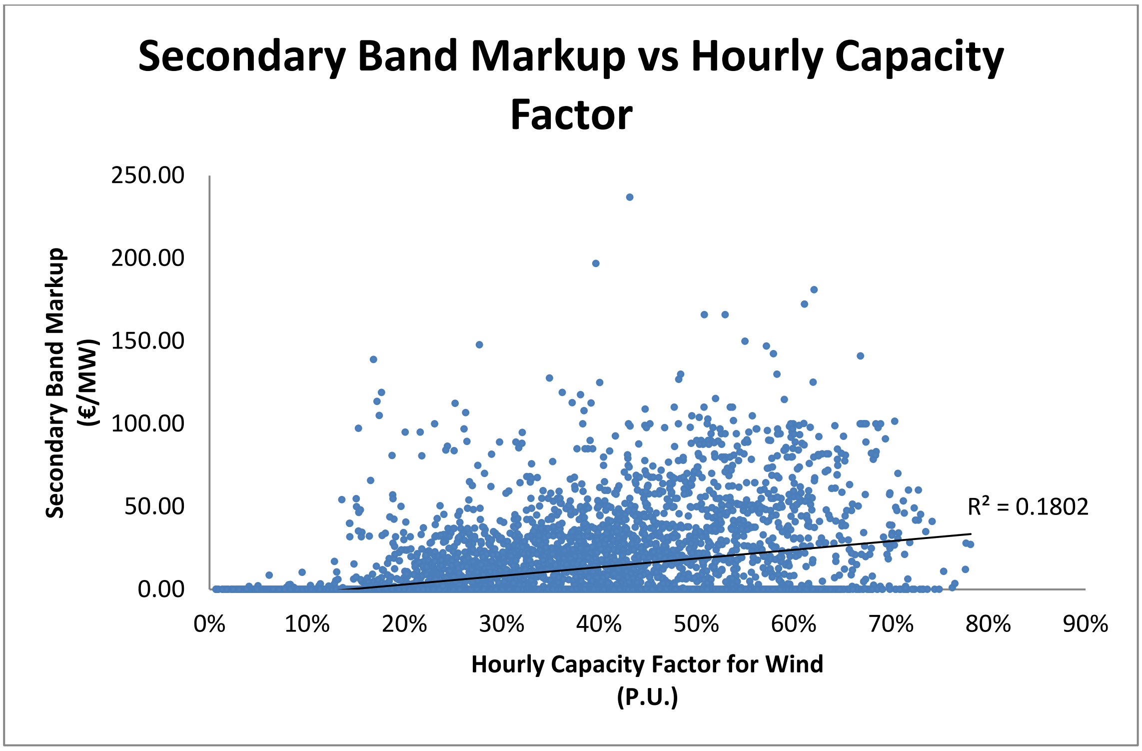


Figure 22: Correlation Plot of Secondary Band Markup vs. Hourly Capacity Factor

While the correlation is relatively weak, with an R^2 value of only 0.18 thus the linear tread-line only accounting for 18% of the data spread, it is positive and does constitute significance in financial terms. If merely the average yearly Capacity Factor was applied, this positive relationship is not taken into account in benefit valuation which, according to analysis throughout this thesis, can make over a 100 percent difference in the final calculation. Thus the importance of factoring the Secondary Band Markup by the *hourly* Capacity Factor is justifiable and has become to be denoted as the Potential Hourly Benefit (PHB) which is shown in ***Figure 23*** below.

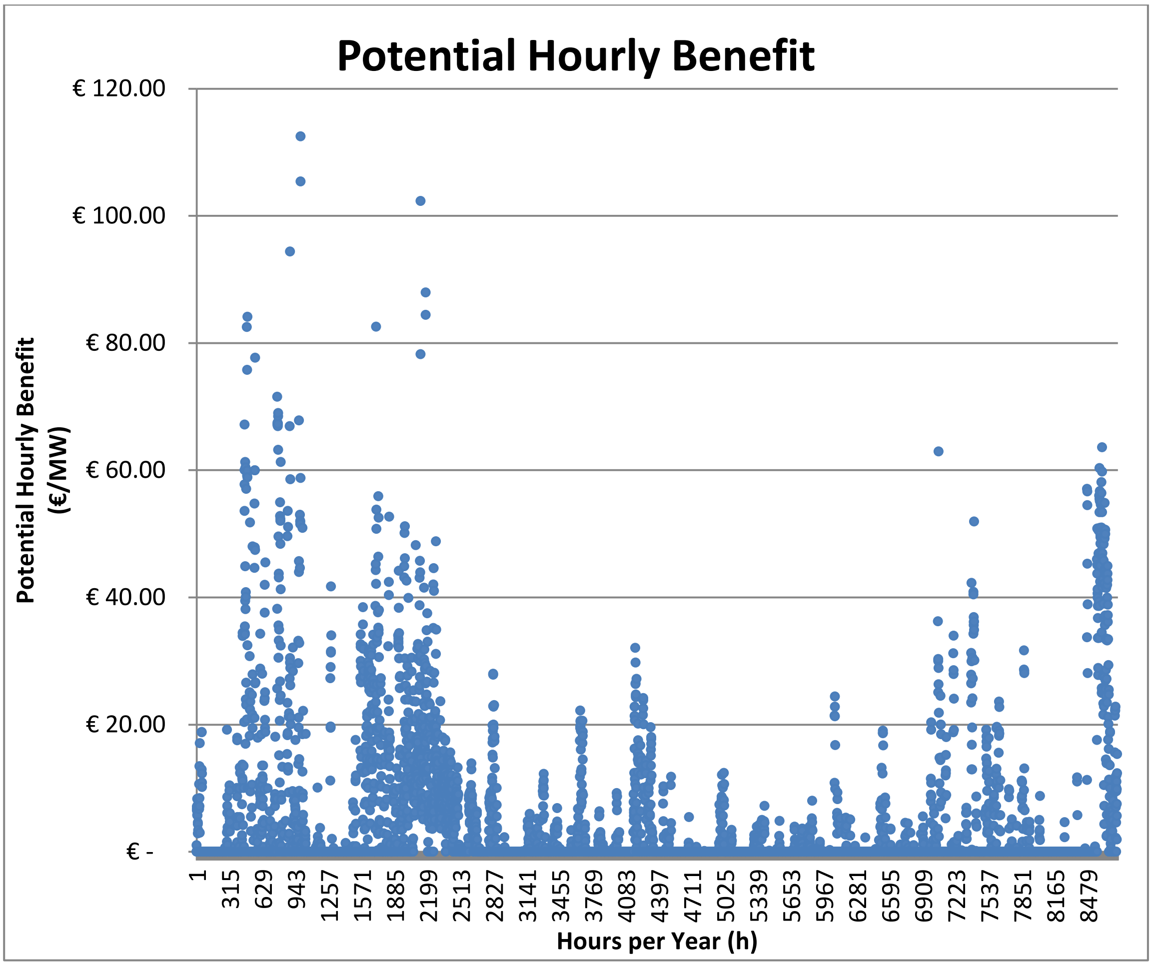


Figure 23: Potential Hourly Benefit (PHB) for 2013

As ***Figure 23*** is still chronological, this graphic is useful to show that there were both high amounts of wind production and high band prices in the months of January and February as well as in the later part of December. The highest point in 2013 is hour 990 which corresponds approximately to the middle of February (as would be expected in Spain as demonstrated by ***Figure 21***) with an PHB of 112.48 €/MW. **This means that every unitary MW of wind power would experience a €112.48 premium to the Daily Market if it could be sold as Secondary Band in this hour.** By rearranging this data into ascending values, the duration curve can be found as shown in ***Figure 24***.

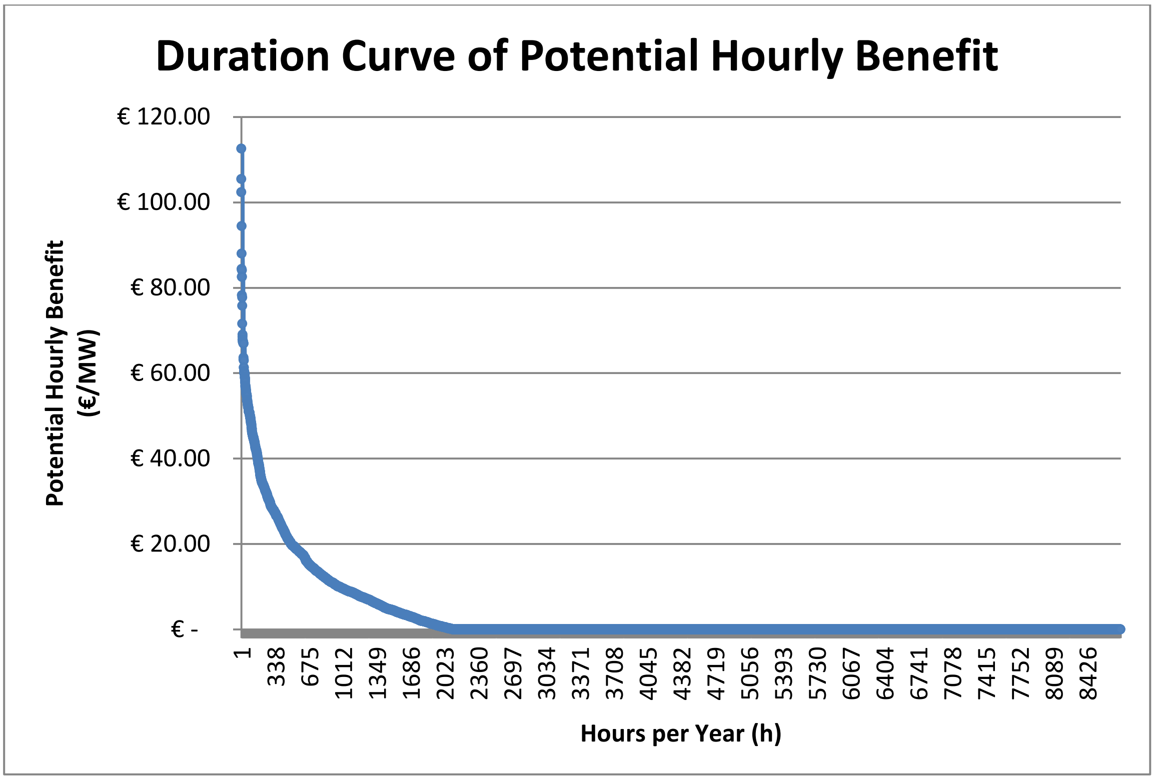


Figure 24: Duration Curve of PHB

The Duration Curve seen in ***Figure 24*** is a highly readable representation of the potential earnings from participation in the SRM. The 2,111 hours of positive benefit are clearly evident by the slope of the curve with the total amount of earnings possible throughout the year represented by the area under the curve. However the PHB metric does not take into account how much wind production could be reliably offered as Secondary Band at each Capacity Factor. Consequently, to develop a more valid representation of Effective Hourly Benefit (EFHB), a ***Realistic Band Offer*** must be taken into account.

Realistic Band Offer (RBO)

As previously mentioned in the ***Band Definition*** section, due to the reliability constraints associated with the offer of Secondary Band (seen in ***Figure 17***), it is necessary to quantify the magnitude of maximum deviation of the real-time (RT) wind production below the PDBF schedule throughout an hour; or, stated differently, the lowest point of real-time production throughout and hour. This data is important to know both what is the Upper Bound for the Secondary Band and to what level a wind producer would likely need to alter a production schedule (and result in the PHF schedule) to offer this maximum reliable band. The first point allows for the final calculation of potential earnings while the second point allows us to quantify the amount of power which would need to be managed in the Intraday market sessions for calculating the ***Intraday Barter Cost (IBC)***.

Quantifying Differences

To clarify, the difference in question is the real-time (RT) wind production subtracted from the PDBF schedule over each hourly period. Referring again to ***Figure 17***, this difference can be either positive or negative as the PDBF schedule is formed so as to be an average of RT production over an hour; at times the RT will be above the PDBF other times below the PDBF but the deviation overtime in both directions ideally is the same. It should be apparent that only the negative differences (which are caused when the RT production is *less* than the PDBF) is the data concerned as it is the minimum point which dictates the band boundary. Furthermore, as it is the magnitude which is relevant, the percentage difference as a factor of PDBF is a valid measurement and is what is presented here.

Descriptive Statistics and Normality Testing

The 10-minute interval RT production data given by (Red Electrica España (REE)) was first converted into hourly data by finding the minimum value across each hour and discarding the rest. The PDBF schedule dataset was then subtracted from the local minima dataset (denoted as Min RT) in each hourly period with the difference expressed in terms of the PDBF to develop the Percentage Difference Main Dataset according to the following equation:

$$Percentage\ Difference_h = \frac{(Min\ RT_h - PDBF_h)}{PDBF_h}$$

Equation 5

Descriptive statistics was performed to characterize the main dataset and generate the histogram seen in ***Figure 25***. Note that only the left hand side of the histogram (those values with negative difference) is relevant, yet for the sake of normality testing both sides are maintained here.

Table 6: Descriptive Statistics of Percentage Difference Main Dataset

Percentage Difference Main Dataset	
Mean	6.44%
Standard Error	0.18%
Median	6.26%
Mode	#N/A
Standard Deviation	17.19%
Sample Variance	2.95%
Excess Kurtosis	5.94
Skew	-0.25
Range	249.86%
Minimum	-153.00%
Maximum	96.86%
Sum	56448.44%
Data Count	8760
Confidence Interval (95.0%)	0.36%
Upper Bound (95%)	**28%**
IQR	17.55%
Weak Outlier Cutoff (-)	-28.93%
Weak Outlier Cutoff (+)	41.28%
Strong Outlier Cutoff (-)	-55.25%
Strong Outlier Cutoff (+)	67.60%

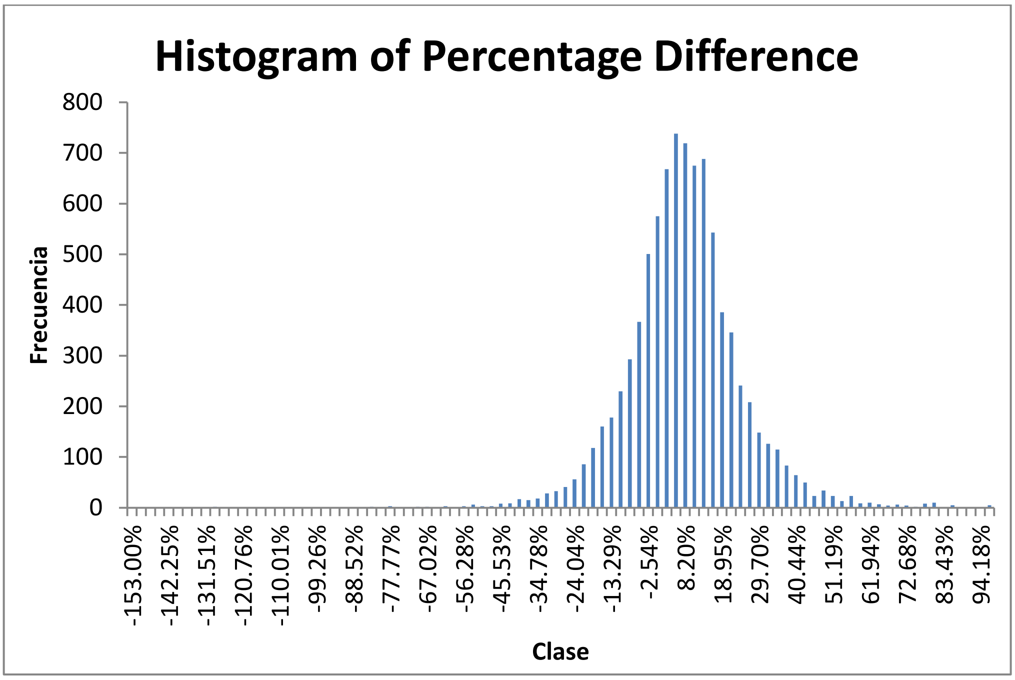


Figure 25: Histogram of Percentage Difference Main Dataset

Next, normality testing was conducted using the methodology proposed in (Harmon, 2011) and the P-P probability plot was developed as can be seen in ***Figure 26***.

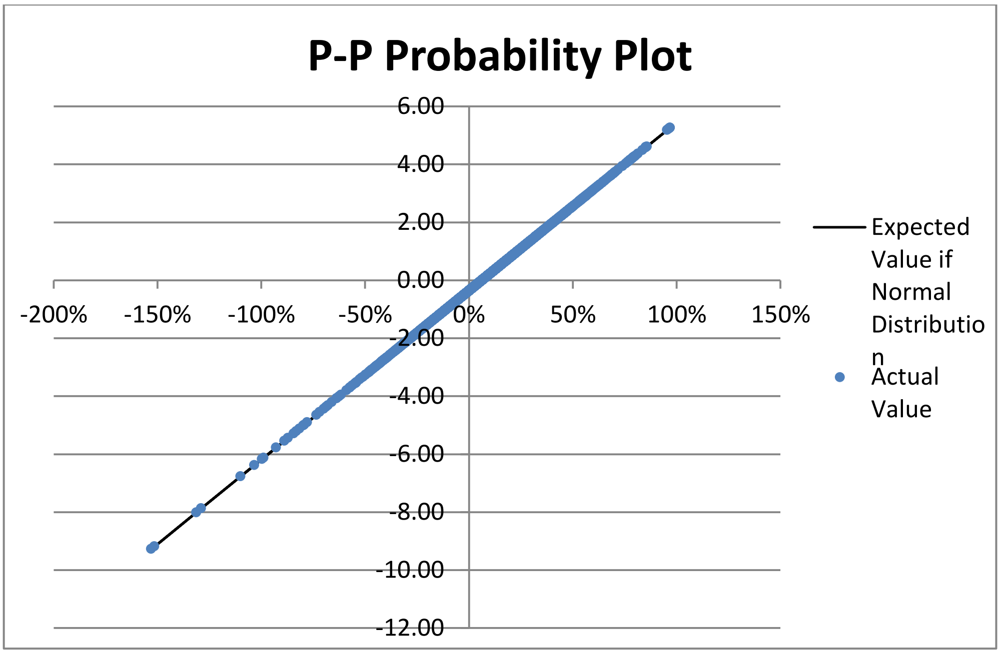


Figure 26: P-P Probability Plot of Percentage Difference Main Dataset

As can be seen by the P-P Probability plot and the Histogram, the main dataset is sufficiently normal albeit with a slight left/negative skew (-0.25) and a relatively large Excess Kurtosis (5.94, a normal distribution is 0) shown in the Descriptive Statistics. The relatively large Excess Kurtosis is created by extreme outliers which create long tails and distorts the measurement; likewise although both tails are long, the left tail is slightly longer thus contributing to a slight negative (left) Skew measurement.

Upper Bound Explained

As confirmed by the normality testing, the dataset is sufficiently close to a normal distribution such that it is possible to draw conclusions with this assumption. To reiterate, the intention with this dataset is to determine how far below the PDBF real-time wind production can be said to deviate, or in other words, what the Upper Bound of the Secondary Band is (referring again to ***Figure 17: Secondary Band Definition***). Each percentage difference data point (negative/left-hand side only) represents where the Upper Bound of the Secondary Band would be for each hourly point, thus to develop a more general definition a value is chosen based upon the entire year.

As denoted by the Three Sigma Rule in statistics, approximately 95% of a normal distribution is contained within 2σ (σ, sigma = standard deviation) of the mean as shown in ***Figure 27*** below.

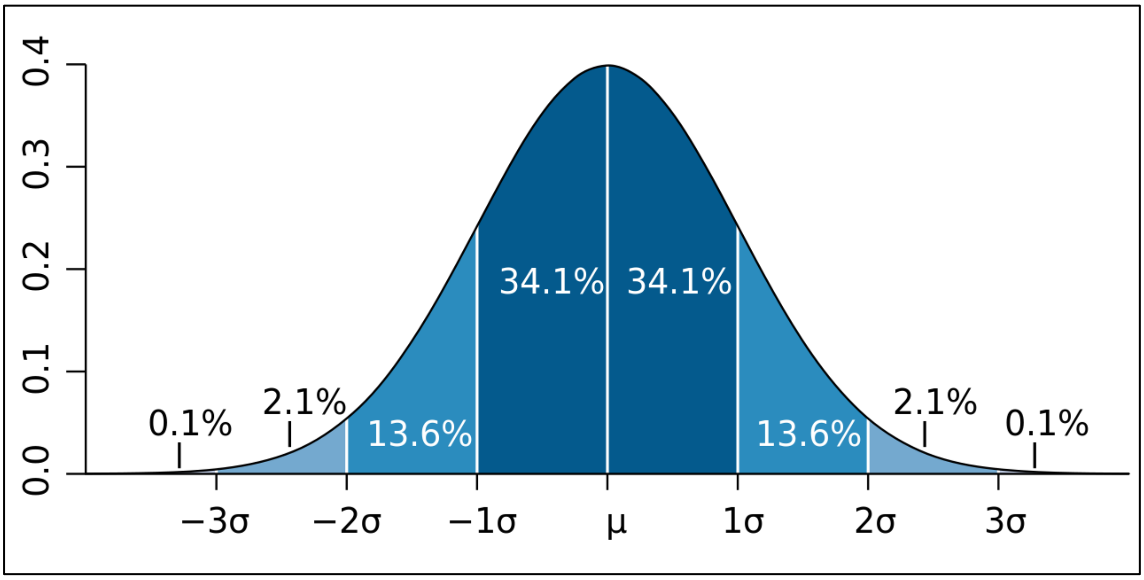


Figure 27: Three Sigma Rule

Source: Wikipedia Commons

Thus in order to incorporate a 95% confidence, meaning that 95% of the time the real-time production will be at or above the point chosen using this method, the Upper Bound is defined as the absolute value of the negative 2σ mark of the percentage difference dataset:

$$|\mu - 2\sigma|$$

abs(6.44% - 2 * 17.19%) = 28%

where μ is the mean and σ is the standard deviation. Again, as the negative or left-hand side of the main dataset represents when the real-time production is *below* the PDBF, choosing the Upper Bound of the Secondary Band using only the left-hand side of the main dataset is valid.

Outlier Detection

As previously mentioned, there are several extreme outliers present which can potentially enlarge the standard deviation and skew the mean. These extreme differences are well beyond the attributable error to Spanish wind forecast methods, which as of 2008 now are approximately 19% for day-ahead and less than 10% at the 4 hour mark with significant decreases closer to real-time (Gonzalez G., 2004); (Ramos, 2014). Accordingly, outliers were identified using the Interquartile Range (IQR) rule.

The Interquartile Range rule for defining outliers is a well-known method for outlier detection as the IQR is a robust metric that is resistant to extremes. This rule defines all weak outliers to be outside of the bounds 1.5*IQR and all strong outliers to be outside of the bounds 3*IQR. Consequently the upper and lower cutoff points are defined as follows:

- Weak Outlier Cutoff(-): Q1-1.5*IQR
- Weak Outlier Cutoff(+): Q3+1.5*IQR
- Strong Outlier Cutoff(-): Q1-3*IQR
- Strong Outlier Cutoff(+): Q3+3*IQR

where Q1 and Q3 are the first and third quartiles respectively and IQR is the Interquartile Range (Q3-Q1). As seen in ***Table 6***, the upper and lower cutoff values for weak outlier detection were 41.28% and -28.93% respectively. The histogram of the main dataset without the statistical outliers can be seen below in ***Figure 28*** as expressed by the descriptive statistics in ***Table 7***.

Table 7: Descriptive Statistics of Percentage Difference Main Dataset (minus outliers)

Percentage Difference Main Dataset (minus outliers)	
Mean	6.26%
Standard Error	0.14%
Median	6.18%
Mode	#N/A
Standard Deviation	13.23%
Sample Variance	1.75%
Excess Kurtosis	-0.06
Skew	0.04
Range	70.09%
Minimum	-28.87%
Maximum	41.23%
Sum	52416.90%
Data Count	8368
Confidence Interval (95.0%)	0.28%
Upper Bound (95%)	**20%**

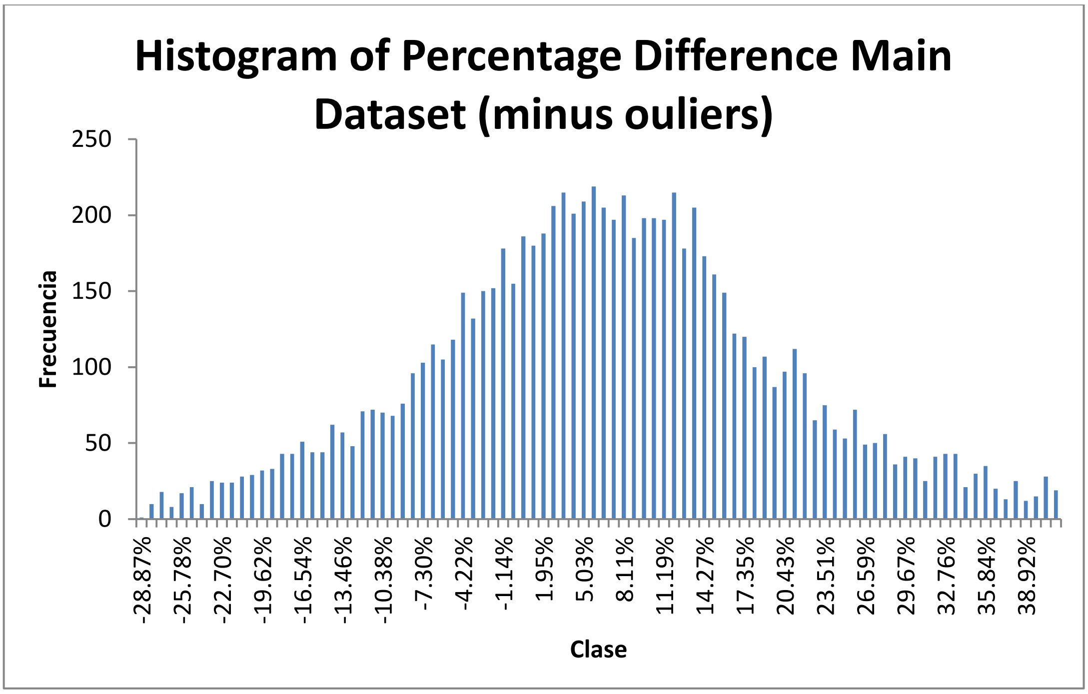


Figure 28: Histogram of Percentage Difference Main Dataset (minus outliers)

Notice that when outliers are disregarded, the Excess Kurtosis (-0.06) is much closer to normal (0) with the negative value indicating that the dataset is slightly flatter which can be readily seen in the ***Figure 28: Histogram of Percentage Difference Main Dataset (minus outliers)***. Skew (0.04) as well is closer to normal (0) with the positive value indicating a slight right skew. However the most relevant difference seen by eliminating outliers is the Upper Bound, which drastically changes from 28 to 20 percent. As this effectively means that 8% more Secondary Band can be offered, outlier detection and removal is a relevant concern in the analysis.

Further Quantifying Differences

Although the full dataset does provide a general conclusion about the Upper Bound of the Secondary Band, as economic viability is the central question of this research, hours which experience a positive EFHB are the only hours which are relevant; thus defining the band based upon profitability criteria is reasonable. Furthermore, only hours with high amounts of wind production (thus a large Capacity Factor) as well would be viable due to the nature of a fixed Lower Bound of the Secondary Band (referring again to ***Figure 17: Secondary Band Definition***). Therefore, the main dataset was filtered for the 2,111 hours of positive EFHB and the following Capacity Factor filters were applied additionally to create the CF30, CF40, CF50, and CF60 datasets:

- CF>= 30%
- CF>= 40%
- CF>= 50%
- CF>= 60%

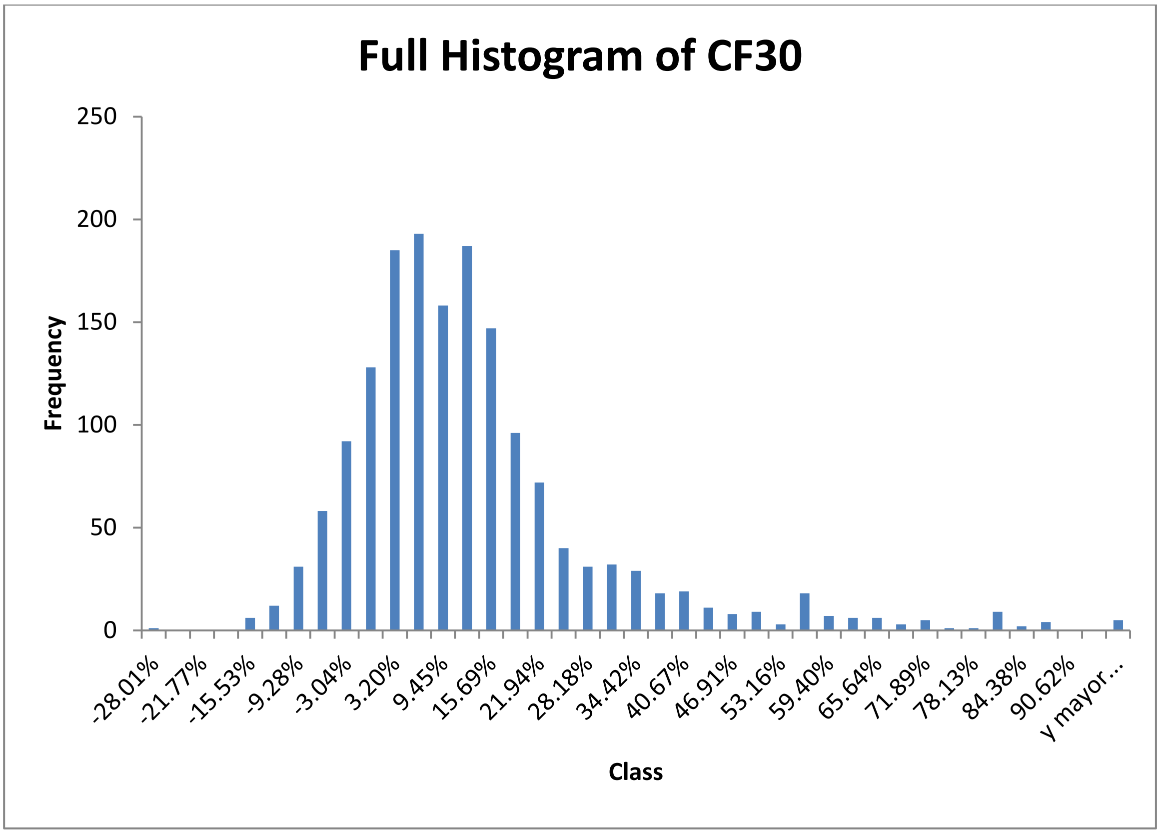


Figure 29: Histogram of CF30 Dataset

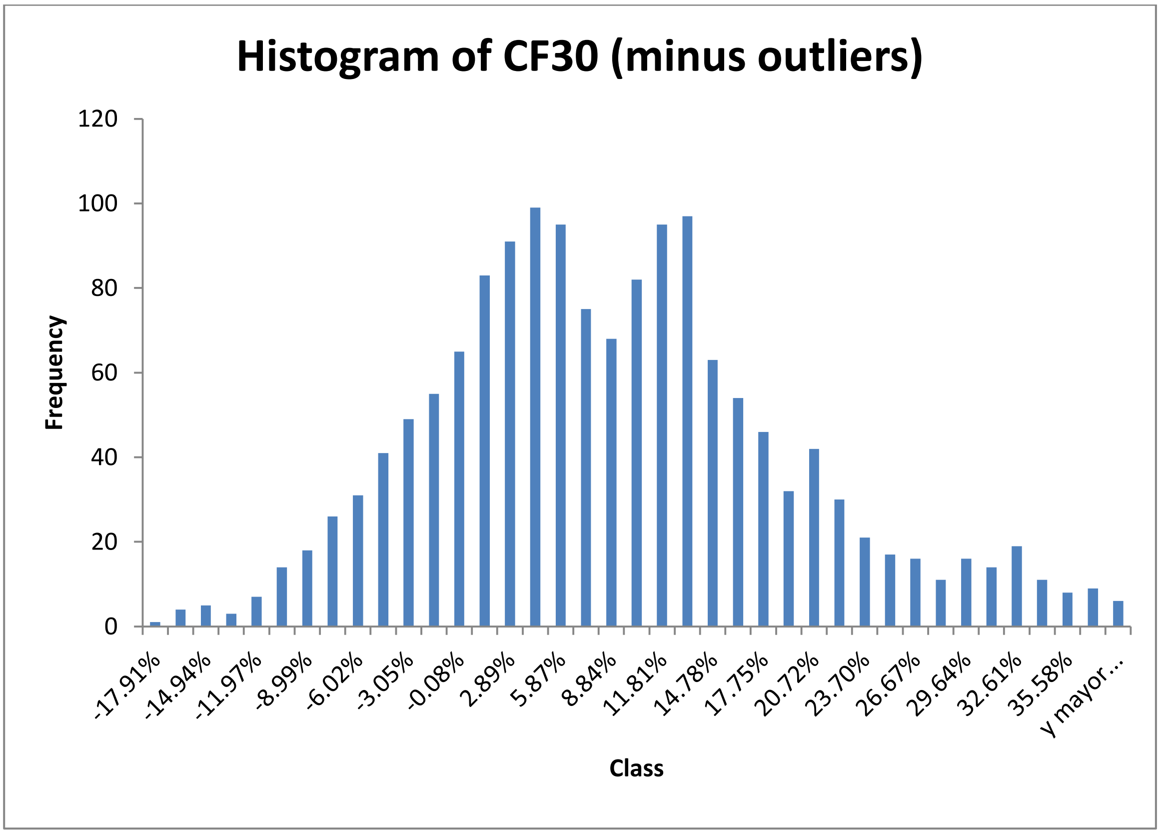


Figure 30: Histogram of CF30 Dataset (minus outliers)

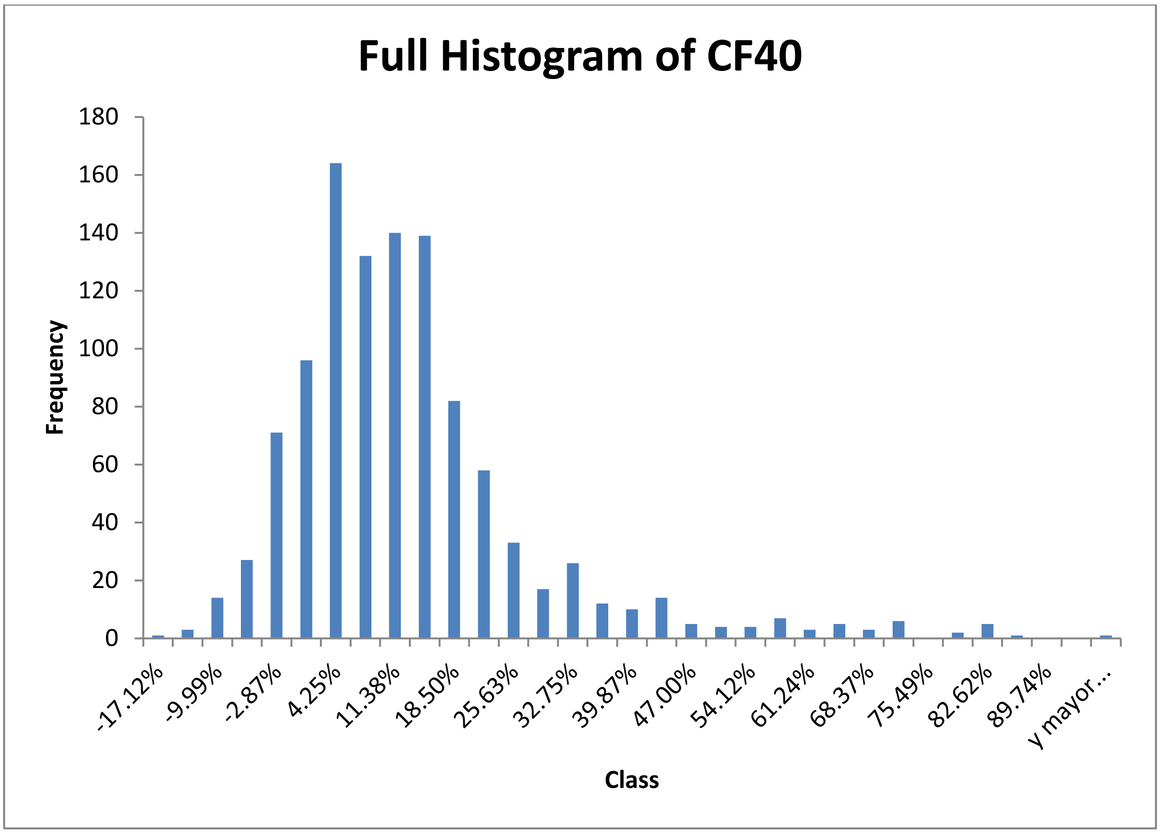


Figure 31: Histogram of CF40 Dataset

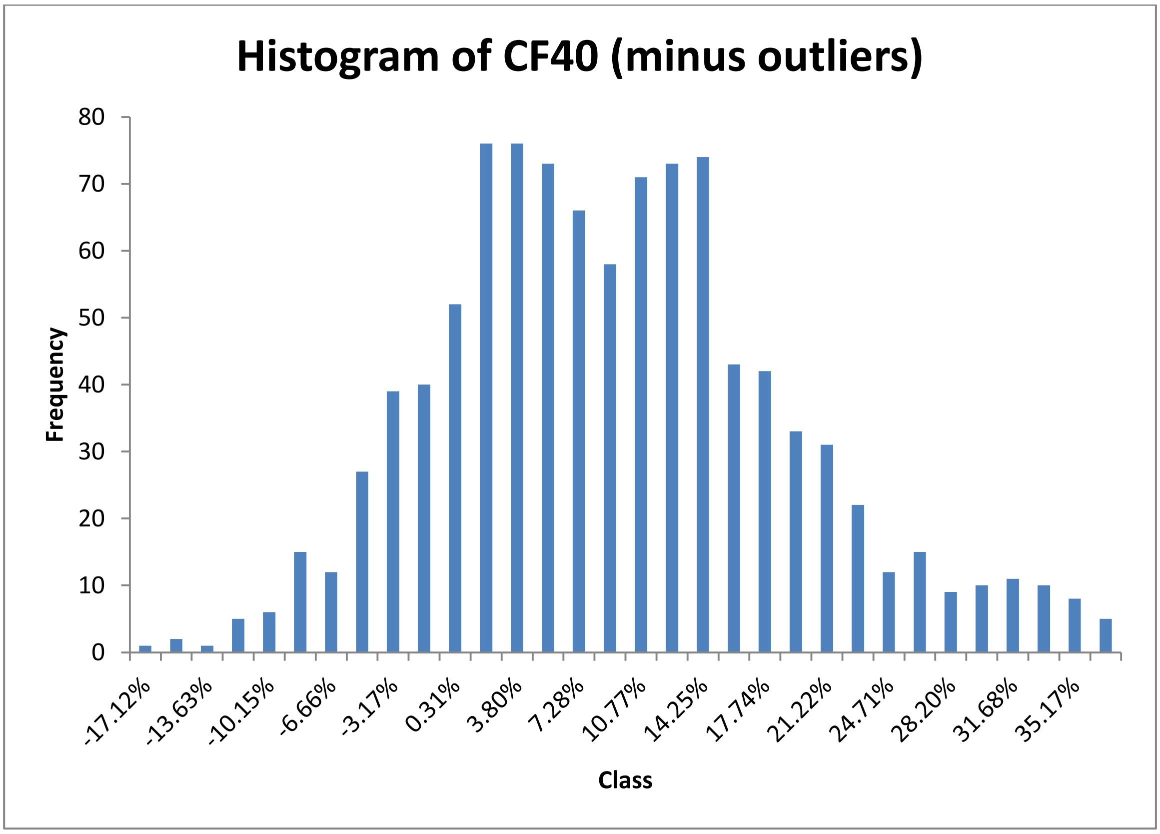


Figure 32: Histogram of CF40 Dataset (minus outliers)

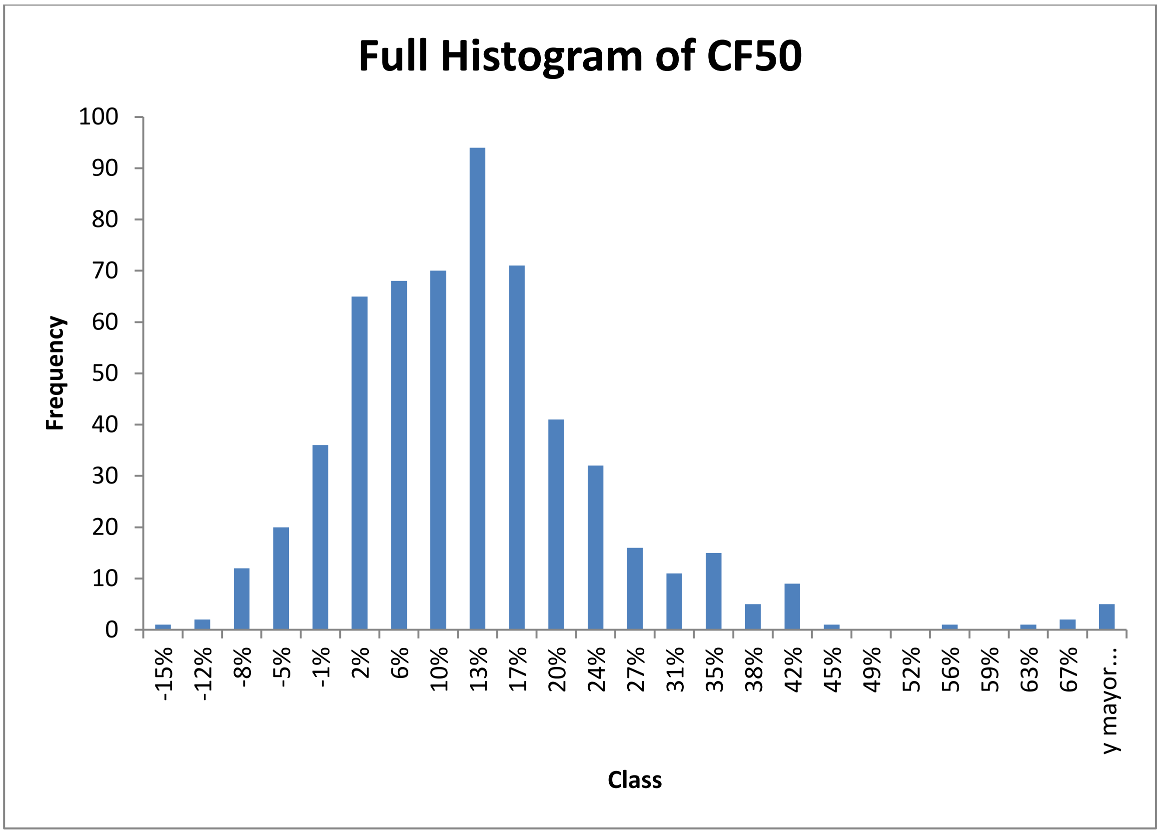


Figure 33: Histogram of CF50 Dataset

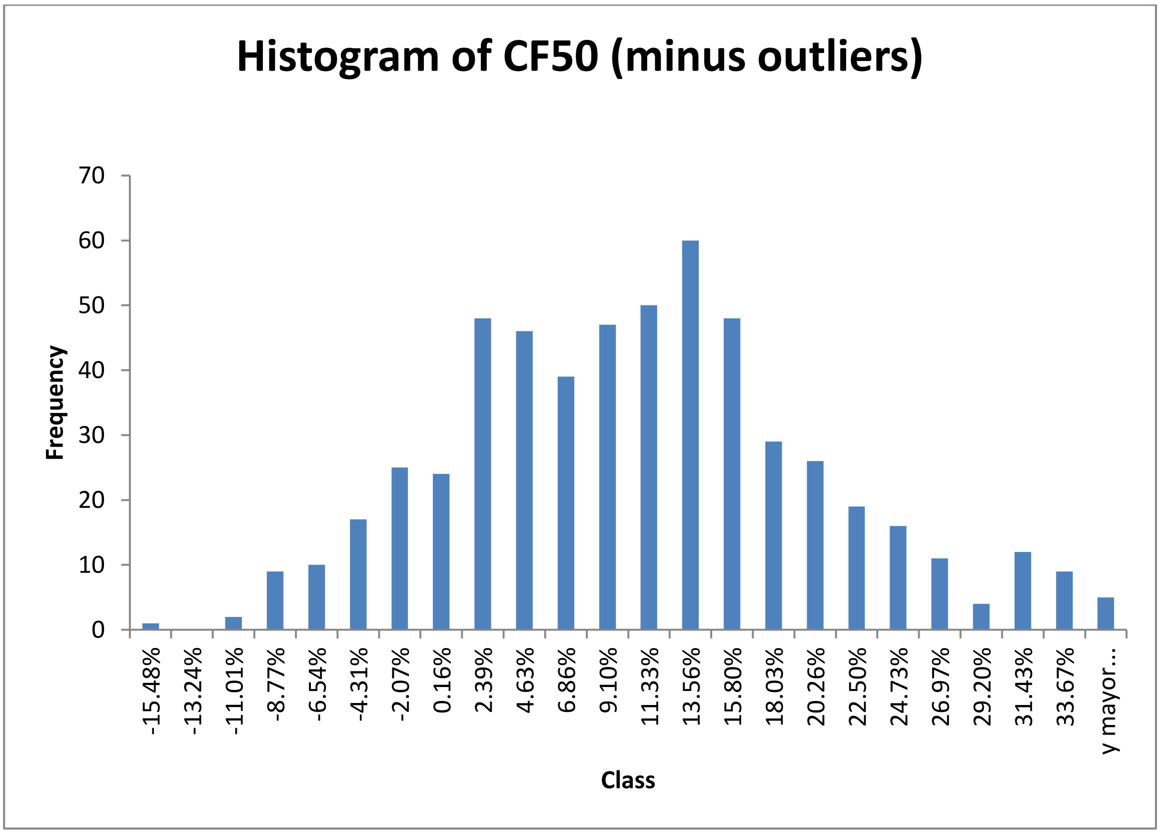


Figure 34: Histogram of CF50 Dataset (minus outliers)

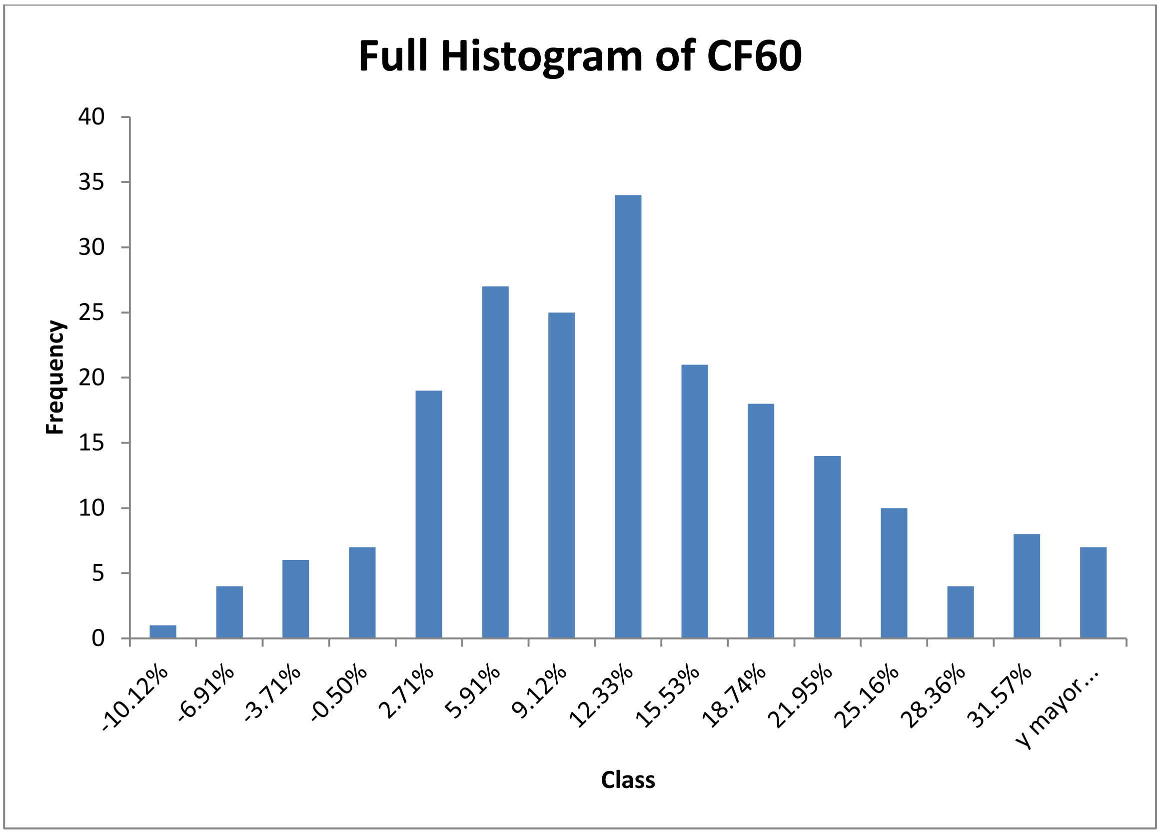


Figure 35: Histogram of CF60 Dataset

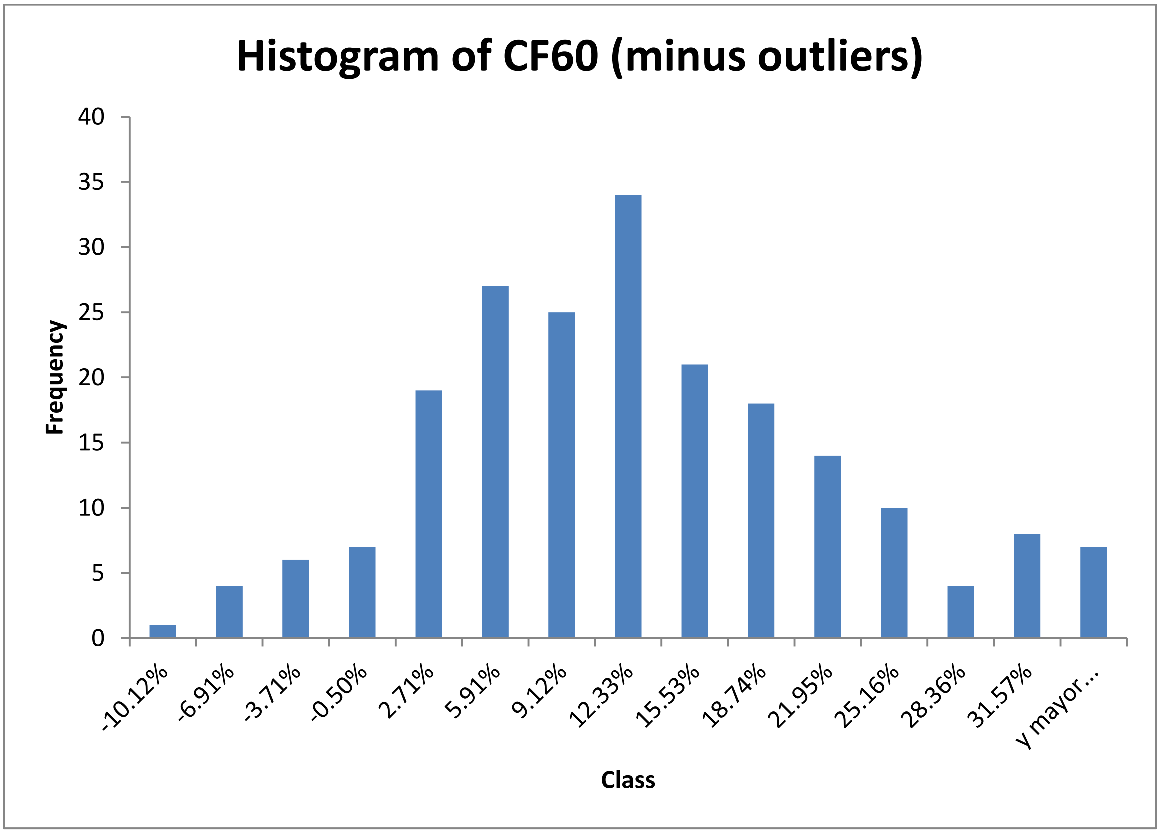


Figure 36: Histogram of CF60 Dataset (minus outliers)

Similarly, normality testing and outlier removal were performed according to the previously explained methods to determine the Upper Bound during relevant hours. All datasets were deemed sufficiently normal and are represented below in Table 8.

Table 8: Descriptive Statistics for Filtered Datasets (minus outliers)

CF30 (minus outliers)	
Mean	8.21%
Standard Error	0.00
Median	7.34%
Mode	#N/A
Standard Deviation	10.47%
Sample Variance	0.01
Excess Kurtosis	0.08
Skew	0.43
Range	56.47%
Minimum	-17.91%
Maximum	38.56%
Sum	12478.33%
Data Count	1519
Confidence Interval (95.0%)	0.53%
Upper Bound (95%)	**13%**

CF40 (minus outliers)	
Mean	8.49%
Standard Error	0.31%
Median	7.85%
Mode	#N/A
Standard Deviation	9.78%
Sample Variance	0.01
Excess Kurtosis	0.07
Skew	0.41
Range	54.03%
Minimum	-17.12%
Maximum	36.91%
Sum	8647.83%
Data Count	1018
Confidence Interval (95.0%)	0.60%
Upper Bound (95%)	**11%**

CF50 (minus outliers)	
Mean	9.67%
Standard Error	0.41%
Median	9.65%
Mode	#N/A
Standard Deviation	9.77%
Sample Variance	0.01
Excess Kurtosis	-0.12
Skew	0.27
Range	51.38%
Minimum	-15.48%
Maximum	35.90%
Sum	5387.00%
Data Count	557
Confidence Interval (95.0%)	0.81%
Upper Bound (95%)	**10%**

CF60 (minus outliers)	
Mean	11.14%
Standard Error	0.01
Median	10.41%
Mode	#N/A
Standard Deviation	9.58%
Sample Variance	0.1
Excess Kurtosis	-0.10
Skew	0.39
Range	44.90%
Minimum	-10.12%
Maximum	34.78%
Sum	2283.88%
Data Count	205
Confidence Interval (95.0%)	1.32%
Upper Bound (95%)	**8%**

An interesting point is that even when filtering for relevant hours using several different parameters, the final datasets display similar calculations of the Upper Bound, merely ranging from 8-13%. Hence, **it was concluded that the Upper Bound would be defined as 13% below the PDBF** and that this relationship held for all hours which experienced a Capacity Factor of 30% and above. With a clear definition of the Secondary Band in place, a ***Realistic Band Offer*** can be developed by investigating the relationship between the Secondary Band and the Capacity Factor as explained in the following section.

Band Relationship

As both the Secondary Band and the Capacity Factor (as defined in ***Equation 4***) are expressed in terms of the PDBF schedule, it is possible to generate a general relationship between them. The Secondary Band can be formally defined as having an Upper Bound of 13% below the PDBF and a Lower Bound of 25% of Installed Capacity. Expressed differently, the Upper Bound can be said to be 87% of the PDBF schedule while the Lower Bound is fixed to 25% of the Installed Capacity. As the Capacity Factor is expressed in terms of the PDBF and Installed Capacity as well, it is possible to represent the Secondary Band as a percentage of the Installed Capacity which could be offered at each Capacity Factor level. This relationship has been denoted as the ***Realistic Band Offer*** (RBO) and has been defined as follows:

$$RBO = CF * 0.87 - 0.25$$

Equation 6

Using the example of a Capacity Factor of 75%, meaning that the PDBF production is 75% of the Installed Capacity, the RBO is calculated as: **CF75%*0.87=> 65.25% - 25% = 40.25%** of Installed Capacity. This calculation has been has been extended across all Capacity Factors experienced in MY 2013 to create a general relationship visible in ***Figure 37*** below.

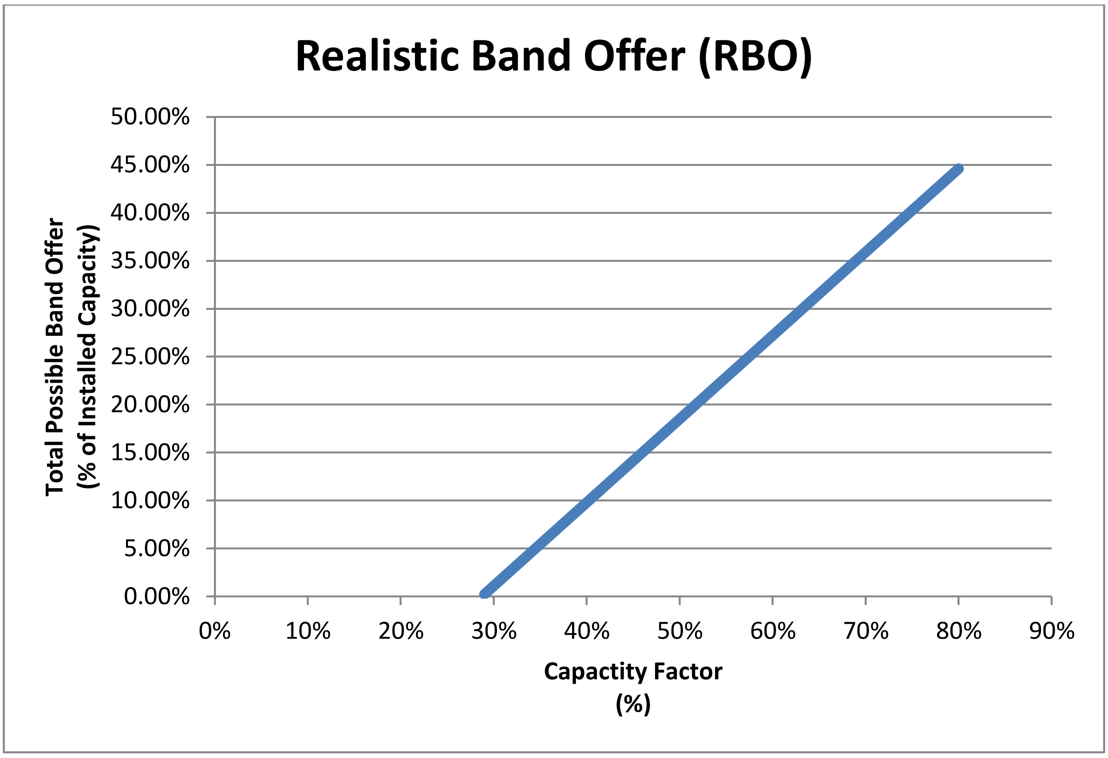


Figure 37: Realistic Band Offer Relationship

As can be seen in ***Figure 37***, only those hours which have a Capacity Factor of 29% or greater can any band be offered thus constituting another profitability criterion. The linearity of the RBO relationship is due to the assumption of a 13% maximum deviation of RT below PDBF for all Capacity Factors above 30% as explained in the previous section.

Reliable Band Offer (RBO) Summary

To summarize the Reliable Band Offer (RBO) concept, a wind turbine/farm/cluster will have an Installed Capacity of which only a portion will be readily available at any given moment. This percentage of available power is known as the Capacity Factor and (as defined by this research) equates to what percentage of Installed Capacity the PDBF schedule is at each hour. As the PDBF is an expected average, real-time wind production is not equal at all times and therefore it is necessary to quantify the minimum point of RT production below the PDBF to generate a realistic Secondary Band Upper Bound. After statistical analysis, this difference was found to be 13% below the PDBF.

With this data, a relationship between the Capacity Factor and the maximum amount of Secondary Band which could reliably be offered can be developed as seen in ***Figure 37***. Using the RBO relationship, a more realistic estimate of potential yearly earnings can be made by factoring the PHB by the RBO thus resulting in the Effective Hourly Benefit (EFHB) seen in ***Equation 3***. The RBO concept is best explained graphically and can be seen in ***Figure 38*** below.

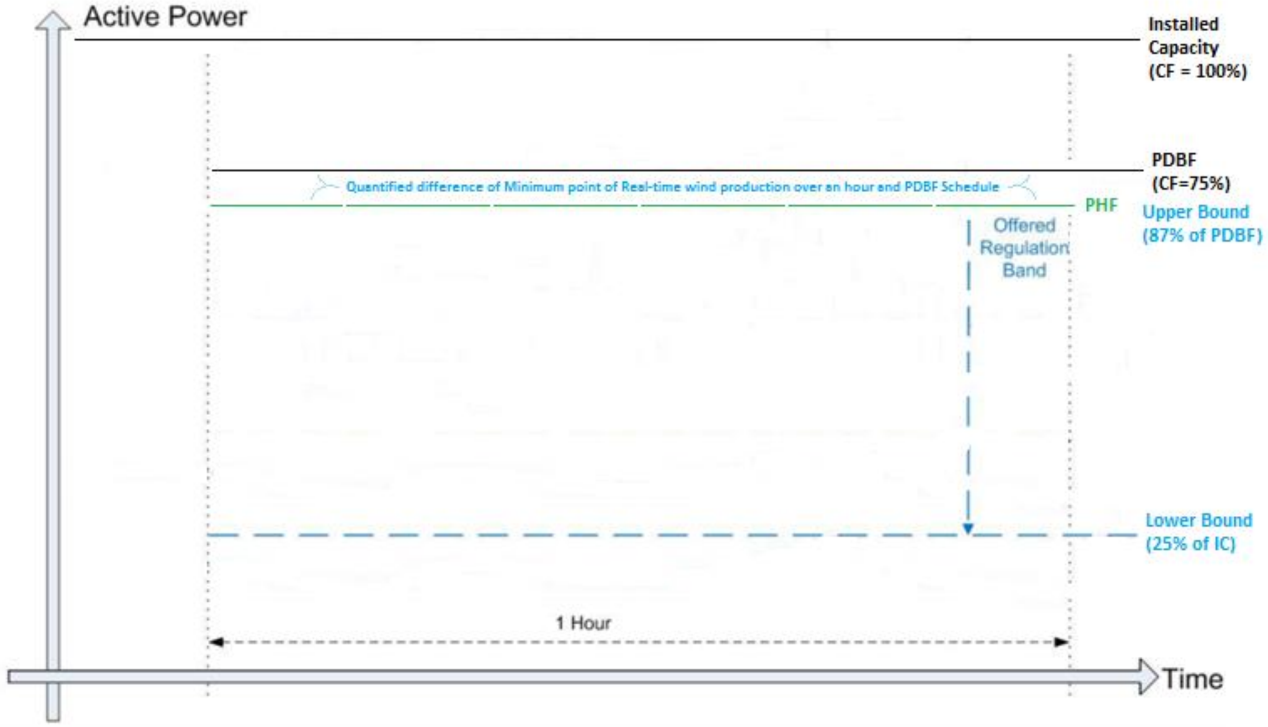


Figure 38: RBO Concept Explained

This concludes the considerations of unitary megawatt direct market revenues or the primary effects seen in the ***Estimated Capturable Income (ECI)*** equation. However the secondary effects, otherwise known as the ***Intraday Barter Cost (IBC)***, are still relevant as a wind producer can face large penalties for unapproved deviations. As provision of Secondary Reserves would likely require a wind producer to change from a PDBF schedule to that which would allow for the maximum amount of band offer, this change must be managed by participation in the Intraday Market. The difference between the PDBF and this resulting PHF schedule then would essentially reflect the energy that must be managed in the Intraday Market. If the Intraday Market price is greater than the Daily Market price, there is a cost involved for changing to a new schedule and if the opposite is true, a benefit. Thus the next section of this thesis explains the Intraday Barter Cost (IBC) and its relevance to the ***Estimated Capturable Income (ECI)***.

Intraday Barter Cost (IBC)

In short, Intraday Barter Cost arises in situations when the Intraday Market price is greater than the Daily Market price as there is a cost involved for changing from the PDBF schedule. Likewise, there is a possibility of a benefit when the IM price is lower than the DM price. Hence the sign of the variable is important and the Intraday Barter Cost (IBC) is added exogenously in the ECI equation.

As explained in ***Chapter 3: Spanish Electricity Market Overview***, the Intraday Market consists of six sessions in which a power producer can bid to alter their PDBF schedule beginning at

17:00 the day before (D-1) and ending at 18:45 the day of (D). However, not all hours are available for bidding in all sessions as demonstrated by ***Table 9*** below, where an example from the 1st of January 2013 can be found. Therefore an algorithm to calculate the IBC, otherwise the additional cost over the Daily Market price *per unitary megawatt per hour,* was designed with this hourly limitation in mind.

Table 9: Intraday Market Session Example

Date	Hour	Session 1	Session 2	Session 3	Session 4	Session 5	Session 6	Session 7 = Session 1 (D-1)
1/1/2013	1	49.01	49.01					
1/1/2013	2	50.00	54.84					
1/1/2013	3	40.01	30.00					
1/1/2013	4	50.00	42.00					
1/1/2013	5	30.00	35.01	45.00				
1/1/2013	6	26.00	35.01	45.02				
1/1/2013	7	26.00	34.01	42.00				
1/1/2013	8	26.00	35.01	37.01	21.00			
1/1/2013	9	35.70	26.00	40.01	21.00			
1/1/2013	10	35.70	35.70	41.02	21.00			
1/1/2013	11	37.01	35.70	45.00	30.00			
1/1/2013	12	43.31	46.81	45.05	40.31	42.89		
1/1/2013	13	46.00	47.45	43.31	39.00	46.08		
1/1/2013	14	40.01	46.07	43.31	37.00	44.03		
1/1/2013	15	42.00	47.45	46.09	46.09	44.03		
1/1/2013	16	35.70	46.81	35.70	42.31	40.01	35.00	
1/1/2013	17	35.70	46.81	37.31	47.45	35.70	28.35	
1/1/2013	18	44.01	47.45	47.45	42.31	46.02	35.19	
1/1/2013	19	49.39	52.84	47.95	47.95	55.48	43.22	
1/1/2013	20	51.06	54.69	51.06	52.49	57.46	55.48	
1/1/2013	21	55.00	57.46	53.25	55.00	61.28	50.00	52.52
1/1/2013	22	61.61	62.07	58.11	60.77	64.65	52.11	60.00
1/1/2013	23	62.07	62.07	58.35	60.77	63.22	50.57	58.00
1/1/2013	24	54.29	57.93	53.57	53.57	55.86	47.32	48.57

IBC Algorithm

The fundamental premise of the algorithm is that a wind agent will only purchase power for a given hour in a given IM session when the price is less than or equal to the DM price; if not, the agent would prefer to wait until the next market session. If the final session arrives in which the hour in question can be bought and the ideal condition has not been encountered, the agent will be forced to buy power and pay whatever price difference occurs to avoid penalties for deviation. Thus the hourly Intraday Barter Cost (IBC) is the difference between the hourly Daily Market Price (DMP) and the Intraday Market Price (IMP) in Hour h, Day d, and Session x. The daily IBC is the sum of all hourly IBC throughout a day and the final IBC is the sum of all daily IBC throughout a year for those hours which satisfy the ***Profitability Criteria Definition*** further elaborated in Chapter 5. The algorithm for calculating IBC is demonstrated in the flowchart seen in ***Figure 39*** below, starting from the first hour in the first day in the first Intraday Market session (h = 1, d=1, x=1).

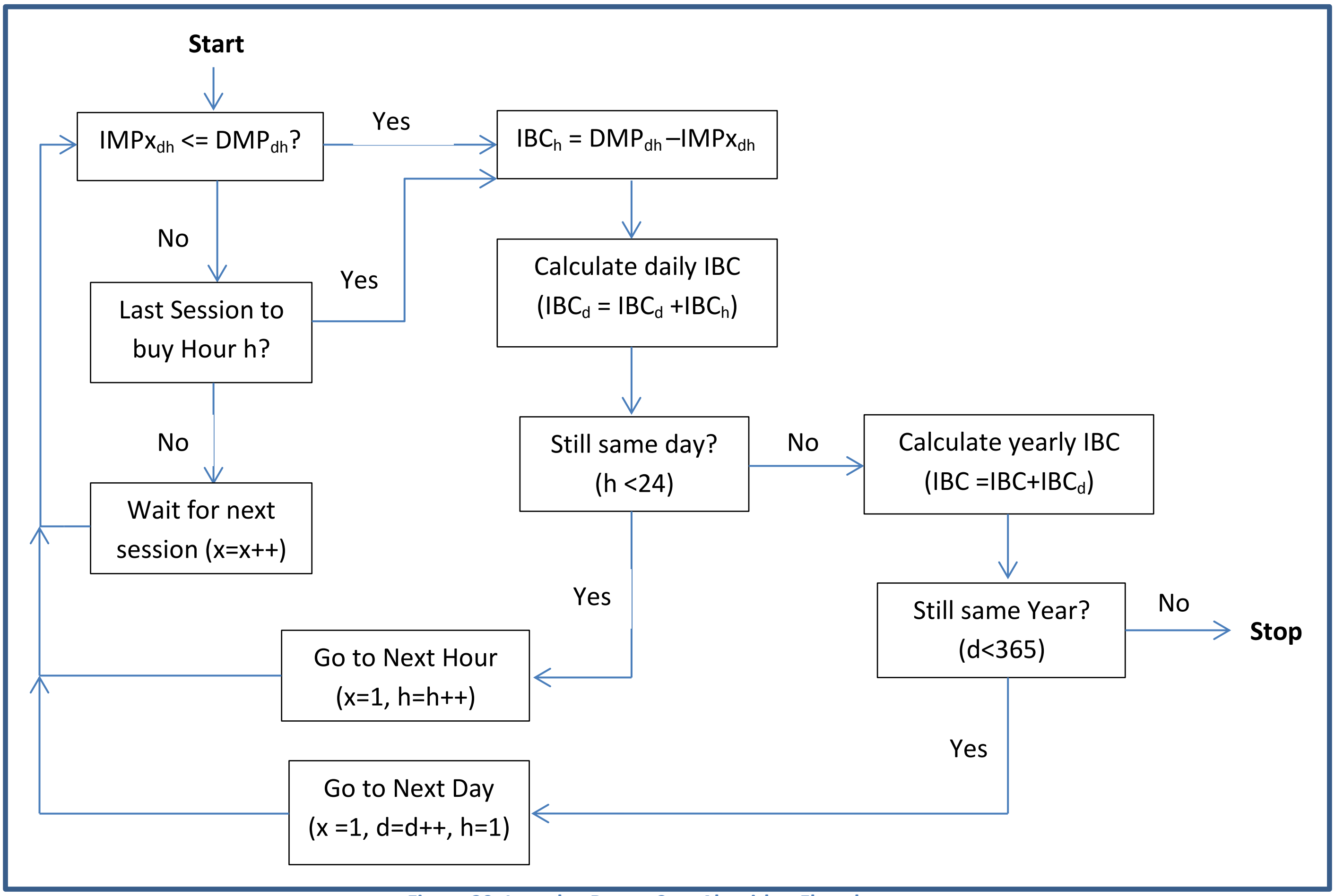


Figure 39: Intraday Barter Cost Algorithm Flowchart

Production Factors

All previous calculations of revenue and cost in the ECI have only taken the unitary megawatt considerations into account (€/MW). However to properly calculate the total expected revenue, the unitary amounts must be multiplied by a factor which represents the amount of production (number of megawatts) in question. For the case of the EFHB, the factor (B) represents the total amount of production which can be offered as Secondary Band. In the case of IBC, the factor (C) represents the total amount of production which must be managed in the Intraday Market.

As seen in ***Figure 38: RBO Concept Explained***, the Secondary Band is represented in terms of the PDBF schedule and the Installed Capacity. The Secondary Band (thus the amount of production which is offered as band, B) is the difference between the Upper and Lower Bounds. Similarly, the amount of production which must be managed in the Intraday market (Factor C) is the difference between the PDBF schedule and the PHF schedule (PHF is also the Upper Bound of the Secondary Band). The production factors, therefore, are dynamic and are dependent on the PDBF schedule which can be found by applying the Capacity Factor to the Installed Capacity in each hourly period.

Furthermore, as it is imperative that the ***Estimated Capturable Income (ECI)*** be comparable to the ***Investment Cost Assumptions***, these production factors must be developed within the same framework. Thus each production factor has been created using an Installed Capacity of 488 MW of wind power as this was the total Installed Capacity used in the ***Investment Cost Assumptions***. Using an example with a Capacity Factor of 50%, the calculation of the production factors are as follows.

Table 10: Example Calculation of Production Factors using CF=50%

Concept	Calculation	Result	Factor B	Factor C
Capacity Factor	-----------------	50%		
Installed Capacity	-----------------	488 MW		
PDBF Schedule	IC*CF	244 MW		
Upper Bound	87% of PDBF	212 MW		32 MW
Lower Bound	25% of IC	122 MW	90 MW	

Thus to complete the Estimated Capturable Income equation,

$$\boldsymbol{ECI = \sum_{h} (B_h * EFHB + C_h * IBC_h)}$$

Equation 7

Chapter 5: Results

This Chapter focuses on the expected revenue from participation in the Secondary Market for a wind producer, beginning with a ***Parameterization of Profitability*** where the conditions of profitability are presented. Next, a discussion of ***Strategy*** to maximize profits in the Secondary Reserves Market is presented where two different strategies are assessed.

Parameterization of Profitability

This section formally defines the criteria of profitability for participation of a wind agent in the Secondary Market and demonstrates the implications of such criteria. This section begins with a ***Profitability Criteria Definition***, then elaborates on the ***ECI Calculation Uncertainty*** from which profits are calculated, ending with a ***Parameter Optimization*** to give the final results of the profitability analysis.

Profitability Criteria Definition

In previous sections throughout the narrative, various conditions of market participation which would result in profits have been identified. These conditions can be understood to be either hard or soft criteria. Hard criteria entail that they must be satisfied to result in profits while soft criteria entail that they are not required but may be preferred.

Hard Criteria

The first and most evident criterion is that there must be a *positive Secondary Band Markup*, or stated otherwise, the Secondary Band Price must be greater than the Daily Market Price. As mentioned previously, this requirement limits the dataset to 2,111 considerable hours for MY 2013. The second hard criterion is derived from the RBO relationship (seen in ***Figure 37***), which shows that only for *Capacity Factors greater than or equal to 29%* will band be available to offer; thus further filtering the considerable hours to 1,686.

The Capacity Factor criterion however can be viewed as sliding scale which allows for considerations of different ranges of Capacity Factors while maintaining the hard limits of 29%-100%. This variability allows for calculation of the ***Estimated Capturable Income (ECI)*** which takes into account both limits due to ***ECI Calculation Uncertainty*** and allows for ***Parameter Optimization*** as further explained in the following sections of the same names. After the two hard criteria are implemented, additional criteria can be identified as significant contributing factors to profitability which however may not need to be satisfied to result in profits.

Soft Criteria

The initial analysis, when looking at the 1,686 relevant hours, resulted in an unexpectedly large yearly ***Intraday Barter Cost*** of -€2,671.95 per MW per year. As this is a significant portion of the yearly ***Effective Hourly Benefit (EFHB)*** of €5,464.12 per MW per year, additional analysis was conducted to identify from where the unexpected costs were arising. It was concluded based on expert advice, that in Valley Hours (hours 0-8), the price of the Daily Market is typically very low while the Intraday price remains high. As there is no well-defined and measurable correlation between market factors and the Intraday Market price, an additional criterion of *Valley Hour elimination* was implemented to lower costs and, in turn, increase profitability. When enacting this criterion the relevant dataset decreased to 857 hours and the IBC drastically changed from -€2,671.95 to -€351.53 per MW per year. The reason for this drastic change in the yearly IBC is evident when comparing the daily IBC with and without Valley Hour elimination as seen in ***Figure 40*** and ***Figure 41*** below.

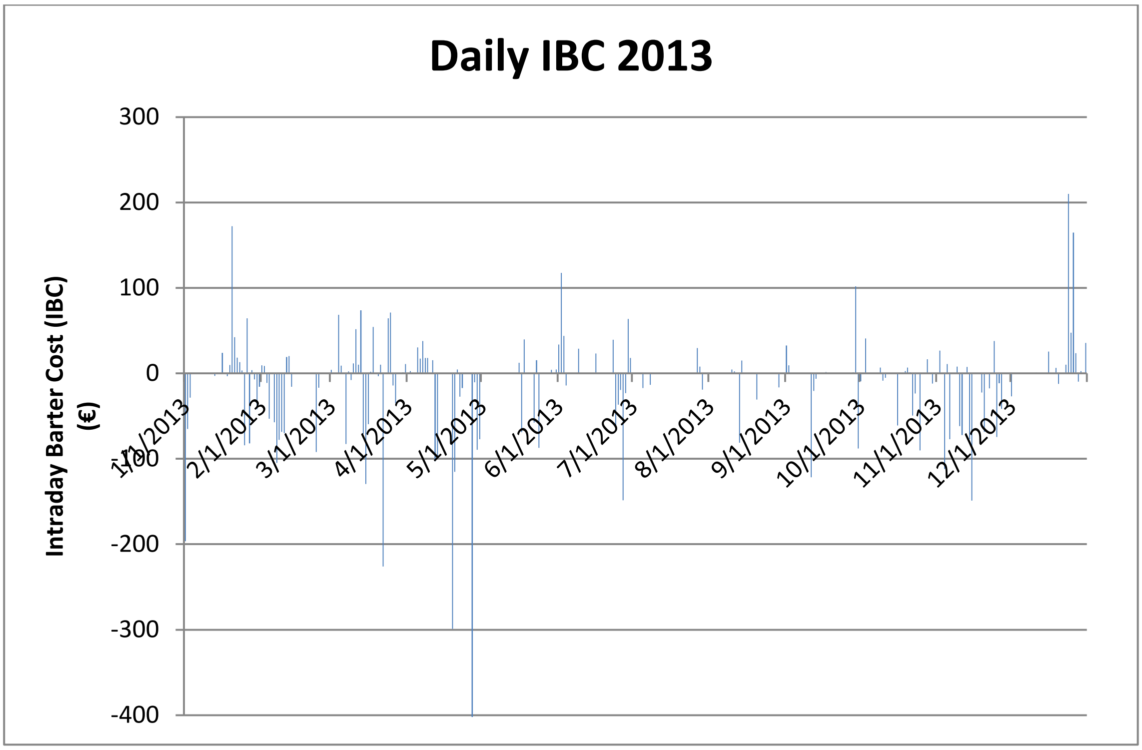


Figure 40: Daily IBC 2013

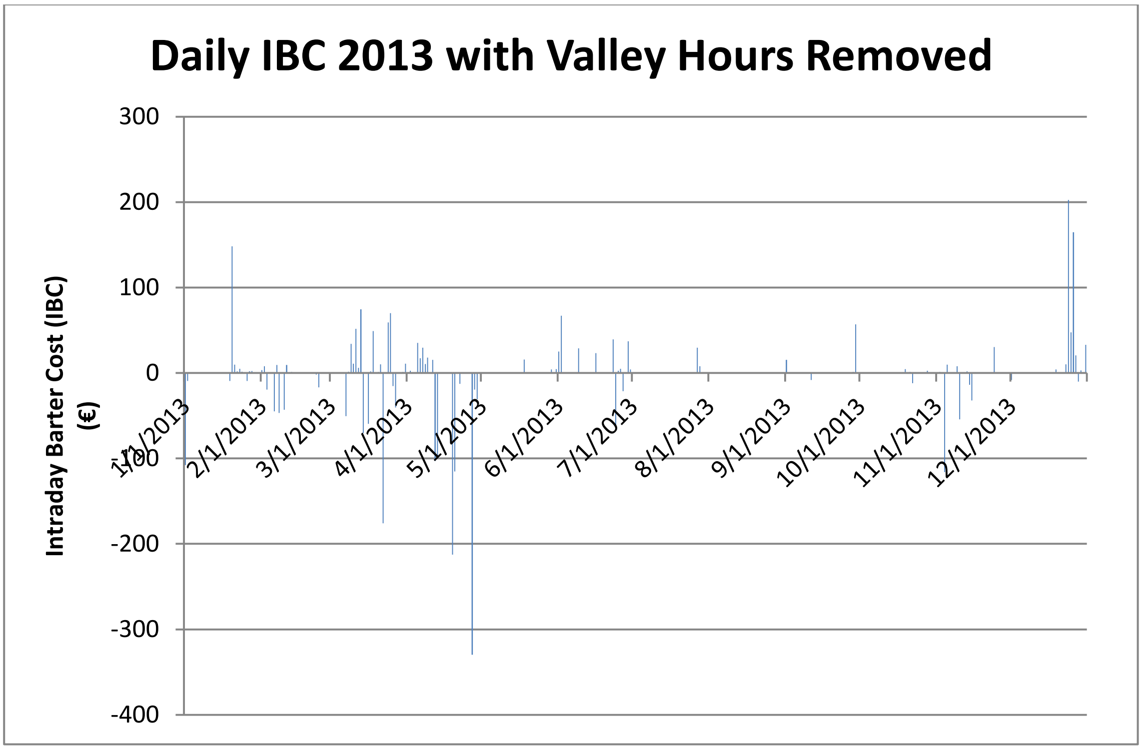


Figure 41: Daily IBC 2013 (with Valley Hour elimination)

As can be seen in the comparison of the two previous figures, Valley Hour elimination vastly reduces the number of days which have a negative IBC, decreases the magnitude of negative IBC in those same days throughout the year, and even increases positive IBC overall. However when prices for the Daily Market are high so tends to be the EFHB as shown previously in ***Figure 22: Correlation Plot of Secondary Band Markup vs. Hourly Capacity Factor***. Yet, if the Daily Market prices are low and the Intraday Market prices are high, the IBC likewise is increased. Furthermore, when eliminating Valley Hours, IBC is decreased yet this limits the number of hours of positive EFHB as well. Additionally, any Capacity Factor constraint put into place limits the number of considerable hours, affecting both the IBC as well as the EFHB.

Therefore, as can be deduced, these profitability criteria work in opposition. The IBC is reduced as is the EFHB and both depend on the range of Capacity Factors considered. Thus the need for ***Parameter Optimization*** based on the overall ECI equation, not the individual elements, is essential. However, before optimization, it is necessary to address the uncertainty present in the current understanding of the ***Estimated Capturable Income (ECI)***.

ECI Calculation Uncertainty

As the RBO relationship was derived from statistical methods, it is subject to uncertainty and ECI calculations should be reflective. Thus to give different perspectives on the possible revenues, three methods of ECI calculation have been developed using different RBO relationships which can be seen in ***Figure 42*** below.

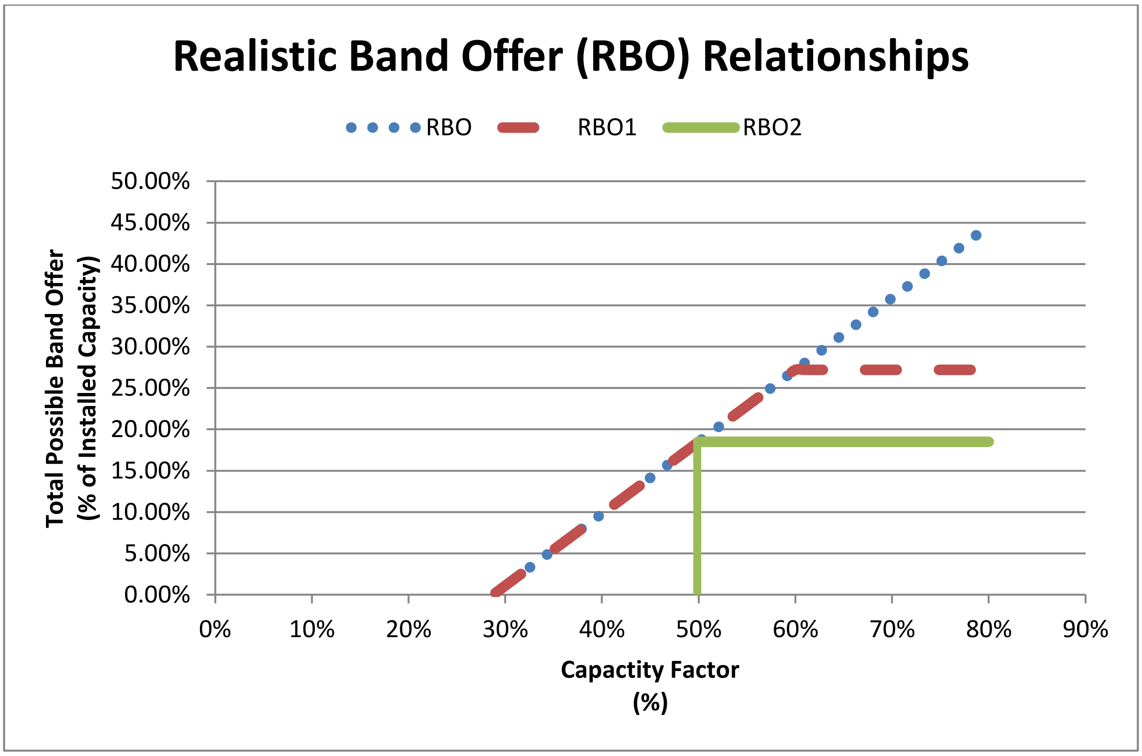


Figure 42: Realistic Band Offer Relationships

The first relationship, denoted RBO shown in the blue dotted line, is the same band-to-Capacity Factor relationship developed in the ***Realistic Band Offer*** section which was assumed to be constant for all Capacity Factors up the CF78, the largest observed in MY2013.

The second relationship, denoted RBO1 shown in the red dashed line, is more conservative and better takes the limitations of the statistical methods employed into account. The original RBO relationship was only tested up the CF60 due to smaller data sets at higher Capacity Factors which yielded less reliable conclusions. Thus RBO1 takes this limitation into account and only assumes the linear relationship up to the CF60 mark. All Capacity Factors above 60% are maintained at a constant band offer equivalent to the CF60 as this was the last confirmable band offer.

The third relationship, RBO2 seen in the green solid line, is the most conservative estimate and only considers band to be offerable at Capacity Factors greater than 50% of the Installed Capacity. While the other two relationships have a possible band offer ranging from the CF29-CF78 (RBO) and the CF29-CF60 (RBO1), RBO2 only considers Capacity Factors higher than 50% with a constant band provision equivalent to the CF50 level or 18.5% of Installed Capacity.

However, when looking at the implications of RBO2, results indicate that it may be overly simplistic. In the MY 2013 there were 602 hours which experienced a CF of 50% or greater. While the RBO2 assumption is the most conservative estimate it only accounts for 6.87% of the year and for 54% of the total possible EFHB. The RBO1, conversely, accounts for 95% of the total possible EFHB and considers the full range of hours with positive benefit which constitute 1,686 hours or 19.23% of the year. ***Table 11*** below shows these results where EFHB is the Effective Hourly Benefit (refer to ***Equation 3***) using the main RBO relationship, EFHB1 using the RBO1 and EFHB2 using the RBO2.

Table 11: Yearly EFHB Calculations from varying RBO Relationships

	EFHB	EFHB1	EFHB2
Yearly Sum	€ 5,464.12	€ 5,193.36	€ 2,945.94
Number of Hours	1,686	1,686	602
Percentage of Total EFHB	100%	95%	54%
Percentage of Year	19.23%	19.23%	6.87%

Thus it can be concluded that the RBO1 relationship is a reasonable approximation of the full available benefit while still incorporating the limits to certainty. The RBO is still a valid metric as well if the uncertainty of the band offer at higher Capacity Factors is tolerable and the RBO2 may be overly conservative.

Parameter Optimization

Due to the interdependencies between the EFHB, IBC, and the constraints imposed by profitability criteria, to better direct the economic analysis it becomes necessary to consider and optimize the overall ECI equation rather than the individual parts. Thus to optimize all parameters, the Primary Effects and the Secondary Effects of the ECI equation, a cumulative approach has been taken.

First, the ECI is calculated for each hour along with the corresponding Capacity Factor in chronological order. Next the hourly ECI dataset is sorted in ascending order based upon Capacity Factor from largest to smallest. Then the cumulative sum of each hourly ECI (CECI) is calculated using the simple formula:

$$CECI_N = \sum_{k=1}^{N} ECI_k$$

for the sequence $\{ECI\}_{k=1}^{8760}$, ordered by Capacity Factor

Effectively it represents the definite integral of the ECI equation as a function of Capacity Factor for each Capacity Factor range, or more simply, it is the cumulative sum of the ECI equation as a function of Capacity Factor. This resorting of data allows for a cumulative calculation which demonstrates at what CF the maximum ECI can be achieved as can be seen in ***Figure 43*** below.

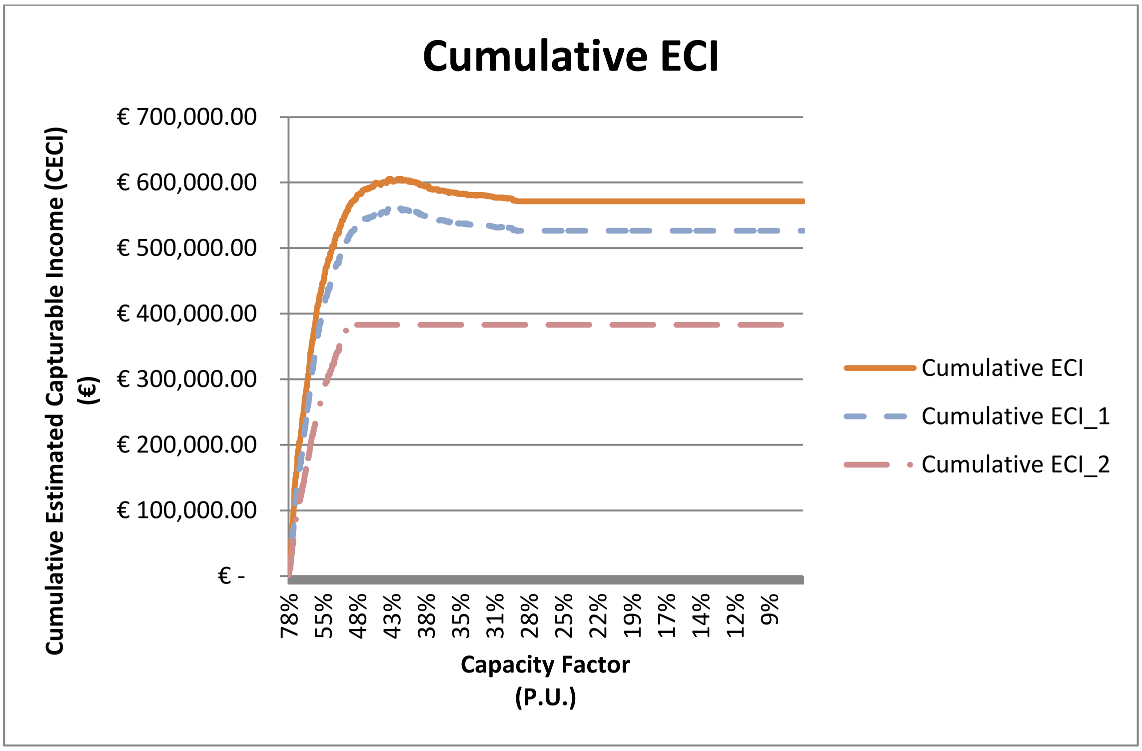


Figure 43: Cumulative ECI Calculation

The Cumulative ECI function has a maximum point at the CF41 for ECI and ECI_1 and at CF50 for ECI_2, this point represents where both the Primary and Secondary Effects of the ECI equation are optimized. Stated otherwise, this maximum point is **where EFHB is maximized and IBC is minimized thus an indication of where the Capacity Factor cutoff should be for**

participation in the Secondary Reserves Market. However this optimum *point* only is an indication as the optimum *range* may differ slightly as it does in this case. Accordingly, a wind producer should only participate in the SRM in hours which experience a Capacity Factor of 42% or greater, which indeed results in the maximum ECI as can be seen in ***Table 12*** below.

Table 12: ECI Optimization

Capacity Factor Range		ECI	ECI_1	ECI_2	Number of Hours
CF 29-100	*Total*	€571,676.39	€526,565.75	€387,094.98	1,686
	ECI per MW	€1,171.47	€1,079.03	€793.23	
CF 42-100	***Total***	**€604,644.77**	**€559,534.14**	**€387,094.98**	**1008**
	ECI per MW	**€1,239.03**	**€1,146.59**	**€793.23**	
CF 60-100	*Total*	€340,117.08	€295,006.44	€209,061.69	226
	ECI per MW	€696.96	€604.52	€428.41	

The ECI_2 is the same for the first two CF ranges as they still incorporate the sub-range CF50-CF100 on which the ECI_2 is based. Only in the last instance does the ECI_2 decrease as the considered CF range is smaller (CF60-CF100) than the ECI_2 optimal. However as previously mentioned, the RBO and RBO1 are relatively close approximations of one another. And as the final CECI and CECI_1 both experience the same optimal point, the CF42-CF100 can be regarded as the overall optimal range as it incorporates the optimal ranges of all considered RBO relationships.

As can be seen in the CECI function in ***Figure 43***, there is a characteristic flattening at the CF29 for CECI and CECI_1 and at CF50 for the CECI_2; this is caused by the RBO definition used in the EFHB calculation. For the RBO and RBO1, benefit is positive at or above the CF29 whereas the RBO2 benefit is only positive at or above the CF50. Hence any cumulative calculation would necessarily end (or flatten) at the point where no further benefit is defined. The reason for the characteristic shape of the CECI can be easily derived from the Cumulative IBC and Cumulative EFHB graphs seen in the following two graphics.

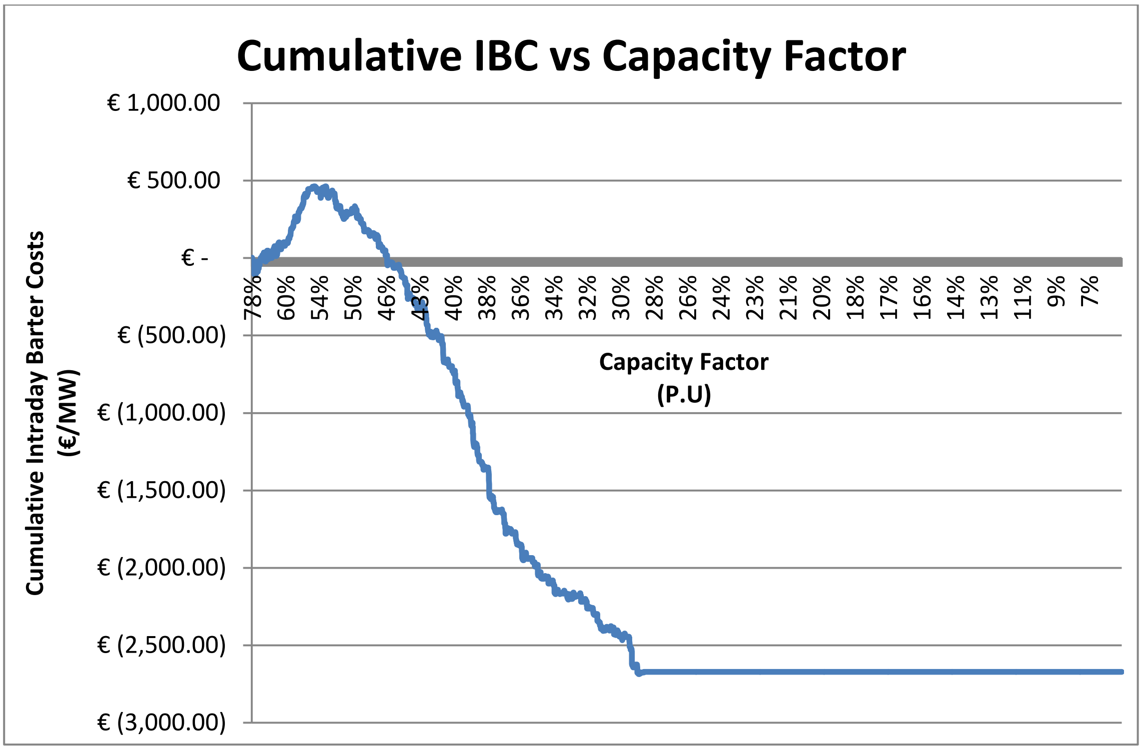


Figure 44: Cumulative Intraday Barter Costs (IBC)

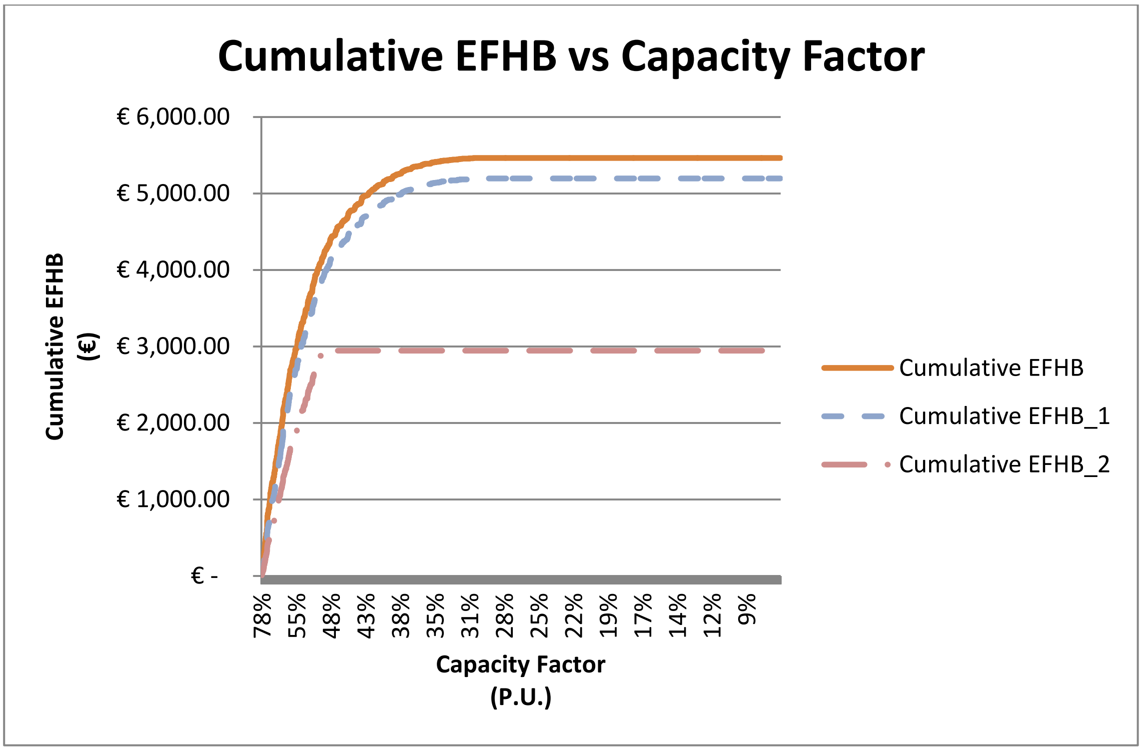


Figure 45: Cumulative Effective Hourly Benefit (EFHB)

As can be seen in ***Figure 44***, up to approximately the CF47 the IBC is actually positive, thus constituting a benefit, with any point beyond the CF47 quickly decreasing. However the reason why the CF42-CF100 is the optimal range even though it constitutes a negative IBC is due to added effect of the Cumulative EFHB which maximizes a later point as can be seen in ***Figure 45***.

However the negative points seen in the Cumulative IBC graph can also constitute a potential benefit if the bidding strategy is changed. All calculations thus far have been based on a bidding strategy which reflects what a wind producer would most likely use, namely the following. All available generation is sold in the Daily Market constituting a PDBF schedule. This PDBF schedule is only modified in the Intraday Market when the Secondary Market is profitable, to allow for maximum band provision and result in the PHF schedule as described in ***Figure 38***. The CECI is then calculated to find the CF range in which this strategy will yield optimal results, which has been shown to be CF42-CF100. An alternative strategy based upon preemptive measures however, can be undertaken as well which is examined in the following section.

Strategy

The two strategies examined in this section can be summarized as follows:

- **Strategy one (S1), status quo**: sell all of power in the DM (result in PDBF) then decide if participating in SRM is beneficial and purchase power as necessary in the IM (result in PHF). Costs arise when the IM price is greater than the DM Price. Calculate up to what CF playing this strategy is optimal; this has been shown to be the CF42 and above for 2013.

- **Strategy two (S2), preemptive**: assume participation in the SRM and withhold some power from the DM (result in a PHBF which would be the PHF in S1 case), and only sell back power in the IM when it is beneficial. The new cost or Secondary Effects then will be the difference in the revenues that could have been received from the DM in comparison to selling that power in the IM. Likewise calculate up to what CF playing this strategy is optimal.

The fundamental assumption for the S2 is that the optimal schedule for offering Secondary Band is known before the Daily Market bid is required. Strategy 2 is assessed thus using the same assumptions as in Strategy 1, namely that the optimal band schedule is 87% of the PDBF schedule. Therefore the S2 is presented as a corollary of S1. An important side note is that during the analysis it was discovered that the ***Soft Criteria*** of eliminating Valley Hours was in all cases inconsequential, thus this consideration has been omitted from further analysis.

Differences in ECI Calculation between Strategies

The revenues from participation in the Secondary Reserves Market (the Primary Effects of the ECI equation) in both strategies are equal since both strategies offer the same amount of band at each Capacity Factor level. However differences in how this optimal band schedule is achieved and the general ***Market Operation*** affect how the cost component (the Secondary Effects of the ECI equation) arises in each strategy. The important point to note is that when the Daily Market closes, neither the Secondary Band Price nor Intraday Market session prices are known. This limitation in knowledge has implications for: which profitability criterion constitutes the fundamental decision making condition, the costs which arise from playing a given strategy, and the selected hours in which these costs arise.

In the S1 the scheduling issue is not crucial because by the time the Intraday Market sessions begin the Secondary Band price is known. Hence a wind producer could choose to continue with the Secondary Reserves Market (through participation in the Intraday) or not based upon price signals which are known when the decision must be made. Therefore in the S1, the fundamental decision condition is when the Secondary Market Price is *greater* than the Daily Market Price, which is captured in the ***Hard Criteria*** of requiring a positive Secondary Band Markup. Costs (Secondary Effects) arise when the Intraday session price is greater than the Daily Market Price for all hours in which there is a *positive* Secondary Band Markup and when there is a sufficient amount of offerable band (CF≥29%). Consequently both Primary and Secondary Effects of the ECI equation are calculated for the same subset of hours, which has been shown to be approximately 1,686 hours for 2013.

However if playing S2, a wind producer would have preemptively changed their schedule to below what could have been sold in the Daily Market assuming they would participate in the SRM without knowing what the Intraday prices will be. Therefore the fundamental decision condition in the S2 is when a sufficient amount of band can be offered as this is the only information available when the decision must be made; this is captured in the ***Hard Criteria*** of requiring a Capacity Factor greater than or equal to 29%.

The advantage of Strategy 2 is that it eliminates the costs which arise in the S1 case as a wind producer would not need to change their schedule in the Intraday Market to offer an optimal amount of band. Essentially by playing S2, a wind producer is only interested in selling power in the Intraday Market as the optimal band schedule is already achieved, thus S2 possibly offers more flexibility. However, "costs" arise when the Daily Market price is greater than the Intraday Price as this constitutes a loss on what could have been made by selling power in the DM. Furthermore, these costs arise in the opposite scenario as in S1, namely for those hours in which the Secondary Band Price is *less* than the Daily Market price because in these hours it would have been a mistake to assume participation in the SRM.

To summarize, costs in the S2 arise when the Daily Market Price is greater than the Intraday Market Price and when there is a sufficient amount of offerable band (CF ≥ 29%) for all hours in which there is a *negative* Secondary Band Markup. Consequently the Primary and Secondary Effects of the ECI Equation are based on different subsets of hours. As previously stated, the Primary Effects are the same in both strategies and thus relevant for 1,686 hours however in S2 the Secondary Effects are relevant for 2,264 hours. While this may seem like a contradiction, the decision condition of S2 only requires Capacity Factor to be greater than or equal to 29% which is a less restrictive criterion than in the S1, which results in a larger initial dataset for S2.

A synopsis of the previously made points is adequately captured in the revised Secondary Effects (SE) portions of ECI equation for each strategy seen below:

$$SE_1 = \sum_{\substack{For\ h\ when: \\ 2MP > DMP \\ and \\ CF \geq 29\%}} C_h * (DMP - IMP)_h$$

Equation 8

$$SE_2 = \sum_{\substack{For\ h\ when: \\ CF \geq 29\% \\ and \\ 2MP < DMP}} C_h * (IMP - DMP)_h$$

Equation 9

Algorithms for Cost Calculation

The algorithm used for calculating the relevant costs in S1 is the same as explained previously in ***Figure 39: Intraday Barter Cost Algorithm Flowchart***. Likewise, rational behavior of an agent is assumed in S2, thus costs are calculated using a similar algorithm with the following changes.

The fundamental premise of the S2 cost algorithm is that a wind agent will only **sell** power for a given hour in a given IM session when the price is greater than or equal to the DM price; if not, the agent would prefer to wait until the next market session. If the final session arrives in which the hour in question can be sold and the ideal condition has not been encountered, the agent will be forced to sell power and accept whatever loss occurs. Thus the hourly Intraday Barter Cost for S2 (IBC_2) is the difference between the hourly Intraday Market Price (IMP) and the hourly Daily Market Price (DMP) as seen in ***Equation 9***. The daily IBC_2 is the sum of all hourly IBC_2 throughout a day and the final IBC is the sum of all daily IBC throughout a year for those hours which satisfy the ***Hard Criteria*** for S2.

Comparison of Results between Strategies

As mentioned previously, the final comparison between the S1 and S2 is made through use of the Cumulative Estimated Capturable Income (CECI) function to compare optimal points of both strategies. For S1 this optimal point was found to be for hours when the Capacity Factor was greater than or equal to 42%. For the S2 the optimal point is less obvious as the CECI function is flatter. Nonetheless by taking a single point observation, the maximum point of 41% is found which implies that the S2 strategy would be optimal for Capacity Factors greater than or equal to 41%. ***Table 13*** below is a monetary comparison of the optimal points of both strategies while ***Figure 46*** and ***Figure 47*** are the CECI functions for S1 and S2 respectively. The reason for the characteristic shapes of the CECI functions can be more easily seen by comparing the Secondary Effects portions of the ECI equation seen in ***Figure 48*** and ***Figure 49*** since the Primary Effects will be the same for both strategies.

Table 13: Comparison of Strategy Results

S1		**ECI**	**ECI_1**	**ECI_2**
CF 42-100	*Total*	€604,644.77	€559,534.14	€387,094.98
	ECI per MW	€1,239.03	€1,146.59	€793.23
S2				
CF 41-100	*Total*	€594,803.58	€549,692.95	€379,687.60
	ECI per MW	€1,218.86	€1,126.42	€778.05
S1-S2	***Total***	**€9,841.19**	**€9,841.19**	**€7,407.38**
	ECI per MW	**€20.17**	**€20.17**	**€15.18**

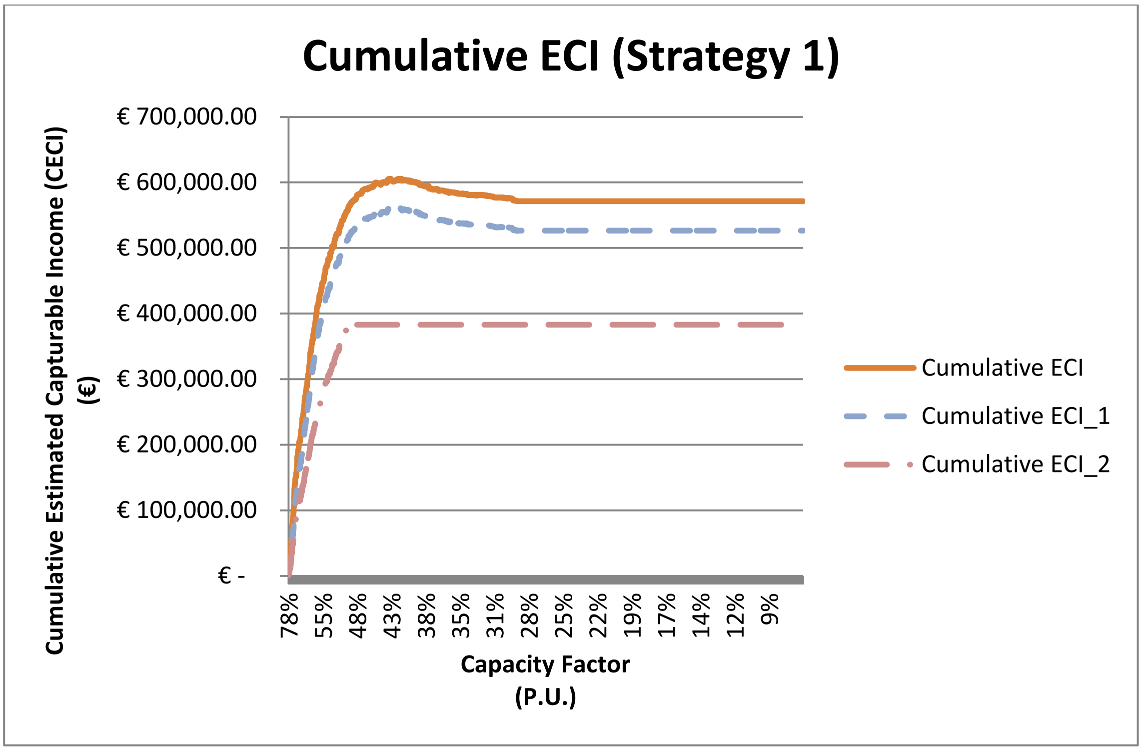


Figure 46: Cumulative Estimated Capturable Income (CECI) for Strategy 1

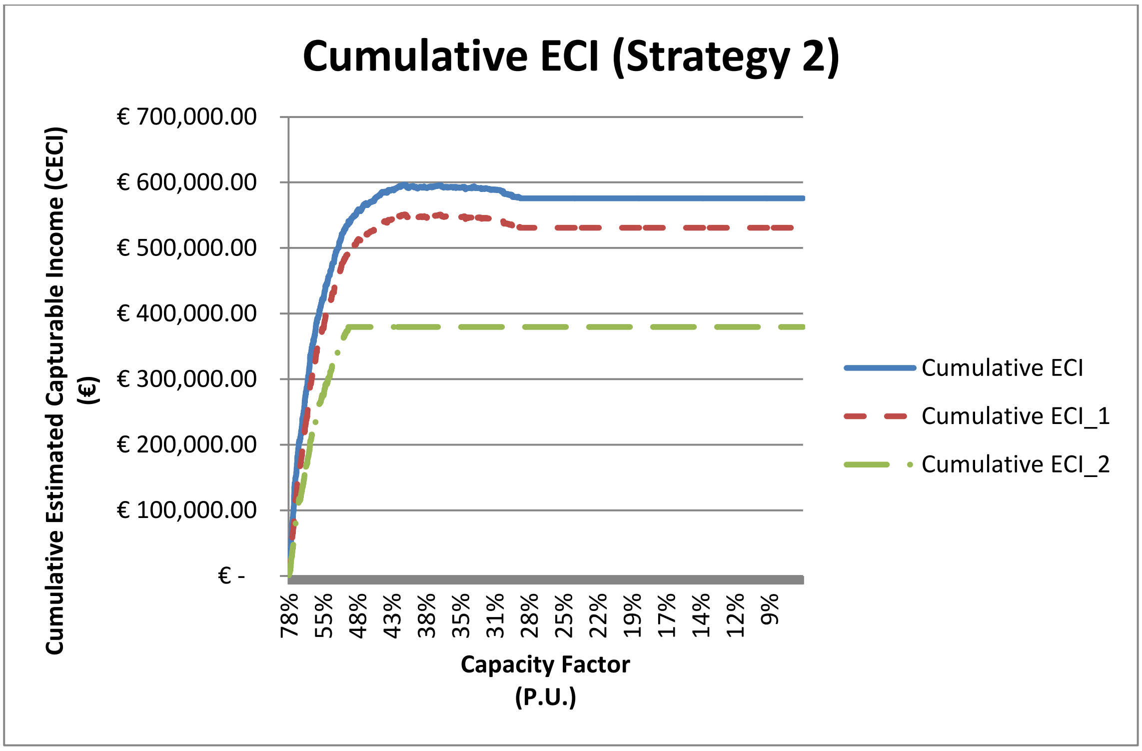


Figure 47: Cumulative Estimated Capturable Income (CECI) for Strategy 2

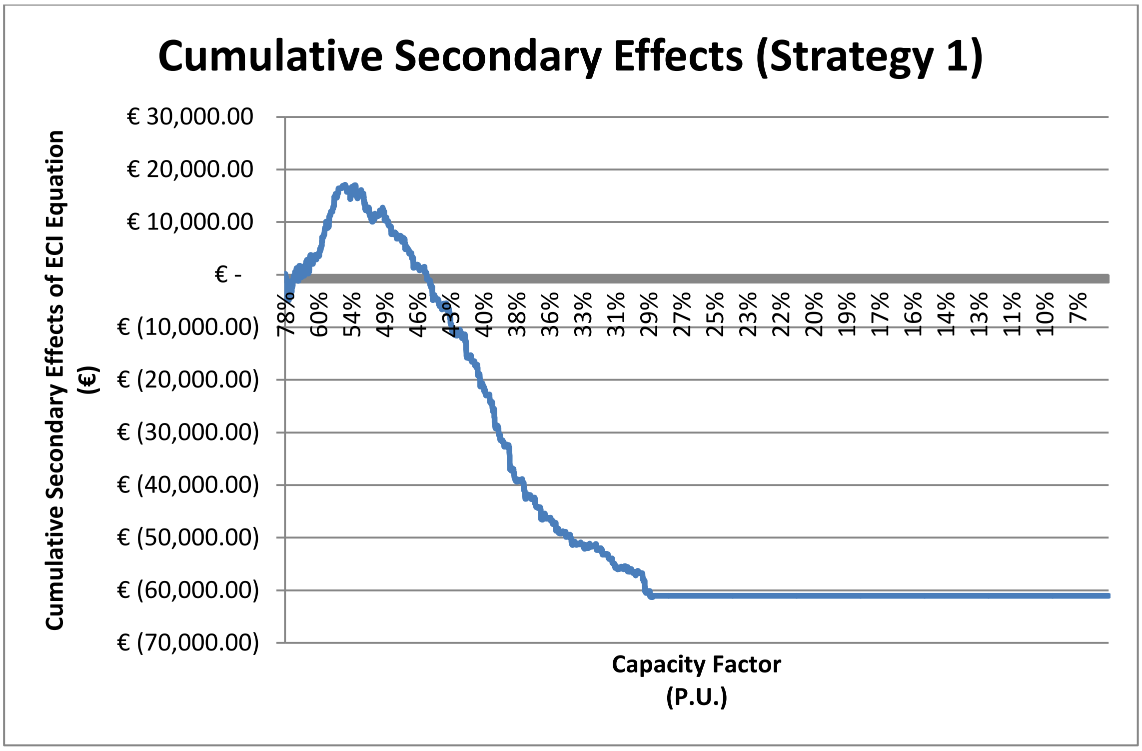


Figure 48: Cumulative Secondary Effects for Strategy 1

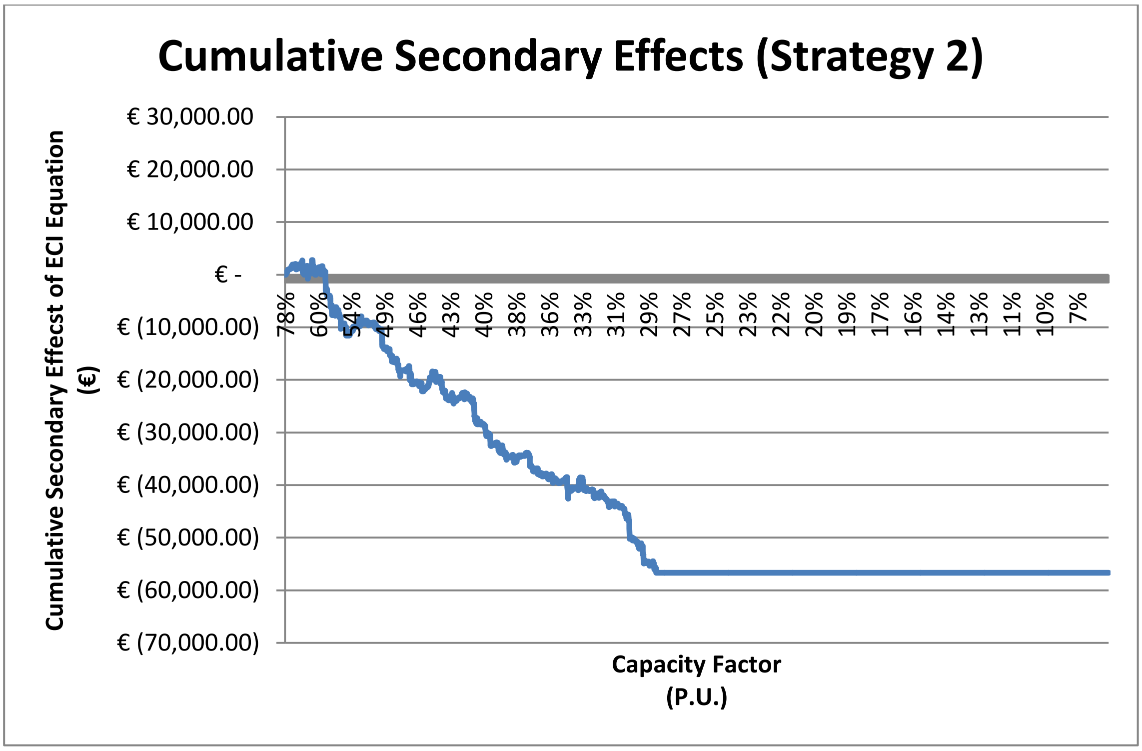


Figure 49: Cumulative Secondary Effects for Strategy 2

At first glance it would seem that Strategy 1 is better than Strategy 2 as it yields a greater monetary amount at its optimal point. According to the analysis, playing S1 would result in nearly €10,000 more per year than the S2 with the optimistic (ECI) and probable (ECI_1) scenarios. S1 also has a clear optimal point as seen in ***Figure 46*** which makes assumptions about how to participate in the market more certain.

However when comparing ***Figure 48*** and ***Figure 49***, it is evident that the prevalent optimal point of the S1 is caused by the positive Secondary Effects seen from CF78-CF45. This effectively means that the final revenue calculation in S1 is being slightly skewed by additional benefits realized by playing the Intraday Market. Also, in S1 the final point of the Cumulative Secondary Effects is lower and the overall function slope is steeper. On the contrary, the CECI for S2 is much flatter and it can be seen that little to no benefit is derived from the Intraday Market in the Cumulative Secondary Effects.

Therefore it is possible to conclude that while playing S1 may lead to greater revenue; it is more dependent on the Intraday Market and may result in larger costs if the IM play differs in other Market Years. S1 thus constitutes the widest range of possible values. S2, in comparison, is more representative of the research question at hand, namely the revenues derived from participation in the Secondary Reserves Market, and may be the better alternative.

Chapter 6: Conclusions and Deliberation

In this Chapter the results of the ***Economic Feasibility Analysis*** are presented along with final ***Conclusions*** of this research. Finally a ***Deliberation*** of interesting points and final remarks is presented which includes recommendations for further research.

Economic Feasibility Analysis

The final results of the economic feasibility analysis, comparing the ***Investment Cost Assumptions*** and ***Estimated Capturable Income (ECI)*** are presented below for both strategies.

Economic Feasibility S1				Cluster		
Costs	Socialized	Per MW		Huéneja	Tajo de la Encantada	Arcos de la Frontera
Turbine Impact	€ 32,100.00	€ 65.78		€ 12,840.00	€ 6,420.00	€ 12,840.00
Wind Farm Impact	€ 438,490.00	€ 898.55		€ 169,246.00	€ 98,544.00	€ 170,700.00
Cluster Impact	€ 1,012,700.00	€ 2,075.20		€ 337,566.67	€ 337,566.67	€ 337,566.67
Production Impact	€ 6,765.85	€ 13.86		€ 3,521.57	€ 1,691.46	€ 1,552.82
Total	**€ 1,490,055.85**	**€ 3,053.39**		**€ 523,174.24**	**€ 444,222.13**	**€ 522,659.49**
Revenues						
ECI	€ 604,644.77	€ 1,239.03		€ 314,712.65	€ 151,161.19	€ 138,770.93
ECI_1	€ 559,534.14	€ 1,146.59		€ 291,232.93	€ 139,883.53	€ 128,417.67
ECI_2	€ 372,250.38	€ 762.81		€ 193,753.27	€ 93,062.60	€ 85,434.51
Economic Profit						
ECI	€ (885,411.08)	€ (1,814.37)		€ (207,646.36)	€ (292,722.64)	€ (385,042.08)
ECI_1	€ (930,521.72)	€ (1,906.81)		€ (231,126.08)	€ (304,000.30)	€ (395,395.34)
ECI_2	€(1,117,805.47)	€ (2,290.58)		€ (328,605.74)	€ (350,821.24)	€ (438,378.49)
Payback Period (years)						
ECI	2.5	2.5		1.7	2.9	3.8
ECI_1	2.7	2.7		1.8	3.2	4.1
ECI_2	4.0	4.0		2.7	4.8	6.1

Figure 50: Economic Feasibility of Strategy 1

Economic Feasibility S2					
			Cluster		
Costs	Socialized	Per MW	Huéneja	Tajo de la Encantada	Arcos de la Frontera
Turbine Impact	€ 32,100.00	€ 65.78	€ 12,840.00	€ 6,420.00	€ 12,840.00
Wind Farm Impact	€ 438,490.00	€ 898.55	€ 169,246.00	€ 98,544.00	€ 170,700.00
Cluster Impact	€ 1,012,700.00	€ 2,075.20	€ 337,566.67	€ 337,566.67	€ 337,566.67
Production Impact	€ 6,765.85	€ 13.86	€ 3,521.57	€ 1,691.46	€ 1,552.82
Total	**€ 1,490,055.85**	**€ 3,053.39**	**€ 523,174.24**	**€ 444,222.13**	**€ 522,659.49**
Revenues					
ECI	€ 594,803.58	€ 1,218.86	€ 309,590.39	€ 148,700.90	€ 136,512.30
ECI_1	€ 549,692.95	€ 1,126.42	€ 286,110.67	€ 137,423.24	€ 126,159.04
ECI_2	€ 379,687.60	€ 778.05	€ 197,624.29	€ 94,921.90	€ 87,141.42
Economic Profit					
ECI	€ (895,252.27)	€ (1,834.53)	€ (212,768.62)	€ (295,182.94)	€ (387,300.71)
ECI_1	€ (940,362.91)	€ (1,926.97)	€ (236,248.34)	€ (306,460.60)	€ (397,653.97)
ECI_2	€(1,110,368.25)	€ (2,275.34)	€ (324,734.72)	€ (348,961.94)	€ (436,671.59)
Payback Period (years)					
ECI	2.5	2.5	1.7	3.0	3.8
ECI_1	2.7	2.7	1.8	3.2	4.2
ECI_2	3.9	3.9	2.6	4.7	6.0

Figure 51: Economic Feasibility of Strategy 2

Overview

In short the following is an investment analysis of expected benefits minus costs. Expected benefits are presented as explained in previous chapters as Optimistic (ECI), Probable (ECI_1), and Conservative (ECI_2) scenarios. In order for a cluster of wind farms to reliably provide Secondary Reserves to capture these potential benefits however, investments in new telemetry/communication equipment and studies to optimize measurement and control algorithms are needed, thus only CAPEX is affected. The economic feasibility analysis for wind participation in the Secondary Reserves Market is as follows.

Unitary Comparison

First the Socialized Investment Costs are compared with the full yearly ECI calculation for each the optimistic (ECI), probable (ECI_1), and conservative (ECI_2) scenarios. As can be seen in the first column of ***Figure 50*** and ***Figure 51*** each scenario will have a payback period associated with it as none of the considered scenarios make profit from the first year alone. This payback period is found by dividing the yearly Socialized Investment costs by the yearly ECI (thus constituting a simple payback period) and is found to be 2-4 years. The Per MW comparison likewise is based upon the ***Investment Cost Assumptions*** test bed and thus is found by dividing the Socialized Costs and yearly ECI by 488 MW. As expected, the Per MW comparison yields the same payback period as before. The unitary MW comparison of costs and benefits is not necessarily valuable alone but the unitary ECI itself is very useful as it allows for a potential wind producer to scale up the factor to a specific case and estimate the amount of expected revenues for particular amount of Installed Capacity.

Scaled Comparison

The scaled comparison is implemented by multiplying each per MW ECI by the Installed Capacity of each cluster and compares this cluster benefit to the actual cluster costs as explained in ***Chapter 4: Economic Analysis*** and shown in ***Annex II: Calculation of Cluster Costs***. When looking at the scaled comparison a slight difference occurs in the pay-back period. For the Huéneja cluster with 254 MW the pay-back period is found to be much lower (1.7 to 2.7 years), the Tajo cluster with 122 MW slightly longer (2.9 to 4.8 years) and the Arcos cluster with 112 MW the longest (3.8-6.1).

Reason would dictate that with more Installed Capacity the potential benefit would also be greater, thus resulting in a lower payback period if the rate at which the unitary cost increases is less than the rate of unitary benefit. This seems to be the case in the Huéneja cluster which is the largest of the three and has a unitary cost of €2,045.88, hence the shortest payback period. However the Arcos cluster has an unusually high unitary cost of €4,652.74 per MW. This unitary cost is well above the average of €3,053.39 per MW and was caused by a high cost for transducer equipment. As transducers are a fixed-rate investment/physical asset and as it follows that those clusters with more wind farms would require more transducers, it possible to determine that this cost is atypical and may be skewing the results. Furthermore, as explained in the ***Deliberation*** section, several cost components are subject to vast reduction in all clusters.

Comparison of Strategies

As shown in the ***Comparison of Results between Strategies*** both strategies result in similar revenues, yet to see if the difference between S1 and S2 results are relevant financially, both the Net Present Value (NPV) and the Internal Rate of Return (IRR) were calculated for all considered scenarios. The NPV was calculated considering ten years of simulated inflows ranging from ± 10% of the calculated 2013 inflows with a discount rate of 3%. The discount rate was chosen to correspond with the Consumer Price Index (*Indice de Precios al Consumo IPC)* of Spain which tends to be around 3% (Instituto Nacional de Estadística (INE)). The IRR likewise was calculated using ten years of simulated inflows ranging from ± 10% of 2013 calculations. It can be seen in a quick comparison of the results in ***Table 14*** and ***Table 15*** that strategy is not relevant in financial terms used for investment decisions. Thus further analysis is based upon Strategy 1 as this constitutes the widest range of values.

Table 14: Investment Analysis for Strategy 1

Strategy 1	Socialized	Huéneja	Tajo	Arcos
NPV				
ECI	€ 3,673,853.03	€ 2,158,038.40	€ 849,172.12	€ 666,642.51
ECI_1	€ 3,291,828.01	€ 1,959,197.51	€ 753,665.86	€ 578,964.64
ECI_2	€ 1,705,792.34	€ 1,133,678.94	€ 357,156.95	€ 214,956.45
IRR				
ECI	40%	61%	33%	24%
ECI_1	37%	56%	30%	22%
ECI_2	22%	36%	17%	11%

Table 15: Investment Analysis for Strategy 2

Strategy 2	Socialized	Huéneja	Tajo	Arcos
NPV				
ECI	€ 3,359,496.91	€ 1,994,418.61	€ 770,583.09	€ 594,495.21
ECI_1	€ 2,994,992.34	€ 1,804,696.97	€ 679,456.94	€ 510,838.42
ECI_2	€ 1,621,309.11	€ 1,089,706.11	€ 336,036.14	€ 195,566.86
IRR				
ECI	37%	56%	30%	22%
ECI_1	34%	52%	27%	19%
ECI_2	21%	35%	16%	10%

It can be seen that in all instances the NPV is positive with IRRs ranging between 11%-61%. As expected, the Arcos cluster has the lowest values with IRRs between 10%-22% with the Huéneja cluster with the highest (35%-56%). In an industry which economic scopes of 20 years or more with the expected regulated rate of return for wind installations at 7.5% according to ***The 2013 Energy Reform Details***, the results indicate that participation in the Secondary Reserves Market for wind producers would be both attractive and economically feasible.

Conclusions

Therefore the principle conclusions from the analyses performed throughout this thesis is that a wind producer could expect to earn between € 762 to € 1,238 per MW of Installed Wind Capacity through participation in the Secondary Reserves Market. When applying this to an existing case, the Huéneja cluster of 254 MW of wind capacity, wind operators/owners could expect to gain between € 193,753 to € 314,712 annually and could recoup investments within three years.

Further investment analysis based upon ten years of simulated inflows would imply that the necessary investment for such a cluster would experience an IRR between 35%-56% and constitute an NPV between € 1.1 – € 2 Million for an initial investment of € 523,174.

In an industry which economic scopes of 20 years or more with the expected regulated rate of return for wind installations at 7.5% according to ***The 2013 Energy Reform Details***, the results indicate that participation in the Secondary Reserves Market for wind producers would be both attractive and economically feasible.

Deliberation

The following section is a narrative of interesting points encountered throughout the thesis, reflections on the work performed, and suggestions for further research. As such, this section is significantly less formal and structured in efforts to pique interest and encourage debate. Main points are provided with subheadings for readability.

Improvements in Model Methodology

In all reality this is a Linear Optimization problem and for instantiations which use a much larger dataset (I.E. several years of market data) a formal Mixed Integer Linear Programming (MILP) model should be used in place of the methodology presented here. Fortunately Excel provides a sufficiently robust medium for the analysis and datasets considered here (8760 points or 1 market year per dataset) however clearly this would become unviable very quickly if the analysis would be extended to more market years. Indeed, this observation is a clear indication of potential future work in this area should it be deemed a worthwhile pursuit.

The Objective Function and the Constraints have already been defined throughout the narrative; however they can be formally defined for use in Mixed Integer Linear Programming such as:

- Objective function Max(ECI)
  - Subject to:
    - Equalities
      - IC = 488
      - Lower Bound = 25% of IC
      - Upper Bound Factor = 0.87 (which when applied to the PDBF schedule will give the resulting Upper Bound for the Secondary Band, the final PHF schedule, as well as

serve for the calculations of the Production Factors B and C)

- Inequalities
  - 2BP-DM >0 or 2BP > DM
  - CF > 0.28 (since the CF29 still is a valid positive result)

Also there are multiple ways of incorporating a forecast error, either by the production or installation side. While the forecast error was out of the scope of this thesis as it dealt only with final wind production, if assuming a forecast error of 10%, it would be possible to either reduce available power by a 10% amount or install 10% more capacity to ensure this baseline power is always available.

Quantification of Reliable Band Offer

While there may be uncertainties and disagreements in the RBO relationships presented here, at the very least this thesis highlights the importance of quantifying the likely offerable amount of band (or Reliable Band Offer) in economic feasibility studies in this area. Furthermore this Reliable Band Offer should be a dynamic variable which is dependent on the hourly Capacity Factor to incorporate changes in wind production and better take advantage of the potential benefits through participation in the SRM.

Predictions for the Ancillary Services Market

In the Ancillary Services Market there is a limited need for Secondary Reserves. In the case of Spain, only around 900 MW of Secondary Reserves will be needed at any given time. As there is more than sufficient Installed Capacity of wind in Spain (over 22,000 MW as of 2013), provision of service would be applicable to those wind installations which experience a modest Capacity Factor and/or are most economically efficient. Thus if wind is indeed allowed into the SRM, other methods for determining service provision will be needed.

Currently the Ancillary Services market is not divided into different prices for Upwards and Downwards Reserves even though they are considered separate products. In a future market scenario this would likely change and price discrepancy between the products would arise thus changing the revenue possible for wind if only offering Downwards Reserves.

Investment Analysis

The investment costs depicted in this thesis are subject to vast reduction. The reason being is that a large portion of CAPEX costs quoted in the ***9.2: Economic Analysis*** of ***The TWENTIES Project*** was due to tests and studies undertaken to optimize communication algorithms, measurement calculations, and forecasting methods. Naturally as the industry develops a knowledge base of Wind providing Secondary Reserves, the need for these tests will be reduced thus the corresponding cost and impact on CAPEX will be drastically reduced if not entirely eliminated. Another point of further research would be to incorporate sensitivity analysis of cost reduction into the economic feasibility analysis presented in this thesis.

Granted the investment analysis presented here is rudimentary and could be improved as well. Better instantiations could run Monte Carlo simulations of the random variables included here to better predict future inflows from the SRM. At the very least though, a rational estimation of the future benefits has been provided here.

Band Definition Considerations

A main assumption in this thesis was that the Lower Bound of the Secondary Band was at 25% Installed Capacity. However as this can extend up to even 50% of the Installed Capacity, those wind turbines with a greater than 25% IC minimum would find their profitability greatly reduced if not entire be excluded from participation. Therefore the minimum technical operation point needs to be better quantified through further studies.

Furthermore, sensitivity analyses should also be conducted on the assumptions of the Upper Bound which was defined as 87% of the PDBF schedule. This assumption was derived from the 2013 yearly real-time, 10 minute interval wind production and effectively concluded that the minimum point of hourly RT wind production throughout the year would be within 13% lower of the hourly PDBF 95% of the time. Granted this was based on data from a single year thus this relationship should be further tested to form a better idea of what RT to PDBF discrepancies can be.

The calculation for RT to PDBF discrepancies does not take the right side of the ***Figure 28: Histogram of Percentage Difference Main Dataset (minus outliers)*** into account. Technically this would correspond to the situation when wind production is *exceeding* even what has been sold (PDBF). Therefore there may be an interest to study positive deviations as well to better quantify expected hourly deviations between RT wind and the PDBF.

In further analysis of the statistical tests presented in ***Table 8: Descriptive Statistics for Filtered Datasets (minus outliers)***, every dataset exhibits a close-to-normal Kurtosis (-0.12 – 0.01) and a slight positive (right-sided) skew. The positive skew could give evidence that the PDBF schedule is created from conservative bids, meaning that the deviations of real-time wind production tend to be *above* rather than *below* the PDBF. This theory has some merit: a wind producer can lower their risk of deviation and uncertainty of production by bidding less power in the Daily Market than is actually forecasted. If the majority of wind producers act similarly, minimizing risk while maximizing profits, this behavior will lead to the development of overall conservative PDBF schedule system-wide. A characterization of risk perceptions of wind producers and how this affects their bidding (thus the final system PDBF schedule) is an interesting concept and one which could merit further research.

Annex I: List of Countries in PCR Initiative

List of coupling countries using PCR in 2014:

Belgium, Denmark, Estonia, Finland, France, Germany/Austria, Great Britain, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland (via the SwePol Link), Sweden, Portugal and Spain.

Price coupling of Regions (PCR) is the initiative of seven European Power Exchanges (APX, Belpex, EPEX SPOT, GME, Nord Pool Spot, OMIE and OTE), to develop a single price coupling solution to be used to calculate electricity prices across Europe and allocate cross-border capacity on a day-ahead basis. This is crucial to achieve the overall EU target of a harmonized European electricity market. The integrated European electricity market is expected to increase liquidity, efficiency and social welfare. PCR is open to other European Power Exchanges wishing to join.

Annex II: Calculation of Cluster Costs

Huéneja Cluster (254 MW)			Unitary MW Cost	Production Impact	Production Impact
WTG			(€/MW)	(MWh)	(€/Yr)
Simulations	€3,600.00		€14.17		
Estimation of Producible Power	€9,240.00		€36.38		
Total	€12,840.00		€50.55		
WF					
New Transducers					
SCADA adjustments to Transducer	€960.00		€3.78		
Cost of transducer equipment	€47,716.00		€187.86		
				20.88	€924.01
SCADA System					
SCADA Server	€116,970.00		€460.51	27.84	€1,232.07
Active Power Regulator	€3,600.00		€14.17	12.43	€550.26
Total	€169,246.00		€666.32		
Cluster					
Data resolution improvements	€40,666.67		€160.10		
Connection Devices	€18,566.67		€73.10		
UCC System Total	€77,000.00		€303.15		
Forecast System	€165,333.33		€650.92		
SCADA CORE Total	€ 25,000.00		€98.43		
Remote Control Equipment	€11,000.00		€43.31		
Total	€337,566.67		€ 1,329.00		€2,706.34
Cluster Total	€519,652.67		€2,045.88	61.14	€2,706.34

Tajo Cluster (122 MW)			Unitary MW Cost	Production Impact	Production Impact
WTG			(€/MW)	(MWh)	(€/Yr)
Simulations	€1,800.00		€14.75		
Estimation of Producible Power	€4,620.00		€37.38		
Total	€6,420.00		€52.62		
WF					
New Transducers					
SCADA adjustments to Transducer	€480.00		€3.93		
Cost of transducer equipment	€25,119.00		€205.89		
				10.44	€462.00
SCADA System					
SCADA Server	€71,145.00		€583.16	13.92	€616.04
Active Power Regulator	€1,800.00		€14.75	6.22	€275.13
Total	€98,544.00		€807.74		
Cluster					
Data resolution improvements	€40,666.67		€333.33		
Connection Devices	€18,566.67		€152.19		
UCC System Total	€77,000.00		€631.15		
Forecast System	€165,333.33		€1,355.19		
SCADA CORE Total	€25,000.00		€204.92		
Remote Control Equipment	€11,000.00		€90.16		
Total	€337,566.67		€2,766.94		€1,353.17
Cluster Total	€442,530.67		€3,627.30	30.57	€1,353.17

Acros Cluster (112 MW)			Unitary MW Cost	Production Impact	Production Impact
WTG			(€/MW)	(MWh)	(€/Yr)
Simulations	€3,600.00		€32.14		
Estimation of Producible Power	€9,240.00		€ 82.50		
Total	€12,840.00		€ 114.64		
WF					
New Transducers					
SCADA adjustments to Transducer	€960.00		€8.57		
Cost of transducer equipment	€49,170.00		€439.02		
				20.88	€924.01
SCADA System					
SCADA Server	€116,970.00		€1,044.38	27.84	€1,232.07
Active Power Regulator	€3,600.00		€32.14	12.43	€550.26
Total	€170,700.00		€1,524.11		
Cluster					
Data resolution improvements	€40,666.67		€363.10		
Connection Devices	€18,566.67		€165.77		
UCC System Total	€77,000.00		€687.50		
Forecast System	€165,333.33		€1,476.19		
SCADA CORE Total	€25,000.00		€223.21		
Remote Control Equipment	€11,000.00		€98.21		
Total	€337,566.67		€3,013.99		€2,706.34
Cluster Total	€521,106.67		€4,652.74	61.14	€2,706.34

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