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Pricing variability in power delivery in markets with
significant renewable energy generation

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Abstract

Increased penetration of renewable energy sources in existing power systems have induced a number of developments in electricity market mechanisms. Most importantly, renewable energy generation is increasingly made accountable for deviations between scheduled and actual energy generation. However, there is no such mechanism to support accountability for the additional system costs induced by power fluctuations. These are usually socialized and eventually supported by electricity customers. This thesis shows that the power variability of renewable energy sources generates a non-negligible cost of ancillary services that is currently not accounted for. Hence mechanisms are proposed for assessing the contribution of all market participants to power regulation needs, and to consequently fairly redistribute related regulation costs. A simulation study based on the test case of Western Denmark allows to illustrate these concepts on the realistic case study of a country already widely penetrated by wind power generation and to show how these mechanisms may affect revenues of the various market participants.

Keywords: Electricity markets, ancillary services, power fluctuations, attribution mechanisms.

Sommario

La percentuale sempre crescente di Fonti di Energia Rinnovabile (FER) all'interno della produzione elettrica ha indotto dei cambiamenti nei meccanismi di funzionamento dei mercati elettrici. In primo luogo si è assistito alla sempre maggiore attribuzione di responsabilità ai produttori rinnovabili relativamente agli sbilanciamenti tra la produzione elettrica prevista ed attuata. Per contro non si è sviluppato un meccanismo che permetta di valutare "le responsabilità" sugli aggiuntivi costi determinati delle loro fluttuazioni di potenza. Attualmente questi maggiori costi vengono solitamente socializzati ed eventualmente addebitati ai consumatori. Con questa tesi si è voluto dimostrare che la variabilità di potenza della energia prodotta da fonti rinnovabili genera un costo, dovuto alla necessità di bilanciamento tramite servizi di dispacciamento, tutt'altro che trascurabile: costo che nel sistema attuale non viene considerato. Vengono così proposti dei meccanismi che permettono di valutare quale sia il contributo di ogni partecipante al mercato al fabbisogno di regolazione di potenza, in modo tale da arrivare a ridistribuire i conseguenti costi in maniera equa. Grazie a simulazioni effettuate utilizzando i dati della regione occidentale della Danimarca si illustrano i concetti sopra esposti; utilizzando come riferimento un caso di studio realistico, con una significativa valenza in quanto riguardante uno stato che ha già una alta percentuale di produzione di energia eolica, si arriva a dimostrare come i meccanismi proposti possano influenzare i ricavi dei diversi attori partecipanti al mercato.

Parole chiave: Mercati elettrici, servizi di dispacciamento, sbilanciamenti di potenza, meccanismi allocativi.

Extended summary

European wholesale electricity markets have not been designed to ensure an efficient operation and the adequate incentives for a power system with significant intermittent renewable energy generation. The increased penetration of Renewable Energy Sources, which their specifities, such as power variability, low predictability and zero marginal costs, is thus creating new technical and economic challenges. Currently, the development of intermittent RES in most European countries is framed by different kinds of support schemes, however a large-scale development of these energy sources cannot be kept separated from electricity markets development. Since the designing process of the electricity markets was based on supply by large power plants with stable and predictable production, an evolution of the electricity markets design is required to support a change in the physical nature of the power system.

Among other things, the necessary constant balance between electricity generation and consumption can be challenged by recent developments in power systems. Mainly, one may think of the rapid increase in the penetration of Renewable Energy Sources, mostly wind and solar power, with their inherent fluctuations in power generation over a broad range of temporal and spatial scales. Similarly, requiring electric loads to become more active could actually induce new types of fluctuations in their consumption patterns. Accommodating the resulting net load fluctuations in a liberalized electricity market environment is one of the current challenges to be faced by system operators. Considering operational time scales, ancillary service procurement is the key mechanism to ensure access to the resources necessary to guarantee a reliable and economic operation of power systems.

Roughly speaking, one may consider that regulation services may be split into power and energy related ones: primary reserves focusing on power only, tertiary reserves on energy only, while secondary reserves comprise a mix of both. Primary reserves are activated in a non-selective manner from the total interconnected system and their deployment proportionally follows the grid frequency deviation from its set point, therefore they are a power-only service. Unlike primary reserves which are exclusively frequency-controlled, the secondary reserves are used to minimize deviations of network frequency from its set point as well as deviations of cross-control area power flows from agreed schedules and, at the same time, these reserve capacities can be deployed not only for a short term but also for a longer time period to restore the balance in the specific affected area. For these reasons, secondary reserves cannot be considered a power-only service. On the other hand, tertiary reserves are an energy-related service used to manage longer lasting system

balance failures.

Wholesale electricity markets were proposed under the aim of making power system operation more economic and efficient. One of the key concept is that of balance responsibility, for which both power suppliers and consumers are deemed accountable for deviations between their scheduled and actual production (resp. consumption). Renewable energy generation, with its limited predictability, is increasingly asked to take entire part in such mechanisms and hence to be financially responsible for the energy regulation needs it induces. Imbalances are assessed for energy only, through the usage of secondary and tertiary reserves, as calculated for each and every market and power system operation time unit (e.g., hourly in the Scandinavian Nord Pool and 15 minutes in the Dutch APX).

In contrast, when it comes to power-related regulation services, the costs are socialized and eventually supported by the demand side. This implicitly assumes that energy is delivered at constant power for each and every Market Time Unit. The accountability of the additional system costs induced by the power fluctuation of the Renewable Energy Sources could represent a further step and a natural development of the process towards the full market integration of these energy sources. In future power systems where the need for increased power-related services may substantially originate from the production side, power suppliers should be made accountable in a way similar to the case of energy-related regulation.

Through an assessment of today's cost of power-related regulation services on the test cases of Western Denmark and Germany, this thesis shows that the power variability of Renewable Energy Sources generates a non-negligible cost of ancillary services that is currently not accounted for. By mean of an indicator, which allows to highlight the relative importance of the power-related regulation cost over the energy-related regulation cost, it has been demonstrated that in Western Denmark the power regulation accounted for approximately 10% of the energy regulation cost, while in Germany it accounted for more than 18%. Meaning that already under the current power system circumstances the power variability of electricity producers and consumers generates a non-negligible cost for the system, which may eventually increase in a future with significant renewable energy generation. Hence four different attribution mechanisms are proposed for assessing the contribution of all market participants to power-related regulation needs, and to consequently fairly redistribute the associated regulation costs.

The proposed attribution mechanisms are designed to readily complement existing mechanisms for energy-related regulation, by pricing the variability in power delivery depending on the resulting need for ancillary services. The concept of energy-neutral power profile, which corresponds to the power profile minus its mean over the considered time period, has been used to separate energy and power-related aspects. Through the energy-neutral power profile it is possible to assess exclusively the power variability, which is necessary since with the existing market mechanisms both power suppliers and consumers are already deemed accountable for energy imbalances.

The idea is to distribute the power variability cost to each actor proportionally to a give metric that depends on the energy-neutral power profile of the specific

actor. The first metric (*power capacity metric*) emphasizes the capacity that may be required to compensate fluctuations by mean of the L_∞ norm of the energy-neutral power profile. This first metric similarly considers positive and negative fluctuations, only focusing on maximum deviation from the constant power profile. The second metric (*integrated mismatch metric*) considers the integrated mismatch as quantity of interest, thus relating to a L_k norm ($k = 1, 2$) of these profiles. The third metric (*mileage metric*) is a mileage-type metric which emphasizes the dynamic properties of energy-neutral profiles by mean of the L_k ($k = 1, 2$) norm of the h-order derivative. The last metric proposed (*inner product metric*) emphasizes the respective contribution of each market participant to the total power profile by mean of the inner product between individual and overall fluctuations.

Interestingly for the case of the inner product metric, owing to its definition, it has been deduced that all contributions can be either negative or positive, meaning that individual generators and demand may work towards or against the formation of this total power profile. Consequently, the contribution of each and every actor to the overall power fluctuations determined through the inner product metric are placed in both one-price and two-price settlement schemes. In a one-price system all the fluctuations are settled with the same price, while in a two-price system a price differentiation is applied based on the respective contribution to the overall power fluctuation. In this latter case, the market participants' power fluctuations counteracting the total power profile fluctuations are settled at a price equal to zero, meaning that they are not penalized.

In order to illustrate these concepts and to show how the proposed mechanisms may affect revenues of the various market participants a simulation study based on the test case of Western Denmark has been carried out. The Western Denmark power system area was found to be the optimal case study to analyze the effects of the short-term power variability of renewable sources, because it is a country already widely penetrated by wind power generation. As of end of July 2014, according to the Danish Register for wind turbines, Denmark had an installed wind capacity of 4.855 MW, where offshore wind power accounted for 1.271 MW. Moreover, in 2013 wind power production accounted for almost 30% of the total domestic electricity supply, with wind turbines producing 9.466 GWh of electricity. Besides, Denmark has a very ambitious plan for the wind power development, which requires that approximately 50% of the electricity consumption of 2025 should be supplied by wind power.

For the simulation study, German data are used to assess the costs of power-related regulation and to build representative supply curves for power-related system services. A sample of 41 wind farms, including 7 offshore and 34 onshore, has been chosen from the existing wind farms located in Western Denmark, for a total installed capacity of approximately 1.500 MW, as representative of the generation side of the simulated power system. The wind producers' power profiles are generated with the Correlated Wind (CorWind) power time series simulation model, developed at Risø DTU, which can simulate wind power time series over the entire Western Denmark area and in time scales where the wind turbines can be represented by simple steady state power curves. The energy-neutral power

profile of the consumption side is statistically generated as superimposition of two time-series with a first order correlation.

The simulation study is performed through the implementation of suitable scripts developed using the software environment for statistical computing and graphics R©. The results showed that according to all four metrics the majority of the power-related regulation cost is supported by the large wind farms and by the demand. In that respect, all the four metrics appears to be consistent, although the shares of the total cost allocated to each of these specific entities differ from metric to metric. In particular, the results of the power capacity metric and the integrated mismatch metric are very similar; the results of the mileage metric penalize more the demand and less the large offshore wind farms compared to the previous two cases; and lastly the results of the inner product metric accentuate the penalization imposed to both types of aforementioned entities.

A further examination, based on the indicator *cost per energy sold*, showed that the relative weight of the high cost allocated to the large wind farms by the first three metrics is indeed low, and therefore large renewable generators have a lower incentive in reducing their power fluctuations compared to the smaller producers, which by contrast receive the strongest incentive toward a better self-regulation. On the contrary, the results of the inner product metric work in the opposite direction in terms of incentives. The results for this specific metric revealed that the strongest incentive toward a better self-regulation of their own production is received by large renewable generators when a one-price settlement scheme is applied.

The contributions of each and every actor to the overall power fluctuations determined on the basis of the inner product metric have also been placed in a two-price settlement scheme, by differentiating the power regulation unit cost between the actors contributing or counteracting the formation of the total power profile. In this case, it has been found that all the renewable generators, independently of their size, receive a strong market incentive. At the same time, since a two-price system is not a zero-sum game for the TSO, the *fluctuation rent* resulting from this settlement scheme can be considered an additional incentive produced by this cost allocation system.

The key challenge for an efficient integration of the RES is that of ensuing that the right incentives are established. With regards to power variability, this can be achieved with the implementation of a mechanism allocating the induced cost on the basis of the contribution of each entity to power regulation needs. As a matter of fact, this thesis demonstrates that such type of attribution mechanism will be able to provide incentives to the involved entities toward a better self-regulation of their own power fluctuations, which may in turn lead to an increased system balancing efficiency. The solutions proposed in the thesis, compared to the cost socialization on the demand side only and the full cost socialization on all market participants, have the merit of achieving the accountability objective, while also actively contributing to the evolution of the power systems toward a design accommodating a large-scale penetration of RES. They allow to develop a market framework in which the systems allowing for smoothing power fluctuations,

such as storage or demand-response, are strongly incentivized whenever the overall system variability, and consequently the induced system cost, become unbearable.

Beside the significant benefits produced, the actual implementation of a mechanism allocating the involved cost on the basis of the respective contribution of each entity requires the collection and the assessment of a huge amount of data, together with an appropriate tuning process of all the concerned parties. Considering an ever-increasing distribution generation connected to the RES deployment, and the consequent increase of market participants, questions may rise on the optimal accuracy and computation preciseness to use in the cost allocation procedure. For instance, an increase of the time resolution used for the collection of the power profiles data certainly enhances the accuracy of the cost redistribution process. Nevertheless, it should be ensured that the running costs won't balance out the benefits produced.

Riassunto esteso

Gli attuali mercati europei dell'elettricità non sono stati progettati per assicurare una gestione efficiente di un sistema di produzione con una quota significativa di energia proveniente da fonti rinnovabili intermittenti, pertanto non prevedono adeguati incentivi. Di conseguenza le specificità delle Fonti di Energia Rinnovabile (FER) quali la variabilità di potenza, la bassa prevedibilità e l'assenza di costi marginali di produzione, stanno creando nuove sfide sia tecniche che economiche per la gestione dei sistemi elettrici. Nella maggior parte dei paesi Europei, lo sviluppo delle FER intermittenti è oggi favorito da differenti sistemi di incentivazione, ma in futuro l'utilizzo, in percentuale sempre maggiore, di queste fonti di energia non potrà non essere integrato con le politiche di sviluppo dei mercati dell'energia elettrica. I mercati elettrici sono stati progettati utilizzando l'ipotesi di una fornitura generata dalle grandi centrali elettriche con produzione stabile e prevedibile, si rende pertanto necessaria un'evoluzione nel disegno dei mercati dell'energia elettrica per supportare il cambiamento in atto nella natura fisica del sistema elettrico.

La necessità di mantenere costante il bilanciamento tra la generazione di elettricità ed il consumo viene messo a dura prova dai recenti cambiamenti nei sistemi di produzione. É proprio il considerevole aumento della penetrazione delle Fonti di Energia Rinnovabile, in primis eolica e solare, e le loro intrinseche fluttuazioni nella generazione di energia su un ampio intervallo di scala temporale e spaziale, a creare nuove sfide. Analogamente, la richiesta di carichi elettrici più attivi potrebbe indurre nuovi tipi di fluttuazioni nei modelli di consumo. Gestire la risultante delle fluttuazioni del carico elettrico in un mercato liberalizzato dell'energia elettrica è una delle principali problematiche che gli operatori del sistema devono affrontare. Prendendo in considerazione la scala temporale operativa, il meccanismo chiave per garantire la disponibilità delle risorse necessarie ad un funzionamento affidabile ed economico dei sistemi di rete elettrica, è quello dell'approvvigionamento di servizi di dispacciamento.

Per semplicità espositiva, si può considerare che i servizi di dispacciamento possano essere divisi in servizi relativi alla potenza e servizi relativi all'energia, dove le riserve primarie rientrano esclusivamente nei servizi di potenza, quelle terziarie nei servizi di energia, mentre le riserve secondarie appartengono ad entrambi i suddetti gruppi. Le riserve primarie vengono attivate in modo non selettivo dal sistema interconnesso e la loro attivazione segue proporzionalmente la scostamento della frequenza dal valore di target, per cui sono unicamente un servizio relativo alla potenza. A differenza delle riserve primarie, le riserve secondarie sono utilizzate sia per minimizzare le variazioni della frequenza di rete dal suo valore target sia

per contrastare le variazioni dei flussi di scambio tra i vari segmenti di rete dai valori concordati. Nel contempo, tali riserve possono essere utilizzate non solo per un breve arco temporale, ma anche per un periodo di tempo più lungo al fine di ripristinare l'equilibrio nella zona interessata. Per questi motivi, le riserve secondarie non possono essere considerate un servizio relativo unicamente alla regolazione della potenza. Le riserve terziarie sono un servizio relativo unicamente all'energia utilizzate per gestire gli squilibri del sistema più prolungati nel tempo.

I mercati dell'energia elettrica sono nati con l'obiettivo di rendere il sistema elettrico più economico ed efficiente. Uno dei concetti chiave è quello del bilanciamento equilibrato, per il quale sia i fornitori di energia che i consumatori vengono responsabilizzati per gli scostamenti tra la produzione programmata e quella reale. Per tale motivo si sta chiedendo alla produzione di energia da fonti rinnovabili, data la sua limitata prevedibilità ed il suo continuo aumento percentuale nel panorama delle fonti di prendere parte a tali meccanismi di bilanciamento e di farsi carico anche finanziariamente del fabbisogno di regolazione dell'energia che ne consegue. Attualmente gli sbilanciamenti sono valutati solo in termini di energia, per l'utilizzo delle riserve secondarie e terziarie, e sono calcolati per unità di tempo operativa del mercato e del sistema elettrico (ad esempio, ogni ora nel Scandinavian Nord Pool e 15 minuti nella APX olandese).

Per quanto riguarda i servizi di dispacciamento collegati alla regolazione della potenza, i costi vengono attualmente socializzati ed eventualmente messi a carico dei consumatori. Questo sistema allocativo dei costi presuppone implicitamente che l'energia venga prodotta o consumata a potenza costante nell'unità di tempo considerata. Responsabilizzare sui costi aggiuntivi di sistema indotti dalle oscillazioni di potenza derivanti dalle fonti energetiche rinnovabili potrebbe rappresentare un ulteriore passo avanti ed uno sviluppo naturale nel processo verso una completa integrazione di queste fonti di energia all'interno dei mercati elettrici. Nelle future reti elettriche in cui il crescente fabbisogno di servizi di dispacciamento relativi alla regolazione di potenza proverrà sostanzialmente dal lato produzione, i produttori dovrebbero essere responsabilizzati con modalità simili a quelle utilizzate per la regolazione degli sbilanciamenti di energia. Tali meccanismi avrebbero anche lo scopo di servire come incentivo per i produttori rinnovabili verso una migliore autoregolazione delle proprie oscillazioni di potenza (per esempio, mediante l'utilizzo di meccanismi di stoccaggio, coordinamento con demand-response, concetti di virtual power plant, ecc).

Questa tesi dimostra, attraverso una valutazione degli attuali costi di tali servizi in Danimarca occidentale e Germania, che la variabilità di potenza indotta dalle fonti di energia rinnovabile genera un costo non trascurabile dei servizi di dispacciamento relativi alla regolazione della potenza. Per mezzo di un indicatore, che permette di evidenziare l'importanza relativa del costo di regolazione di potenza rispetto al costo di regolazione in materia di energia, è stato dimostrato che in Danimarca occidentale la regolazione della potenza rappresenta circa il 10% del costo per la regolazione di energia, mentre in Germania rappresenta oltre il 18%. Il che significa che già nella situazione attuale la variabilità di potenza dei produttori e consumatori di energia elettrica genera un costo non trascurabile per il sistema,

il quale è inoltre destinato ad aumentare in futuro. Partendo da questo risultato sono stati proposti quattro differenti meccanismi di attribuzione che consentono di pesare il contributo che ogni partecipante al mercato dà all'esigenza di regolazione della potenza, e conseguentemente di ridistribuire in maniera equa i costi di regolazione associati.

I meccanismi di attribuzione proposti sono stati ideati per integrarsi facilmente con i meccanismi esistenti per la regolazione in materia di energia, attraverso l'attribuzione di un costo variabile in funzione del fabbisogno di servizi di dispacciamento. É stato utilizzato il concetto di profilo di potenza "energy-neutral", che corrisponde al profilo di potenza meno la sua media nel periodo di tempo considerato, al fine di separare i contributi di energia e da quelli di potenza. Utilizzando il profilo di potenza "energy-neutral" è possibile valutare unicamente l'effetto dovuto alla variabilità di potenza, dal momento che gli attuali meccanismi di mercato tengono già in considerazione gli sbilanciamenti di energia sia dei produttori che dei consumatori.

L'idea di base è quella di ridistribuire il costo indotto dalla variabilità di potenza di ciascun attore proporzionalmente ad una metrica, funzione del profilo di potenza "energy-neutral" dell'attore stesso. La prima metrica (*power capacity metric*) rimarca la capacità necessaria a compensare le oscillazioni di potenza, attraverso la norma L_∞ del profilo di potenza "energy-neutral". Questa prima metrica considera in egual modo le oscillazioni positive e negative, concentrandosi solo sul massimo scostamento dal profilo di potenza costante. La seconda metrica (*integrated mismatch metric*) considera l'integrale dello scostamento come quantità di interesse, attraverso la norma L_k $(k = 1, 2)$ di questi profili. La terza (*mileage metric*) è una metrica legata alla duranta dei cicli ("mileage") che permette di prendere in considerazione le proprietà dinamiche dei profili di potenza "energy-neutral" per mezzo della norma L_k $(k = 1, 2)$ della derivata di ordine h di tali profili. La quarta ed ultima metrica (*inner product metric*) enfatizza il contributo di ogni attore al profilo di potenza totale per mezzo del prodotto scalare tra oscillazioni di potenza individuali e totali.

È interessante notare che nel caso della metrica basata sul prodotto scalare i contributi possono essere sia positivi che negativi, nel senso che i singoli produttori o la domanda possono alimentare o contrastare la formazione del profilo di potenza totale. Di conseguenza, i contributi determinati attraverso la metrica basata sul prodotto scalare sono inseriti sia in uno schema a singolo prezzo che in uno schema di prezzo in due parti. In un sistema a singolo prezzo a tutte le oscillazioni di potenza viene attribuito lo stesso costo unitario, mentre in un sistema di prezzo in due parti viene applicato un differente costo unitario a seconda del verso del contributo all'oscillazione totale di potenza. In questo ultimo caso, alle fluttuazioni di potenza degli attori che contrastano la formazione dell'oscillazione totale viene applicato un costo unitario pari a zero, in questo modo non risultano essere penalizzati.

Una simulazione basata sui dati della Danimarca occidentale consente inoltre di illustrare questi concetti e di mostrare come questi meccanismi influenzano i ricavi dei diversi operatori di mercato. La regione occidentale della Danimarca

si può considerare un caso di studio ottimale, per analizzare gli effetti della variabilità di potenza delle fonti rinnovabili, in quanto paese avente una produzione eolica significativa. A fine luglio 2014, secondo il registro danese per le turbine eoliche, la Danimarca aveva una capacità eolica installata pari a 4.855 MW, in cui i parchi eolici offshore rappresentavano 1.271 MW. Inoltre, nel 2013 la produzione di energia elettrica eolica ha rappresentato quasi il 30% del dell'energia elettrica interna totale, con 9,466 GWh di energia elettrica prodotta da turbine a vento. La Danimarca ha inoltre un piano molto ambizioso per lo sviluppo dell'energia eolica, il quale prevede che circa il 50% del consumo di elettricità del 2025 venga coperto da energia eolica.

Nella simulazione, per valutare i costi correlati e costruire curve di offerta rappresentative sono stati utilizzati i dati della Germania relativi ai servizi per la regolazione di potenza. Per quanto riguarda il lato produzione, un campione costituito da 41 parchi eolici, di cui 7 offshore e 34 onshore, è stato scelto tra gli esistenti parchi eolici situati in Danimarca occidentale, per una capacità installata totale di circa 1.500 MW. I profili di potenza dei produttori eolici sono stati generati con il modello di simulazione Correlated Wind (CorWind), sviluppato presso Risø DTU. Questo modello permette di simulare serie temporali di profili di potenza eolica su tutta l'area della Danimarca occidentale, in scale temporali in cui le turbine eoliche possono essere rappresentate da semplici curve di potenza stazionarie. Per quanto riguarda il lato consumatori, il profilo di potenza "energy-neutral" è stato generato statisticamente come sovrapposizione di due serie temporali con una correlazione di primo ordine.

La simulazione è stata eseguita con l'ambiente per l'analisi statistica dei dati R, utilizzando script appositamente scritti per questo fine. I risultati della simulazione hanno mostrato che, per tutte e quattro le metriche, la maggior parte del costo connesso alla regolazione della potenza è attribuito ai grandi impianti eolici ed alla domanda. Questo risultato si mantiene coerente in tutte le metriche, anche se la ripartizione del costo complessivo tra ciascuno di questi soggetti differisce a seconda del meccanismo considerato. In particolare, i risultati della *power capacity metric* e dell' *integrated mismatch metric* sono molto simili tra loro; i risultati della *mileage metric* penalizzano in misura maggiore la domanda ed in misura minore i grandi parchi eolici offshore, rispetto ai due casi precedenti; infine i risultati della *inner product metric* accentuano la penalizzazione imposta ad entrambi i soggetti menzionati in precedenza.

Un ulteriore analisi, basata sull'indicatore *costo per energia venduta*, ha messo in luce come il peso relativo dell'elevato costo allocato ai grossi produttori eolici dalle prime tre metriche è in realtà basso. Ne consegue che, nei primi tre casi, i grandi generatori rinnovabili ricevono un incentivo minore per la riduzione delle oscillazioni di potenza rispetto ai piccoli produttori, i quali invece ricevono un incentivo maggiore per giungere ad una migliore autoregolazione del profilo di potenza. Gli incentivi prodotti dalla *inner product metric* invece vanno nella direzione opposta. Nel caso in cui venga utilizzato uno schema a prezzo singolo, i risultati di quest'ultima metrica rivelano che il maggiore incentivo verso una migliore autoregolazione della produzione viene dato ai grandi generatori rinnovabili.

I contributi di ciascun attore alle oscillazioni del profilo totale di potenza determinati attraverso la *inner product metric* sono stati poi valutati secondo uno schema di compenso in due parti, andando a differenziare il costo unitario di regolazione della potenza tra i soggetti che contribuiscono o contrastano la formazione del profilo di potenza totale. In questo caso, si è trovato che tutti i generatori rinnovabili, indipendentemente dalle loro dimensioni, ricevono un forte incentivo. Dal momento che un sistema a due prezzi non è a somma zero, la risultante *fluctuation rent* può essere considerata un ulteriore incentivo, a favore del TSO, prodotto dall'applicazione di questo sistema di ripartizione dei costi.

Un fattore fondamentale per una efficace integrazione delle FER all'interno dei sistemi elettrici è quello di generare i giusti incentivi. Per quanto riguarda la variabilità di potenza, questo può essere ottenuto attraverso l'implementazione di un meccanismo di allocazione del costo indotto che tenga conto del contributo che ciascun attore apporta al fabbisogno di regolazione di potenza. Infatti, questa tesi dimostra che un tale meccanismo attributivo è in grado di fornire incentivi ai soggetti coinvolti al fine di ottenere una migliore autoregolazione delle proprie oscillazioni di potenza. Il risultato così ottenuto può produrre un incremento di efficienza nel meccanismo di bilanciamento del sistema. Comparando gli attuali sistemi di socializzazione del costo unicamente sul lato della domanda o su tutti gli operatori del mercato con le soluzioni proposte nella tesi, quest'ultime hanno il pregio di ribaltare il costo a chi compete, contribuendo pertanto all'evoluzione dei sistemi elettrici verso un modello più adatto ad accogliere una sempre maggiore penetrazione delle rinnovabili. I meccanismi allocativi proposti permettono infatti di sviluppare una struttura di mercato in cui vengono incentivati i sistemi che consentono di smorzare le oscillazioni di potenza, come ad esempio lo stoccaggio, e l'incentivo cresce nel momento in cui la variabilità totale del sistema aumenta generando costi progressivamente insostenibili.

L'effettiva implementazione di un meccanismo di ribaltamento dei costi basato sul contributo dei singoli produce significativi vantaggi, ma per contro richiede la raccolta e la valutazione di un'enorme quantità di dati ed una equilibrata definizione dei processi. Considerando la crescente generazione distribuita collegato al sempre maggiore utilizzo delle Fonti di Energia Rinnovabile, ed il conseguente aumento degli operatori di mercato, potrebbe essere sollevata la questione inerente l'accuratezza e la precisione di calcolo ottimale da utilizzare nella procedura di assegnazione dei costi. Ad esempio, un aumento della risoluzione temporale utilizzata per la raccolta dei dati relativi ai profili di potenza migliora la precisione del processo di ridistribuzione del costo, ma incrementa i costi di gestione. Diventa pertanto fondamentale garantire un adeguato bilanciamento tra costi e benefici.

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Chapter 1

Introduction

European wholesale electricity markets have not been designed to ensure an efficient operation and the adequate incentives for a power system with significant intermittent renewable energy generation. The specifities of Renewable Energy Sources, such as power variability, low predictability and zero marginal costs, are thus creating new technical and economic challenges. Currently, the development of intermittent RES in most European countries is framed by different kinds of support schemes, however a large-scale development of these energy sources cannot be kept separated from electricity markets development. Since the designing process of the electricity markets was based on supply by large power plants with stable and predictable production, an evolution of the electricity markets design is required to support a change in the physical nature of the power system.

Among other things, the necessary constant balance between electricity generation and consumption can be challenged by recent developments in power systems. Mainly, one may think of the rapid increase in the penetration of Renewable Energy Sources, mostly wind and solar power, with their inherent fluctuations in power generation over a broad range of temporal and spatial scales. Similarly, requiring electric loads to become more active could actually induce new types of fluctuations in their consumption patterns [1]. Accommodating the resulting net load fluctuations in a liberalized electricity market environment is one of the current challenges to be faced by system operators. Considering operational time scales, ancillary service procurement is the key mechanism to ensure access to the resources necessary to guarantee a reliable and economic operation of power systems. The need to redesign ancillary service markets in a new context of high renewable energy penetration is receiving renewed attention, see e.g. [2, 3]

Roughly speaking, one may consider that regulation services may be split into power and energy related ones: primary reserves focusing on power only, tertiary reserves on energy only, while secondary reserves comprise a mix of both. Primary reserves are activated in a non-selective manner from the total interconnected system and their deployment proportionally follows the grid frequency deviation from its set point, therefore they are a power-only service. Unlike primary reserves which are exclusively frequency-controlled, the secondary reserves are used to minimize deviations of network frequency from its set point as well as deviations of

cross-control area power flows from agreed schedules and, at the same time, these reserve capacities can be deployed not only for a short term but also for a longer time period to restore the balance in the specific affected area. For these reasons, secondary reserves cannot be considered a power-only service. On the other hand, tertiary reserves are an energy-related service used to manage longer lasting system balance failures.

Wholesale electricity markets were proposed under the aim of making power system operation more economic and efficient. One of the key concept is that of balance responsibility, for which both power suppliers and consumers are deemed accountable for deviations between their scheduled and actual production (resp. consumption). Renewable energy generation, with its limited predictability, is increasingly asked to take entire part in such mechanisms and hence to be financially responsible for the energy regulation needs it induces. Imbalances are assessed for energy only, through the usage of secondary and tertiary reserves, as calculated for each and every market and power system operation time unit (e.g., hourly in the Scandinavian Nord Pool and 15 minutes in the Dutch APX). In contrast, when it comes to power-related regulation services, the costs are socialized and eventually supported by the demand side. This implicitly assumes that energy is delivered at constant power for each and every Market Time Unit. In future power systems where the need for increased power-related services may substantially originate from the production side, power suppliers should be made accountable in a way similar to the case of energy-related regulation. Such mechanisms would also serve as an incentive for renewable energy generators to better self-regulate their own power fluctuations (for instance, using storage, coordination with demand-response, virtual power plant concepts, etc.).

1.1 Thesis contents

This thesis shows that the power variability of Renewable Energy Sources generates a non-negligible cost of ancillary services that is currently not accounted for. Hence four different attribution mechanisms are proposed for assessing the contribution of all market participants to power-related regulation needs, and to consequently fairly redistribute the associated regulation costs. These attribution mechanisms are designed to readily complement existing mechanisms for energy-related regulation, and thus they rely on the concept of energy-neutral power profiles, which allows to separate energy and power-related regulation needs. The contribution of each and every actor to the overall power fluctuations is determined based on various norms for individual and overall fluctuations, or an inner product between these two. These are consequently placed in both one-price and two-price settlement schemes. A simulation study based on the test case of Western Denmark allows to illustrate these concepts on the realistic case study of a country already widely penetrated by wind power generation and to show how these mechanisms may affect revenues of the various market participants. German data is additionally employed to assess the costs from power-related regulation and to build representative supply curves for power-related system services.

1.2 Thesis structure

Chapter 2 - Background information This chapter introduces the concepts of ancillary service, system service and balancing market, within the larger picture of power system operation, liberalized electricity markets and electricity markets integration. It also include a literature study on the ancillary service markets rules, on the impacts of Renewable Energy Sources on the reserve requirements and finally on the ancillary services cost allocation mechanisms.

Chapter 3 - Ancillary Services framework In this chapter the current status of the ancillary service harmonization process in Europe is evaluated and some of the ancillary service definitions adopted at the European level are described. Moreover, the issues related to these two topics are underlined and analyzed. Following, a detailed analysis of the ancillary service characteristics in the two countries of interest for the thesis, namely Western Denmark and Germany, is provided.

Chapter 4 - The cost of power variability This chapter aims at assessing the cost generated by the power variability of electricity producers and consumers by building a theoretical framework that allows to separate energy and power related aspects. Following, an assessment of today's cost of power-related regulation services is carried out based on the test cases of Western Denmark and Germany, in order to demonstrate its non-negligibility.

Chapter 5 - Attribution mechanisms In this chapter, the market framework is first described by defining how energy and power-related aspects are considered. Secondly, the extension of current settlement mechanisms to consider costs from fluctuations in power delivery is given. Finally, the proposed attribution mechanisms are defined and their main properties are evaluated.

Chapter 6 - Simulation study In this chapter, the objectives of the simulation study are first described, allowing for the understanding of its scope and thus its implementation perspective. Secondly, the selected case study is introduced together with the reasons behind the choice. Moreover, the simulation set-up, consisting of ancillary service market supply curves, wind producers' power profiles and demand energy-neutral power profile is detailed. Lastly, a short analysis of different market time units and settlement schemes, together with their implications, is carried out.

Chapter 7 - Application results This chapter provides an insight on the simulation study results, obtained through the implementation of suitable scripts developed using the software environment for statistical computing and graphics R©. First of all, the effects of the Market Time Unit change in terms of power variability cost are evaluated. Secondly, the attribution mechanisms results for one hour and one month of operation are illustrated together with an analysis of the resulting revenues for selected market participants. Following, the differences between a one-price and a two-price settlement scheme are examined. Lastly, a summary validation process for the simulation study, based on three indicators, is carried out.

Chapter 8 - Conclusion In this chapter a general discussion on the rationale and the results of the proposed attribution mechanisms is given. Following, a conclusive summary of the thesis and the possible future development are presented.

Appendices

Chapter 2

Background Information

The main topic of this thesis is the allocation of the ancillary services costs. In order to provide a proper framework for the development of the study, this chapter introduce the concepts of ancillary service, system service and balancing market, within the larger picture of power system operation, liberalized electricity markets and electricity markets integration. Following a literature study on the ancillary services market rules in different jurisdiction, on the impacts of RES on the reserve requirements and on the ancillary services cost allocation mechanisms.

2.1 Ancillary and system services

The term "ancillary services" refers to the resources exploited for the power system operation services involving the continuous balancing of the electrical energy supply and demand in a power system, which is necessary to preserve the security of electricity supply. The total production of electricity needs to be equal to the total consumption at each time to keep the network frequency and voltage within acceptable boundaries, therefore these system services are sometimes called frequency and voltage control. Within a power system, the System Operator [1] is the party responsible for power transmission and system operation, which include system services. To perform this task, the System Operator usually relies on facilities owned by the users of the power system, which are then the ancillary services providers. Figure 2.1 provides a schematic illustration of the distinction between ancillary and system services.

Any user of the power system benefits from the system services without depriving any other user of the same benefit, while the entry of a new user does not reduce the benefits of the other users (non-rivalry). At the same time, with the current state of technology, it is impossible to impede a specific user from taking advantage of these services (non-excludability). Therefore, system services are what the economists call public goods. [5, 6]

[1] A Transmission System Operator (TSO) owns the transmission grid while an Independent System Operator (ISO) does not. Since this distinction is not relevant here, the general term System Operator is preferred

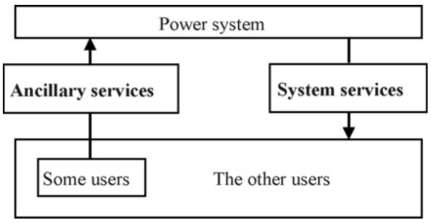


Figure 2.1: Distinction between Ancillary and System services [4]

With regard to security of electricity supply, a distinction can be made between the long-term security and the short-term operational security. System services mainly deal with the operational security of supply, since power balancing is a real-time process. At the same time, the procedure of contracting ancillary services resources in order to ensure an adequate amount of available capacity to meet the demand at all times, is a long-term security aspect. In view of the goal of the contracting procedure and considering that the contracting period is usually shorter than a year, also this feature can be related to the operational security of supply [7].

2.2 Liberalized electricity industry

In the last decade of the 20th century, many power systems began a de-verticalization process moving from a monopoly to an unbundled structure, with the introduction of deregulated electricity markets where private energy companies could compete. In Europe the liberalization of the electricity industry, enforced by the Electricity Directive 96/92/EC, has introduced competition in generation, trade and retail. With regard to system services, the most relevant change is the unbundling of generation and transmission, with the consequent introduction of competition in generation and the establishment of the System Operator as the independent party responsible for power transmission and system operation.

Within the previous electricity industry structure, the network company had full control over generation planning and dispatch, which eased an economically optimal system balance planning and implementation. After the unbundling process and the integration of multiple generation companies, the system balancing process has become a more complex task. When the System Operator does not have control over generation, the market participants need to receive incentives to supply balancing resource and reduce their imbalances. Therefore, the efficiency and effectiveness of system services rely on the incentives received by the market, typically sent by mean of rules and regulations.

In a liberalized electricity industry, the electricity trading takes place in a sequence of markets as illustrated in Figure 2.2. The balancing market is part of the overall electricity market, and it is usually the last electricity market on which energy can be traded. This market is used for the procurement of the electricity required to maintain system balance, which corresponds to the real-time difference

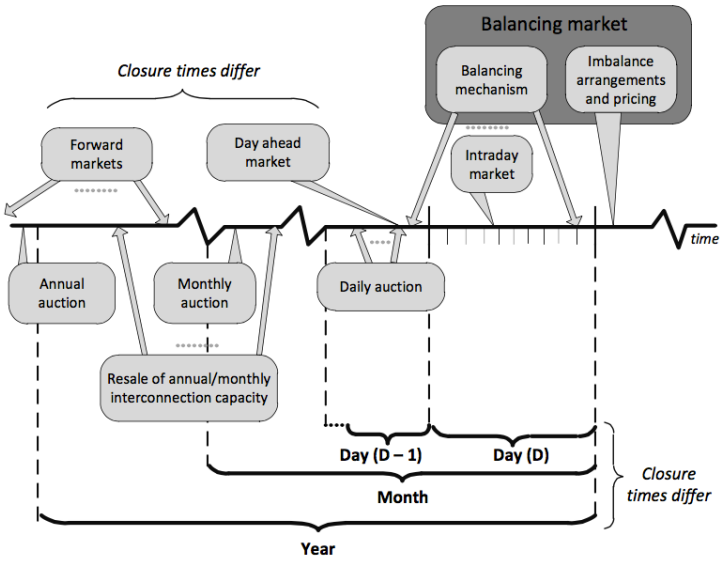


Figure 2.2: Time sequence of electricity markets [8]

between generation and consumption. Therefore, the demand is constituted by the system imbalance volume, which is usually small but highly volatile, and the System Operator acts as single-buyer of the market. The creation of a market for ancillary services is a way of solving the conflict between buyers and sellers to their mutual benefit: the System Operator would like to maintain the system balance by procuring the needed resources at minimum cost, while the providers would like to maximize their sale profit.

However, since ancillary services are not simple commodities, different types of balancing markets exist, a first distinction can be made between reserve capacity and balancing energy markets, but also between upward and downward regulation markets, and markets for different service qualities. Moreover, several design variables differentiates the aforementioned balancing markets, for example the voluntariness of bidding, the time units for market clearing, the gate closure times, the pricing mechanisms and many others, which will be further discussed later in the thesis. At the same, it is worth mentioning that the balancing market is much more than the real-time market, it also includes imbalance arrangements and pricing which are performed after the electricity delivery time as illustrated in Figure 2.2.

2.3 Balancing markets integration

In recent years, the European Commission (EC) through the Agency for the Cooperation of Energy Regulators (ACER) is striving for the creation of a single European electricity market, with the aim of increased transparency and enhanced competition between market players. Following initiatives for the integration on the day-ahead and intra-day stage, the balancing market integration is seen as a

logical follow-up. For this purpose, a Network Code on Electricity Balancing (EB) is currently being prepared by experts from the European Commission.

The Network Code on Electricity Balancing is a crucial piece of work for the enhancement of the European security of electricity supply. It will establish a correct framework for the harmonization of electricity balancing rules, which is a prerequisite for the trading of balancing resources between the European TSOs and the development of cross border balancing markets. The effectively share of balancing resource between countries is expected to lead to a more efficient use of the available resources, an increased competition in balancing markets, a costs reduction and an enhanced security of supply. [9]

Because the liberalization process has proceeded independently in different countries and because of the structural differences in the underlying power systems, the current balancing market designs significantly differ between the European countries [10–14]. Given the low level of current European harmonization, the complexity of balancing and the key role it has in European security of supply, the draft of this Network Code is an arduous work.

Despite the numerous similarities existing between the ancillary services and the other electricity markets, when dealing with balancing markets, among other things, specificities due to geographical constraints, appropriate methods for quantifying the needs and long-term procurement strategies needs to be cagily considered.The design of a balancing market entails other issues than those prevailing in the design of a wholesale market, which may potentially set back the harmonization and internationalization processes, as explicity underlined in several articles.

For example,Rebours, Kirschen and Trotignon [4] highlight nine fundamental issues in the design of markets for ancillary services, which solving is essential for the development of efficient and durable markets. These are: defining the users' needs in terms of quantity, quality, price and location; choosing the entity responsible for the procurement; matching supply and demand; choosing the procurement method; defining the bids and payments structure; organizing the market clearing procedure; avoiding price caps, both as offer cap and purchase cap; providing incentives to the service providers and to the power system users; assessing the procurement method in terms of effectiveness, minimal running costs and economic efficiency. On the other hand Vandezande, Meeus and Belmans [15] point out seven key aspects to consider for the proper design of balancing markets: balancing service definitions; times and methods of services procurement; methods of remuneration; gate closure times; methods of imbalance volume calculation; methods of imbalance pricing.

2.4 Literature study

2.4.1 Literature on ancillary service markets rules

The review of the ancillary services requirements and rules in different jurisdictions all over the world and in Europe is a useful input to understand the similarities and dissimilarities characterizing the ancillary services markets, which represent the context of this thesis.

Comparison by Rebours, Kirschen, Trotignon and Rossignol [11, 12] In Rebours, Kirschen, Trotignon and Rossignol [11] the technical features and requirements of frequency and voltage control ancillary services are compared for eight jurisdictions, namely North America, Continental Europe, Germany, France, Spain, the Netherlands, Belgium and Great Britain. From their survey arises a profusion of terms used to define the ancillary services in the analyzed areas, which may lead to misunderstandings when comparing services from different jurisdictions, as the same term is sometimes used to define totally different services. Besides the differences in terminology, significant differences in implementation also stand out from the comparison, some of which can be explained by the different size of the analyzed systems, the relative amount of interconnection capacity or the technical features of the available generation capacity. Furthermore, the survey also covers the main technical characteristics that must be taken into account when procuring or trading ancillary services, such as deployment times, time to full availability, accuracy of frequency measurements and frequency characteristics requirements. With regards to primary frequency control ancillary service, the parameters have almost the same values among all the analyzed European countries, since they are part of a single synchronous area. Only Great Britain stands out, because the size of this system makes it more susceptible to frequency variations. On the other hand, the North American Electric Reliability Council (NERC) does not provide any recommendations on primary and secondary services parameters. It is concluded by Rebours, Kirschen, Trotignon and Rossignol [11] that primary frequency control ancillary service is a much differentiated product because of its decentralized nature and multiple parameters. Secondary frequency control ancillary services is a less differentiated product, because it is centrally managed by the TSO, and it is not always necessary, especially for non-interconnected systems. Lastly, tertiary frequency control reserves do not lend themselves to an easy comparison because TSOs have adopted widely different approaches for the non-synchronized generating units' management.

In Rebours, Kirschen, Trotignon and Rossignol [12] the economic features of frequency and voltage control ancillary services are compared for eight jurisdictions, namely Australia, France, Germany, Great Britain, New Zealand, PJM, Spain and Sweden. The specific ancillary services considered in this paper are primary frequency control, secondary frequency control and tertiary frequency control, while the main economic characteristics of the markets for these ancillary services analyzed are type of procurement methods, type of remuneration methods and structure of remuneration. With regards to the type of procurement methods, four

options are available: compulsory provision, bilateral contracts, tendering and spot market. Primary frequency control is the ancillary service with the widest choice of procurement methods applied, while secondary frequency control is never procured in a compulsory manner and only in France bilateral contracts are used. Moreover, Sweden and Great Britain do not exploit this ancillary service, as Sweden relies on fast manual tertiary control provided by the large hydro generating capacity, and Great Britain is a single synchronous system that does not need to correct deviations from interchange schedules [11]. The other analyzed systems rely on the two more competitive procurement methods. With regards to the type of remuneration methods, four option are available: non-remuneration, regulated price, pay-as-bid and common clearing price. Primary frequency control is not remunerated in those countries applying a compulsory provision, namely Spain and PJM, while the pay-as-bid is the remuneration method preferred where the service is remunerated. Contrarily, secondary frequency control is remunerated in all the eight systems with pay-as-bid and common clearing price as preferred remuneration methods. With regards to the structure of remuneration, an availability payment is in most cases the only remuneration received by primary frequency control, while in three of the six systems using secondary frequency control both an availability and utilization payment are offered. The same lack of homogeneity among the eight areas can be observed for the other economic features analyzed in the survey.

Comparison by Raineri, Rios and Schiele [13] In Raineri, Rios and Schiele [13] the technical and economic features of the ancillary services are compared for six markets, namely England and Wales, Nordic Countries, California, Argentina, Australia and Spain. With regards to primary frequency regulation, similarities are found in the response time, which is always under 60 seconds in the analyzed systems, while the most outstanding characteristic is the required amount, generally indexed to a percentage of the system's demand to ease the comparison. Moreover, it is found that primary frequency control is mandatory in all the regions except for California, where it is optional because of the minimal frequency variations characterizing the system. With regards to the economic features of primary control regulation, the use of bilateral contracts as procurement method and the integration of the payments on the consumers' transmission tariffs stand out. On the other hand, secondary frequency regulation is found to have a wide range of response time, from 30 seconds in England to 15 minutes in the Nordic countries, and also broad values for the required amount. Unlike the previous analyzed service, the provision of secondary regulation is optional in all the analyzed systems and it is provided by a great variety of suppliers. With regards to the economic features of secondary control regulation, the integration of the payment in the customers' transmission tariffs stands out, while the preferred procurement methods are auctions and competitive offers. Lastly, primary frequency regulation is found to be the most profitable service, since the response time demanded is directly related with the price that the consumers pay for the service, although the relevance given to the ancillary services costs varies upon the considered system.

Comparison by ENTSO-E [14] The European Network of Transmission System Operators for Electricity has prepared an overview of the market arrange-

ments in place throughout Europe with regards to ancillary services procurement and balancing market design. The study includes 27 European countries, and cover separately the characteristics of Frequency Containment Reserve, Frequency Restoration Reserve and Replacement Reserve, also distinguishing between reserve capacity and balancing energy. The most common balancing process in Europe is Self-Dispatch – Unit Based while the least common is the Central Dispatch. With regards to Frequency Containment Reserve capacity, the preferred procurement schemes are organized markets and mandatory provision, while no European countries uses bilateral markets to procure this service; generators only are the service providers in all the countries except for Germany, Ireland and Belgium, where generators, pump storage units and load are accepted; the preferred settlement rule is pay-as-bid, followed by marginal pricing and regulated price, which are implemented in four countries each. With regards to Frequency Restoration Reserve capacity, the most common procurement scheme is the organized market, which is used in eleven European countries; the service providers are only the generators in all the countries except for Germany, where pump storage units and load are also allowed to provide this service; the preferred settlement rule is once again the pay-as-bid, followed by marginal pricing and regulated price. Lastly, with regards to Frequency Restoration Reserve energy, the activation rule is Pro Rata (Parallel Activation) in all the countries except for five of them where the merit-order is used; the providers are the generators everywhere except for Germany; the most common settlement rules are pay-as-bid and marginal pricing.

2.4.2 Literature on the impacts of Renewable Energy Sources on the reserve requirements

Expectations are that a large proportion of renewable power will be installed in order to respond to the climate change challenge, especially in the European and North American countries. This generation will in some cases replace the energy produced by large conventional plants, raising questions about the ability of such a system to guarantee a sufficient level of security of supply, because of the concerns on whether or not renewable generation will be able to replace the capacity and flexibility of the conventional generation plants. Moreover, a large portion of the renewable power will be provided by variable generators, who have an availability limit that changes over time (variability) and cannot be currently predicted with perfect accuracy (uncertainty). Therefore an additional variability and uncertainty with unique characteristics will be added to the current system, which may require a change in the way the system operator maintain a reliable power system.

Over the last decade, researchers have made significant effort to evaluate the impacts of Renewable Energy Source, especially wind generation, on the operation of power systems of different nations. Following, a short literature study on some relevant papers on the topic.

Makarov and Hawkins [16] used a mathematical model of the CAISO operations and market, to discover that the wind generation had a considerable impact on the regulation and load following requirements of the analyzed system. How-

ever, this former study was oriented to the previous CAISO operational and market systems, hence it did not simulate an advanced wind generation forecasting service. In a further study, **Makarov et al. [17]** used a mathematical model mimicking the actual CAISO's scheduling, real-time dispatching and regulation processes to evaluate the impact of the integration of 6.700 MW of wind in the load following and regulation of the CAISO power system. Minute-to-minute variations and statistical interactions of the system parameters of wind generation and load forecast were modeled in greater detail, and it was found that the wind installed capacity has a significant impact on the load following and regulation capacity, as well as ramp rate and duration requirements.

Holttinen [18] conducted a study to estimate the increase in the hourly load-following reserve requirements based on real wind power production and synchronous hourly load data in the four Nordic countries, namely Norway, Sweden, Finland and Denmark. Moreover, the need for more flexibility in the electricity system, due to short-term variations of wind power, was estimated for Denmark, Finland and the combined Nordic countries. It was concluded that the hourly variations of large-scale wind power will generate an increase of operating reserve requirements of the power system, which impact will increase parallel to the share of the gross demand produced by wind power.

Jaehnert et al. [19] simulated the actual and forecasted wind power production for five different scenarios covering the years 2010, 2015 and 2020 in the northern European area, based on high resolution numerical weather prediction models and wind speed measurements, in order to analyze the impacts on the procurement of regulating reserves and their activation. They concluded that without market integration, the 2010 real installed wind power capacity produces a doubling of the gross imbalance and gross activation of regulating reserves, and therefore quintuples the balancing costs. In the 2020 high wind scenario, a further triplication of the 2010 results is observed in terms of imbalances and reserves activation. On the other hand, the market integration with its system-wide reserve procurement and exchange and with the possibility of utilizing the flexibility offered by the Nordic hydro-based power, allows to halve the procurement and balancing costs relative to the non-integrated case.

Strbac et al. [20] assessed the costs and benefits of wind generation on the UK power system assuming different levels of wind power capacity. Their study concluded that the English system will be able to accommodate significant increases in wind power generation with relatively small increases in the overall costs of supply. The net additional costs amounted to 5% of the domestic electricity price in case of 20% of energy produced by wind power, with the additional costs driven by the wind generation capital costs and network connection and reinforcement costs, while the additional cost of system balancing were relatively less influential.

Others. Mount et al. [21] determined the system costs of adding wind generation and found that the benefits are highly dependent on how much the inherent variability of wind generation is mitigated. Moreover, some studies, such as [22], performed a more detailed modelling of the ancillary service deployment to determine the ancillary service procurement as a function of the wind penetration and

to evaluate the suitability of the different procurement procedures. Haring et al. [23] assessed the incidence of strategic behavior of demand and supply units to determine the drawbacks of different reserve power market designs which should enable the efficient feed-in of Renewable Energy Sources. While other studies, such as [24], propose novel algorithms to determine the minimum costs reserves for power systems with high wind penetration, or directly a new market design for primary frequency response ancillary service, which includes the right incentives to provide the response reliably [2, 3]. Lastly, Halamy et al. [25] in their study show that a diversified renewable energy mix can reduce the reserve requirements and the effects of variability when compared to a renewable portfolio composed exclusively of wind generation.

Clearly, system balancing and procurement of regulation reserve are challenges of outstanding importance for the secure operation of a sustainable energy system in the future.

2.4.3 Literature on ancillary services cost allocation

As demonstrated in the previous section, market designs for reserve capacity face new challenges and therefore need to evolve to efficiently incorporate the large-scale penetration of renewable energy sources. In order to enhance the power system flexibility and at the same time reduce the amount of reserve capacity required to maintain a sufficient level of security of supply two main issues need to be tackled. On the one hand, the establishment of financial incentives for demand side participation in ancillary service markets, and on the other hand, the establishment of incentives for intermittent energy sources and demand to adhere to their scheduled in-feed/withdraw.

Although many studies have already demonstrated that the ancillary services requirements may increase in the future to give system operators the ability to cope with the increasing uncertainty in the net load, the costs for the procurement of these reserves are currently still allocated merely on administrative rules, i.e. system-wide socialization. These allocation mechanisms do not provide any incentive to encourage market participants to provide flexibility from existing resources or to invest in new sources of flexibility, and therefore create additional system costs (e.g. excessive ramping cause additional wear and tear on the generators providing reserves). On the other hand, currently some market participants have few or no obligations to respect the announced schedule of in-feed/withdraw, and the costs related to the reserve holding caused by these market participants are socialized.

Following a short literature study on the ancillary services cost recovery schemes currently applied in Europe, and a review of new proposed methodologies for the cost allocation in ancillary service markets, which aim at overcoming the deficiencies of the current allocation mechanisms.

Cost recovery schemes by ENTSO-E [14] The survey on ancillary services procurement and balancing market design created by the European Network of

Transmission System Operators for Electricity [14], provides an overview of the ancillary services cost recovery schemes currently applied in the majority of the European countries, which can be used as a basis for the cost allocation mechanisms comparison. With regards to Frequency Containment Reserve capacity, the costs are recovered from the grid users in all the countries, except for the three Nordic countries, namely Norway, Sweden and Finland, were they are recovered from a mix of grid users and Balance Responsible Parties. With regards to the Automatic Frequency Restoration Reserve capacity, the costs are recovered once again from the grid user in the majority of the European countries, except for Sweden, Finland and Portugal were these costs are borne by the BRPs, and for Austria and Croatia were they are borne by a mix of grid users and BRPs. Contrarily, with regards to Frequency Restoration Reserve energy, the costs are borne by the BRPs in the majority of the countries, and only in six European countries they are recovered from the grid users.

Cost allocation by Haring and Andersson [26] Haring and Andersson [26] proposed a novel methodology for the cost allocation of non-event driven reserve capacity, i.e. regulating reserves and ramping reserves, based on the economic principle of "cost-by-cause". Their approach is similar to the economic theory of pricing the economic activity of a market participant who negatively influences the economic goals on another one and thus distorts the market outcome. It is based on the idea that the output of fluctuating power can be pushed to a social optimum level if the marginal costs of avoiding imbalances are equal to the marginal system costs of balancing them. Haring and Andersson [26] found that the determination of the reserves requirements based on this cost analysis leads to a reduction of the required reserves, and it also establishes incentives, which can be used by renewable generators to invest in measures for the reduction of deviations from the schedule, or in case of demand units, they can be used to adapt grid tariffs in order to create financial incentives for demand-side participation.

Cost allocation by Haring et al. [27] In another paper, Haring et al. [27] proposed a methodology to efficiently reduce the costs of providing reserve and ramping capacities, which takes a decentralized approach to balancing, instead of the usual approach where the system operator centrally coordinates balancing. According to their proposal, market participants which cause fluctuations in power balance and ramping requirements, are individually charged on the basis of their willingness to abate these market disturbances. The proposed mechanism is found to produce and incentive-compatible and Pareto-efficient cost allocation of the costs of non-event based reserves and ramping, and also a cost reduction, which is relatively greater for non-event based reserves than for ramping requirements. On the hand, the authors also highlight a possible drawback of this efficient cost allocation mechanism, that is the significant amount of information and computational effort required for its implementation.

Cost allocation by Hirst and Kirby [28, 29] The major premise to Hirst and Kirby's studies [28, 29] is the economically inefficient and inequitable system for charging customers of the costs of the real-power ancillary services used in USA, which is based on their hourly energy consumption and therefore bears no rela-

tionship with the customers-specific costs produced and does nothing to encourage the reduction of these costs. Hence, because of the high costs of these services and the possible inequities of the current system, the authors propose an alternative method, which charges the individual loads, and in principle, individual generators, on the basis of their contribution to the overall variability of system load. The cornerstone of the proposed mechanism are the standard deviations of the 1-minute load fluctuations of the individual customers and the correlations between customer-specific loads and the total system load.

Chapter 3

Ancillary Services Framework

In this chapter, the current status of the ancillary service harmonization process in Europe is evaluated, together some of the ancillary service definitions adopted at the European level are described and the pertinent issues analyzed. Secondly, a detailed analysis of the ancillary service characteristics in the two countries of interest for this thesis, namely Western Denmark and Germany, is provided.

3.1 Preliminary remarks

In any power system, a balance between the generation and the consumption of electricity must be guaranteed at all times. Changes in production or consumption of electricity undermine the system balance and cause grid frequency deviations. The procurement of ancillary services ensures access to the resources required to guarantee a reliable and stable operation of the power system, and it is therefore one of the most important duties of Transmission System Operators (TSOs).

Currently there is no uniform definition for ancillary services, however they can broadly be defined as the range of functions contracted by the TSOs in order to guarantee system security. They usually include black start capabilities, frequency response, reactive power and various other services, which are provided by generators and also demand response through operating patterns change [30]. Access to a broad range of different services from a wide range of providers gives the TSOs flexible options, which allows them to make efficient and economic decisions.

The introduction of competitive electricity markets and the liberalization of the electricity supply industry have a natural consequence in the increased internationalization of the ancillary service markets, in order to gain access to the necessary control reserves via larger markets characterized by fair and effective competition (see also Section 2.3). Despite the harmonization of operational standards currently taking place at the European level through the European Network of Transmission System Operators for Electricity (ENTSO-E), significant differences between the reserve services specifications and definitions still persist in the various European jurisdictions [10–14].

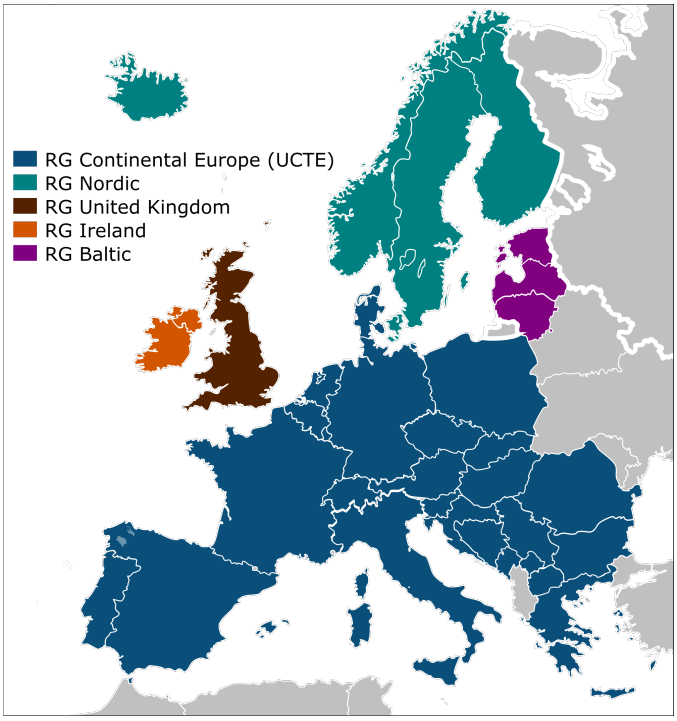


Figure 3.1: Regional Groups (RG) within the ENTSO-E area

With the EU's Third Legislative Package for the Internal Energy Market, the European Network for Transmission System Operators was established and given legal mandate in 2009. The main objectives of this association are the integration of Renewable Energy Sources (RES) and the completion of the Internal Energy Market (IEM), in order to meet the European Union's energy policy objectives of sustainability, security of supply and affordability [31]. ENTSO-E represents 41 electricity transmission system operators from 34 different countries across Europe. Figure 3.1 illustrates the resulting subdivision of the European electricity system into five synchronous areas called Regional Groups (RG).

ENTSO-E is working on the harmonization of the current system operation agreements stipulated by the six former TSO organizations (see Section 2.3). Among other things, the ongoing work aims at establishing uniform definitions for the reserve services across the five synchronous areas. For the time being, the proposed type of reserves are [14]:

- **Frequency Containment Reserves (FCR)**: automatic reserves that stabilize the frequency in case of any frequency deviation.
- **Frequency Restoration Reserves (FRR)**: automatic or manual reserves that restore the frequency to 50 Hz.
- **Replacement Reserves (RR)**: manual reserves that release the aforementioned reserves.

However, until the completion of ENTSO-E's work, the current system operation agreements will remain into force, leaving the various European jurisdiction

with different definitions and specifications for the reserve services. A simple analysis of the current agreements with regards to ancillary services in two different European synchronous areas is sufficient to demonstrate the persisting differences.

The requirements in terms of ancillary services to be met by the countries belonging to the Continental Europe synchronous area are described in the ENTSO-E RG Continental Europe's Operation Handbook – Policy 1 (Operation Handbook) [32], where a distinction is made between three different control levels: primary, secondary and tertiary, the first two being automatic and the latter being manual. The following briefly describes the characteristics and purposes of the different reserve qualities, while Figure 3.2 provides an overview of their responsibilities and applications.

- **Primary Control** is a local automatic control aiming at the operational reliability of the power system: it stabilizes the system frequency at a stationary value after any disturbance in a time-frame of seconds by delivering reserve power in opposition to any frequency change, but without restoring the system frequency and the power exchanges to their target values.
- **Secondary Control** is a centralized automatic control used to maintain a constant balance between generation and consumption: it delivers reserve power in order to bring back the system frequency and the power exchanges to their target values in a time-frame of seconds up to typically 15 minutes after an incident.
- **Tertiary Control** is usually manually activated by the TSOs in case of prolonged activation of secondary control: it is primarily used to free up the secondary reserves in a balanced system state, but it can also be activated as addition to the secondary reserves in the event of larger incidents in order to restore the system frequency and consequently free up the system wide activated primary reserves.

On the other hand, the requirements in terms of ancillary to be met by the countries belonging to the Nordic synchronous area are described in the Nordic System Operation Agreement of 2006 [34], where a distinction is made between manual and automatic reserves. Moreover, automatic reserves are divided into Frequency-controlled Normal operation Reserves (FNR), Frequency-controlled Disturbance Reserves (FDR) and voltage-controlled disturbance reserves; while manual reserves are divided into fast active disturbance reserves and slow active disturbance reserves.

- **Frequency-controlled normal operation reserve** is automatically activated by the system frequency and it is the momentarily available active power for frequency regulation in the range 49.9 – 50.1 Hz.
- **Frequency-controlled disturbance reserve** is automatically activated by the system frequency and it is the momentarily available active power for frequency regulation in the range of 49.9 – 49.5 Hz.

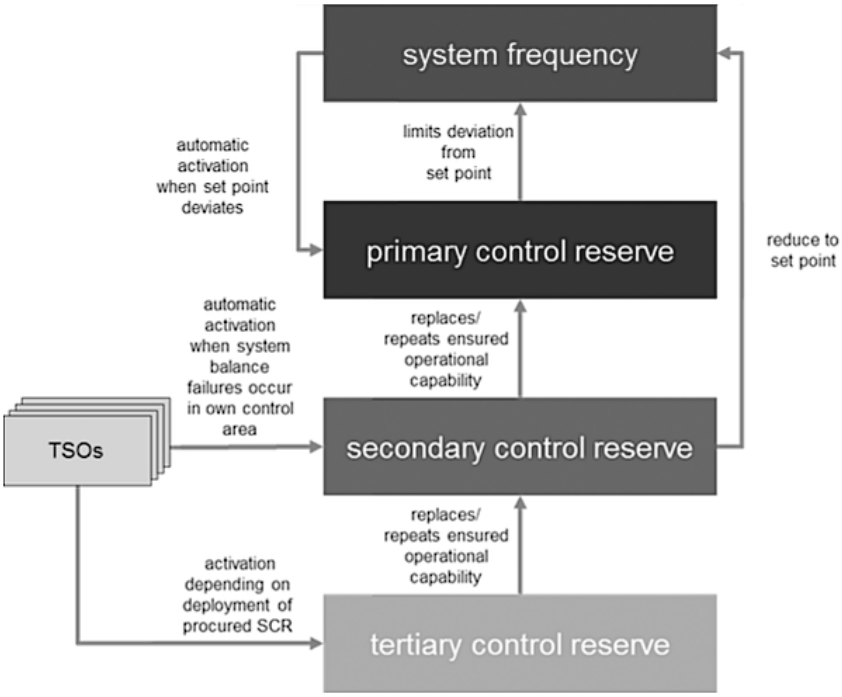


Figure 3.2: Overview of responsibilities and applications of the different reserve qualities operated in the ENTSO-E RG Continental Europe's area [33]

- **Voltage-controlled disturbance reserve** is automatically activated by the network voltage and it is the momentarily available active power used for operational disturbances, often established as system protection.
- **Fast active disturbance reserve** is the manual reserve available within 15 minutes after an incident, which restores the frequency-controlled reserves and transmissions within applicable limits following disturbances.
- **Slow active disturbance reserve** is the active power available after 15 minutes.

The ancillary services categorization in the two mentioned synchronous areas, firmly proves the significant differences still existing at the European level in terms of ancillary services definitions. Nevertheless, similar ambiguities and dissimilarities also endured within the individual synchronous areas, interfering with the desirable European ancillary service markets integration process.

In order to highlight the dissimilarities persisting in the different Continental synchronous' control areas and in order to be able to define an appropriate ancillary services framework for the development of the study, a detailed analysis of the ancillary services characteristics in Western Denmark and Germany has been carried out. For the sake of simplicity and consistency with the rest of the study, only primary and tertiary reserves are fully investigated, secondary reserve is only partly considered for some technical reasons explained in the following chapters, while the other ancillary services are disregarded.

Figure 3.3: Danish power system, including the international electricity interconnections [35]

3.2 Ancillary Services in Western Denmark

Denmark is the only country in Europe belonging to two different synchronous areas, the Continental synchronous area and the Nordic synchronous area, therefore different requirements apply to Western Denmark and Eastern Denmark. For the purpose of this study the only system considered is Western Denmark, i.e. west of the Great Belt (called DK1), which was a member of both the Union for the Coordination of Electricity Transmission (formerly UCTE [1]) and the Nordic cooperation on system operation (formerly Nordel [2]). Figure 3.3 illustrates the entire Danish power system and its international electricity interconnections, including the Great Belt which connects the Western Danish power system with the Eastern Danish power system.

Western Denmark is not a totally independent control area, since it is a part of TenneT GmbH's control area under the bilateral agreement stipulated between Energinet.dk and TenneT GmbH. However, it mostly acts as an independent control area in accordance with the above-mentioned agreement, which comprises Energinet.dk's obligations towards TenneT [36].

As the transmission system operator, Energinet.dk is the party responsible for ensuring security of supply in West Denmark. In order to fulfill this duty, among other things, it purchased the following ancillary services in DK1 from either production or consumption units [37]:

[1] UCTE has now been replaced by ENTSO-E Regional Group Continental Europe.
[2] Nordel has now been replaced by ENTSO-E Regional Group Nordic.

- Primary reserves
- Secondary reserves (Load Frequency Control)
- Manual reserves
- Black-start capability
- Short-circuit power, reactive reserves and voltage control

3.2.1 Primary reserve

Primary reserve regulation ensures the restoration of the balance between production and consumption and the stabilization of the system frequency in the event of frequency deviations. It is automatic and provided by production or consumption units which are able to respond to grid frequency deviations by means of control equipment.

All the TSOs within ENTSO-E RG Continental Europe's area are jointly responsible for guarantying the availability of a sufficient level of primary reserves, by providing the system with a share of the combined requirement for primary reserves in the total synchronous area, which is equal to +/- 3.000 MW. The share to be supplied by each TSO is determined by the production in the controlled area relative to the total production of the ENTSO-E RG Continental Europe and fixed once a year. In 2011, the requirement for Energinet.dk was +/- 27 MW. [38]

Primary regulation must as minimum be supplied linearly at a frequency deviation of up to +/- 200 mHz, relative to the reference value of 50 Hz, with a permitted dead band of +/- 20 mHz. The first half of the activated reserve must be supplied within 15 seconds from the frequency deviation event, while the other half must be supplied within 30 seconds. It must be possible to maintain the regulation until the other reserves are activated, which corresponds to a maximum of 15 minutes, and the reserve must be able to be re-established after 15 minutes following the end of the regulation.

Energinet.dk buys two different types of primary reserves at daily auctions: upward regulation power, in case of under-frequency, and downward regulation power, in case of over-frequency. An auction is held once a day for the following day of operation, with the gate closure set at 15:00. For this specific auction, each day of operation is divided into six equally sized blocks of four hours each:

- Block 1: 00.00 – 04.00
- Block 2: 04.00 – 08.00
- Block 3: 08.00 – 12.00
- Block 4: 12.00 – 16.00
- Block 5: 16.00 – 20.00
- Block 6: 20.00 – 24.00

The bids must state a volume in MW and a price per MW per hour for each hour of the following day of operation, and the two values must be the same for entire block of hours. Each bid must be of at least 0.3 MW and combined deliveries of several production/consumption units are allowed. Then Energinet.dk sorts the bids for upward and downward regulation capacity separately according to the price per MW and covers the requirements by choosing the bids according to the marginal price principle. Finally each accepted bid for upward regulation will receive an availability payment corresponding to the price of the highest bid for upward regulation accepted, while the same applies to downward regulation. Deliveries of energy from primary reserves do not receive any energy payment, but they are settled as ordinary imbalances at the balance price.

3.2.2 Secondary reserve (LFC)

Secondary reserve regulation is used to restore the frequency to its target value of 50 Hz in the event of major operational disturbances, after the frequency stabilization conducted by the primary regulation. Its purposes are to release the primary reserves and to restore any power exchange imbalances in order to follow the agreed schedule. It is automatic and provided by production or consumption units which are able to respond to signals sent by Energinet.dk by means of control equipment.

There is no mandatory size for secondary reserve, however ENTSO-E RG Continental Europe's recommendation is of approximately +/- 90 MW, although the individual TSO can increase the reserve level in excess of 90 MW. Energinet.dk's requirements are usually determined on the basis of ENTSO-E RG Continental Europe's recommendation. The minimum value suggested in the Operation Handbook is usually sufficient in Western Denmark, since Energinet.dk uses to a large extent operational planning, which makes possible to forecast the majority of imbalances that occur and consequently activate the slower manual reserves. [38]

Secondary regulation is usually supplied by units in operation, since it must be possible to supply the agreed reserve within 15 minutes. However, the reserve can also be supplied by a combination of units in operation and fast-start units, although the reserve to be supplied within any coming five minutes period must be produced by units in operation.

Energinet.dk buys secondary reserve on a monthly basis as a symmetrical reserve of combined upward and downward regulation. The requirements for the upcoming month of operation are published on Energinet.dk's website at the latest on the 10th day of the previous month concurrently with the announcement of the deadline for submitting secondary reserve bids.

Following, Energinet.dk carries out a bid evaluation and held any negotiations with relevant bidders. When assessing the bids special emphasis is placed on: service price, delivery place and technical properties of supplying unit. The price for secondary regulation is arranged individually between the bidder and Energinet.dk based on the submitted bid and the consecutive negotiations, therefore secondary reserve capacity is settled using the pay-as-bid method. Moreover supplies of energy

from secondary upward regulation are remunerated at the DK1 electricity spot price plus 100 DKK/MWh, but not less than the balance price for energy upward regulation. While supplies of energy from secondary downward regulation are remunerated at the DK1 electricity spot price less 100 DKK/MWh, but not more than the balance price for energy downward regulation.

Energinet.dk expects the secondary regulation activation to decline by 50% in the future as a consequence of the agreement signed with TenneT on the automatic avoidance of counter activation of reserves across the Jutland-German border. Furthermore, from 2014/2015 Energinet.dk will no longer purchase secondary reserve because of the agreement signed with the Norwegian TSO for the delivery of +/- 100 MW of Load Frequency Control with a matching 100 MW reservation, in connection with the establishment of the Skagerrak 4 interconnector. [36]

3.2.3 Manual reserve and regulating power

Manual reserve is an upward and downward regulation reserve manually activated by Energinet.dk's Control Centre by ordering upward and downward regulation to the relevant suppliers. In the event of minor imbalances, manual reserves are used to release the secondary and primary reserves, while they are used to guarantee balance in case of outages or limitations involving production plants and interconnections.

The purpose of purchasing manual reserve is to guarantee that there is always a minimum amount of regulating power bids in Western Denmark, so that Energinet.dk has access to the reserves equivalent to the outage of a dimensioning unit, as required by the international agreements (called the N-1 criteria). Manual reserves are then activated through the common Nordic regulating power market and they must be fully supplied within 15 minutes after the activation. Thus manual reserves cover the capacity reservation, while regulating power is the energy supplied after activation.

Energinet.dk buys upward regulation power and downward regulation power separately with an auction held once a day for each hour of the coming day of operation. The expected reserve requirements are announced on Energinet.dk's website by 9.00 on the day before the day of operation and the bid must be submitted by 9.30 at the latest. The bids must state a volume in MW and a price per MW for each hour in question, also each bid must be of at least 10 MW and of maximum 50 MW.

Then Energinet.dk sorts the bids for upward and downward regulation capacity separately according to the price per MW and covers the requirements by choosing the bids according to increasing price. In those particular cases when the capacity need to be available at a specific geographical location, Energinet.dk can disregard the bids not complying with the requirements.

Each accepted bid for upward regulation will receive an availability payment corresponding to the price of the highest bid for upward regulation accepted, regardless of activation, while the same applies to downward regulation. If the re-

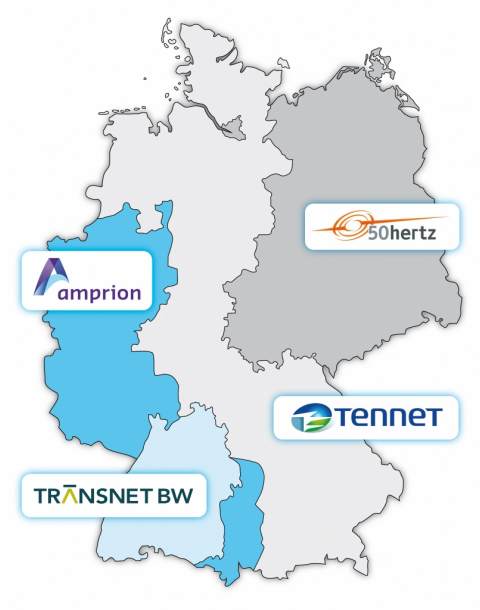


Figure 3.4: TSOs and respective control areas of the German power system

served capacity is then activated in the regulating power market, the market player also receives an energy payment on top of the availability payment. Furthermore, manual regulation providers are allowed to submit bids in the regulating power market although they haven't contracted a binding agreement to provide reserve capacity.

3.3 Ancillary services in Germany

According to the German Energy Act (in German: Erneuerbare-Energien-Gesetz) four different entities are responsible for the load-frequency control regulation in Germany. Each of the four TSO, namely 50 Hertz, Amprion, TenneT and Transnet BW with the respective control areas illustrated in Figure 3.4, operates a separate control area in which it needs to guarantee the system balance by continuously operating and coordinating different control mechanisms. Therefore, within the German legal framework, load-frequency control is a task undertaken by each TSO for each grid user within its control area as part of its responsibilities, with the arising cost passed on to the users. [33]

In order to preserve the system balance with continuous and active regulation, the four German TSOs purchase three qualities of control reserves, which can be activated at different ramp rates and are thus used in successive steps over time:

- Primary Control Reserve (PCR)
- Secondary Control Reserves (SCR)
- Tertiary Control Reserves (TCR)

Currently, 14 entities are prequalified to provide primary control reserve, 20 entities to provide secondary control reserve and 36 to provide tertiary control reserve [33]. The providers of PCR and SCR are mainly the operators of large power plants, while large consumers and local municipalities operating smaller generating units typically provide TCR.

With regard to control reserves, and in particular to secondary and tertiary reserves, a cooperation between TSOs with the purpose of reducing the costs of network regulation within the total system, as in the German case, is feasible with different levels of intensity [39]:

- **Netting of power imbalances**: this optimization level allows to reduce or avoid counteracting deployments of reserves by determining the power exchanges after the detection of the control reserves' demand in each single control area. The reduction of counteracting deployment of reserves consequently reduces the demand for control energy.
- **Reciprocal support in case of shortage**: in this level of optimization the involved control areas support each other with a deliberate power exchange in cases when the control reserves available in one control area are insufficient.
- **Cost-optimized deployment**: this optimization level aims at a cost-effective deployment of reserves through the usage of a common merit-order-list comprising all selected bids of the involved control areas. The cost-optimized deployment entails the exclusion of counteracting activation of reserves, since the demands of the involved control areas are considered in total, and also the reciprocal support in case of shortage.
- **Joint dimensioning procedure**: in this level of cooperation the dimensioning procedure is carried out considering the total demand over all the operating control areas, while before-hand each control area had to completely cover its own demand and to dimension the reserves independently. This procedure makes it possible to take into account portfolio effects, which for example reduces the demand of control reserve in case of forecast failures, and consequently allows a reduction of the procured reserves and the arising costs.
- **Joint tendering procedure**: in this type of cooperation the control reserves are partly or entirely tendered in common, thus a bidder can provide its control reserve to any control area, as far as potential technical limitations are observed.

Since there are no structural bottlenecks within the German transmission grid, from the year 2008 the German TSOs established the German grid control cooperation (in German: Netzregelverbund). In the cooperation initial phase only power imbalances were netted, while nowadays the cooperation within the German TSOs includes the cost-optimized deployment, the joint dimensioning and the joint tendering procedures. The natural consequences of this cooperation have been the

reduction of the control reserves demand and the reduction of the deployed control energy costs.

Moreover, the German regulation on access to power system (in German: Stromnetzzugangsverordnung) defines precise requirements for the market-based procurement of balancing services: control reserves and control energy have to be procured via a common internet platform (i.e. regelleistung.net [40]) through an anonymous tendering process, and they then have to be deployed according to the merit-order-list resulting from this tendering process.

In addition to the national grid control cooperation, the four German TSOs cooperate with different TSOs from the neighboring countries in the so-called International Grid Control Cooperation (IGGC), where currently only power imbalances are netted [33]. This international cooperation allows the avoidance of counteracting deployment of reserves when the transport capacities across control areas are available. However, under such circumstances the previously mentioned higher levels of cooperation are not easy to put into force, since the national markets for control reserves still differ in many features and the availability of transmission capacities is not always guaranteed.

3.3.1 Primary Control Reserve

In the event of a failure Primary Control Reserve has to rapidly stabilize the grid frequency at a new operating point: to guarantee a fast reaction and to keep each unit's contribution small, this type of reserve is activated in a non-selective manner from the total interconnected system. Moreover, its deployment proportionally follows the deviation of the grid frequency from its target value of 50 Hz, therefore no central control is required but the decentralized controllers of the participating technical units are employed for the activation.

The German pre-qualification requirements for primary control reserve call for a full activation within 30 seconds. Accordingly, possible suppliers of PCR are large-scale thermal and hydro power plants, which are able to rapidly change their power output. For example, in thermal power plants the steam storage capacity of the vessels produces an adequate power increase.

According to the ENTSO-E rules, a total primary control reserve of 3.000 MW has to be provided in the Continental Europe synchronous area, in order to be able to withstand two simultaneously occurring reference incidents. In the current system the reference incidents refers to the failure of a nuclear power plant with nominal power of approximately 1.500 MW. Furthermore, each control area has to provide a share of this total PCR volume proportional to the share of the total generation taking place in the control area relative to the total interconnected system. In the year 2014, the primary control reserve demand for Germany was 568 MW. [33]

The German TSOs procure PCR as a symmetrical product in weekly tenders, therefore suppliers have to be able to guarantee an upward and a respective downward regulation related to their offered power for a weekly period, although dif-

ferent technical units can be deployed for the two regulations. The minimum bid amount is set equal to 1 MW, while the bid increment is 1 MW. Finally, the provision of PCR is settled according to the pay-as-bid principle based on the offered capacity price and the provision of energy from this type of reserve is not separately paid.

3.3.2 Secondary Control Reserve

Secondary Control Reserve is an automatic control reserve whose deployment takes into account responsibilities for imbalances, therefore it is always only activated in the control area where the system imbalance occurs. Consequently, no cross-border transmission capacity needs to be allocated to the potential activation of SCR. This type of reserve is used to minimize the deviations of network frequency from its target value as well as the deviations of the cross-border power flows from the agreed schedules. As a result of secondary control no steady state deviation of network frequency remains.

The German prequalification requirements for secondary control reserve call for a full activation within 5 minutes. At the same time, the reserve capacities providing secondary control need to be able to provide system support for a longer time period. Therefore, thermal power plants in dispatchable operation are an example of units capable of providing SCR since they can adjust their operating point within a short time. However, for an optimized outcome power plants pools are usually deployed so that the regulation requirements can be fulfilled in the most economical conditions.

ENTSO-E does not provide any relevant specifications to dimension the procured amount of SCR in each control area, therefore the dimensioning techniques of the different European TSOs significantly differ. The German TSOs apply a probabilistic approach that enables to dimension the demand in a way that the procured reserves are insufficient to balance system only approximately 4 hour every year. This process is undertaken every three months for the next quarter (in March, June, September and December) and it considers the empirical data from the four previous quarters. In the first quarter of 2014, 2.042 MW of positive SCR and 1.969 MW of negative SCR were procured through weekly tenders in Germany. [33]

Positive and negative SCR are tendered separately with two different time slices called “peak” and “off-peak”. The term “peak” refers to Monday to Friday between 8 a.m. and 8 p.m. without public holidays, while “off-peak” refers to the remaining time periods. The minimum bid amount is set equal to 5 MW, while the bid increment is 1 MW. Furthermore, the provision of reserve capacity and control energy are separately paid, therefore each supplier’s bid has to specify both a capacity price and an energy price. The bids are then selected in accordance with the merit-order of capacity prices, with energy prices considered only in those cases where marginal bids have identical capacity prices. Finally, all accepted bids are settled with pay-as-bid mechanism according to the individual capacity price.

3.3.3 Tertiary Control Reserve

In the event of longer lasting system balance failures, tertiary control reserve is deployed to release the more valuable SCR which can be activated at short notice. In contrast to the previous two control reserves, TCR is not automatically activated, but the responsible TSO activate this type of reserves on a case-by-case basis, depending on the utilization of SCR and the foreseeable development of the critical situation. In Germany, tertiary control reserve is electronically activated using the merit-order-list of the offers received on the reserve market.

The technical requirements to be met by this type of reserves are lower, therefore units having less flexibility that those providing SCR may provide TCR. The German prequalification requirements for tertiary control reserve call for a full activation within 15 minutes and a delivery of control energy on the basis of schedules defined in 15 minutes intervals without continuous control signal. Accordingly, possible suppliers of TCR are open-cycle gas turbines, demand-side management sources or marketed RES generators (especially biomass).

As in the case of SCR, ENTSO-E does not provide any relevant specifications to dimension the procured amount of TCR in each control area, therefore the German TSOs apply the same probabilistic approach that enables to dimension the demand in a way that the procured reserves are insufficient to balance system only approximately 4 hour every year. In the first quarter of 2014, 2.472 MW of positive SCR and 2.838 MW of negative SCR were procured through daily tenders in Germany. [33]

Positive and negative TCR are tendered separately with six different time slices consisting of four hours. The minimum bid amount is set equal to 5 MW, while the bid increment is 1 MW. Furthermore, the provision of reserve capacity and control energy are separately paid, therefore each supplier's bid has to specify both a capacity price and an energy price. The bids are then selected in accordance with the merit-order of capacity prices, with energy prices considered only in those cases where marginal bids have identical capacity prices. Finally, all accepted bids are settled with a pay-as-bid mechanism according to the individual capacity price.

3.4 Ancillary services comparison

Due to the ongoing harmonization process in the European grid codes the technical requirements for the reserve services in Western Denmark and Germany are very similar, however the tenders design and the remuneration mechanisms are still rather different. The main characteristics of the procurement of primary, secondary and tertiary reserves are respectively summarized in Table 3.1, Table 3.2 and Table 3.3.

In particular, regarding the primary reserve provision, two characteristics, among the others, substantially differentiate the Danish and German markets. On the one hand, the use of the pay-as-bid principle for the German capacity payments rather than the marginal pricing mechanism used in West Denmark. And on the other

hand, the tender period which is weekly in the German system while daily in the Danish one. This latter difference is very important when evaluating the suppliers' strategic behavior, since the gate closure of the Danish day ahead market is set at 12:00 on the day before the day of operation and therefore only in Denmark it is possible for the suppliers to adjust the primary reserve bids according to the outcome of the day ahead market.

Energinet.dk's short-term strategic objective is to become part of the German cooperation for the procurement of primary reserves, in order to promote competition and ensure reciprocity by giving access to a large international market to both Danish players and Energinet.dk itself. The cooperation with the four German TSOs would ensure a more efficient procurement of primary reserves by giving the Danish players the opportunity to submit bids in a market with total demand of 600-650 MW. However, Energinet.dk believes that daily asymmetrical purchasing allows to obtain the most reserves possible and therefore will work towards a common daily market set up. [36]

The establishment of a common Danish/German market based on weekly auction, would constitute a loss of some of the flexibility introduced in West Denmark in September 2009 with daily auctions. In a weekly purchasing set up, the reserve suppliers keep the capacity out of the spot market and in certain situations can also offer more capacity than with daily auction where the capacity may have already been sold on the spot market. However, this market set-up requires the balance responsible parties to be able to pool and distribute the available capacity over the week period, since some suppliers can't make the capacity available for an entire week.

With regard to the regulating power market, the operating philosophy of the Danish and German TSOs completely diverge. The German TSOs emphasize the automatic reserves while Energinet.dk places emphasis on manual regulating power. Consequently, relatively speaking, the German TSOs purchase more automatic reserves and less manual reserves compared to the Danish TSO. Moreover, in Germany only reserved tertiary capacity can be activated and it is activated only when it is absolutely necessary to relieve the secondary reserves, which represent the Germany primary balancing resource. Contrarily, Energinet.dk's operational planning makes possible to forecast the majority of imbalances and consequently activate the slower manual reserves, which do not need to be reserved in order to be activated.

Table 3.1: Main characteristics of primary reserve procurement in West Denmark and Germany

PRIMARY RESERVE		
	West Denmark	**Germany**
Total volume	The total volume for Continental Europe is +/- 3.000 MW, each controlled area has to provide a share determined by the production in the controlled area relative to the total production of ENTSO-E RG Continental Europe and fixed once a year	
Share of total volume	Energinet.dk's share in 2011 was +/- 27 MW	Germany's share in 2014 was 568 MW
Tender Period	Daily auctions	Weekly auctions
Tender time	At 15:00 on the day before the day of operation (D-1)	As a rule on every Tuesdays (W-1)
Product time-slice	6 equally sized blocks of 4 hours each	None (total week)
Product differentiation	Upward regulation power and downward regulation power	None (symmetric product)
Minimum bid amount	0,3 MW	1 MW
Increment of bid	0,1 MW	1 MW
Call for tender	Capacity price merit order	Capacity price merit order
Remuneration	Price corresponding to the capacity price of the highest bid accepted (uniform price)	Pay as bid (capacity price)

Table 3.2: Main characteristics of secondary reserve procurement in West Denmark and Germany

SECONDARY RESERVE		
	West Denmark	**Germany**
Volume	Energinet.dk used to purchase around 90 MW, calculated on the basis of maximum consumption in the relevant month	In the 1st quarter of 2014, 2.042 MW (positive) and 1.969 MW (negative) were tendered
Tender Period	Monthly auctions	Weekly auctions
Tender time	At 15:00 on the day before the day of operation (D-1)	As a rule on every Wednesdays (W-1)
Product time-slice	None (total month)	Peak: Mo-Fri, 8 am – 8 pm Off-peak: residual period
Product differentiation	None (symmetric product)	Positive and Negative Secondary Control Reserve
Minimum bid amount	0,3 MW	5 MW
Increment of bid	0,1 MW	1 MW
Call for tender	Price of service; Place of delivery; Technical properties of the units;	Capacity price merit order
Remuneration	Pay as bid (capacity price)	Pay as bid (capacity price and energy price)

Table 3.3: Main characteristics of tertiary reserve procurement in West Denmark and Germany

TERTIARY RESERVE		
	West Denmark	**Germany**
Volume	Each TSO must have access to an amount of reserves equivalent to the outage of a dimensioning unit (also known as the N-1 criterion), be it domestic transmission lines, international interconnections or generation units.	
	Approximately 250 MW in 2011.	In the 1st quarter of 2014, 2.472 MW (positive) and 2.838 MW (negative) were tendered.
Tender Period	Daily auctions	Daily auctions
Tender time	At 9:30 on the day before the day of operation (D-1)	As a rule Mo-Fri, 10 a.m.
Product time-slice	Each hour of the coming day of operation	6 equally sized blocks of 4 hours each
Product differentiation	Upward regulation power and downward regulation power	Positive and Negative Tertiary Reserve
Minimum bid amount	10 MW	5 MW
Increment of bid	0,1 MW	1 MW
Call for tender	Capacity price merit order	Capacity price merit order
Remuneration	Price corresponding to the capacity price of the highest bid accepted (uniform price)	Pay as bid (capacity price and energy price)

Chapter 4

The cost of power variability

As demonstrated in Section 2.4.3, current power systems structures do not include any mechanism to support accountability for the costs directly induced by power fluctuations. Imbalances are assessed for energy only through the usage of secondary and tertiary reserves, as calculated for each and every market and power system operation time unit. Contrarily, when it comes to power-related regulation services, the costs are socialized and eventually supported by electricity consumers.

The purpose of this thesis is to propose new mechanisms for assessing the contribution of the market participants to power regulation needs, and to consequently fairly redistribute the related regulation costs. In addition, an assessment of today's costs of power-related regulation services, based on the test cases of Western Denmark and Germany, is carried out beforehand in order to quantify the costs currently induced by the power variability and demonstrate its non-negligibility.

4.1 Empirical assessment of the cost of variability

In a theoretical framework designed to completely separate energy and power related aspects, the short-term power variability of electricity producers and consumers generates a cost for the system, which can be linked to the procurement of primary reserves and partly to that of secondary reserves. These type of reserves, often referred to as frequency-controlled reserves, are automatic and provided by production and consumption units which are able to respond to grid frequency deviations by means of control equipment.

Primary reserves are activated in a non-selective manner from the total interconnected system and their deployment proportionally follows the grid frequency deviation from its set point. Therefore they are a power-only service, which total related cost can be allocated to the short-term power variability. The cost for the procurement of primary reserves is the availability payment paid to the suppliers. Since the activation of these reserves does not result in any additional payment, the submitted bids for primary control power cover the expenses for the provision of primary control capacity and energy, the latter being usually relatively smaller.

Secondary reserves are not deployed in a non-selective manner but their activation takes into account responsibilities for imbalance, hence they are only activated in the control area where the system imbalance occurs. Unlike primary reserves which are exclusively frequency-controlled, the secondary reserves are used to minimize deviations of network frequency from its set point as well as deviations of cross-control area power flows from agreed schedules. At the same time, these reserve capacities can be deployed not only for a short term but also for a longer time period to restore the balance in the specific affected area.

For the above mentioned reasons, secondary reserves cannot be considered a power-only service, and consequently their total cost cannot be fully allocated to the short-term power variability. In order to include these type of reserves in the designed theoretical framework, it is necessary to be able to sort out power and energy related costs, which is usually complicated. In practice, the deployed secondary control energy is commonly included in the overall imbalance settlement, while the remaining costs have been neglected in the following analysis.

On the other hand, tertiary reserves are an energy-related service used to manage longer lasting system balance failures. These reserves, often referred to as manual reserves, are activated by manually ordering upward or downward regulation to the relevant suppliers. The cost related to tertiary reserves is made up of two component, the first linked to the provision of control reserve capacity and the second linked to the deployed control energy, the former being usually relatively smaller.

In order to evaluate the cost of the short-term power variability and to quantify its importance for the power systems, an analysis of the current power variability costs in Western Denmark and Germany is presented in the following sections of the thesis, where an assessment of both power-related regulation cost and energy-related regulation cost is made, in order to ease the results comprehension. Based on the previous considerations, the main basis for comparison is the ratio between the cost of primary control reserve and the costs associated with energy-related services, represented by the Cost Ratio Indicatior defined in Section 4.2.3. Moreover, the analysis covers an entire year of operation (in particular 2014) in the above-mentioned controlled areas.

4.2 Power variability cost in Western Denmark

Data regarding the procurement and usage of ancillary services over the year 2014 in Western Denmark has been downloaded from Energinet.dk website, where all the necessary data are provided on an hourly basis using Euro as currency. The analyzed data sample for the year 2014 is therefore made up of 8.760 values for each parameter.

Power-related regulation data and energy-related regulation data are first individually analyzed, then three indicators are defined and calculated, in order to ease a quantitative comparison with the German data analyzed in the following Section 4.3.

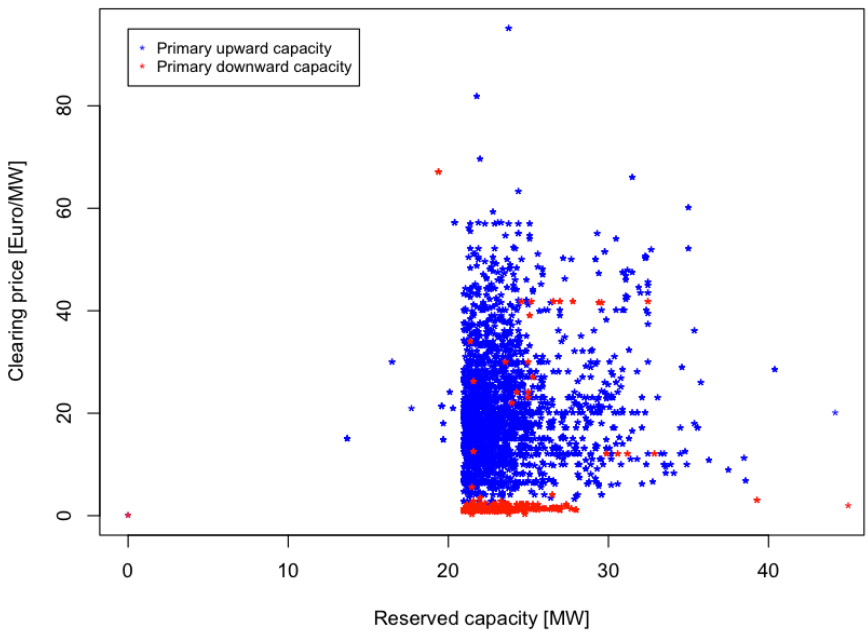


Figure 4.1: Primary reserved upward and downward capacity with respective market clearing price for each hour of the year 2014 in West Denmark

4.2.1 Power-related regulation data analysis

In the theoretical framework designed beforehand to completely separate energy and power related aspects, which partially disregard secondary reserve regulation, and bearing in mind that Energinet.dk will no longer book secondary reserve because of the agreement signed with the Norwegian TSO, only primary reserve belongs to the power-related regulation services.

The capacities reserved for primary regulation in each hour of the year 2014 are illustrated in Figure 4.1 with the respective market clearing prices. Since Energinet.dk purchases two different type of primary reserves, two data samples are depicted: in blue the primary upward capacities and in red the primary downward capacities. It is worth noticing that the reserved capacity ranges between 20 and 30 MW in most of the hours, in accordance with the ENTSO-E requirements of +/- 27 MW. However, in numerous hours of the year Energinet.dk actually purchases more capacity than that required by the European agreement, with spikes of over 40 MW, while there are only few hours when the primary reserved capacity is below the level of 21 MW. Furthermore, with regards to the clearing prices of the primary reserve market, it appears that the price level for primary downward capacity is lower than the one of primary upward capacity, with many hours of close-to-zero clearing prices. On the other hand, the clearing prices for primary upward capacity are more fluctuating, usually ranging between 0 and 60 €/MW, with spikes of over 80 €/MW.

Figure 4.2 shows the development over the year 2014 of the costs associated with power-related regulation in West Denmark. The hourly costs of primary upward and downward capacities have been kept separated as they are respectively

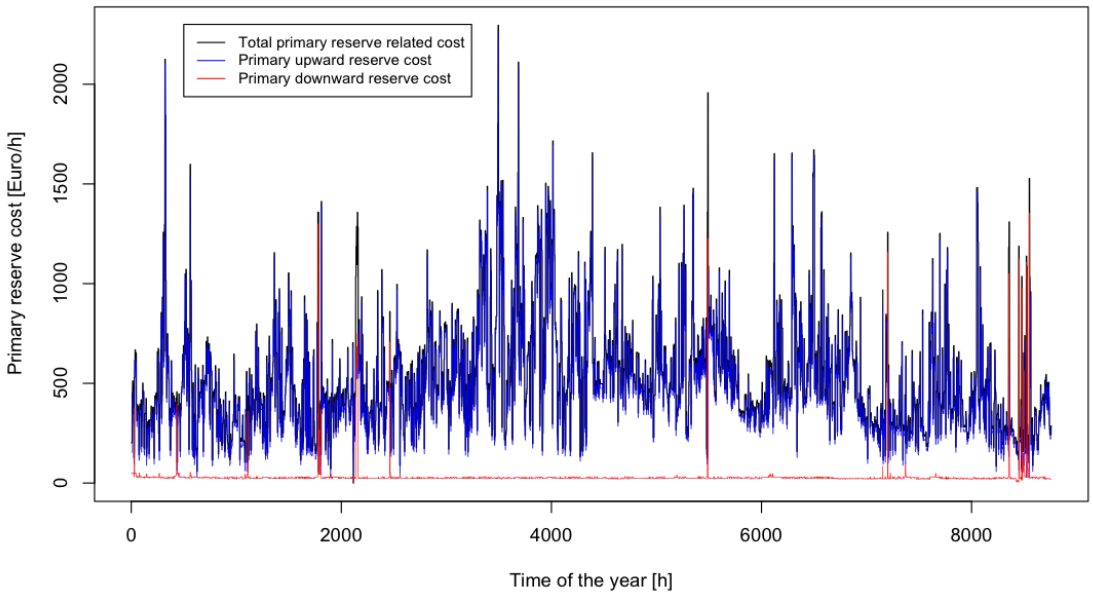


Figure 4.2: Development over the year 2014 of power-related regulation hourly costs in West Denmark

depicted with the blue and red line. Moreover, the total hourly cost of primary regulation, given by the sum of the two previously mentioned costs, is also illustrated with a black line. As foreseeable from the observation of the preceding Figure 4.1, in most cases the prevailing cost is the one related with primary upward capacity, and only in few hours of the year the one related with primary downward capacity is sizeable. Furthermore, with regards to the total cost trend, Figure 4.2 highlights the fluctuating feature of the total power-related regulation cost, which in Western Denmark ranges between 100 and over 2.000 €/h, with an average value of approximately 500 €/h.

4.2.2 Energy-related regulation data analysis

In the theoretical framework designed beforehand to completely separate energy and power related aspects, energy-related regulation is made up of the control energy provided by secondary and tertiary reserves but also of the capacities reserved for tertiary regulation, since tertiary reserves are an energy-only service. Contrarily, capacities reserved for secondary regulation have been neglected from the analysis, since secondary reserves are both a power-related and an energy-related regulation service, which sorting is very complicated with the available data.

The capacities reserved for tertiary upward regulation for each hour of the year 2014 are illustrated in Figure 4.3 with the respective market clearing prices. In theory Energinet.dk can purchase both upward and downward tertiary capacity, but since in practice the downward capacity is almost never reserved, it has been omitted from the graph. From Figure 4.3 it appears that the capacity reserved for tertiary upward regulation widely ranges between 0 and over 500 MW, with a market clearing price usually below 4 €/MW and only few spikes of approximately

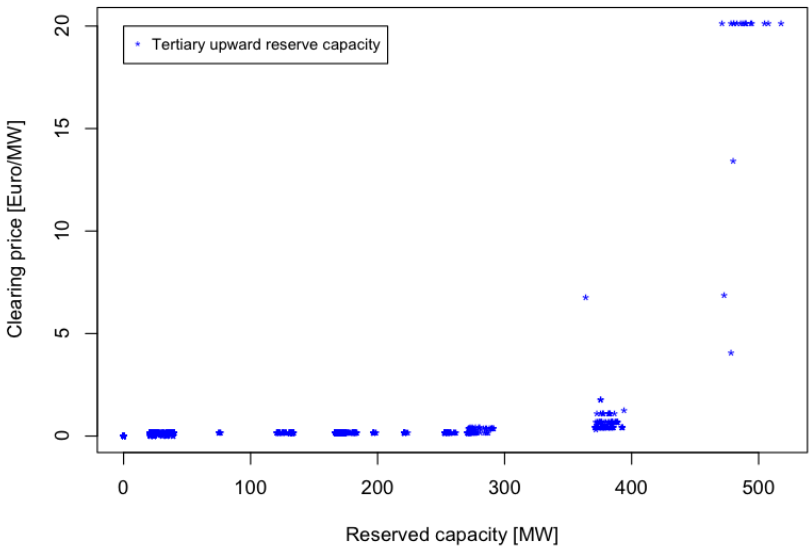


Figure 4.3: Tertiary reserved upward capacity with respective clearing price for each hour of the year 2014 in West Denmark

20 €/MW. The copious amount of low capacities reserved by Energinet.dk over the year 2014 is clarified by the fact that in the Nordic balancing market it is not mandatory for the market participants to have signed a reservation agreement with the respective TSO in order to submit regulating power bids. Manual reserves are booked only to guarantee a minimum amount of regulating power bids from Western Denmark in the Nordic balancing market.

With regard to the regulating power deployed in Western Denmark over the year 2014, Figure 4.4 shows the system energy imbalance with the respective regulating power clearing price for each hour of the year. The parameter "system energy imbalance" is reported on the x-axis of this graph because it represents the actual amount of regulating power deployed in Western Denmark in each given hour. Since the activation of energy-related services occurs through the common Nordic balancing market, the regulating power produced by the Danish suppliers does not always coincide with the Danish actual regulating power need. From Figure 4.4 it appears that the Danish system imbalance has no particular tendency, and it is almost evenly distributed between the positive and negative values, with in both cases a higher concentration close to zero. Moreover, the highest value of the negative energy imbalance occurred in 2014 was of over 1 GWh, while the highest positive one was a little lower than 1 GWh. With regards to the balancing market clearing prices, in most cases they are positive and ranging between 0 and 100 €/MWh, however negative clearing prices have also occurred.

Lastly, Figure 4.5 shows the development over the year 2014 of the total cost associated with energy-related regulation in West Denmark. Based on the previous considerations, this total cost includes both the regulating power cost and the tertiary reserves reservation cost. It is in most cases positive, but in those hours when the market clearing price for regulation power is negative. Moreover, it is characterized by notable spikes of over 50.000 €/h.

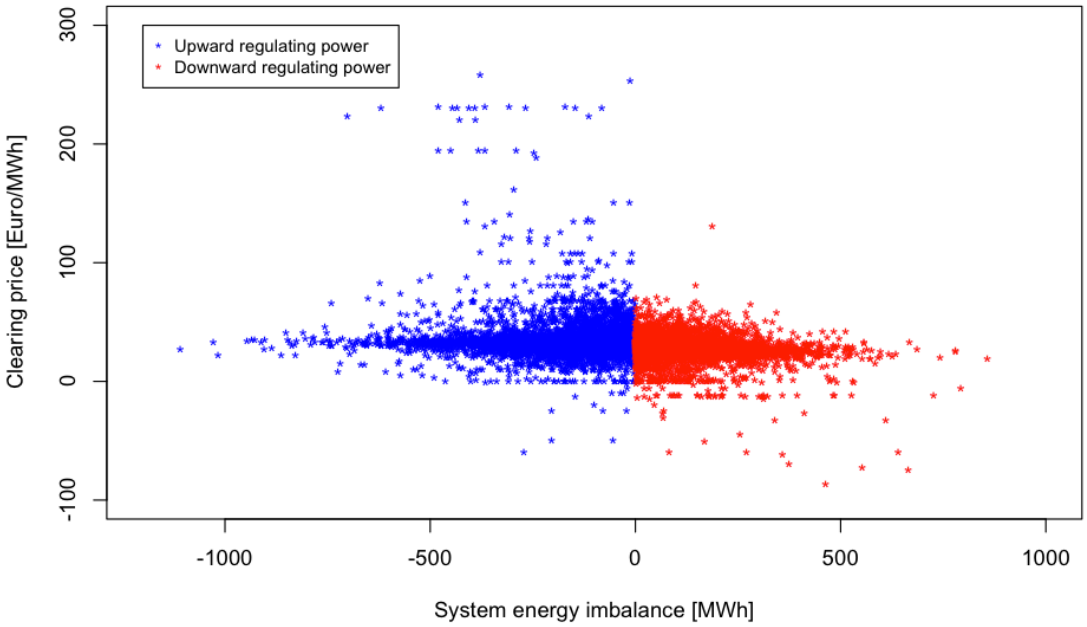


Figure 4.4: System energy imbalance with respective regulating power clearing price for each hour of the year 2014 in West Denmark

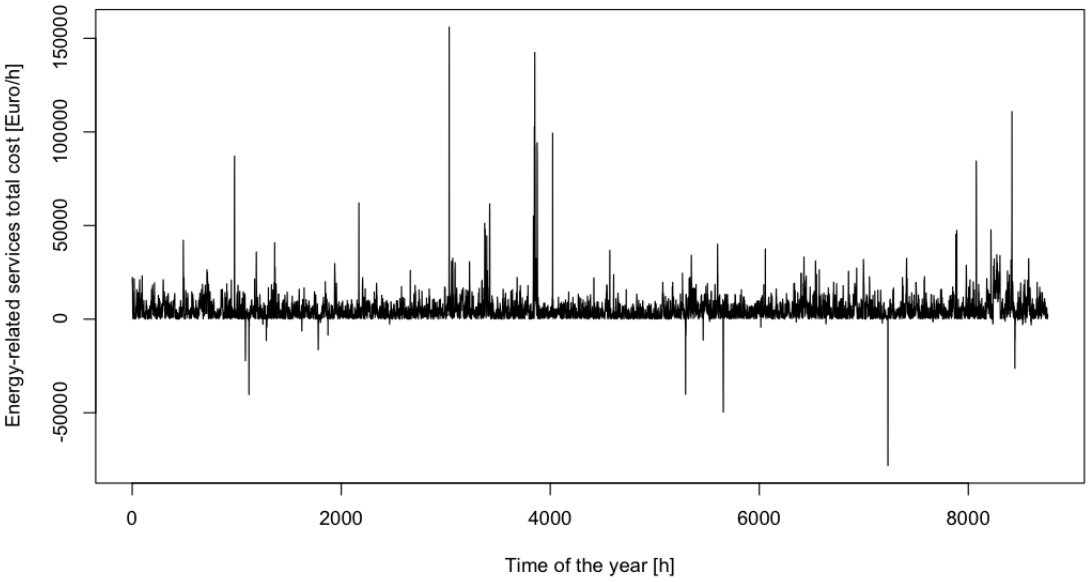


Figure 4.5: Development over the year 2014 of energy-related services total hourly costs in West Denmark

4.2.3 Quantitative comparison indicators

In order to compare ancillary service data from different control areas, it is useful to calculate indicators, which allow to overcome the comparison limitations imposed by the system specifities, such as the power system size. In this section three indicators are defined and then calculated for the Danish system. The first one is related with the volumes of ancillary services procured by the TSO, while the remaining two are costs-related. Moreover, the first two indicators have been found in literature, while the latter has been specifically developed for this thesis.

Volume Indicator (VI) In order to compare the volumes of ancillary services procured, system specificities, and especially the size of the power system, need to be taken into account. Therefore, the volume indicator can be calculated by dividing the amount of procured reserve in MW by the hourly average energy production or consumption in MWh/h [12]. Consequently, a high value of the Volume Indicator indicates that the TSO of a system procures more reserves per unit of energy produced or consumed than the one of the area with a lower VI.

The power-related regulation services VI over the year 2014 in Western Denmark was equal to 10,28%, while the energy-related regulation services VI to 7,06%. Both indicators have been calculated using the hourly average energy consumption as denominator, while the energy-related indicator has been calculated using the average amount of capacity reserved for tertiary upward regulation.

Cost Indicator (CI) The cost indicator for any ancillary service can be calculated by dividing the annual ancillary service cost by the annual wholesale energy cost, where the latter is obtained by multiplying the average wholesale market price by the energy consumption of the controlled area [12]. The wholesale market price is preferred over the end users electricity cost in order to avoid price distortions, for instance due to taxes.

The power-related regulation services CI over the year 2014 in Western Denmark was equal to 0,72%, while the energy-related regulation services CI to 7,23%.

Cost Ratio Indicator (CRI) The cost ratio indicator can be calculated for any control area by dividing the total cost of power-related regulation services by the total cost of energy-related regulation services. One advantage of this indicator is that it allows an easy comparison of the costs of the two types of regulation services involved, and therefore to highlight the relative importance of the power regulation cost, which is in the end the cost that this thesis aims at fairly redistribute.

The total annual cost of power-related regulation services was equal to approximately 4,6 millions of Euros in 2014 in Western Denmark, while the total annual cost of energy-related regulation services to approximately 46 millions of Euros, leading to an annual CRI of 9,94%. Figure 4.6 shows the distribution of the hourly CRI, while Figure 4.7 illustrates the development over the year 2014 of the same indicator. The hourly CRI is found to have a high concentration in the range between 0 and 5%, but also numerous spikes over the 15% level, highlighting the dynamic disposition of the cost of power variability in current power systems.

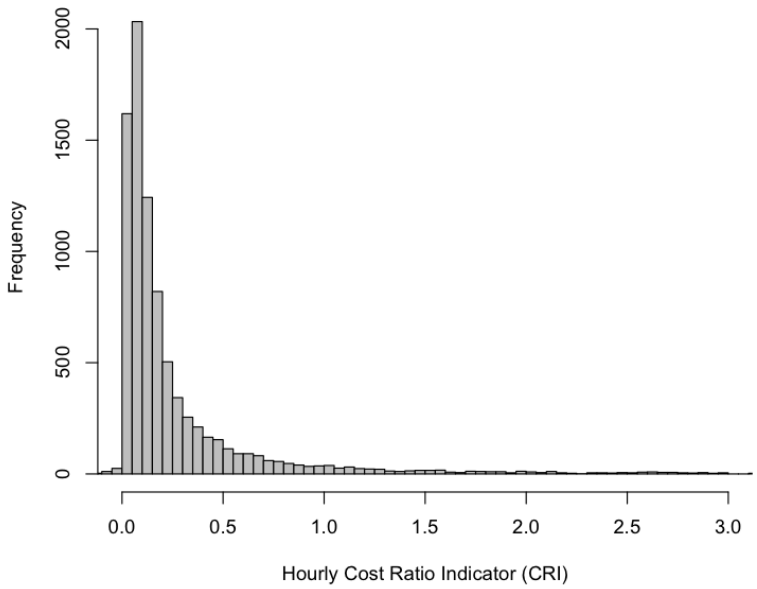


Figure 4.6: Distribution of the hourly cost ratio over the year 2014 in West Denmark

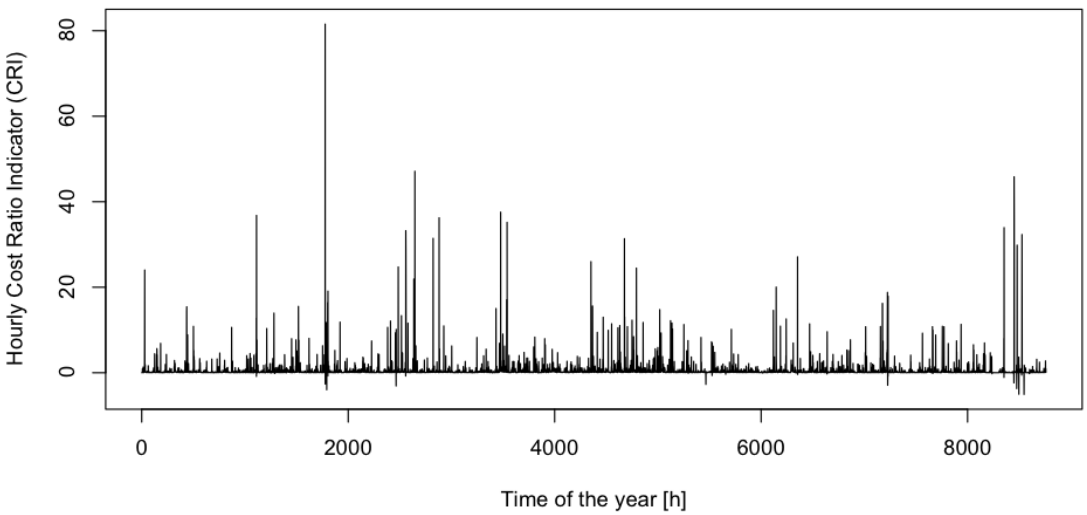


Figure 4.7: Development over the year 2014 of cost ratio in West Denmark

4.3 Power variability cost in Germany

Data regarding the procurement and usage of ancillary services over the year 2014 in Germany has been downloaded from the internet platform for control reserve tendering (www.regelleistung.net) of the four German TSOs, where the necessary data are provided using Euro as currency. However in this case, based on the different tender designs, some data, in particular those regarding primary control reserve, are only available on a weekly basis.

Power-related regulation data and energy-related regulation data are first individually analyzed, then the three indicators defined in Section 4.2.3 are calculated and a quantitative comparison with the Danish data is carried out.

4.3.1 Power-related regulation data analysis

In the theoretical framework designed beforehand to completely separate energy and power related aspects, which partially disregard secondary reserve regulation, only the German primary control reserve belongs to the category of power-related regulation services.

Since June 2011, the tender submission period for primary control reserve in Germany is one week and the call for tenders is symmetrical, meaning that there is no separate call for tenders for positive PCR and negative PCR, contrarily to the previous case of Western Denmark. As a consequence, the analysis of power-related regulation services has been carried out on a weekly basis for the total reserved PCR over the year 2014.

Moreover, in the German ancillary service market set-up, primary control reserve is remunerated through the pay-as-bid mechanism and all the accepted bids are published on the TSOs' shared internet platform. Therefore, with the available data it is possible to build the merit-order curves for the primary control reserve market. The 53 weekly supply curves of the PCR market, built by mean of the software environment for statistical computing and graphics R© from the published data of the year 2014, are illustrated in Figure 4.8. Each curve represents the capacity price offered and obtained by each market participant to make a certain capacity available for an entire week, since only the accepted bids are published.

From Figure 4.8, it is possible to notice that in general the total reserved capacity is around 630 MW, which exceeds the ENTSO-E requirement of +/- 568 MW, because in addition to the German primary reserve demand, a share of 25 MW from the demand of Switzerland and 35 MW from the demand of the Netherlands are also tendered on the German internet platform. On the other hand, the last bid accepted, to which corresponds the highest capacity price paid by the German TSOs for PCR, in most cases offered a price lower than 5.000 €/MW.

Furthermore, the weekly merit-order curves for the primary reserve market have been pooled together in seven different groups, on the basis of the curve trends. The grouping is illustrated in Figure 4.8 with the colors separation, and will be used in the following chapters of the thesis to extract suitable trends for the

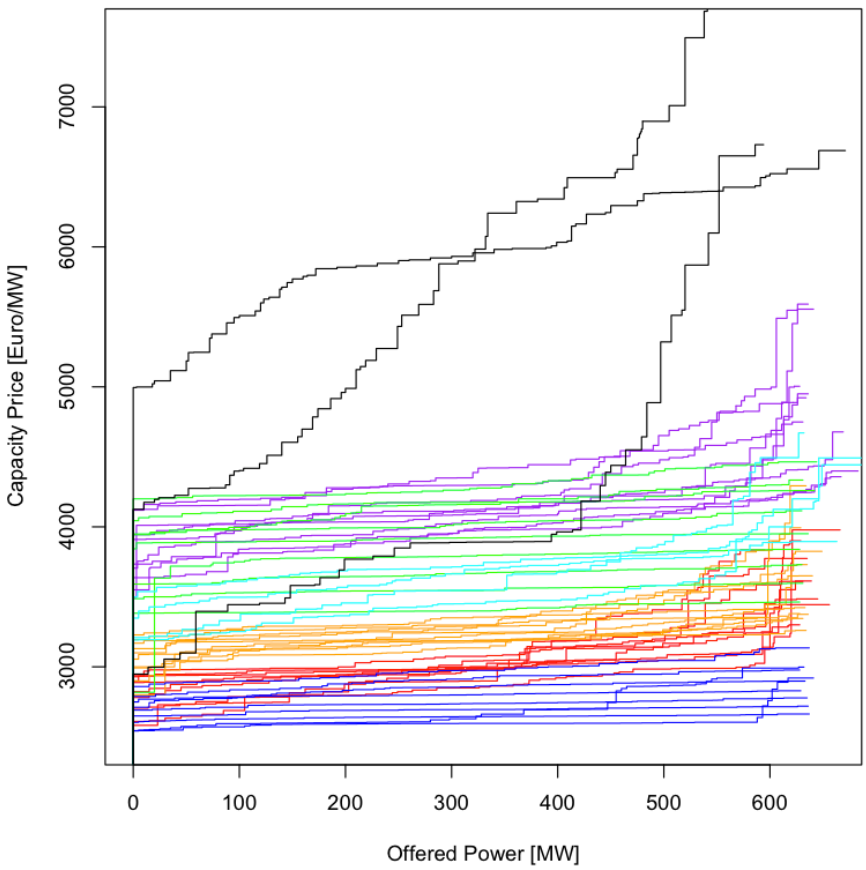


Figure 4.8: Supply curves for the primary control reserve capacity market for the year 2014 in Germany

supply curves of the PCR market. The seven identified trends are presumptively representative of different market circumstances, since the market participants' bids are influenced by factors other than the real costs for the service supply (e.g. expected price levels in the wholesale markets). It has been found, for example, that during the weeks of Christmas and New Year the offered prices for PCR are considerably higher compared to the remaining weeks, as clearly showed by the black curves of Figure 4.8, which precisely concerns these particular weeks.

Figure 4.9 shows the development over the year 2014 of the total weekly cost for power-related regulation in Germany, which corresponds to the total availability payments corresponded by the German TSOs to the PCR suppliers. The availability payments have been calculated by multiplying the offered price of each accepted bid by the corresponding capacity, then the total weekly cost is obtained by summing together all the availability payments of each week. As foreseeable from the previous remark on the black curves depicted in Figure 4.8, the power-related regulation cost during the weeks of Christmas and New Year, namely week 1, 52 and 53, is relatively higher. Moreover, this total cost appears to have a seasonal trend, with relatively lower values in the spring and autumn months and relatively higher values in the summer and winter months. However, an analysis of data from additional years would be required to confirm or prove wrong this remark.

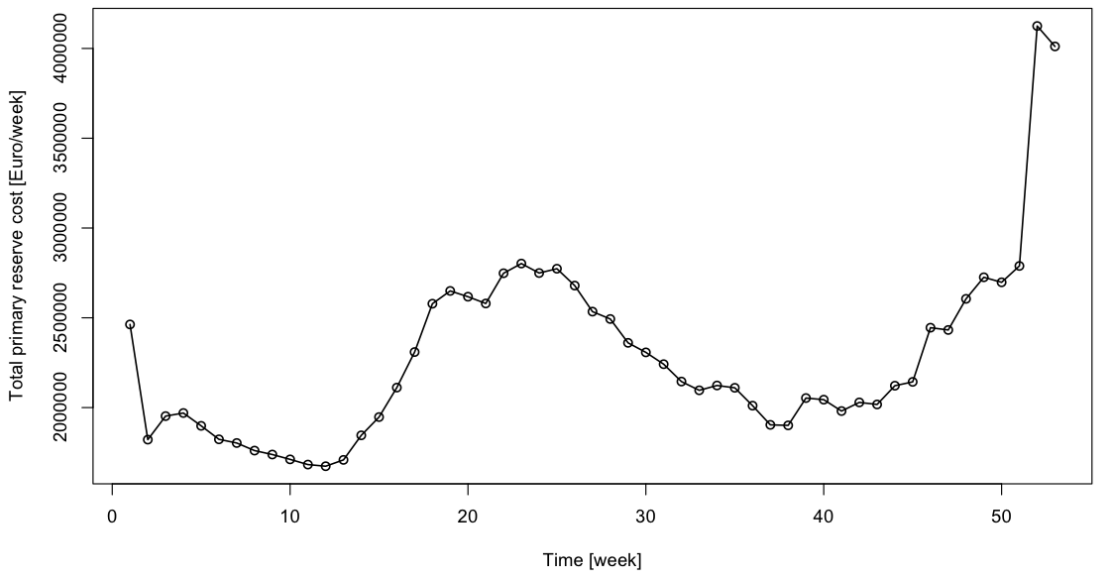


Figure 4.9: Development over the year 2014 of power-related regulation cost in Germany

4.3.2 Energy-related regulation data analysis

In the theoretical framework designed beforehand to completely separate energy and power related aspects, energy-related regulation is made up of the regulation power provided by both secondary and tertiary reserves but also of the capacities reserved for tertiary regulation, since tertiary reserves are an energy-only regulation service. Contrarily, secondary reserved capacities have been neglected from the following analysis, since secondary reserves are both a power-related and an energy-related regulation service, which sorting is very complicated with the available data.

Upward and downward tertiary control reserve capacities are purchased by the four German TSOs at daily auctions with 4-hours time slices. Just as for PCR, these reserves are remunerated through the pay-as-bid mechanism and all the accepted bids are published on the TSOs' shared internet platform. In theory, with the available data, it would therefore be possible to build the merit-order curves for both the positive and negative tertiary control reserve market for each block of hours and for each day of the year 2014, for a total of 4.380 supply curves. Since the graphical representation of such a copious amount of curves would be overwhelmed and meaningless, a study aimed at identifying a proper representative curve for each block of hours have been carried out, thus reducing the supply curves to 12 (i.e. 6 for each type of tertiary reserve, one for each block of hours).

Figure 4.10 illustrates the chosen representative supply curves for the tertiary control reserve capacity market for the year 2014, which have been built by mean of the software environment for statistical computing and graphics R© from the on-line published data. The merit-order curves of both positive and negative tertiary reserve capacities have been plotted on the same graph, where they are respectively depicted by the red and blue curves. Moreover, six different curves for each type of tertiary reserve are illustrated, each one representing a different 4-hours time slice. The selected supply curves, depicted in Figure 4.10, stand for the most frequent

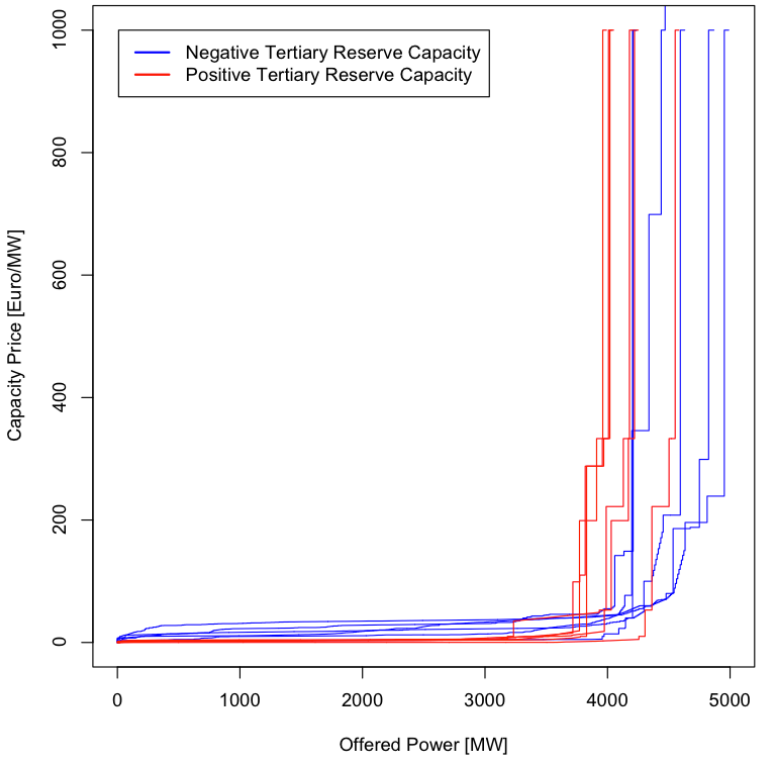


Figure 4.10: Representative supply curves for the tertiary control reserve capacity market for the year 2014 in Germany

trend, although they do not symbolize the average trend. As observed for the PCR supply curves, the merit-order curves of the TCR market are characterized by various trends depending on other markets circumstances, and there are, also in this case, particular weeks when the offered prices are considerably higher compared to the remaining weeks, although they have been omitted from Figure 4.10.

From Figure 4.10 it appears that the capacity reserved for tertiary regulation by the four German TSOs usually ranges between 4.000 and 5.000 MW, independently of the block of hours, with the negative tertiary capacity being slightly higher compared to the positive one. Moreover,the last bid accepted, to which corresponds the highest capacity price paid by the German TSOs for TCR, in most cases offered a price around 1.000 €/MW, although higher prices also occurred as demonstrated by one of the blue curves depicted in the graph.

The tertiary control reserve bids submitted by the suppliers on the TSOs shared internet platform include both a capacity price and energy price, because only the reserved tertiary capacity is eligible for activation, with an activation procedure based on the merit-order curve of the energy prices. Therefore, with the data available on the German internet platform it is also possible to built the supply curves for tertiary regulating power. However, contrarily to the previous merit-order curves depicted in Figure 4.8 and Figure 4.10, these supply curves do not only represent the accepted bids, but all the energy bids eligible for activation.

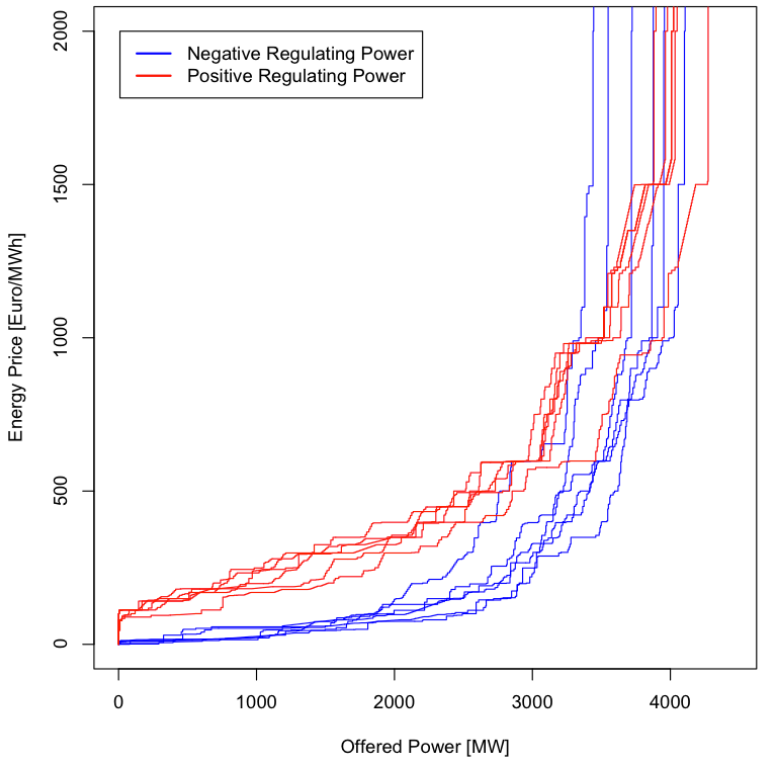


Figure 4.11: Representative supply curves for the tertiary control reserve energy market for the year 2014 in Germany

Figure 4.11 shows some representative curves for the German tertiary regulating power market for the year 2014, which have been built by mean of the software environment for statistical computing and graphics R© from the online published data. These representative curves have been chosen from all the available curves using the same procedure described for the tertiary capacity supply curves. Consequently, also these curves stand for the most frequent trend, although they do not symbolize the average trend. The graph reported in Figure 4.11 had been cut to the value of 2.000 €/MW, in order to increase the resolution of the curves. However, in some cases, the highest offered energy price reaches the level of over 40.000 €/MW, which is reasonable only recalling that also the rejected bids are being illustrated.

To properly evaluate the costs associated with the energy-related services, the energy prices bidded by the TCR suppliers, such as the one used to build the supply curves in Figure 4.11, cannot be used, because they do only refer to the energy provided by the tertiary reserves, while in reality the four German TSOs employ a mix of energy from secondary and tertiary reserves to manage the system energy imbalances and the actual value of energy provided by each type of reserve is not available. Therefore, the uniform Balancing Energy Price (reBAP) applied across the whole Germany to balance responsible parties' imbalances is a more appropriate price. The Balancing Energy Price is calculated for each balancing interval, which is equivalent to the scheduling interval of a quarter of hour, based on the TSO's payments or earnings for the total activated control energy. Because

the energy prices for tertiary and secondary control reserves can be negative, the Balancing Energy Price can also be negative. Thus, knowing the Balancing Energy Price and total amount of control energy deployed it is possible to evaluate the total regulating power cost for each balancing interval. The development over the year 2014 of this cost is illustrated in Figure 4.12b, where each daily cost is calculated summing together the costs of the respective 96 balancing intervals (i.e. 4 quarters of hour for each of the 24 hours making up the day). The total regulating power cost appears to be very fluctuating on a daily basis, with values ranging from close to zero to over 12 millions of Euros.

The cost supported by the German TSOs for the procurement of the tertiary control reserve capacity also belongs to the energy-related services costs. Contrarily, this cost can be simply evaluated by multiplying the accepted tertiary capacity bids by the respective offered price for each and every market time unit, which in this case is a 4-hours time slice. The development over the year 2014 of the cost incurred for the procurement of tertiary reserve capacity on a daily basis is illustrated in Figure 4.12a, where the total daily cost is calculated by summing together the costs of the respective 6 blocks of hours. Compared to the regulating power one, this cost displays a more flat trend, although characterized by astonishing spikes over 30 millions of Euros.

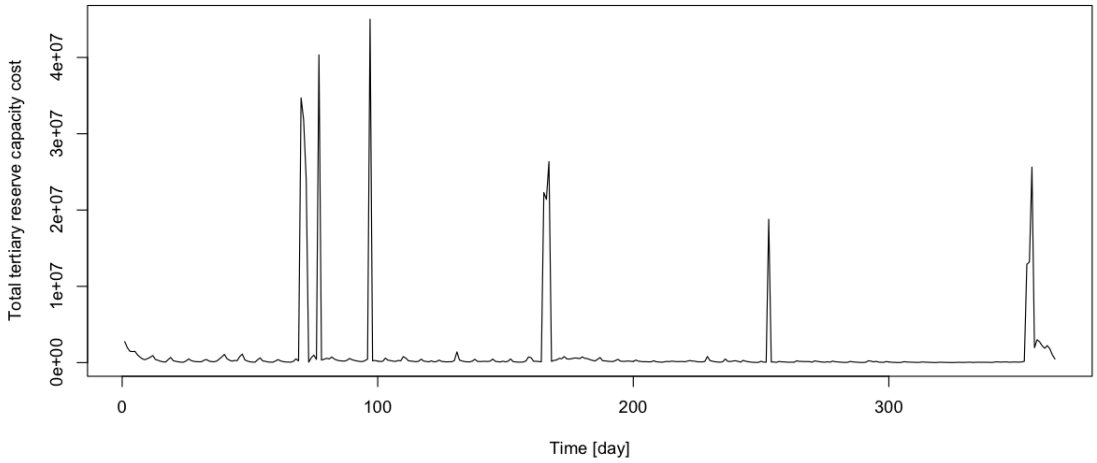
Lasty, the energy-related services total cost on a daily basis for the entire year 2014 is depicted in Figure 4.12c, as given by the sum of the two previously mentioned costs. It also shows spikes of over 30 millions of Euros.

4.3.3 Quantitative comparison indicators

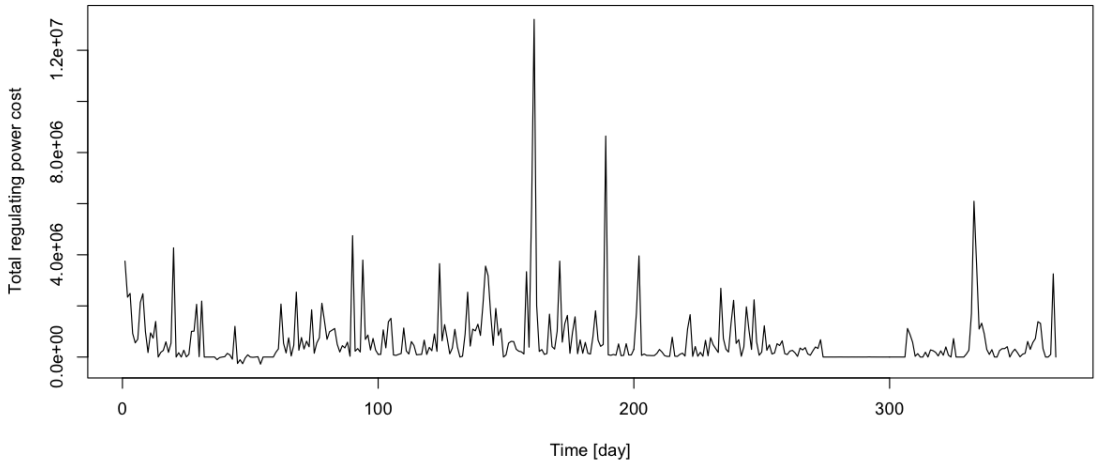
In order to be able to compare the German ancillary service data with those of Western Denmark, overcoming the comparison limitation imposed by the system specificities, and especially the power system size, the three indicators defined in Section 4.2.3 are calculated for the German system. After each indicator evaluation, a comparison between the Danish and German indicators is carried out, and when available in literature indicators from other countries are also compared.

Volume Indicator (VI) The power-related regulation services VI over the year 2014 in Germany was equal to 10,32%, while the energy-related regulation services VI was equal to 9,24%. Both indicators have been calculated using the hourly average energy consumption as denominator, while the energy-related indicator has been calculated using the average amount of capacity reserved for tertiary regulation.

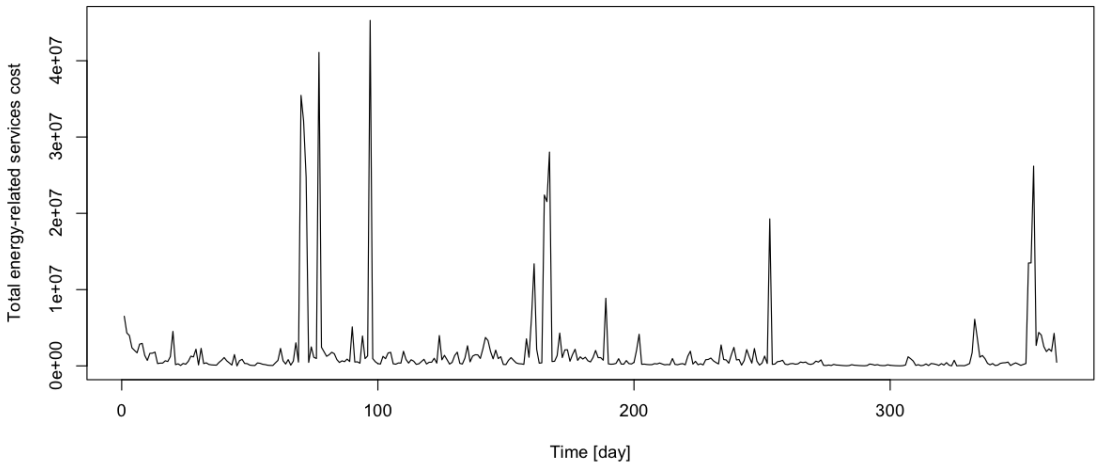
As foreseeable, the power-related regulation services VI is almost the same in Western Denmark and Germany, since the contribution coefficients of the ENTSO-E requirements are calculated on the basis of the annual production of each control area. These results are in accordance with the results of Rebours et al. [12], who found similar indicators values for the analyzed countries belonging to the Continental Europe's synchronous area, with only Spain having a slightly higher primary reserve VI because of the compulsory policy adopted in this country. Moreover,



(a) Tertiary reserve capacity cost



(b) Regulating power cost



(c) Energy-related services total cost

Figure 4.12: Development over the year 2014 of the costs associated to the energy-related services in Germany

Rebours et al. [12], based on the 2004-2005 data, found a VI for the German primary reserve of approximately 10%, which supports the above-mentioned 2014 result. Furthermore, from their results is it possible to notice that the VI is usually higher in small systems with no or limited interconnection capacity, such as Great Britain and New Zealand.

On the other hand, the energy-related regulation services VI is higher in Germany compared to Western Denmark, despite Energinet.dk's operating philosophy based on manual regulating power. The higher German result is probably due to the compulsory policy adopted in this country, according to which only the reserved capacity can be activated in the balancing market, which therefore entails a higher capacity reservation in Germany compared to Denmark.

Cost Indicator (CI) The power-related regulation services CI over the year 2014 in Germany was equal to 0,71%, while the energy-related regulation services CI was equal to 3,95%.

The power-related regulation services CI is almost the same in Western Denmark and Germany, which suggests that there is a similar costs level in the two countries' markets. The two CI results are once again in accordance with those of Rebours et al. [12], that, based on the 2004-2005 data, found a CI ranging from 0,5 and 0,7% in all the analyzed countries, including Germany.

On the other hand, the energy-related regulation services CI of Western Denmark is approximately double the one of Germany for the year 2014. This result is probably due to the different operating philosophy adopted by the respective TSOs. Energinet.dk places emphasis on the manual reserves, while the German TSOs emphasize the automatic reserves, consequently, relatively speaking, Energinet.dk purchases more energy-related services compared to the German TSOs.

Cost Ratio Indicator (CRI) The total annual cost of power-related regulation services was equal to approximately 117,8 millions of Euros in 2014 in Germany, while the total annual cost of energy-related regulation services to approximately 652,5 millions of Euros, leading to an annual CRI of 18,06%.

The CRI results, and in particular the German one which was found to be double the one of Western Denmark, prove that already under the current power system circumstances the power variability of electricity producers and consumers generates a non-negligible cost for the system.

In view of future energy systems with significant renewable energy generation, where the amount of reserve capacity required to maintain a sufficient level of security of supply may increase and may substantially originate from the production side, it is therefore important to introduce new allocation mechanisms for the power variability cost, in order to make the power suppliers accountable for the costs they induce. In particular, it is essential to find mechanisms to assess the contribution of all market participants to power regulation needs, in order to be able to set up a fair cost allocation system. Such mechanisms would also need to provide incentives to the new intermittent energy sources and the demand to reduce their power variability and to invest in new sources of flexibility, in order to ensure that an appropriate level of security of electricity supply is always guaranteed.

Chapter 5

Attribution mechanisms [1]

In this chapter, the market framework is first described by defining how energy and power-related aspects are considered. Secondly, the extension of current settlement mechanisms to consider costs from fluctuations in power delivery is given. Finally, the proposed attribution mechanisms are defined and their main properties are evaluated.

5.1 Power profiles and energy-neutral power profiles

Let us consider a given market participant i, being on either the generation or the consumption side. Its power production or consumption profile is denoted by $q_i(t)$, where t denotes the time. In the case of renewable energy generator or weather-dependent demand, this power profile would be a direct function of the weather. Different forms of control, e.g. direct control of generators, of demand-response or storage, may allow the alteration of $q_i(t)$ and the consequent achievement of the *power profile* $p_i(t)$ eventually delivered to the market and power system. The lack of any form of control translates to $p_i(t) = q_i(t)$. Theoretically, a power profile is a continuous function over a time period $\mathcal{T}$ (say, a market time unit of duration T), while $\int_{\mathcal{T}} p_i(t)\ dt$ is the total energy generated during the same time period. In practice, since these would never be measured in continuous time, power profiles are usually obtained based on a sampling of p, most likely uniform. This yields the *sample power profile* $\mathbf{p}_i = [p_{i,t_1} \quad p_{i,t_2} \quad \dots \quad p_{i,t_n}]^\top$ of actor i, which is a discretized version of p_i for a number n of time measurements t_j, $j = 1, \dots, n$. Continuous and sampled version of power profiles will be used interchangeably in the following.

Energy imbalances are already settled through existing market mechanisms, consequently a separation of energy and power related aspects is required to assess only the short-term power variability of each market participant power profile. This naturally leads to the definition of the *energy-neutral power profile* $\tilde{p}_i$ of mar-

[1] This chapter contains contributions from other academics (P. Pinson, J.Y. Le Boudec, N. Gast, D. Tomazei)

ket participant i, which corresponds to its power profile minus its mean over the considered time period:

$$\tilde{p}_i(t) = p_i(t) - \frac{1}{T}\int_{\mathcal{T}} p_i(t)\ dt \tag{5.1}$$

Similarly, its sampled version is denoted by $\tilde{\mathbf{p}}_i = [\tilde{p}_{i,t_1}\ \ \tilde{p}_{i,t_2}\ \ \dots\ \ \tilde{p}_{i,t_n}]^\top$

Consequently, power delivery can be split into an energy part $E_i = \bar{p}_i|T|$ and its energy-neutral power profile $\tilde{p}_i$,

$$p_i(t) = \frac{E_i}{|T|} + \tilde{p}_i(t), \quad \forall i \tag{5.2}$$

In practice, when sampling power production, an energy-neutral power profile can be readily obtained by subtracting the average power generation $\bar{p}_i$ over the considered time period.

5.2 Extension of current market settlement

Consider a market time unit T, over which market participants have received their energy production and consumption schedules after day-ahead market clearing. Typically in Europe, $T = 1$ hour, though this is expected to shorten in future market designs to better accommodate renewables and pro-active demand. As of now, a market participant i has a revenue (if on the supply side) or payment (if on the demand side) related to energy only, more precisely its schedule E_i^{c} remunerated at a spot price π^{s}, and imbalances $(E_i^* - E_i^{\mathrm{c}})$ settled through the balancing market at price π^{b}, i.e.,

$$R_i = \pi^{\mathrm{s}} E_i^{\mathrm{c}} + \pi^{\mathrm{b}}(E_i^* - E_i^{\mathrm{c}}) \tag{5.3}$$

In the above, π^{s} is the result of the day-ahead market-clearing, while π^{b} is the result of the balancing market clearing, under one-price or two-price settlement approaches. For an extensive discussion on these aspects, the reader is referred to [41].

For the example of the Nord Pool, with a two-price imbalance system, the price π^{b} is a function of the imbalance of the system as a whole, as well as the contribution of the market participant of interest to that imbalance. The overall result of the balancing market clearing is then

$$\pi^{\mathrm{b}} = \begin{cases} \pi^{\mathrm{b}+},\ \pi^{\mathrm{b}+} \leq \pi^{\mathrm{s}}, & \text{if } (E^* - E^{\mathrm{c}}) \geq 0 \\ \pi^{\mathrm{b}-},\ \pi^{\mathrm{b}-} \geq \pi^{\mathrm{s}}, & \text{if } (E^* - E^{\mathrm{c}}) < 0 \end{cases}. \tag{5.4}$$

In this case, the second part of the revenue in (5.3) is actually penalizing, in the sense that

$$R_{E^{\mathrm{c}}} \leq R_{E^*}, \quad R_{E^*} = \pi^{\mathrm{s}} E^*. \tag{5.5}$$

This would not necessarily be the case in a one-price imbalance system. Here with the two-price imbalance system, a market participant offering renewable energy generation into the electricity market gets at best the revenue that would obtain with perfect information on future power generation. Gaming on E^{c} can never be rewarded.

In this current setup, there is no consideration for the power profile allowing for such energy delivery over this time period. Not penalizing generators for their power profile is like assuming that these power profiles are constant. More realistically a tollerance margin exists, i.e.

$$\tilde{p}_i(t) \in [-\varepsilon, +\varepsilon], \quad \forall i, t \tag{5.6}$$

with ε small. Such an approach was fine when considering conventional generators only who can stick to a constant power profile, while the costs induced by non-constant power consumption was socialized on the consumption side. This cannot be valid anymore when having a significant penetration of renewable energy generators, which induce potentially large power fluctuations, with their costs still socialized on the demand side.

It is the aim of the present work to analyse how variability in power delivery may be priced depending on the resulting need for ancillary services. As a general formulation, the revenue of a renewable energy provider in a the market could be generalized as

$$R_{E^{\mathrm{c}}} = \pi^{\mathrm{s}} E^{\mathrm{c}} + \pi^{\mathrm{b}}(E^* - E^{\mathrm{c}}) + R_{\mathrm{power}} \tag{5.7}$$

where R_{power} is the revenue linked to the profile of the power delivery. It is expected to be negative for renewable energy generators, since penalizing them for fluctuations in their power delivery. The revenue formulation in (5.7) can be seen as similar to that of conventional generator participating in both energy and ancillary service markets today, though for them R_{power} should be positive as consequence of the payment for the system services provided.

It is to be noted that applying controls on original power generation $q(t)$ to improve the power delivery $p(t)$ does not have an impact on the day-ahead revenue $\pi^{\mathrm{s}} E^{\mathrm{c}}$, while potentially affecting the revenue from the balancing market $\pi^{\mathrm{b}}(E^* - E^{\mathrm{c}})$ and power delivery R_{power}.

5.3 Proposed attribution mechanisms

From the previous Chapter 4, we assume that we know how to measure the cost of variability, that we denote c_{tot}. Our idea is to distribute the cost of the variability c_{tot} proportionally to each actor and proportionally to a given metric d_i, that

depends on the energy neutral profile of actor i, $\tilde{p}_i$. As such, actor i would pay a share of the total cost given by:

$$\frac{d_i}{\sum_j d_j} c_{tot} \tag{5.8}$$

For a continuous power profile, various forms of metrics may be defined depending upon the objective of interest. In the following emphasis has been placed on metrics that relate to power capacity, integrated mismatch, mileage, and contribution to the total power profile. This last metric is to be seen as different from the others, since it requires comparison of individual and total power profiles, while the first 3 are defined based on individual profiles only.

5.3.1 Power capacity metric

In the first stage, if focus is on capacity that may be required to compensate fluctations, a relevant metric relates to the L_∞ norm of the energy-neutral power profile. Such a metric similarly considers positive and negative fluctuations, only focus on maximum deviation from the constant power profile.

Definition: For an energy-neutral power profile $\tilde{p}_i$, related to renewable energy generator i, the *power capacity metric* $d_{\mathrm{c},i}$ is defined as

$$d_{\mathrm{c},i} = \|\tilde{p}_i\|_\infty = \max_t |\tilde{p}_i(t)| \tag{5.9}$$

In its sampled version this translates to

$$d_{\mathrm{c},i} = \|\tilde{\mathbf{p}}_i\|_\infty = \max_j |\tilde{p}_{i,t_j}| \tag{5.10}$$

For a robust estimate $d_{\mathrm{c},i}$, instead of looking at the maximum in (5.10), one would prefer to estimate a quantile with nominal level close to 1 from the distribution of the $|\tilde{p}_{i,t_j}|$'s.

5.3.2 Integrated mismatch metric

Alternatively to capacity, which relates to some extreme characteristics of $\tilde{p}_i$, one may consider that the integrated mismatch is the quantity of interest, thus relating to a L_k norm ($k = 1, 2$) of these profiles.

Definition: For an energy-neutral power profile $\tilde{p}_i$, related to renewable energy generator i, the *integrated mismatch metric of order k* $d_{k,i}$ is defined as

$$d_{k,i} = \|\tilde{p}_i\|_k = \int_T |\tilde{p}_i(t)|^k dt \tag{5.11}$$

In its sampled version this translates to

$$d_{k,i} = \|\tilde{\mathbf{p}}_i\|_k = \frac{1}{n}\sum_{j=1}^{n} |\tilde{p}_{i,t_j}|^k \tag{5.12}$$

5.3.3 Mileage metric

If in addition to capacity and integrated mismatch, some of the dynamic properties of energy-neutral profiles are of importance, mileage-type metrics can be introduced, related to the L_k $(k = 1, 2)$ norm of the h-order derivative of $\tilde{p}_i$. In practice, it might be most relevant to stick to the case for which $k = 1$ and $h = 1$.

Definition: For an energy-neutral power profile $\tilde{p}_i$, related to renewable energy generator i, the *mileage metric* $d_{\mathrm{m},i}$ is defined as

$$d_{\mathrm{m},i} = \|\tilde{p}_i'\|_1 = \int_T |\tilde{p}_i'(t)|dt \tag{5.13}$$

In its sampled version this translates to

$$d_{\mathrm{m},i} = \|\Delta\tilde{\mathbf{p}}_i\|_1 = \frac{1}{n-1}\sum_{j=1}^{n-1} |\tilde{p}_{i,t_{j+1}} - \tilde{p}_{i,t_j}| \tag{5.14}$$

5.3.4 Inner product metric

We assume here that only renewable energy producers and demand as a whole, since the costs they induce will eventually be socialized, contribute to deviations from an ideal flat power profile. The overall energy-neutral power profile $\tilde{p}_{\mathrm{tot}}$ is hence defined as

$$\tilde{p}_{\mathrm{tot}}(t) = \sum_{i=1}^{m} \tilde{p}_i(t) + \tilde{p}_{\mathrm{d}}(t), \quad \forall t \tag{5.15}$$

in its continuous version, where $\tilde{p}_d$ is the overall demand-side contribution. In its sampled version, this directly translate to

$$\tilde{p}_{\mathrm{tot},t_j} = \sum_{i=1}^{m} \tilde{p}_{i,t_j} + \tilde{p}_{\mathrm{d},t_j}, \quad \forall j \tag{5.16}$$

In contrast to the previous 3 metrics introduced, emphasis can be placed on the respective contribution for all renewable energy generators, as well as consumption, to the total power profile. We use a geometric approch in order to define the respective contribution of each of the $m + 1$ profiles making up the overall one, based the inner product between two functions f and g,

$$\langle f, g \rangle = \int_{u \in \mathbb{R}} fg \; du \; , \tag{5.17}$$

in a vector space of real functions.

Consequently and geometrically, the scaled inner product of $\tilde{p}_i$ and $\tilde{p}_{\text{tot}}$ represents the component of $\tilde{p}_i$ in the direction of $\tilde{p}_{\text{tot}}$.

Definition: For an energy-neutral power profile $\tilde{p}_i$, related to renewable energy generator i, its contribution to the total power profile $\tilde{p}_{\text{tot}}$, and thus its *inner product metric* $d_{\text{s},i}$, is defined as

$$d_{\text{s},i} = \frac{\langle \tilde{p}_i, \tilde{p}_{\text{tot}} \rangle}{\langle \tilde{p}_{\text{tot}}, \tilde{p}_{\text{tot}} \rangle}, \quad \forall i \; . \tag{5.18}$$

In its sampled version this translates to

$$d_{\text{s},i} = \frac{\langle \tilde{\mathbf{p}}_i, \tilde{\mathbf{p}}_{\text{tot}} \rangle}{\langle \tilde{\mathbf{p}}_{\text{tot}}, \tilde{\mathbf{p}}_{\text{tot}} \rangle}, \quad \forall i \; . \tag{5.19}$$

It is to be noted that the component of $\tilde{p}_{\text{d}}$ in the direction of $\tilde{p}_{\text{tot}}$ can be similarly defined. The normalized contribution Δ_{d} of the demand to the overall energy-neutral power profile is then

$$d_{\text{s,d}} = \frac{\langle \tilde{p}_{\text{d}}, \tilde{p}_{\text{tot}} \rangle}{\langle \tilde{p}_{\text{tot}}, \tilde{p}_{\text{tot}} \rangle} \; , \tag{5.20}$$

while its sampled version can be readily obtained as in the above for the case of renewable energy generators.

5.4 Properties of the attribution mechanisms

Interestingly for the case of the inner product metric, owing to its very definition in (5.15), the following properties can be deduced. Firstly, all contributions can be either negative or positive, meaning that individual generators and demand may work towards or against the formation of this total power profile. In addition, it satisfies an additivity property.

Property: The inner product metric d_{s} is additive, i.e. if the total energy-neutral power profile $\tilde{p}_{\text{tot}}$ is the resultant of m power profiles from renewable energy generators $\tilde{p}_i$, plus that on the demand side $\tilde{p}_{\text{d}}$, as in (5.15), one then have:

$$d_{\text{s,tot}} = d_{\text{s,d}} + \sum_{i}^{m} d_{\text{s},i} \; . \tag{5.21}$$

Besides, since dealing with normalized projections, one has $d_{\text{s,tot}} = 1$.

Proof: This results follows from the basic concept of projecting individual vectors onto their resultant using a scalar product.

In contrast, the other 3 metrics defined in the above (capacity, integrated mismatch and mileage) do not have this additivity property. This might prompt discussion on fairness in the following.

5.5 Theoretical Analysis

5.5.1 Natural decomposition of the regulation cost in terms of energy cost and variability cost

Assume the cost of regulation over a time slot T is the integral of a function of the power mismatch at time t:

$$\text{total regulation cost} = \int_T f(\sum_j p_j(t))dt \tag{5.22}$$

Let $\bar{p}_i = \int_T p_i(t)dt/|T|$ be the average power of actor i and $\tilde{p}$ its energy neutral profile. If f can be approximated by a quadratic function around $\sum_j \bar{p}_j$, then this cost rewrites:

$$\begin{aligned}
&\text{total regulation cost} = \int_T f(\sum_j \bar{p}_j + \tilde{p}_j(t))dt \\
&\approx \int_T f(\sum_j \bar{p}_j) + f'(\sum_j \bar{p}_j)\sum_j \tilde{p}_j(t) + \frac{1}{2}f''(\sum_j \bar{p}_j)(\sum_j \tilde{p}_j(t))^2 dt \\
&= f(\sum_j \bar{p}_j)|T| + \int_T a(\sum_j \tilde{p}_j(t))^2 dt,
\end{aligned}$$

where $a = f''(\sum_j \bar{p}_j)/2$.

As a result, the total regulation decomposes naturally in a sum of two terms. The first one depends only on the total energy produced by all players $\sum_j \bar{p}_j$. The second one is the integral of the square of the instantaneous power mismatch.

The first term is compensated by the energy market, the second term should be compensated by the *variability market*.

Chapter 6

Simulation study

In this chapter, the objectives of the simulation study are first described, allowing for the understanding of its scope and thus its implementation perspective. Secondly, the selected case study is introduced together with the reasons behind the choice. Moreover, the simulation set-up, consisting of ancillary service market supply curves, wind producers' power profiles and demand energy-neutral power profile is detailed. Lastly, a short analysis of different market time units and settlement schemes, together with their implications, is carried out.

6.1 Simulation scope

A simulation study is performed in order to apply the concepts introduced in Chapter 5 on a realistic test-case. The main objective of this study is the evaluation of the effects of the implementation of the proposed attribution mechanisms in current power systems, and in particular the illustration of how the introduction of these mechanisms may affect the revenues of the various market participant. The purpose of a simulation based on real data is that of producing results which are then comparable with the current allocation system outcome, in order to prompt a discussion on the benefits of the new cost allocation structure in view of future power systems with significant renewable energy generation. At the same time, a simulation framework is essential to be able to compare with each other the four proposed mechanisms, in order to assess their strengths and weaknesses. But also, to place the inner product metric in both one-price and two-price settlement schemes.

6.2 Simulation set-up

As of end of July 2014, according to the Danish Register for wind turbines [42], Denmark had an installed wind capacity of 4.855 MW, where offshore wind power accounted for 1.271 MW. Moreover, in 2013 wind power production accounted for almost 30% of the total domestic electricity supply, with wind turbines producing

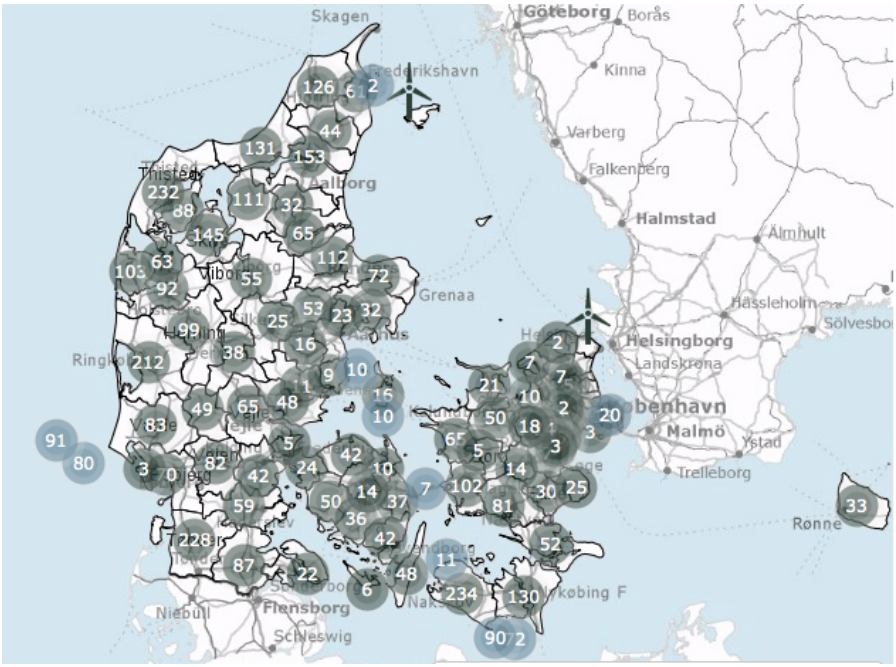


Figure 6.1: Map of Denmark's offshore and onshore installed wind turbines [45]

9.466 GWh of electricity [43]. Besides, Denmark has a very ambitious plan for the wind power development, which requires that approximately 50% of the electricity consumption of 2025 should be supplied by wind power [44]. For these reasons, the Western Denmark power system area was found to be the optimal case study to analyze the effects of the short-term power variability of renewable sources and to investigate the effects of the mechanisms proposed in Chapter 5 to fairly redistribute the cost related to this variability.

Wind power fluctuations are quite smooth within an hour if the wind turbines are dispersed over a large power system area, but when the wind turbines are concentrated in large wind farms, the power output can fluctuate significantly within the hour [46]. Since the Danish wind power development plan includes the deployment of very large offshore wind farms, the wind power is expected to be substantially concentrated in a relatively small geographical area, thus influencing the size of the wind power fluctuations, because nearby wind turbines see more coherent flow than turbines with long distances. In that respect, being able to quantify the reserve requirements due to the wind power variability and find ways to incentive the wind power producers to better self-regulate their power fluctuations are becoming an always more important issue for the operation of the Danish power system.

For example, Energinet.dk has already observed that the power fluctuations from the first large Danish offshore wind farm Horns Rev, located in the Western Denmark power system area, contributes to the deviations in the planned power exchange with the Central Europe power system [47]. On the other hand, Sørensen and Cutululis [46] showed the significant importance of the wind farms spatial distribution on power system operation, and found that if the concentrated wind power development plan proposed by the Danish Energy Authority is implemented,

the reserve requirements can increase of almost 30% of the wind power installed capacity.

For all the above, the simulation study is based on the test case of Western Denmark, country already widely penetrated by wind power generation, as demonstrated by the aforementioned data and by Figure 6.1, which illustrates the existing offshore and onshore wind turbines. However, German data are additionally used as explained in details in the following section of the thesis.

6.2.1 Ancillary service market supply curves

In order to develop a simulation framework that allows to study the impacts of the proposed mechanisms, it is necessary to define the possible trends of the ancillary service markets supply curves. In particular the primary reserve market supply curve is essential to be able to evaluate the total cost of variability for different system operation points but also to determine how the cost of power-related regulation services varies depending on the trend of the energy neutral power profile of the entire investigated system. Moreover, the energy-related services supply curves are used to develop a summary validation process that allows to prove the consistency of the simulation study, by mean of the indicators introduced in Section 4.2.3.

The above-mentioned supply curves can be produced from the market data analyzed in the Chapter 4. Even though the data from a real market do not represent the *true cost* sustained by the services providers to supply the system with the established capacity and energy, it definitely better portrays the cost arising in a market environment. As a matter of fact, in such context various parameters influence the market behavior of the service providers and therefore it is unlikely that their offered price reflects their actual *true cost*.

The merit-order curves of the Danish reserve markets are strictly confidential and Energinet.dk is not allowed to share other information than the total reserved capacity and the corresponding clearing price for each and every Market Time Unit. In the German system the ancillary service auctions are remunerated through the pay-as-bid mechanism and all the accepted bids are published on the TSOs' shared internet platform. From this data it is therefore possible to build the merit-order curves for the regulation service markets and extract some suitable trends for these type of supply curves, as already explained in Section 4.3, and in particular as illustrated in Figure 4.8, Figure 4.10 and Figure 4.11. Because of the different tender design and remuneration mechanisms characterizing the Danish and German ancillary service markets, underlined in Section 3.4, the suitability of the German supply curves in representing the Danish markets has been carefully studied. At the same time adjustments would certainly need to be made in order to take into account the differences in terms of system specificities, and in particular the power system size.

With regard to power-related regulation services, Figure 4.8 showed the weekly supply curves of the German PCR market for the year 2014 and their relative

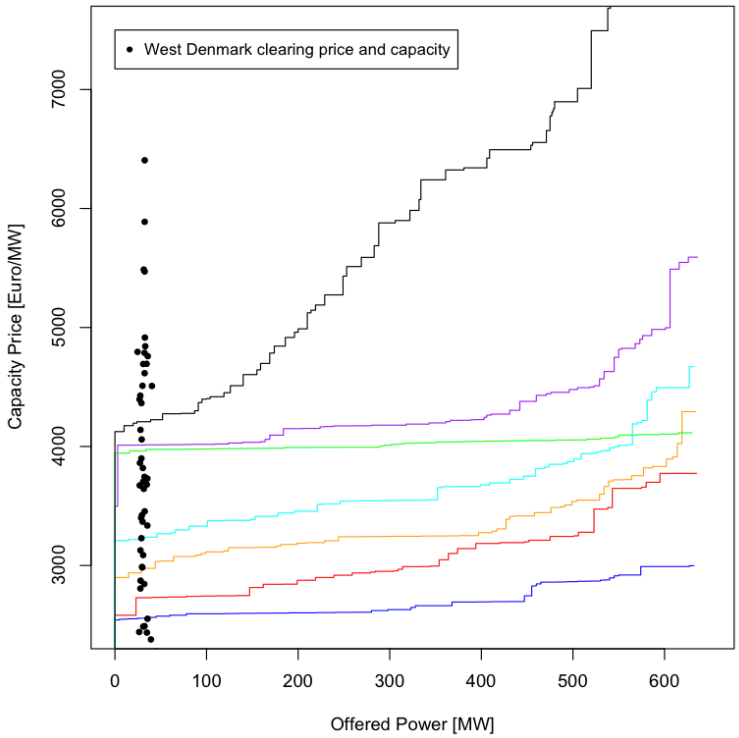


Figure 6.2: Representative primary reserve supply curves for the German market and clearing points of the Danish primary reserve market for the year 2014

grouping based on the curves trends. From the entire set of German curves it is therefore possible to extract seven curves as representative of the German primary reserve market. Figure 6.2 illustrates the selected representative curves, with a color separation identical to that of Figure 4.8, since one curve for each previously determined group has been selected. In the same graph, the clearing points of the Danish primary reserve market for the same year have been also depicted, in order to prove the suitability of the selected curves sample in representing the typical outcome of the Danish primary reserve market.

Figure 6.2 demonstrates that the German curves sample is suitable for the Danish context because of the similar capacity price variation range, although it is necessary to scale the power axis based on the Danish market size. Such a result is not surprising because of the two markets cost level similarities, with respect to power-related regulation services, already underlined in Section 4.3.3 based on the Cost Indicator values, and on the other hand, because of the volume level dissimilarities highlighted in the same Section 4.3.3 based on the Volume Indicator values.

With regard to energy-related regulation services, and in particular to the tertiary reserve capacity procurement, Figure 6.3 shows some representative supply curves for the German market for TCR capacity for the year 2014, with a distinction made between tertiary upward and downward regulation, but also between the six 4-hour time slices characterizing the German auctions. In this case, since the German tertiary supply curves set for the year 2014 is made up of 4.380 curves,

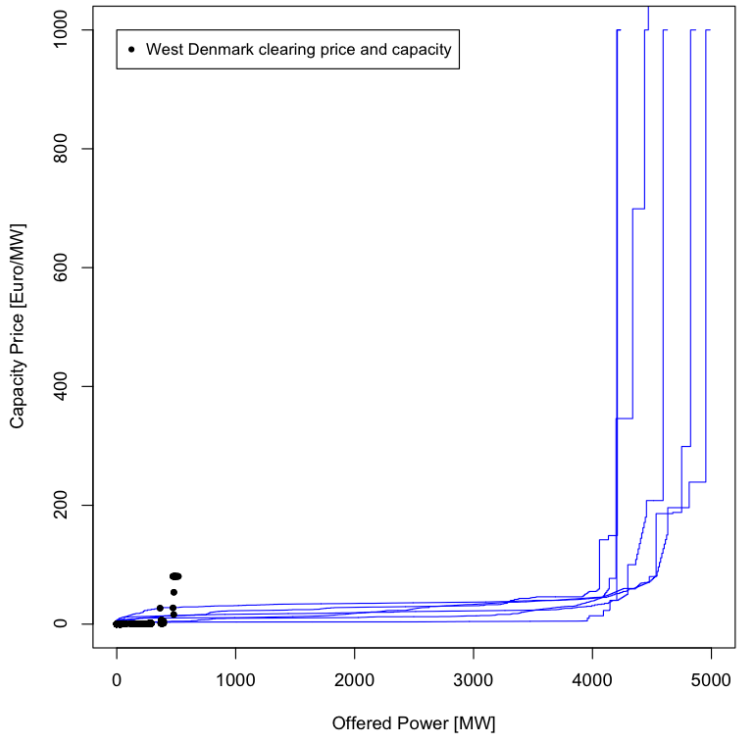


Figure 6.3: Representative tertiary reserve capacity supply curves for the German market and clearing points of the Danish tertiary reserve capacity market for the year 2014

the selection of the representative curves for the German TCR capacity market has been performed before the creation of Figure 6.3, as already pointed out in Section 4.3 when describing Figure 4.10. Therefore, the supply curves illustrated in Figure 6.3 are the twelve curves chosen as representative of the German market for TCR capacity.

Together with the selected supply curves, Figure 6.3 reports the clearing points of the Danish market for tertiary reserve capacity, in order to prove the suitability of the selected curves sample in representing the typical outcome of the Danish market. Although it is necessary to scale the power axis based on the Danish market size, also in this case, Figure 6.3 shows that the German curves sample can be considered sufficiently suitable for the Danish context. Contrarily to the primary reserve case, the greater dissimilarities existing between the German and Danish tertiary reserve markets, and in particular the compulsory policy adopted in Germany for the activation of these reserves in the balancing market, result in a lower suitability. This deficiency, however, will not significantly influence and will not compromise the simulation study outcome, since the energy-related supply curves will only be moderately used in a summary simulation validation process, which is performed apart from the evaluation of the proposed attribution mechanisms.

With regard to the regulating power supply curves, to properly evaluate the cost associated with any power system energy imbalance, it would be necessary

to take into account the control energy provided by both secondary and tertiary reserves together with the details on the two reserves deployment strategies (e.g. circumstances for mutual activation, or separation times for the univocal activation, etc), so to determine the amount of energy supplied by each type of reserve and its resulting cost. Since this set of information is unknown a simplifying assumption has been made, according to which the supply curves for tertiary reserve energy will be used to obtain a rough estimate of the costs associated with energy imbalances. Based on this assumption, the possible existing differences between the cost of the control energy provided by secondary reserves and that supplied by tertiary reserves are neglected, and all the energy imbalances will be priced as they were entirely balanced by mean of tertiary regulating power. Because of the operating philosophy adopted by the Danish TSO, which favors the usage of manual reserves over the frequency-controlled ones, this assumption is expected not to importantly influence the results.

From the remarks arose from the comparison of Danish markets clearing points with the German supply curves, it is clear that, in order to employ the German merit-order curves to simulate the Danish ancillary service markets, it is necessary to re-dimension the German offered power to fit the size of the Danish market. Since the focus of this thesis work is placed on power-related regulation services, which are the system services employed to manage the short-term power variability, the reshaping process is carried out on the basis of the size of the primary reserve markets of the two countries of interest. In particular, the scaling factor is calculated as the ratio between the maximum capacities reserved for primary regulation in Western Denmark and Germany in the year 2014. The maximum value of the reserved capacity has been preferred over the mean value, since the German curves represent only the accepted bids and therefore a portion of the entire supply curve is actually unknown. The maximum capacity reserved for primary regulation in Western Denmark in 2014 was equal to 31,48 MW, while the maximum capacity reserved in the German power system was 688 MW, leading to a scaling factor of 15,29. This scaling factor has been then applied to the offered power of all the supply curves selected as representative of the German markets, so to obtain the Danish ancillary service markets merit-order curves, required for the simulation study. Moreover, a linear scaling has been applied to capacity price values of power-related regulation services, in order to take also into account the tender period difference. Hence, the prices offered by the German providers to supply a certain capacity for an entire week have been divided by 168 (24 hours for 7 days a week) to obtain the respective hourly price, required for the Danish context. As an example of the outcome of the described reshaping process, Figure 6.4 shows three supply curves for the Danish primary reserve market.

The simulation study is based on the analysis of three scenarios which represent a low cost, mid cost and high cost scenario, therefore the supply curves taken into account has been reduced to three, as evident in Figure 6.4. Moreover, in a preventive manner, an additional last step has been added to the supply curves, since the German supply curves only represent the accepted bids, thus neglecting the portion of the curves representing the rejected bids. For each curve, the capacity price of the last step has been calculated with a 40% increase over the price of

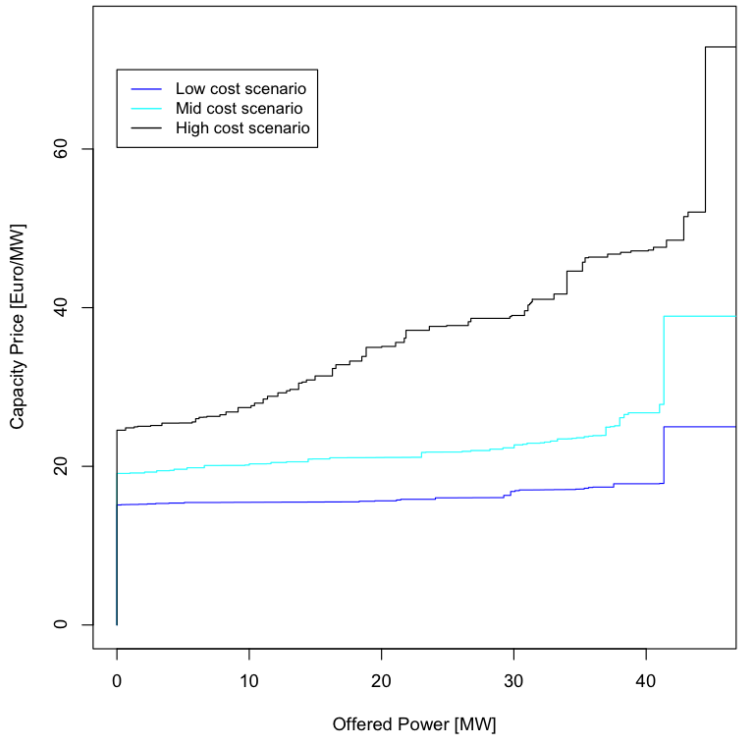


Figure 6.4: Three supply curves for the Danish primary reserve market, representative of a low cost, mid cost and high cost scenario

the last bid "accepted" and it is introduced in order to build a solid simulation framework able to withstand extreme situations.

6.2.2 Wind producers' power profiles

The simulation study performed emphasizes the analysis of renewable energy generation since, if not coupled with any system allowing for smoothing fluctuations, e.g. using storage or demand-response in a virtual power plant setup, it is naturally expected to deliver highly fluctuating power production. Among the Renewable Energy Sources, focus here is placed on wind power generation because in areas with planned large scale wind power development, such as West Denmark, the wind power variability is becoming a challenge to the power balancing, due to the intermittent and stochastic nature of the available wind power. However, similar simulation studies could be performed using a mix of renewable energy generation sources, depending for example on the country of interest current or planned generation mix. Considering that generally conventional generators can stick to a nearly constant power profile, the generation side of the simulation study will only be composed by wind producers.

As a basis for the simulations, wind producers' power profiles are generated with the Correlated Wind (CorWind) power time series simulation model, developed at Risø DTU [48]. This model can simulate wind power time series over the entire Western Denmark area and in time scales where the wind turbines can be repre-

sented by simple steady state power curves (typically greater than a few seconds). CorWind is an extension of the linear and only stochastic PARKSIMU model [49], which simulates stochastic wind speed time series for individual wind turbines, with fluctuations according to specified power spectral densities and correlations between different turbines time series according to specified coherence functions. The linear approach applied in PARKSIMU assumes constant mean wind speeds and wind directions during the entire simulation period, which therefore limits the geographical area and the simulation time period significantly. On the other hand, the extension of PARKSIMU allows simulations over large areas and long time periods, by using reanalysis data over a large region, and then adding a stochastic contribution using an adapted version of the PARKSIMU approach that allows the mean flows to vary in time and space. Subsequently, CorWind requires in input the main wind farm data, including the total wind farm capacity and the geographical position of each wind farm, but also the normalized power curves.

For the simulation study a sample of 41 wind farms, including 7 offshore and 34 onshore, has been chosen from the existing wind farms located in West Denmark, for a total installed capacity of approximately 1.500 MW, where offshore wind power accounts for 700 MW. The main data of the wind farms sample is summarized in Table 6.1, including installed capacity and type of each selected wind farm, while more detailed information on the entire set of input data implemented in the CorWind simulation model can be found in Appendix A.

CorWind is able to produce the actual power observation for any wind farm located in West Denmark as a power time series based on the specified time resolution, but also to provide the day ahead power forecast with a time resolution of one hour. Therefore, through CorWind simulation model is it possible to get access to high frequency data for the wind producers' power profile, and thus to generate the energy-neutral power profile of the simulated power system production side, necessary to study the power variability of renewable energy generation sources and to evaluate the cost for the system caused by this power variability.

On the other hand, the day ahead power forecasts can be used to evaluate the energy deviations from schedule, by comparing the actual power observation with the forecasts on an hourly basis. Figure 6.5 shows three examples of the total energy-neutral power profile over an hour time period of the 41 wind farms considered in this simulation study, where the total profile has been calculated as sum of the individual wind farms power profiles. Moreover, as stated in Section 5.1, the energy-neutral power profiles have been obtained by subtracting the average power generation over the hour time period depicted, since CorWind produces a sampled power profile as output. In particular, the time resolution chosen for CorWind output is 30 seconds, since some preliminary simulations (see Appendix B) demonstrated that the total power profile of the analyzed wind farms fluctuates very little in time scales lower than the selected one.

Table 6.1: Main data for the forty-one simulated wind farms

Name	Power [MW]	Type
Horns Rev 2	209,3	Off
Anholt	399,6	Off
Frederikshavn	7,6	Off
Horns Rev 1	160	Off
Ronland	17,2	Off
Samso	23	Off
Tuno Knob	5	Off
Ajstrup	10,475	On
Arrild	12,62	On
Asted	14,15	On
Bajlum	15	On
Billund	48,9	On
Brejning	11,16	On
Bronderslev	53	On
Dostrup	18,3	On
Dronninglund	14,61	On
Eggebaek Tinglev	16	On
Gammel Vraa Enge	11,25	On
Henjsvig	12	On
Hemmet	27	On
Herning	18	On

Name	Power [MW]	Type
Hollandsbjerg	16,5	On
Horsens	17,6	On
Hvam	13,26	On
Klim	21	On
Lem	29,36	On
Lemvig	26,3	On
Nees	23,3	On
Osterild	18	On
Remme	17,4	On
Ringkobing-Skjern	135,6	On
Skive	39	On
Struer	21	On
Thisted	14,2	On
Tim	15,3	On
Tjaereborg	18,9	On
Udbyneder	35,5	On
Ulvemosen	33	On
Vederso	15	On
Vejrum	16,8	On
Vra	23,67	On

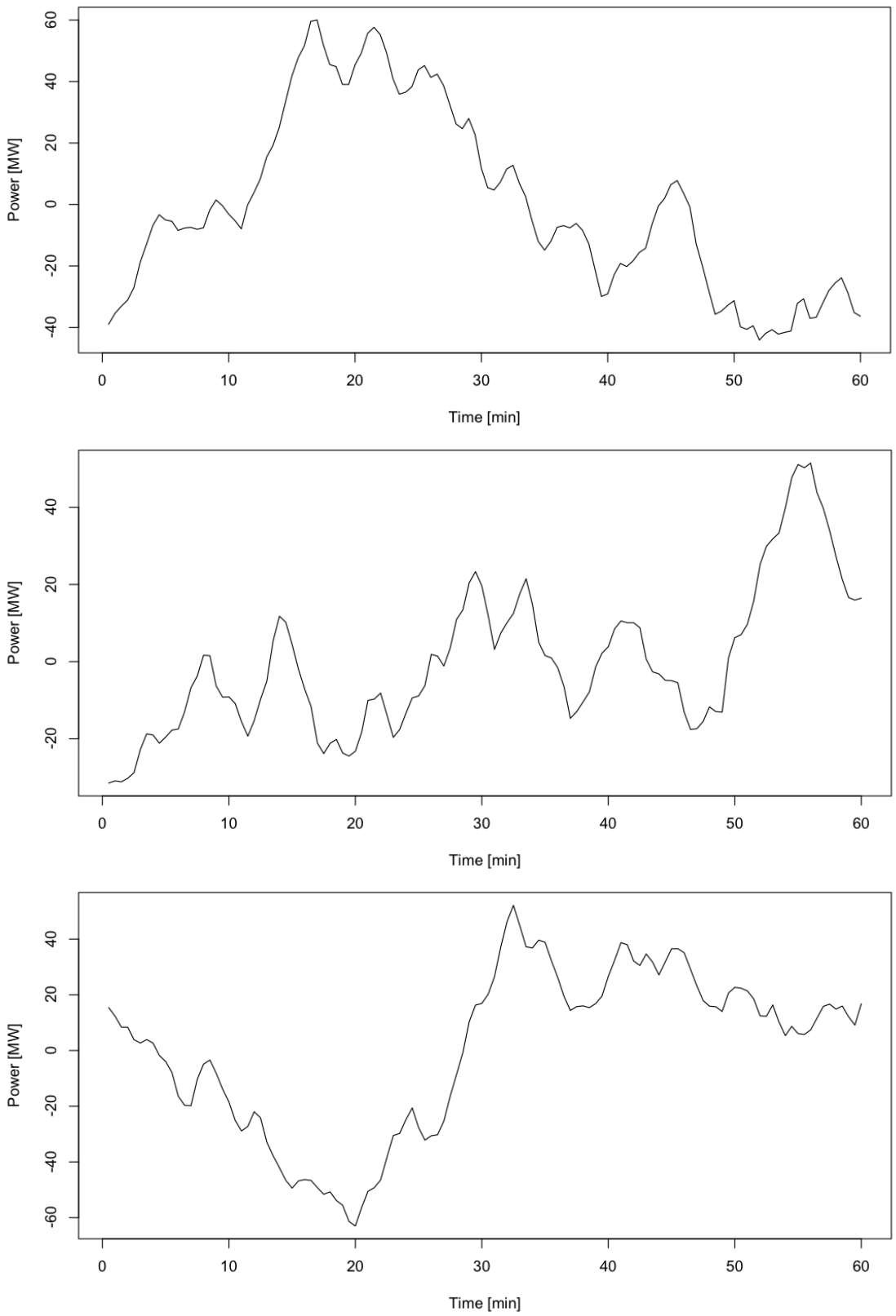


Figure 6.5: Three examples for the total production energy-neutral power profile over an hour time period

6.2.3 Demand energy-neutral power profile generation

In order to properly simulate a power system, both generation and consumption side need to be taken into account. Therefore, together with the wind producers' power profiles, which represent the production group of the simulated market, a power profile representing the total demand need to be contemplated. In particular, a single power profile for the entire system demand is sufficient, since the power variability costs induced by the consumption side will be eventually socialized.

High resolution load data were not available, therefore the energy-neutral power profile is statistically generated as superimposition of two time-series with a first-order correlation. Considering a Gaussian noise ε with finite variance σ^2, each energy-neutral power profile value is obtained as

$$\tilde{p}_0 = \varepsilon_0 \tag{6.1}$$

$$\tilde{p}_i = \rho \tilde{p}_{i-1} + \sqrt{1-\rho^2}\varepsilon_i \tag{6.2}$$

For the simulation, we set $\rho_{\mathrm{d},1} = 0,95$ to generate an energy-neutral power profile highly correlated in time, necessary to properly simulate the real trend of the load power profile over a certain time period, and $\rho_{\mathrm{d},2} = 0,2$ to simulate the fluctuations to add on top of the first profile. Moreover, the value of the variance is obtained from the quantile with nominal level 0,99 of the wind producers' total energy-neutral power profile, in order to generate fluctuations with reasonable amplitude. Lastly, the time resolution chosen for the generation of the demand energy-neutral power profile is 30 seconds, for coherence and consistency with the production data collection.

Figure 6.6 shows three examples of the generated energy-neutral power profile for the total demand over an hour time period. While Figure 6.7 illustrates the energy-neutral power profiles of both total production and total consumption for an entire day of operation.

The energy-neutral power profiles of both production and consumption side, and in particular the absolute maximum value of the total power system profile, calculated as the sum of the two energy-neutral profiles, represent the power-related regulation need (i.e. inelastic market demand curve). Consequently it is the value used to evaluate the total cost of the short-term power variability for each Market Time Unit, by determining the reserves procurement price from its intersection with the power-related regulation services supply curves produced with the strategy described in Section 6.2.1 and illustrated in Figure 6.4. For a more realistic outcome, a security coefficient should be applied to the absolute maximum value of the energy-neutral power profile before determining the required reserves capacity as a result of the possible forecast errors, however it has been neglected in this simulation study. On the other hand, the individual energy-neutral power profiles are necessary for the calculation of the various metrics, and thus to proportionally redistribute the total variability cost according to the proposed attribution mechanisms.

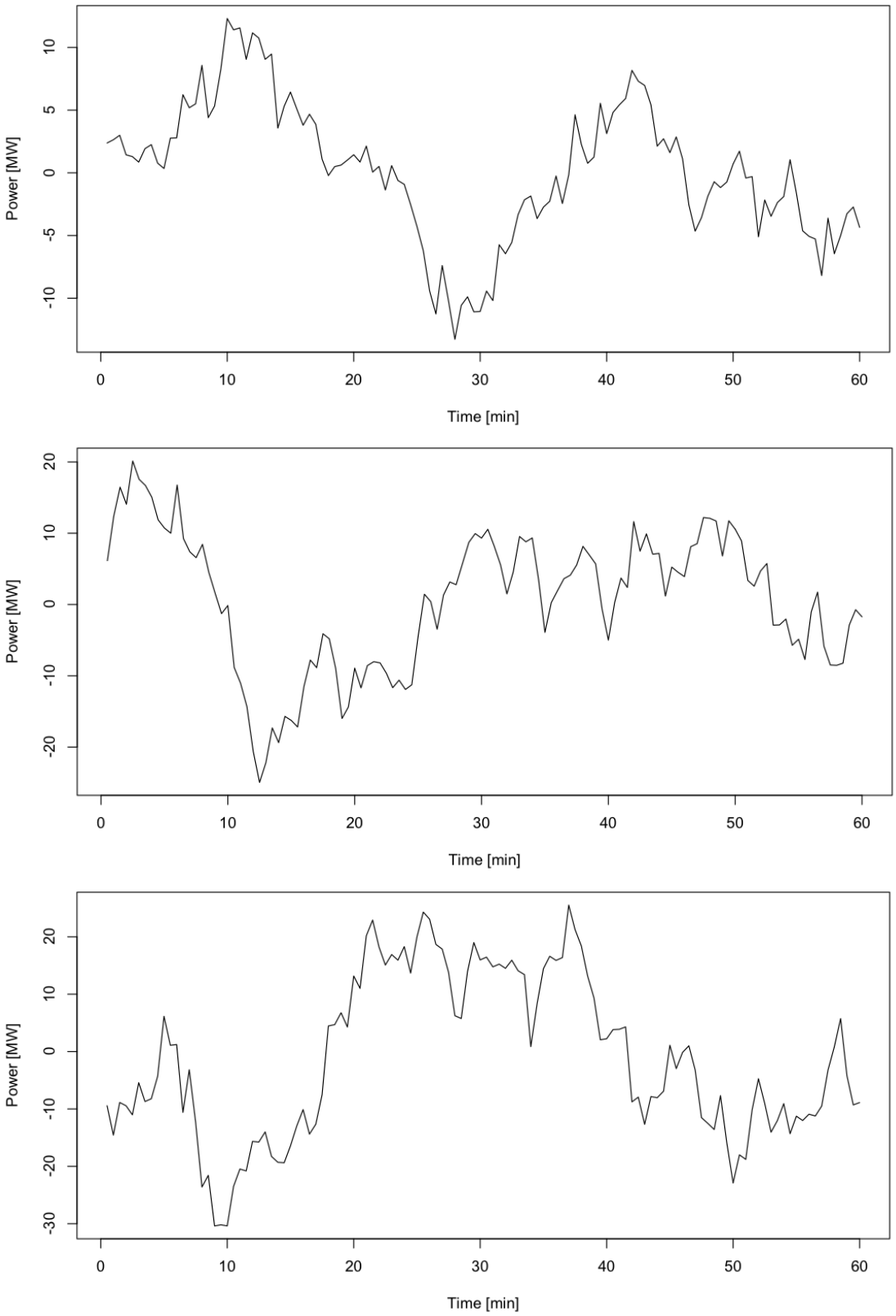


Figure 6.6: Three examples of the generated energy-neutral power profile for the demand over an hour time period

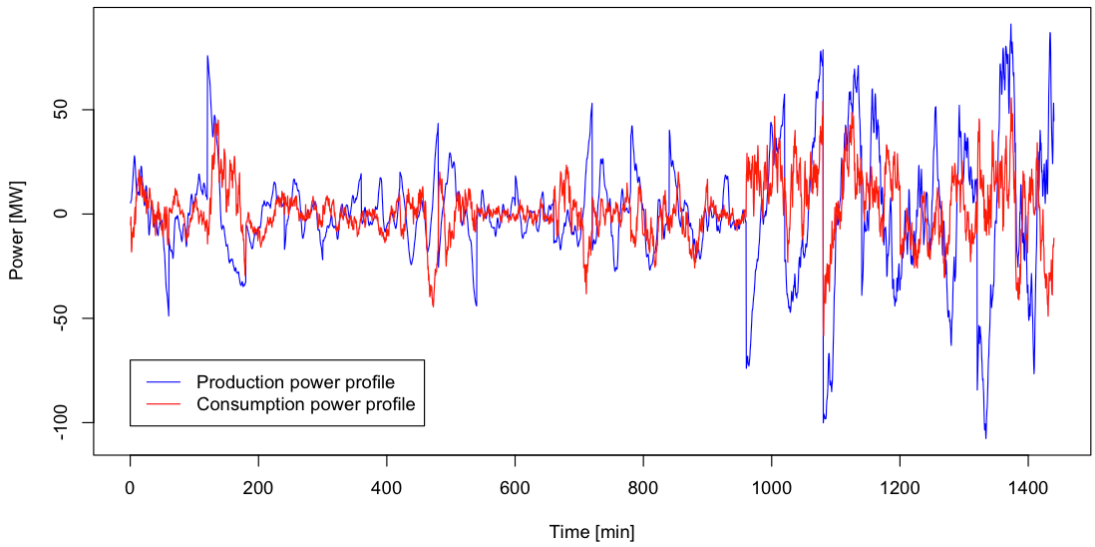


Figure 6.7: Energy-neutral power profiles of both total production and total consumption for an entire day of operation

6.3 Market Time Unit

As a basis for the evaluation of the short-term power variability, a time period T, over which market participants have received their energy production and consumption schedules after the day-ahead market clearing, is considered. Currently, in Europe these market time units are typically $T = 1$ hour, but they are expected to shorten in future market designs in order to better accommodate renewables and a more pro-active demand (see e.g. [50]). For this reasons, the simulation study has been performed using four different Market Time Units, in particular $T = 1$ hour, $T = 30$ minutes, $T = 15$ minutes, $T = 5$ minutes have been considered.

The Market Time Unit influences the computation of the energy-neutral power profiles and consequently the power variability cost. An example of the effects of using different Market Time Units when determining the energy-neutral power profile is given in Figure 6.8, while the resulting differences are illustrated in Figure 6.9, where the energy-neutral power profiles calculated using $T = 1$ hour and $T = 5$ minutes have only been depicted for the sake of clarity and simplicity. From these two figures, it appears clear that a reduction of the Market Time Unit produces a reduction of the fluctuations amplitude in the resulting total energy-neutral power profile, which will consequently lead to a decrease in the power-related regulation needs. On the other hand, the reduction of the Market Time Unit could probably contribute to shifting risks from the Transmission System Operators to Balancing Responsible Parties.

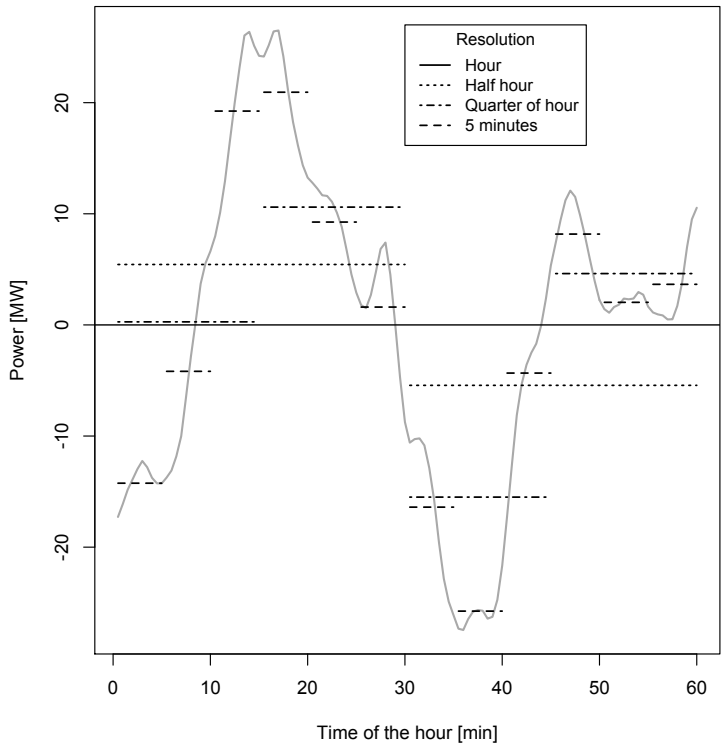


Figure 6.8: Energy-neutral power profile computation using four different Market Time Units

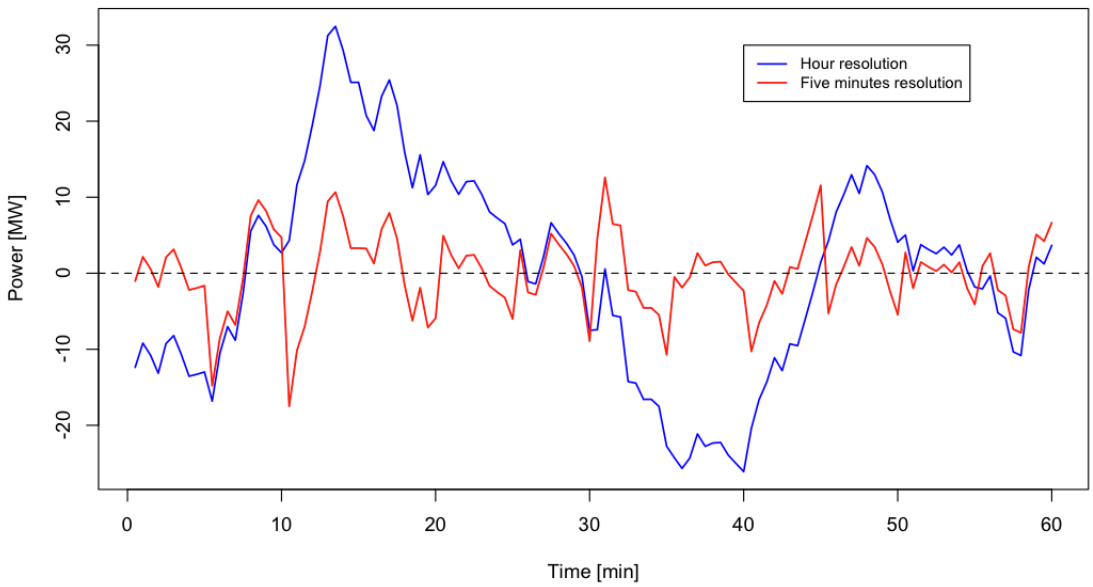


Figure 6.9: Energy-neutral power profiles calculated using the hour and five minutes Market Time Units

6.4 One-price and two-price settlement schemes

In order to understand the description of the two different settlement schemes presented in this section, it is necessary to provide a definition for the three following terms: Balancing Responsible Party, Balancing Service Providers and Program Time Unit.

- **Balancing Responsible Party (BRP)** All market participants either interact with the market through a BRP or are a BRP themselves. Before the hour of operation, each BRP has a market position deriving from the sum of all its obligations (sales or purchases) in the organized markets, such as day-ahead and intra-day, and through bilateral agreements. The market position of each BRP is defined for each Program Time Unit, typically 15, 30 or 60 minutes. Each BRP is responsible for its balance over the whole PTU, while the TSO is responsible for balancing within the PTU.
- **Balancing Service Providers (BSP)** To compensate the aggregate deviations of the BRPs, the TSO uses the resources provided by the BSP, which can be either producers or consumers.
- **Program Time Unit (PTU)** The PTU represent the time resolution of the energy programs sent by the BRPs to the TSO. Its duration is typically of 15 minutes, 30 minutes or 60 minutes.

Imbalance prices, such as the German reBAP mentioned in Section 4.3.2, are typically calculated based on the upward and downward regulating power offers accepted by the TSO in the real-time balancing markets. Hence, they are based either on the price of the *marginally* accepted upward or downward regulating power offer or on the *average* price of all the accepted upward or downward regulating power offers, depending on the remuneration mechanism adopted for the BSP. Several papers argue on the pros and cons of the BSP remuneration by means of marginal pricing or pay-as-bid pricing, for example [51]. Briefly, there is commonly held view that marginal pricing is economically more adequate and will lead to a more efficient resources allocation compared to pay-as-bid pricing. Apart from the difference between marginal and pay-as-bid pricing, a difference exists also between a one-price and two-price imbalance settlement schemes. Table 6.2 and Table 6.3 respectively describe the functioning of a one-price and a two-price system, for the sake of simplicity only the marginal pricing is represented, but similar tables could be produced using the average pricing.

Under a one-price imbalance settlement scheme, the imbalance prices always correspond to the marginal/average procurement price of balancing services, which could be either upward or downward regulating power depending on the overall imbalance status of the system. The same imbalance price, but with a different sign, is applied to all BRPs, irrespective of their imbalance status, theoretically making the imbalance settlement a zero-sum game for the TSO.

On the other hand, under a two-price imbalance settlement scheme, a different imbalance price is applied for negative and positive BRPs' imbalances. The BRPs'

Table 6.2: Typical imbalance settlement in a one-price system

		System imbalance	
		negative	**positive**
BRP imbalance	**negative**	+ MPu	+ MPd
	positive	- MPu	- MPd

[1] MPu = marginal price of upward regulation: MPd = marginal price of downward regulation

Table 6.3: Typical imbalance settlement in a two-price system

		System imbalance	
		negative	**positive**
BRP imbalance	**negative**	+ MPu	+ Pda
	positive	- Pda	- MPd

[1] MPu = marginal price of upward regulation: MPd = marginal price of downward regulation; Pda = day-ahead power exchange price

imbalances contributing to the overall system imbalance are settled at prices deriving from the costs for the procurement of balancing services, while the BRPs' imbalances counteracting the overall system imbalance are settled on the basis of the wholesale price, typically day-ahead prices. Because of the presence of the power exchange prices, a two-price system does not imply a zero-sum game for the TSO.

In a one-price system the settlement of BRPs' imbalances counteracting the system imbalance is based on the marginal costs, meaning the additional costs that the TSO would have paid if the BRPs in question were not imbalanced. On the contrary, a two-price system is typically implemented to prevent generators from speculating on the direction of the overall system imbalance (i.e. being negatively imbalanced if they expect the system to be positively imbalanced and viceversa). However, such "gaming" actions are unlikely to be profitable for the generators and endanger the system security at the same time, in other words, usually profitable actions go hand in hand with the system security increase. Furthermore, a two-price settlement scheme put small market participants at disadvantage, because it involves lower imbalance costs for large market participants due to netting. On the other hand, in a one-price imbalance settlement scheme there is no discrimination according to the size of the market parties. [52]

In a similar way, these two type of settlement schemes can be applied to the power variability cost allocation by mean of the inner product metric. As already mention in Section 5.4, for the case of the inner product metric, owning to its very own definition in (5.15), the market participants contribution can be either positive or negative, meaning that individual generators or the demand may work towards

or against the formation of the total power profile. Therefore, when evaluating the power fluctuation through the inner product metric is possible to apply a one-price settlement scheme, in which all the fluctuations are settled with the same price, or a two-price settlement scheme, with a price differentiation based on the respective contribution to the overall power fluctuation. In this latter case, however, the market participants' power fluctuations counteracting the total power profile fluctuations will be settle at a price equals to zero, instead of the day-ahead power exchange price.

Similarly to the case of energy imbalances, a two-price system avoids any strategic behavior of the market participants, since it is impossible to be rewarded (i.e. the power fluctuations counteracting the overall power system fluctuations are just not penalized), while a one-price system allows for strategic behaviors intended to get a reward. However, it is rather doubtful whether generators could change their fluctuation tendency on the basis of a very-short term settlement period. In these cases, where it is pretty much impossible to predict the overall system status, a one-price system is more efficient, because the "pot of money" at stake is smaller. On the other hand, since a two-price system does not imply a zero sum game for the TSO, it provides an earning for the TSO, which can be called *fluctuation rent*, similar to the congestion rent

Chapter 7

Application results

This chapter provides an insight on the simulation study results, obtained through the implementation of suitable scripts developed using the software environment for statistical computing and graphics R©. First of all, the effects of the Market Time Unit change in terms of power variability cost are evaluated. Secondly, the attribution mechanisms results for one hour and one month of operation are illustrated together with an analysis of the resulting revenues for selected market participants. Following, the differences between a one-price and a two-price settlement scheme are examined. Lastly, a summary validation process for the simulation study, based on three indicators, is carried out.

7.1 Effects of Market Time Unit change

As previously mentioned, Market Time Units are expected to shorten in future market designs in order to better accommodate Renewable Energy Sources and a more pro-active demand. For example, in the Australian National Energy Market a 5 minutes dispatch interval has already been implemented in recent years. With this in mind, an analysis has been carried out in order to evaluate the effects of the Market Time Unit reduction in terms of power variability cost.

The power-related regulation needs and their respective costs have been evaluated using four different Market Time Units: from $T = 1$ hour, which is the typical MTU applied in Europe nowadays, to $T = 5$ minutes, which is the smallest MTU currently being used, considering also $T = 30$ minutes and $T = 15$ minutes. The resulting total costs for the procurement of power-related services are summarized in Table 7.1 and Table 7.2, respectively for a randomly chosen hour of operation and an entire month of operation, in particular March 2014. The costs reported in these tables clearly shows that the reduction of the time unit yields to a reduction of the total cost on an hourly basis, and consequently on a monthly basis.

For the mid cost scenario, the total hourly cost for the procurement of power-related services resulted to be reduced of -35,3% when switching the time unit from $T = 1$ hour to $T = 15$ minutes, and of -70,1% when moving from $T = 1$ hour to

$T = 5$ minutes. Moreover, for the same scenario, the total monthly cost resulted to be reduced of -59,6% when changing the MTU from $T = 1$ hour to $T = 15$ minutes, and of -84,1% when changing from $T = 1$ hour to $T = 5$ minutes.

The order of magnitude of total hourly costs, depicted in Table 7.1, appears to be quite consistent with the real Danish power-related market hourly costs, which over the year 2014 had a mean value of 522 €/h and a maximum value of 2.296€/h. These cost results, especially the ones calculated using a Market Time Unit of $T = 1$ hour, are likely to be overestimated, because the simulation study is based on the hypothesis that only primary reserves are deployed to manage the power variability of the total energy-neutral power profile over the entire hour, while in reality the Danish TSO might also schedule tertiary reserves to manage some long lasting energy imbalances, thus reducing the actual need of primary reserves.

Table 7.1: Total hourly costs for the procurement of power-related reserves using four time resolutions for each of three scenarios

	Hour resolution [€/h]	**Half hour resolution [€/h]**	**Quarter of hour resolution [€/h]**	**Five minutes resolution [€/h]**
Low cost scenario	418,5	403,6	273,3	127,3
Mid cost scenario	571,2	546,5	369,7	167
High cost scenario	985,3	960,7	589,1	231,1

Table 7.2: Total monthly costs for the procurement of power-related reserves using four time resolutions for each of three scenarios

	Hour resolution [€]	**Half hour resolution [€]**	**Quarter of hour resolution [€]**	**Five minutes resolution [€]**
Low cost scenario	1.032.816	688.343	433.756	180.594
Mid cost scenario	1.593.876	1.048.248	643.599	249.220
High cost scenario	2.940.254	1.901.308	1.133.944	405.428

7.2 Attribution mechanisms results

After the power-related services cost evaluation, the four types of metrics proposed to redistribute the short-term power variability cost are computed for all the forty-two market participants of the simulation. Following the attribution mechanisms and based only on the cost associated with the mid cost scenario, the shares of the total cost to be supported by each renewable generator and by the demand as a whole are calculated using a Market Time Unit of $T = 15$ minutes. The mid cost scenario has been chosen as representative of the average market outcome, while a MTU of $T = 15$ minutes has been preferred because it is expected to be the most plausible time unit for the market design of future energy systems with significant renewable energy generation.

The results of the attribution mechanisms are first presented for a single hour of operation and then for an entire month of operation. Moreover, the results are illustrated in three different ways: first in terms of total cost in Euro to be supported by each market participant, second in terms of percentage contribution of each market participant to the total system cost, and lastly in terms of cost per energy sold [€/MWh]. The cost per energy sold has been calculated by dividing the total cost to be supported by each market participant by the mean value of the individual power profile in the considered time unit, and it is meaningful from the market participants points of view since it represents the incidence of the cost of variability on each MWh sold or purchased on the electricity markets.

7.2.1 Results for one hour of operation

The simulation study results for one hour of operation are illustrated in Figure 7.1, Figure 7.2 and Figure 7.3 for each of the four proposed mechanisms. On the x-axis of all the graphs, the wind power producers are first reported in the same exact order in which they are listed in Table 6.1, then the demand as a whole is placed as last market participant. Hence, the first seven barplots represent offshore wind farms, while the remainings, except for the last one, represent onshore wind farms. In addition to the three figures, the results for five selected market participants, in particular the demand, two offshore wind farms (Horns Rev 2 and Horns Rev 1) and two onshore wind farms (Ringkobing-Skjern and Dostrup), are shown in detail in Table 7.3, Table 7.4 and Table 7.5. These tables also report the result of two additional allocation mechanisms, which are the typical cost recovery schemes currently applied throughout Europe to power-related services costs: the cost socialization on the demand side only and the full cost socialization on all the market participants. Contrarily to the four proposed attribution mechanisms, these two type of cost allocation do not take into account the accountability of each market participant to the cost induced by its power fluctuations, but allocate the total cost merely on the basis of the usage of the power system, given by the energy production or consumption of each party relatively to the total energy flown in the system over the considered time unit.

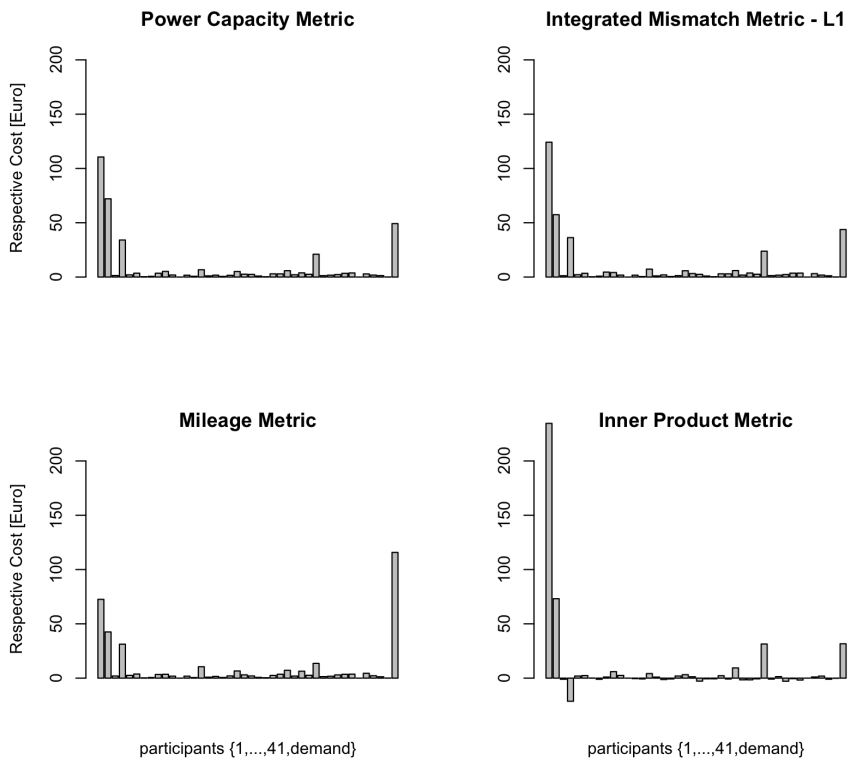


Figure 7.1: Attribution mechanisms results for one hour of operation in terms of total cost to be supported by each market participant

Table 7.3: Total costs to be supported by each of the five selected market participants for one hour of operation according to six different cost allocation mechanisms

	Demand-only socialization [€]	**Full socialization [€]**	**Power Capacity Metric [€]**	**Integrated Mismatch Metric [€]**	**Mileage Metric [€]**	**Inner Product Metric [€]**
Demand	369,7	184,7	49,2	43,7	115,8	31,6
Mrkp 1 (Off)	0	73,7	110,6	124,2	72,6	234,6
Mrkp 4 (Off)	0	20,8	34,1	36,3	31,3	-21,3
Mrkp 31 (On)	0	9,2	21,0	23,8	13,6	31,4
Mrkp 15 (On)	0	2,4	6,7	7,3	10,5	4,2

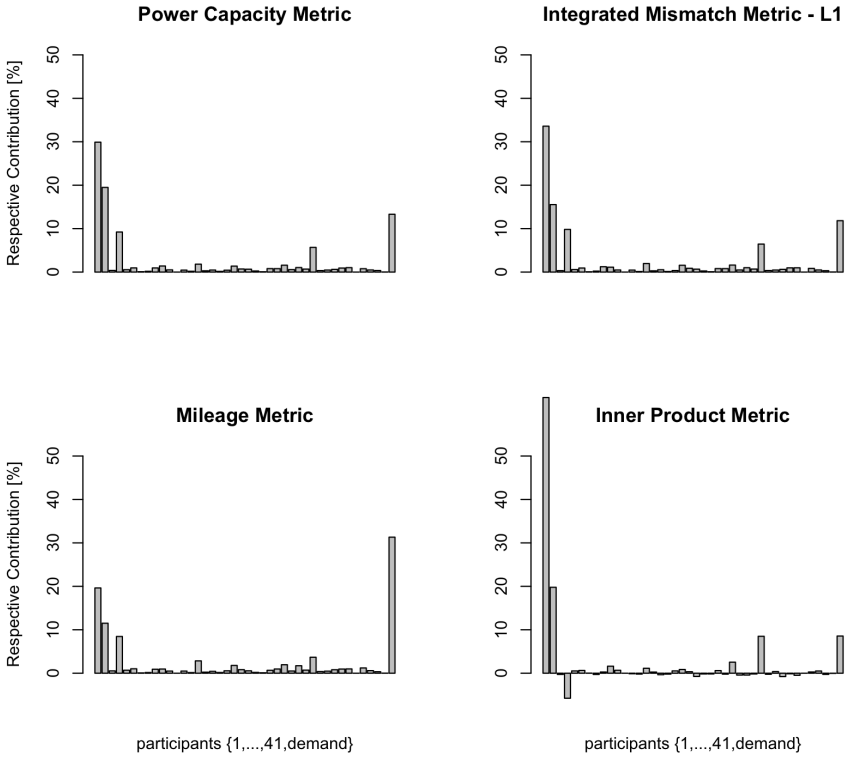


Figure 7.2: Attribution mechanisms results for one hour of operation in terms of percentage contribution of each market participant to the total power-related services cost

Table 7.4: Percentage contributions of each of the five selected market participants for one hour of operation according to six different cost allocation mechanisms

	Demand-only socialization [%]	Full socialization [%]	Power Capacity Metric [%]	Integrated Mismatch Metric [%]	Mileage Metric [%]	Inner Product Metric [%]
Demand	100%	50%	13,4%	11,8%	31,3%	8,6%
Mrkp 1 (Off)	0%	19,9%	29,9%	33,6%	19,6%	63,5%
Mrkp 4 (Off)	0%	5,6%	9,2%	9,8%	8,4%	-5,8%
Mrkp 31 (On)	0%	2,5%	5,7%	6,4%	3,7%	8,5%
Mrkp 15 (On)	0%	0,7%	1,8%	2%	2,8%	1,1%

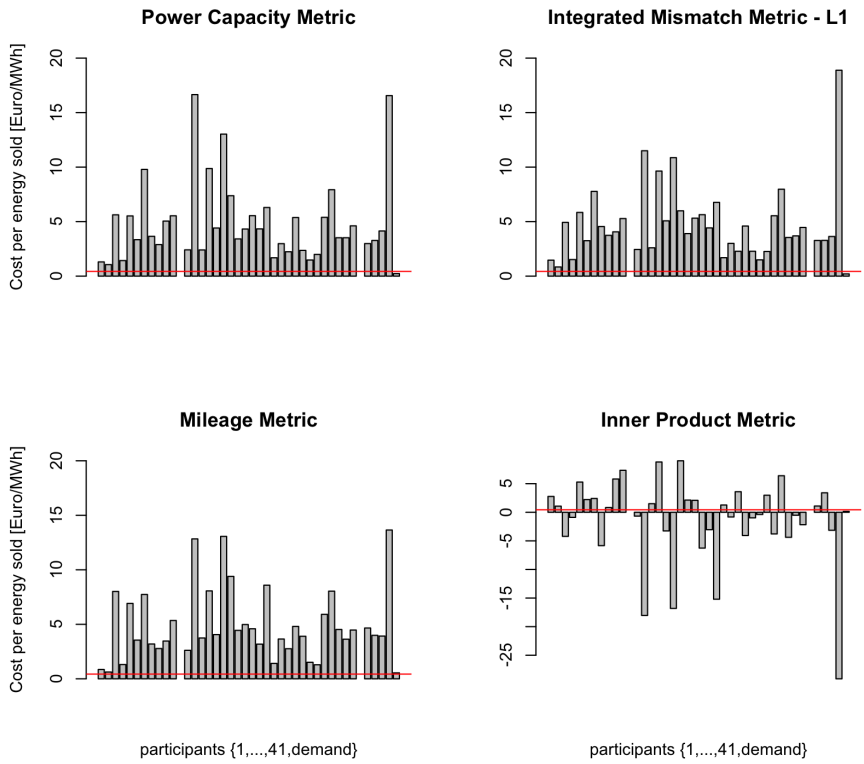


Figure 7.3: Attribution mechanisms results for one hour of operation in terms of cost per energy sold/purchased on the wholesale markets

Table 7.5: Costs per energy sold to be supported by each of the five selected market participants for one hour of operation according to six different cost allocation mechanisms

	Demand-only socialization [€/MWh]	Full socialization [€/MWh]	Power Capacity Metric [€/MWh]	Integrated Mismatch Metric [€/MWh]	Mileage Metric [€/MWh]	Inner Product Metric [€/MWh]
Demand	1,74	0,87	0,23	0,21	0,54	0,15
Mrkp 1 (Off)	0	0,87	1,3	1,47	0,86	2,77
Mrkp 4 (Off)	0	0,87	1,43	1,52	1,31	-0,89
Mrkp 31 (On)	0	0,87	2,00	2,26	1,29	2,98
Mrkp 15 (On)	0	0,87	2,40	2,60	3,75	1,50

With respect to the total cost supported by each market participant, and consequently to their percentage contributions, Figure 7.1 and Figure 7.2 show that in all the four cases the majority of the power-related regulation cost is supported by the large wind farms, whether offshore or onshore, and by the demand. This result is legitimate, since the power output of wind turbines concentrated in a relatively small geographical area significantly fluctuates, while the power fluctuations of dispersed wind turbines are smoother. In that respect, all the four proposed mechanisms appear to be fair and equal, although the actual costs to be supported by the various market participants differ from mechanism to mechanism. As a matter of fact, for the specific hour under investigation, Horns Rev 2 (Mrkp 1), large offshore wind farm with an installed capacity of approximately 210 MW, is charged with a cost of 110,6 €, corresponding to 29,9% of the total power-related regulation cost, according to the power capacity metric, and with a cost of 234,6 €, corresponding to 63,5% of the same total cost, according to the inner product metric (i.e. more than double).

In this part of the simulation study, a one-price settlement scheme is applied, therefore no price differentiation is applied to generators or demand working toward or against the formation of the total power profile. Interestingly, only for the case of the inner product metric, owning to its very own definition, the contribution of the various market participants can also be negative, meaning that the individual generators and demand working against the formation of the total power profile fluctuations are actually rewarded. For example, in the specific hour under investigation, Horns Rev 1 (Mrkp 4), large offshore wind farm with an installed capacity of 160 MW, on average helped the system and therefore its contribution according to the inner product metric is negative and equal -21,3 €.

Overall the results of the power capacity metric and integrated mismatch metric, in terms of total cost to be supported by each market participant, and consequently in terms of percentage contributions, appears to be very similar with respect to all the analyzed parties. The results of the mileage metric are only slightly different, with the demand being a little more penalized and the large wind producers a little less penalized compared to the two previously mentioned cases. The results of the inner product, on the contrary, appears to be completely differentiated from the other three metrics, mainly because of the negative contribution possibility.

The significant difference between the results of the inner product metric and those of the other three metrics, becomes obvious in Figure 7.3, which illustrates the cost per energy sold or purchased on the electricity markets to be borne by the various market participants. The cost per energy sold is an artificial indicator used to evaluate the incidence of the additional cost being allocated to each party with the various metrics, since electricity generators earn money through the electricity sale.

By mean of this indicator, it is possible to notice that the high costs in absolute terms allocated to the big wind farms and to the demand by the four metrics actually have a small incidence on their earnings or costs compared to the other market participants. The relative weight of the cost allocated to the large wind

farms is low, and therefore large renewable generators will have a lower incentive in reducing their power fluctuations compared to the smaller producers. On the other hand, the smaller producers will be the entities receiving the strongest market incentive toward a better self-regulation of their own power production, since the additional cost that they need to bear could endanger their profits.

In this regard, for example, the results in terms of cost per energy sold of the small onshore wind farm Dostrup (Mrkp 15), which has an installed capacity of 18,3 MW, can be compared to those of the large offshore wind farm Horns Rev 2 (Mrkp 1). In the case of the integrated mismatch metric the smaller producer has a cost per energy sold of 2,6 €/MWh while the larger one has a cost of 1,47 €/MWh; while in the case of the mileage metric the cost per energy sold of the smaller generator is 3,75 €/MWh and that of the larger generator is 0,86 €/MWh. Assuming an identical price for the electricity sale, deriving from a wholesale market clearing, in the former case the power-related cost has a double incidence on the smaller producer than on the bigger one, while in the latter case the cost allocated to the smaller producer has a more than quadrupled incidence compared to the one allocated to the larger generator.

With regard to the demand as a whole, obviously the results of the four proposed mechanisms reduce the power-related regulation cost compared to the case of cost socialization on the demand side only. In addition, all the attribution mechanisms reduce the share of the total power regulation cost to be supported by the consumption side also compared to the full cost socialization case, in terms both of total cost and cost per energy purchased. The total cost to be borne by the demand in the case of full socialization is 184,7 €, while with the attribution mechanisms it ranges between 31,6 € and 115,8 €, as a results of respectively inner product and mileage metric. The cost per energy purchased to be additionally supported by the demand, usually through the grid tariff, in the case of full socialization is 0,87 €/MWh, while with the attribution mechanisms it ranges between 0,15 €/MWh and 0,54 €/MWh, as a result of respectively inner product and mileage metric.

7.2.2 Results for one month of operation

The results for one month of operation are illustrated in Figure 7.4, Figure 7.5 and Figure 7.6 for each of the four proposed mechanisms. On the x-axis of all the graphs the market participants are reported in the same order as in the previous section, with the wind power producers first and then the demand as the latest. In addition to the three figures, the results for the same five selected market participants, are shown in detail in Table 7.6, Table 7.7 and Table 7.8. These tables also report the result of the two allocation mechanisms, which are the cost recovery schemes currently applied throughout Europe to power-related services costs: the cost socialization on the demand side only and the full cost socialization on all market participants. For example, according to the full socialization, the power regulation unit cost is calculated by diving the total cost by the total MWh produced or consumed in the considered time unit, and it is then multiplied by the production or consumption of each entity to determine the individual shares.

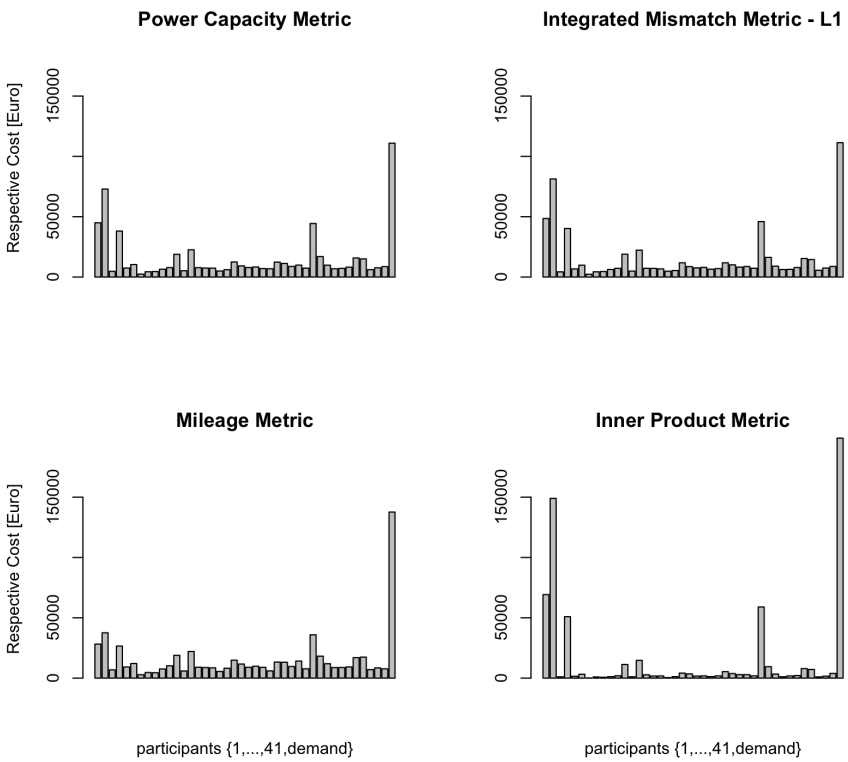


Figure 7.4: Attribution mechanisms results for one month of operation in terms of total cost to be supported by each market participant

Table 7.6: Total costs to be supported by each of the five selected market participants for one month of operation according to six different cost allocation mechanisms

	Demand-only socialization [€]	Full socialization [€]	Power Capacity Metric [€]	Integrated Mismatch Metric [€]	Mileage Metric [€]	Inner Product Metric [€]
Demand	643.599	321.803	110.940	111.360	137.644	198.930
Mrkp 1 (Off)	0	43.997	44.963	48.530	28.200	69.277
Mrkp 4 (Off)	0	32.442	38.105	40.215	26.590	50.946
Mrkp 31 (On)	0	24.294	44.359	45.954	35.888	58.971
Mrkp 15 (On)	0	3.187	7.765	7.244	9.034	2.750

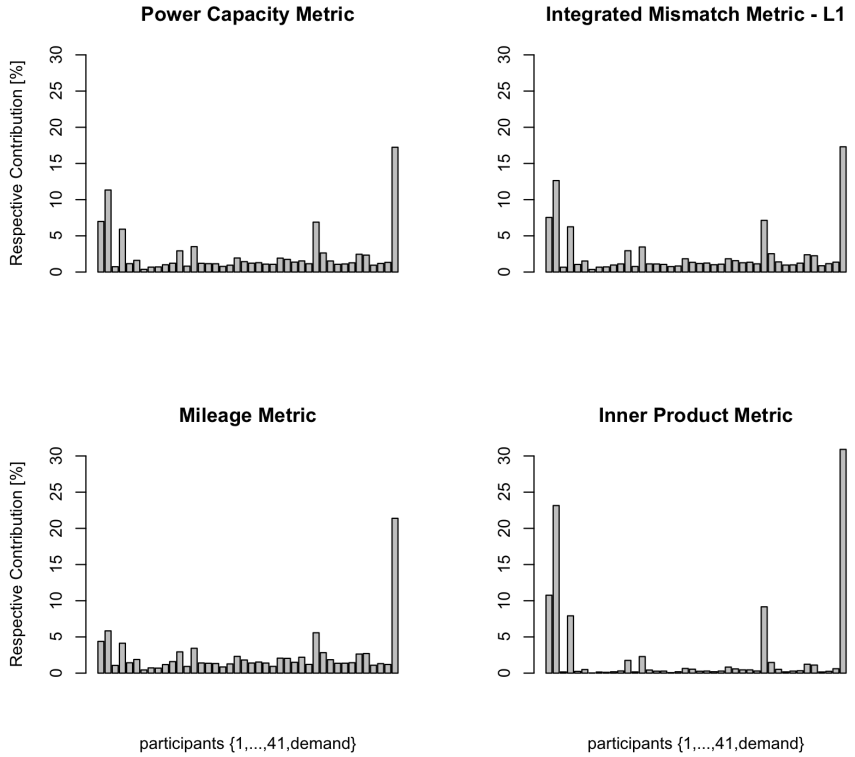


Figure 7.5: Attribution mechanisms results for one month of operation in terms of percentage contribution of each market participant to the total power-related services cost

Table 7.7: Percentage contributions of each of the five selected market participants for one month of operation according to six different cost allocation mechanisms

	Demand-only socialization [%]	**Full socialization [%]**	**Power Capacity Metric [%]**	**Integrated Mismatch Metric [%]**	**Mileage Metric [%]**	**Inner Product Metric [%]**
Demand	100%	50%	17,2%	17,3%	21,4%	30,9%
Mrkp 1 (Off)	0%	6,8%	7,0%	7,5%	4,4%	10,8%
Mrkp 4 (Off)	0%	5%	5,9%	6,2%	4,1%	7,9%
Mrkp 31 (On)	0%	3,8%	6,9%	7,1%	5,6%	9,2%
Mrkp 15 (On)	0%	0,5%	1,2%	1,1%	1,4%	0,4%

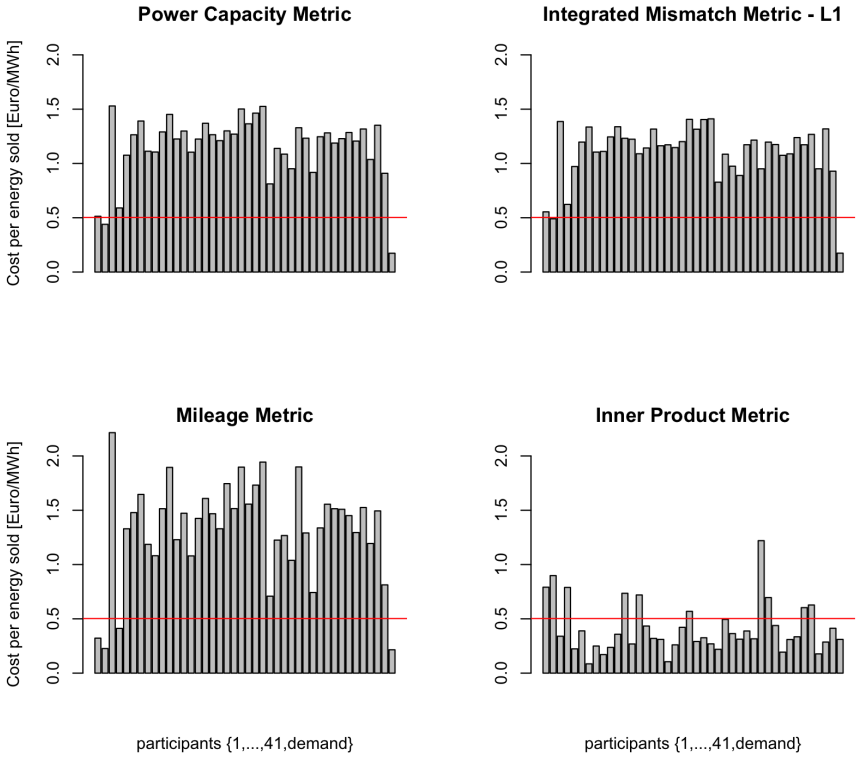


Figure 7.6: Attribution mechanisms results for one hour of operation in terms of cost per energy sold/purchased on the wholesale markets

Table 7.8: Costs per energy sold to be supported by each of the five selected market participants for one month of operation according to six different cost allocation mechanisms

	Demand-only socialization [€/MWh]	Full socialization [€/MWh]	Power Capacity Metric [€/MWh]	Integrated Mismatch Metric [€/MWh]	Mileage Metric [€/MWh]	Inner Product Metric [€/MWh]
Demand	1,01	0,50	0,17	0,17	0,21	0,31
Mrkp 1 (Off)	0	0,50	0,51	0,55	0,32	0,79
Mrkp 4 (Off)	0	0,50	0,59	0,62	0,41	0,79
Mrkp 31 (On)	0	0,50	0,92	0,95	0,74	1,22
Mrkp 15 (On)	0	0,50	1,22	1,14	1,42	0,43

With regard to total costs to be supported by each market participant and their percentage contributions illustrated in Figure 7.4 and Figure 7.5, observations similar to those made for the results of one hour of operation can be made. Also in this case, according to all the four attribution mechanisms the majority of the power-related regulation cost is supported by the large wind farms, whether offshore or onshore, and by the demand. In that respect, all the four metrics used to allocate the total cost appear to be consistent, although the shares of the total cost allocated to each of these specific entities are different from metric to metric. In particular, the results of the power capacity metric and the integrated mismatch metric are very similar; the results of the mileage metric penalize more the demand and less the large offshore wind farms compared to the previous two cases; and lastly the results of the inner product metric accentuate the penalization imposed to both types of aforementioned entities.

For example, the demand has to bear 17,2% and 17,3% of the total power-related regulation cost respectively in the case of power capacity and integrated mismatch metrics, 21,4% in the case of the mileage metric and 30,9% in the case of the inner product metric; while Horns Rev 2 (Mrkp 1) has to sustain 7% and 7,5% in the case of the first two metrics, only 4,4% in the case of the mileage metric and 10,8% in the case of the inner product metric. To the two market participants considered in this example a share of the total power-related regulation cost ranging from 24,2% to 41,7% has been allocated through the proposed mechanisms, hence these two entities alone bear at least a quarter of the total monthly cost in every case.

Interestingly for the case of the inner product metric, the results for an entire month of operation do not present any negative contribution, meaning that overall all the market participants contributed towards the formations of the total power profile fluctuations more than against it. Even though in the single Market Time Units and over short periods of time negative contributions are possible for any kind of entity, as demonstrated in the previous section, these results show that over a longer time period, such as a month, it is unlikely for the generators or the demand to actually be rewarded from this type of attribution mechanism, though theoretically possible. For example, Horns Rev 1 (Mrkp 4), that in the hour investigated in the previous section resulted to have a negative contribution of -5,8% of the total power-related regulation cost of the considered hour, over the entire month positively contributes to the total monthly cost, with a percentage share of 7,9%.

With regard to the cost per energy sold or purchased over an entire month of operation, the results for the power capacity metric and the integrated mismatch metric appear to be once again very similar. In both cases, the demand results to be the less penalized entity, with a cost per energy purchased equals to 0,17 €/MWh, which is less than half the cost per energy purchased that the consumption side would have in the case of full cost socialization. On the other hand, the three large offshore wind farms have a cost per energy sold very similar to the full socialized one and all the other producers have a cost higher, and sometime more than double the one they would have in the case of full socialization. For example, Horns Rev 2

(Mrkp 1) has a cost per energy sold of 0,51 €/MWh in the case of power capacity metric and of 0,50 €/MWh according to the full socialization, while Dostrup (Mrkp 15) has a cost per energy of 1,22 €/MWh in the former case and of 0,50 €/MWh in the latter.

The results in terms of cost per energy sold or purchased for the mileage metric are more favorable for the demand and the large wind farms, whether offshore or onshore, while they penalize more the other producers compared to the two previous cases. Although different, the first three metrics show results in term of cost per energy sold or purchased not completely discordant. On the contrary, the inner product metric produces results which are quite contrasting in respect to the previous ones, as the large wind farms are the most penalized entities with costs per energy sold exceeding the full socialized value of 0,50 €/MWh, and with the demand being less favored than in the previous cases. In addition the entire set of values produced by the inner product metric in terms of cost per energy sold are lower, since the values of the market participants producing a large amount of electricity are higher than in the three previous cases.

The relative weight of the high cost allocated to the large wind farms by the first three metrics is indeed low, and therefore large renewable generators will have a lower incentive in reducing their power fluctuations compared to the smaller producers, which by contrast will receive the strongest incentive toward a better self-regulation of their own power production in these three cases. On the contrary, the results of the inner product metric work in the opposite direction in terms of incentives. The monthly results for this specific metric reveal that the large renewable generators will receive the strongest incentive toward a better self-regulation of their own production, since the additional cost related to power regulation that they need to bear could endanger their profits. For instance, a better self-regulation could be achieved by mean of storage, coordination with demand-response or through virtual power plants concepts.

7.3 One-price and two-price settlement schemes

The contributions of each and every actor to the overall power fluctuations determined on the basis of the inner product metric can be placed in both one-price and two-price settlement schemes. A one-price system has been applied in the previous section of the thesis, where no price differentiation has been made to the generators or demand working towards or against the formation of the total power profile. Consequently, the same power regulation unit cost has been applied to each and every market participant, enabling the entities to be rewarded when counteracting the total power profile fluctuations. The same contributions to the overall power fluctuations can also be placed in a two-price settlement scheme, by differentiating the power regulation unit cost between the actors contributing or counteracting the formation of the total power profile. In this case the power regulation unit cost for the entities helping the system is set equal to zero, meaning that they are no longer rewarded but they are just not penalized.

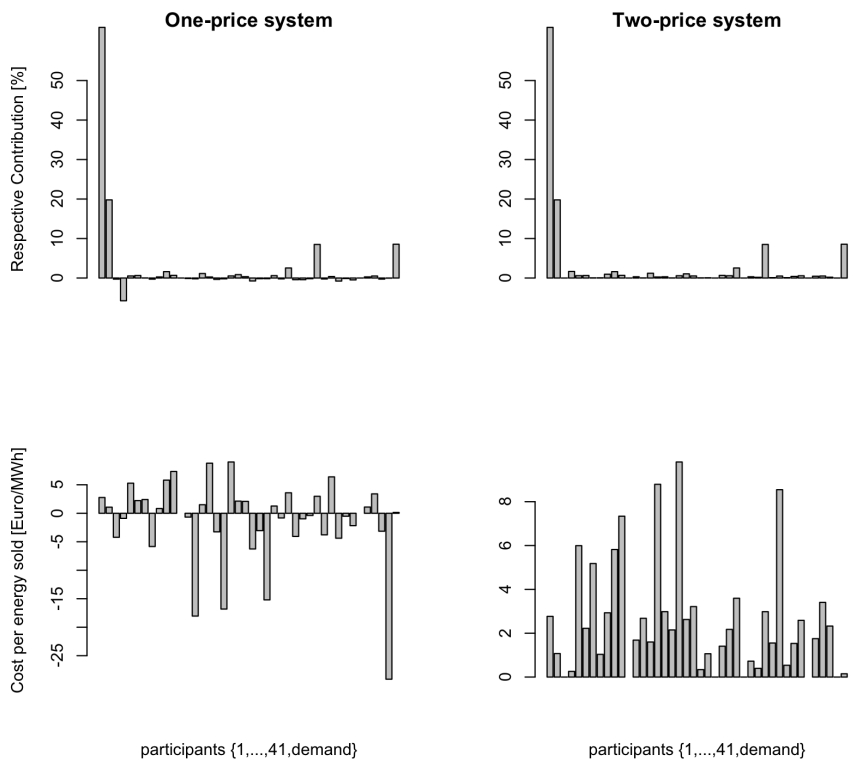


Figure 7.7: Inner product metric results for one hour of operation in a one-price and two-price system

Table 7.9: Percentage contributions and costs per energy sold of each of the five selected market participants for one hour of operation in a one-price and two-price system

	One-price system		Two-price system	
	Percentage contribution [%]	**Cost per energy sold [€/MWh]**	**Percentage contribution [%]**	**Cost per energy sold [€/MWh]**
Demand	8,6%	0,15	8,6%	0,15
Mrkp 1 (Off)	63,5%	2,77	63,5%	2,77
Mrkp 4 (Off)	-5,8%	-0,89	1,7%	0,26
Mrkp 31 (On)	8,5%	2,98	8,5%	2,98
Mrkp 15 (On)	1,1%	1,50	1,2%	1,00

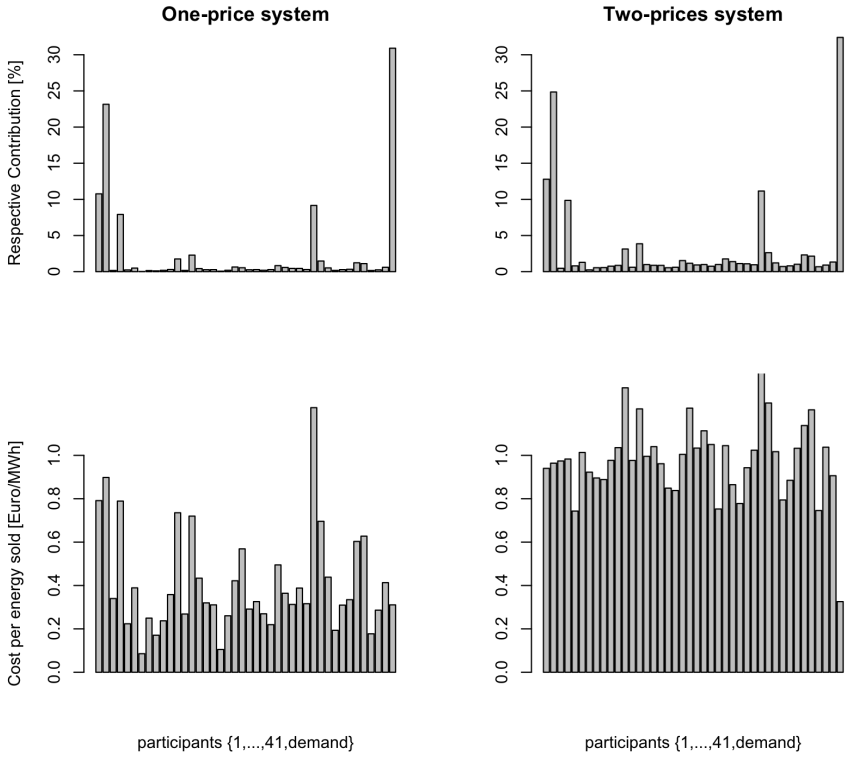


Figure 7.8: Inner product metric results for one month of operation in a one-price and two-price system

Table 7.10: Percentage contributions and costs per energy sold of each of the five selected market participants for one month of operation in a one-price and two-price system

	One-price system		Two-price system	
	Percentage contribution [%]	**Cost per energy sold [€/MWh]**	**Percentage contribution [%]**	**Cost per energy sold [€/MWh]**
Demand	30,9%	0,31	32,4%	0,33
Mrkp 1 (Off)	10,8%	0,79	12,8%	0,94
Mrkp 4 (Off)	7,9%	0,79	9,9%	0,98
Mrkp 31 (On)	9,2%	1,22	11,2%	1,49
Mrkp 15 (On)	0,4%	0,43	1,0%	1,60

The results for one hour and one month of operation for each of the two mentioned price systems are respectively illustrated in Figure 7.7 and in Figure 7.8. The results are shown both in terms of percentage contribution of each market participant to the total power regulation cost and in terms of cost per energy sold or purchased. On the x-axis of all the graphs the actors are reported in the same order as in the previous sections, with the wind producers first and then the demand as the latest. In addition to the two figures, the results for the same five selected market participants are reported in detail in Table 7.9 and Table 7.10, respectively for one hour and one month of operation.

The results of one hour of operation illustrated in Figure 7.7 show, as foreseeable, that a two-price settlement scheme does not produce any negative value. Despite the absence of negative results, the outcome in terms of percentage contribution deriving from the two systems appear to be similar. Also in a two-price settlement scheme the large wind farms, whether offshore or onshore, and the demand support the majority of the power regulation cost, as already noticed for all the proposed attribution mechanisms in the previous sections. On the other hand, the results in terms of cost per energy sold or purchased of the two settlement schemes are more differentiated. Due to the lack of the reward possibility, the cost per energy sold of those entities counteracting the total power fluctuations more than contributing to them, in a two-price system is at minimum equal to zero, and sometime also greater than zero, because of the penalizations of the positive contributions occurred in the single market time units making up the investigated hour. The cost per energy sold of the market participants that work toward the formation of the total power profile fluctuations over the entire hour are the same in both systems.

In this regard, for example, the results in term of cost per energy sold of Horns Rev 1 (Mrkp 4) and Ringkobing-Skjern (Mrkp 31) can be analyzed in detail. In a one-price system, Horns Rev 1 has a negative cost per energy sold of -0,89 €/MWh, while in a two-price system it has a positive cost per energy sold of 0,26 €/MWh, meaning that at least in one market time unit the considered actor contributed to the overall power fluctuations, although its counteractions were greater over the entire hour. Ringkobing-Skjern, on the contrary, has to support the same cost per energy sold of 2,98 €/MWh in both price systems, meaning that this market participant worked towards the formation of the total power profile fluctuations in all the market time units making up the hour.

The results of one month of operation illustrated in Figure 7.8 show once again the two-price settlement scheme does not produce any negative value. In terms of percentage contribution of each market participant to the total power regulation cost, in a two-price system the majority of the cost is borne by large wind farms, whether offshore or onshore, and by the demand. In this case all the entities result to be more penalized compared to the case of the one-price system. For example, Horns Rev 2 (Mrkp 1) contributes to the total cost with a percentage share of 12,8% in the former case and with a percentage share of 10,8% in the latter, while the demand contributes with a share of 32,4% in a two-price system and with a share of 30,9% in a one-price system. Also the results in terms of cost per energy

sold or purchased are overall higher in the two-price settlement scheme.

The general value increase can be explained by the fact that a two-price system does not imply a zero-sum game for the TSO, as instead does the one-price system, because of the price differentiation imposed to positive and negative contributions. As a consequence a two-price settlement scheme produces an earning for the TSO, which can be called *fluctuation rent*. In the case of one-price system, for one hour of operation, the TSO collects 369,7 € from the market participants, corresponding exactly to the total cost for the procurement of power-related regulation services. On the other hand, with a two-price settlement scheme, for the same hour of operation, the TSO collects 436,6 € from the involved entities, amount exceeding the costs for the reserve procurement. The difference between the money collected from the market participants and the actual cost borne by the TSO for the procurement of power-related regulation services, is the *fluctuation rent*, which in this case is equal to approximately 67 €. For the entire month of operation, the *fluctuation rent* is equal to 222.256 €, given that the sum of the market participants payments in the two-price system amount to 865.855 € and the total monthly cost for the reserves procurement is 643.599 €.

With regards to the cost per energy sold or purchased for a month of operation in a two-price system, the demand results to be the less penalized entity with a cost per energy purchased of 0,33 €/MWh, similar to the one supported in a one-price system, which is 0,31 €/MWh. All the renewable generators are penalized in a similar size, with costs per energy sold ranging between 0,75 €/MWh and 1,2 €/MWh, without any apparent discrimination based on the actors sizes. The only wind producer bearing a cost higher than the average range is Ringkobing-Skjern (Mrkp 31), which has a cost per energy sold of 1,49 €/MWh. This large onshore wind producer is hence the most penalized entity, just as in the case of a one-price system.

Since the cost per energy sold is an artificial indicator, which can be used to evaluate the incidence of the additional cost being allocated to each actor with the various mechanisms, it can be noticed that the results of the inner product metric work in a different direction in terms of incentives when a one-price or a two-price settlement scheme is applied. As already mentioned in the previous section, in a one-price system the large renewable producers will receive the strongest incentive toward a better self-regulation of their own production. In a two-price system, on the contrary, all the renewable generators, independently of their size, receive a strong market incentive, since the high cost per energy sold allocated to each of them may endanger their profits. Bearing in mind that a two-price system is not a zero-sum game for the TSO, the fluctuation rent resulting from this settlement scheme can be considered an additional incentive produced by this system. Since the TSO is a regulated company it is not financially interested in making a profit from the power system operation, especially in Denmark where Energinet.dk is a non-profit company, the fluctuation rent could be used to improve the power system operation in terms of power fluctuations control.

7.4 Indicators

A summary validation process for the simulation study has been set up based on the three indicators defined in Section 4.2.3. These indicators allow to overcome the comparison limitations imposed by the different power systems size (i.e. entire Western Denmark and simulated portion of Western Denmark) but at the same time to conduct a general evaluation on the simulation study performed, on the basis of the "real world" data. The first two indicators, namely Volume Indicator and Cost Indicator, has been calculated from the simulation study results obtained using a Market Time Unit of $T = 1$ hour, in order to ease a comparison with the indicators values calculated in Section 4.2.3 relative to the entire Western Denmark over the year 2014. A Market Time Unit of $T = 1$ hour is currently used in Western Denmark and therefore indicators calculated using the results illustrated in the previous sections using a $T = 15$ minutes would be useless.

On the other hand, in order to calculate the Cost Ratio Indicator a separate simulation has been performed, in which the demand has been neglected. To calculate the CRI it is necessary to evaluate the energy-related regulation cost, which can only be calculated knowing both the forecasted and the actual energy production of each market participant. Since the demand has been generated as superimposition of two time-series with a first order correlation, the forecast information is missing, and thus its energy imbalance cannot be evaluated. For this reason, a simulation study including only the wind generators, for which all the necessary data are available, has been performed.

Volume Indicator (VI) the Volume Indicator is calculated by dividing the average amount of procured reserves in MW by the hourly average energy consumption in MWh/h. The power-related regulation services VI for the simulation study is equal to 16,71%.

Cost Indicator (CI) the Cost Indicator is calculated by dividing the monthly ancillary service cost by the monthly wholesale energy cost, where the latter is obtained by multiplying the average wholesale market price from the real Danish market by the monthly energy consumption of the simulated system. The power-related regulation services CI for the simulation study is equal to 8,12%.

Cost Ratio Indicator (CRI) the Cost Ratio Indicator can be calculated by dividing the total cost of power-related regulation services by the total cost of energy-related regulation services. For the simulation study including only the wind generators, the CRI is equal to 12,52%.

The values of the three indicators concerning the simulation study resulted to be greater than the values obtained in Section 4.2.3 for the entire Western Denmark control area over the year 2014. The possible explanation for this difference lies in the configuration of the simulated power system, compared to the actual Danish power system. Under the assumption that only renewable energy producers and demand contribute to deviations from an ideal flat power profile, emphasis has been placed on the analysis of renewable energy generators. These entities, if not coupled with any system allowing for smoothing fluctuations, are naturally expected

to deliver highly fluctuating power production. In view of future power systems with significant renewable energy generation, the simulation study focused on wind power production. Consequently the production side of the simulated power system was made up of wind producers only. On the other hand, to simulate the real functioning of an electric power system, the consumption side was dimensioned so that the total electricity production corresponded exactly to the total electricity consumption at all times. Therefore, the simulated power system presumed an 100% renewable power generation, because no additional electricity production has been considered apart from that coming from the selected wind farms.

Despite the ambitious plans of the Danish government intended to achieve a totally renewable energy system by the year 2050, and a completely renewable electric system by the year 2025, currently wind power production accounts for almost 30% of the total domestic electricity supply. Since the denominator of both the Volume Indicator and the Cost Indicator includes the hourly average energy consumption, the indicators results for the simulated portion of Western Denmark and the entire Western Denmark inevitably differ. If the wind power production of the simulation study is made accountable for 30% of the total electricity consumption, indicators values more similar to those reported in Section 4.2.3 are obtained. However, when increasing the total electricity consumption, possible changes in the numerators of the two indicators should be taken into account, because the increased portion of renewable generation and the greater demand may influence the power regulation needs.

With regard to the Cost Ratio Indicator, two assumptions of the simulation study, among the other, could be used to explain the indicators values difference. On the one hand, the simplifying assumption according to which the supply curves for tertiary reserve energy has been used to obtain a rough estimate of the cost associated with the energy imbalances, while in reality a mix of control energy provided by secondary and tertiary reserves are deployed by the TSO to maintain a constant energy balance. On the other hand, the hypothesis behind the implementation of the simulation, according to which only power-related services are deployed to manage the power variability of the total energy-neutral power profile over the entire hour of operation, while in reality the Danish TSO might also schedule tertiary reserves to manage some long lasting energy imbalances, especially bearing in mind that Energinet.dk's operational philosophy emphasizes manual reserves over the frequency-controlled ones. Both these assumptions could have produced a decrease of the CRI denominator for the simulation, hence explaining why the simulation study result is greater than the CRI calculated for the entire Western Denmark over the year 2014.

Chapter 8

Conclusion

8.1 Discussion

Following the large-scale deployment of wind farms and photovoltaic panels occurred in recent years, the debate on the economic integration of intermittent Renewable Energy Sources into the European electricity markets has gained importance. The main discussion topic is how to ensure efficient and effective investments and then operation of these RES, while achieving the coveted decarbonisation targets. In many European countries, renewable generation is kept out of the markets and receives different kinds of support schemes, in order to promote a fast deployment of these resources until they become competitive with conventional generation units. Once the competitiveness is achieved, a possible further development is that of aligning the RES rules and economic incentives with those of dispatchable generators. This type of development has been recently undertaken in some of the countries characterized by a significant penetration of variable energy sources (e.g. Denmark, Spain, Germany, Italy). For instance, in Spain the support scheme for this type of resources has evolved from feed-in-tariff to feed-in-premium, in order to increase the participation and exposure of RES to the wholesale electricity markets.

In the same direction, actions has been undertaken to subject the RES to the same scheduling and balancing obligations as conventional power plants, hence they are increasingly asked to be financially responsible for the energy regulation needs they induce. A further step towards the full responsibility of the RES is represented by the accountability of the additional system costs induced by their power fluctuations, which are currently supported by the consumption side, usually through grid tariffs. This seems to be a natural development of the process that has already started in many European countries towards the full market integration of the RES.

Variability has always been a feature of electric power systems as a result of demand variation, but a significant penetration of renewable generation is commonly expected to increase the power system variability, thus enhancing the need for system flexibility. In future power systems where the need for flexibility and reserves

regulation may increase and substantially originate from the production side, the power generators should be made accountable for the costs they induce. The simplest and straighfoward solution to develop a system in which also the generation side bears a portion of the power variability cost is represented by the socialization of the cost on all market participants causing it, on the basis of the energy consumption or production. Such a solution has the merit of being rather easy to implement, in particular it does not required the collection of any additional data more than those already in possession of the TSO. However, while achieving the accountability objective, it risks to be a self-seeking mechanisms that won't work toward the efficient and effective operation and investment in these resources. In view of power systems with always increasing need of flexibility and real-time regulation, such a solution won't be able to provide any productive incentive toward the power system improvement, and may end up being only an additional cost to be supported by renewable generators.

The key challenge for an efficient integration of the RES is that of ensuing that the right incentives are established. With regards to power variability, this can be achieved with the implementation of a mechanism allocating the induced cost on the basis of the contribution of each entity to power regulation needs. As demonstrated in this thesis, such type of attribution mechanism will be able to provide incentives to the involved entities toward a better self-regulation of their own power fluctuations, which may in turn lead to an increased system balancing efficiency. This solution has the merit of achieving the accountability objective, while also actively contributing to the evolution of the power systems toward a design accommodating a large-scale penetration of RES. It allows to develop a market framework in which the systems allowing for smoothing power fluctuations, such as storage or demand-response, are strongly incentivized whenever the overall system variability, and consequently the induced system cost, become unbearable.

Beside the significant benefits produced, the actual implementation of a mechanism allocating the involved cost on the basis of the respective contribution of each entity requires the collection and the assessment of a huge amount of data, together with an appropriate tuning process of all the concerned parties. Considering an ever-increasing distribution generation connected to the RES deployment, and the consequent increase of market participants, questions may rise on the optimal accuracy and computation preciseness to use in the cost allocation procedure. For instance, an increase of the time resolution used for the collection of the power profiles data certainly enhances the accuracy of the cost redistribution process. Nevertheless, it should be ensured that the running costs won't balance out the benefits produced.

8.2 Final remarks

Due to their variability and limited predictability, the presence of a large amount of renewable generation in a power system is expected to increase the power-related regulation requirements. Through an assessment of today's cost of power-related

regulation services on the test cases of Western Denmark and Germany, this thesis showed that the power variability of Renewable Energy Sources already generates a non-negligible system cost.

In many European countries, renewable generation is so far not burdened with full balancing responsibility, consequently the costs induced by their power fluctuations are socialized and eventually supported by electricity consumers through grid tariffs. In future energy systems where the need for increased power-related services may substantially originate from the production side, power suppliers should be made accountable for the system costs they induce. Hence, four attribution mechanisms have been proposed in this thesis for assessing the contribution of all market participants to power regulation needs, and to consequently fairly redistribute the related regulation costs.

The proposed mechanisms are designed to readily complement the existing mechanisms for energy-related regulation, by pricing the variability in power delivery depending on the resulting need for ancillary services. Therefore, the concept of energy-neutral power profile has been used to separate energy and power-related aspects, since with the existing market mechanisms both power suppliers and consumers are already deemed accountable for energy imbalances.

The idea is to distribute the power variability cost to each actor proportionally to a give metric that depends on the energy-neutral power profile of the specific actor. The first metric (*power capacity metric*) emphasizes the capacity that may be required to compensate fluctuations by mean of the L_∞ norm of the energy-neutral power profile, which similarly considers positive and negative fluctuations, only focusing on maximum deviation from the constant power profile. The second metric (*integrated mismatch metric*) considers the integrated mismatch as quantity of interest, thus relating to a L_k norm ($k = 1, 2$) of these profiles. The third metric (*mileage metric*) is a mileage-type metric which emphasizes the dynamic properties of energy-neutral profiles by mean of the L_k ($k = 1, 2$) norm of the h-order derivative. The last metric proposed (*inner product metric*) emphasizes the respective contribution of each market participant to the total power profile by mean of the inner product between individual and overall fluctuations.

In order to illustrate these concepts and to show how these mechanisms may affect revenues of the various market participants a simulation study based on the test case of Western Denmark, country already widely penetrated by wind power generation, has been carried out. The results showed that according to all four metrics the majority of the power-related regulation cost is supported by the large wind farms and by the demand. In that respect, all the four metrics appeared to be consistent, although the shares of the total cost allocated to each of these specific entities differ from metric to metric.

A further examination showed that the relative weight of the high cost allocated to the large wind farms by the first three metrics is indeed low, and therefore large renewable generators have a lower incentive in reducing their power fluctuations compared to the smaller producers, which by contrast receive the strongest incentive toward a better self-regulation. On the contrary, the results of the inner product metric work in the opposite direction in terms of incentives. The results

for this specific metric revealed that the strongest incentive toward a better self-regulation of their own production is received by large renewable generators when a one-price settlement scheme is applied.

The contributions of each and every actor to the overall power fluctuations determined on the basis of the inner product metric have also been placed in a two-price settlement scheme, by differentiating the power regulation unit cost between the actors contributing or counteracting the formation of the total power profile. In this case, it has been found that all the renewable generators, independently of their size, receive a strong market incentive. At the same time, since a two-price system is not a zero-sum game for the TSO, the *fluctuation rent* resulting from this settlement scheme can be considered an additional incentive produced by the cost allocation system.

8.3 Further work

Toward the actual implementation of the proposed attribution mechanisms, simulation studies on a wider geographical scale are necessary and an evaluation of their suitability in the larger context of the Internal Energy Market might be required. In this regard, it will be indispensable to include the import-export in the simulations in order to determine its implications and propose management strategies. Furthermore, the strategic behavior of the various market participants needs to be carefully studied, in particular since the coalition of producers may alter the theoretical outcome of the proposed attribution mechanisms illustrated in this thesis.

With regard to the simulation study performed in this study, further research includes the refinement of the power-related regulation supply curves in order to take into account the dissimilarities existing between the Danish and German context (e.g. technological mix of service providers and remuneration mechanisms) and the refinement of the demand energy-neutral power profile on the basis of real data.

Appendix A

Wind farms data

For the simulation study the wind producers' power profiles are generated with the CorWind power time series simulation model, developed at Risø DTU. This model can simulate wind power time series over the entire Western Denmark geographical area for different time scales when the wind turbines can be represented by simple steady state power curves. In order to produce the power observations of any wind farm located in Western Denmark, it requires in input the main wind farm data, including the total wind farm capacity and the geographical position (i.e. latitude and longitude), but also the normalized power curves.

The main input data for each of the forty-one simulated wind farms has been collected from the Danish Register for wind turbines [42], since they have all been chosen from the existing wind farms located in Western Denmark. The collected data for offshore and onshore wind farms are respectively illustrated in Table A.1 and Tables A.2 and A.3, they include total installed capacity, latitude and longitude of the installation site. In addition, the number of wind turbines included in each wind farm has also been collected from the same register.

The wind turbines number has been used to determine the diameter of the area of each wind farm installation site, which is a mandatory input data for CorWind. Since the Danish Register included the value of the diameter of the installation site area only for two offshore wind farms, namely Anholt and Horns Rev 1, the value for the remaining wind farms has been determined by mean of a linear proportion on the basis of the number of wind turbines included in each wind farm (these estimated values are marked with an asterisk in the tables).

Because most diameter values has been estimated through a proportion, a preliminary study has been carried out in order to evaluate the influence of this parameter on CorWind output data (see Appendix B for the preliminary study results). For this purpose two trials have been executed on the simulation model using the exact same input data but the diameter values, which have been respectively set equal to the values obtained with the linear proportion and half of these values, as illustrated in Table A.1, Table A.2 and Table A.3. The choice of halving the diameter values was justified by the fact that offshore wind farms are usually spread over a larger geographical area relatively to onshore wind farms, and since the

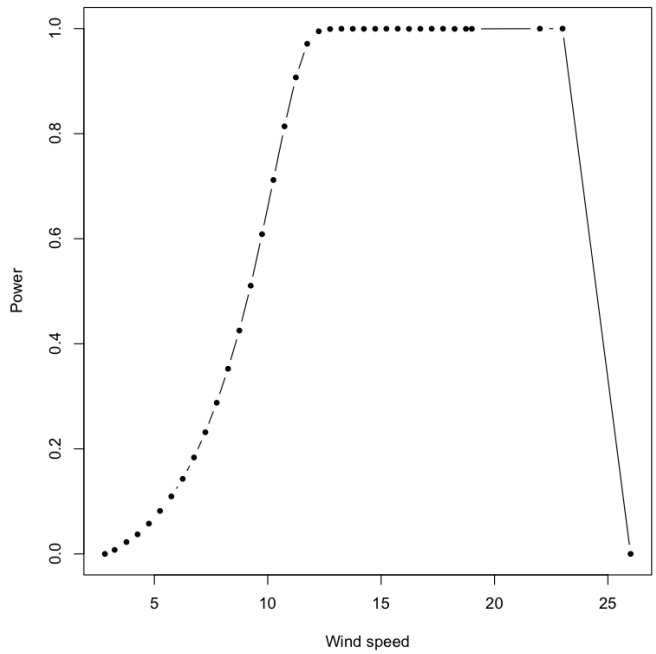


Figure A.1: Normalized power curve used for the simulation of the forty-one wind farms sample

proportion was based on offshore cases the resulting diameter values are likely to be overestimated.

Lastly, for all the wind farms included in the simulation study the normalized power curve illustrated in Figure A.1 has been used.

Table A.1: Data regarding the Danish offshore wind farms simulated

Name	Power [MW]	Turbines	Latitude	Longitude	Diameter [km]	Half Diameter [km]
Anholt	399,6	111	56.5354	11.2112	10,5851	5,29255*
Frederikshavn	7,6	3	57.4429	10.5636	0,2298*	0,1149*
Horns Rev 1	160	80	55.4854	7.8397	5,0463	2,52315*
Horns Rev 2	209,3	91	55.6008	7.5825	6,482*	3,241*
Ronland	17,2	8	56.6628	8.22	0,6128*	0,3064*
Samso	23	10	55.7230	10.5840	0,766*	0,383*
Tuno Knob	5	10	55.9682	10.3548	0,766*	0,383*

Table A.2: Data regarding the Danish onshore wind farms simulated (I part)

Name	Power [MW]	Turbines	Latitude	Longitude	Diameter [km]	Half Diameter [km]
Ajstrup	10,475	18	57.1793	9.9659	1,3788*	0,6894*
Arrild	12,62	20	55.1488	8.96097	1,532*	0,766*
Asted	14,15	10	55.7969	8.4264	0,766*	0,383*
Bajlum	15	5	56.7689	8.9438	0,383*	0,1915*
Billund	48,9	18	55.7286	9.2606	1,3788*	0,6894*
Brejning	11,16	10	56.1126	8.5026	0,766*	0,383*
Bronderslev	53	21	57.2699	9.94097	1,6086*	0,8043*
Dostrup	18,3	10	55.1148	8.8006	0,766*	0,383*
Dronninglund	14,61	11	57.1598	10.2993	0,8426*	0,4213*
Eggebaek Tinglev	16	8	56.43997	8.58997	0,6128*	0,3064*
Gammel Vraa Enge	11,25	15	57.0353	9.93397	1,149*	0,5745*
Henjsvig	12	4	56.7197	8.3825	0,3064*	0,1532*
Hemmet	27	9	55.85	8.3728	0,6894*	0,3447*
Herning	18	6	56.1386	8.9673	0,4596*	0,2298*
Hollandsbjerg	16,5	11	56.47997	10.25997	0,8426*	0,4213*
Horsens	17,6	9	55.8604	9.8496	0,6894*	0,3447*
Hvam	13,26	6	56.6627	9.5143	0,4596*	0,2296*

Table A.3: Data regarding the Danish onshore wind farms simulated (II part)

Name	Power [MW]	Turbines	Latitude	Longitude	Diameter [km]	Half Diameter [km]
Klim	21	35	57.07997	9.21	2,681*	1,3405*
Lem	29,36	14	56.0315	8.3886	1,0724*	0,5362*
Lemvig	26,3	9	56.5443	8.3025	0,6894*	0,3447*
Nees	23,3	13	56.3944	8.2136	0,9958*	0,4979*
Osterild	18	3	57.0301	8.8468	0,2298*	0,1149*
Remme	17,4	15	56.2067	8.9179	1,149*	0,5745*
Ringkobing-Skjern	135,6	38	56.0447	8.5059	2,9108*	1,4554*
Skive	39	13	56.5636	9.0321	0,9958*	0,4979*
Struer	21	7	56.4849	8.5899	0,5362*	0,2681*
Thisted	14,2	7	56.9592	8.7035	0,5362*	0,2681*
Tim	15,3	6	56.1953	8.3064	0,4596*	0,2298*
Tjaereborg	18,9	11	55.46	8.60997	0,8426*	0,4213*
Udbyneder	35,5	17	56.0610	10.2374	1,3022*	0,6511*
Ulvemosen	33	10	55.6231	8.4821	0,766*	0,383*
Vederso	15	10	56.2342	8.2013	0,766*	0,383*
Vejrum	16,8	12	56.4376	9.5572	0,9192*	0,4596*
Vra	23,67	33	57.3527	9.946	2,5278*	1,2639*

Appendix B

Preliminary studies on CorWind output data

Before implementing the thesis simulation study, two preliminary studies on CorWind output data have been performed in order to evaluate the influence of the wind farms area and the time resolution on the power profiles produced by the simulation model. This Appendix illustrates the results of the two preliminary studies.

B.1 Influence of the wind farms area on the power profiles

The values of the wind farms area, and in particular of the diameter of the installation site area, have been determined by mean of a linear proportion on the basis of the number of wind turbines included in each wind farm, since this specific information was only available for two offshore wind farms. Because offshore wind farms are usually spread over a larger geographical area relatively to onshore wind farms, the diameter values resulting from the proportion are likely to be overestimated. Consequently, it has been decided to perform a preliminary study in order to evaluate the influence of this parameter on CorWind output data.

For this purpose two trials have been executed on the simulation model using the exact same input data but the diameter values, which have been set equal to respectively the values obtained with the proportion and half of these values. The results in terms of total power profile for the entire production side produced by CorWind using the two aforementioned set of diameter values are shown in Figure B.1 and Figure B.2, respectively for an entire day of operation and two hours of operation. In both figures, the total power profile resulting from the simulation using the diameter values obtained with the proportion is illustrated in blue, while the one obtained with half of the previous diameter values is depicted in red.

From Figure B.1 and Figure B.2, it is possible to notice that the wind farm area does not have a major influence on CorWind output data, since the two power

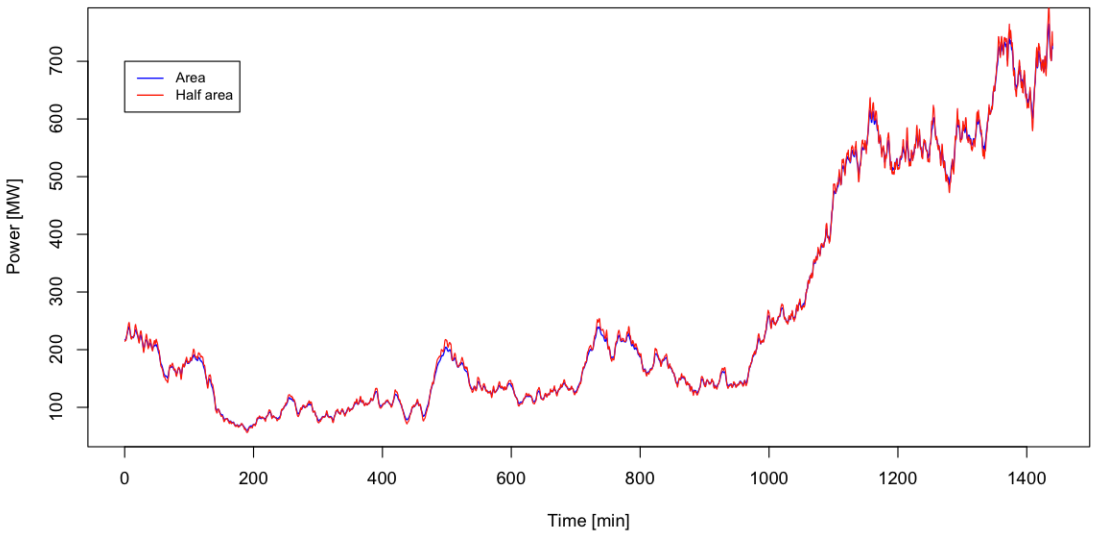


Figure B.1: Total power profiles for the production side, simulated using different values for the wind farms areas by mean of CorWind

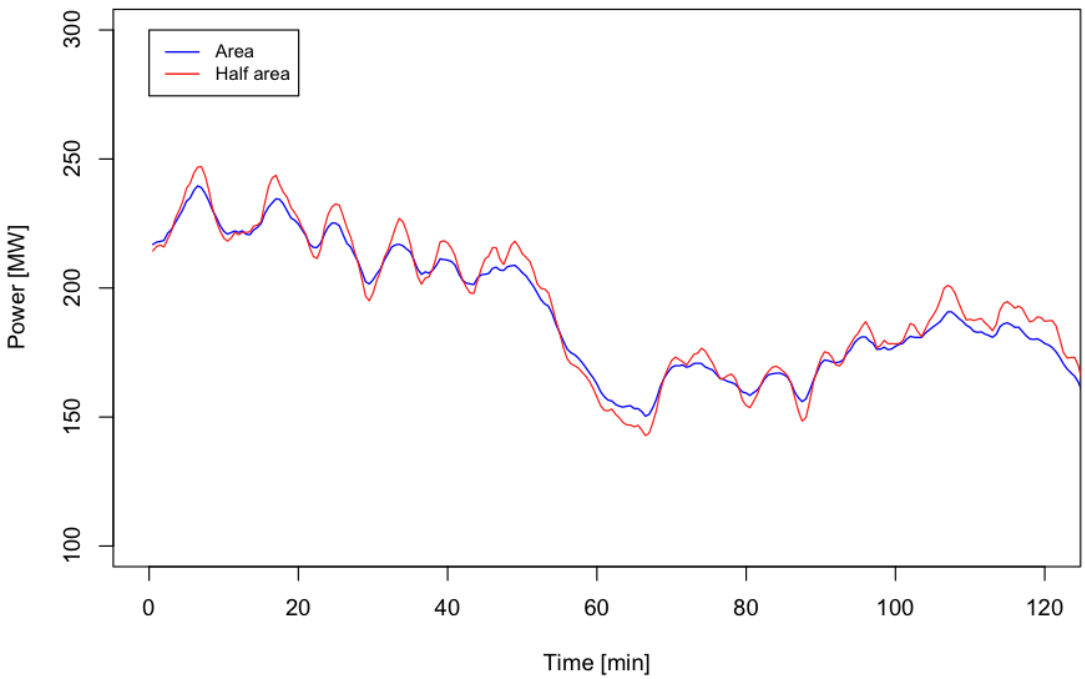


Figure B.2: Close-up of the total power profiles for the production side, simulated using different values for the wind farms areas by mean of CorWind

profile curves are very similar. In particular, the close-up depicted in Figure B.2, clearly shows that the power profile obtained using the half diameter values has slightly more emphasized fluctuations, but the same exact trend of the other power profile. From this preliminary study, it has been decided to use the diameter values obtained by mean of the linear proportion for the simulation study of the thesis.

B.2 Influence of time resolution on the power profiles

A key parameter to perform a simulation using CorWind is the output time resolution, which represents the temporal distance between two consecutive power observations. A decrease of the output time resolution is generally expected to produce an increase of the results accuracy, as it should better characterize the power fluctuations. On the other hand, a decrease of the output time resolution also produces an increase of the dataset volume, especially when simulating a long time period, such as a month. An appropriate balance between these two counterposed aspects needs to be found. Consequently it is particularly important to evaluate the extent to which the simulator is actually able to produce a results accuracy increase, because of the intrinsic limits of a model.

For this purpose three trials have been executed on the simulation model using the exact same input data but the output time resolution, which have been set equal to 30 seconds, 10 seconds and 5 seconds. The results of this preliminary study are illustrated in Figure B.3 and Figure B.4, respectively for an entire day of operation and 10 minutes of operation. In the first figure the resulting power profile for 5 seconds time resolution has been omitted in order to ease the graph comprehension.

Given that the same value of the random seed, in particular 3, has been used for all three simulations, the resulting power profiles have a different trend. However, from both figures it appears clear that the order of magnitude of the power fluctuations amplitude is the same in all three cases. Consequently, it has been deduced that the a decrease of the output time resolution below 30 seconds doesn't produce any significant results accuracy increase, and therefore an output time resolution of 30 seconds has been used for the thesis simulation study.

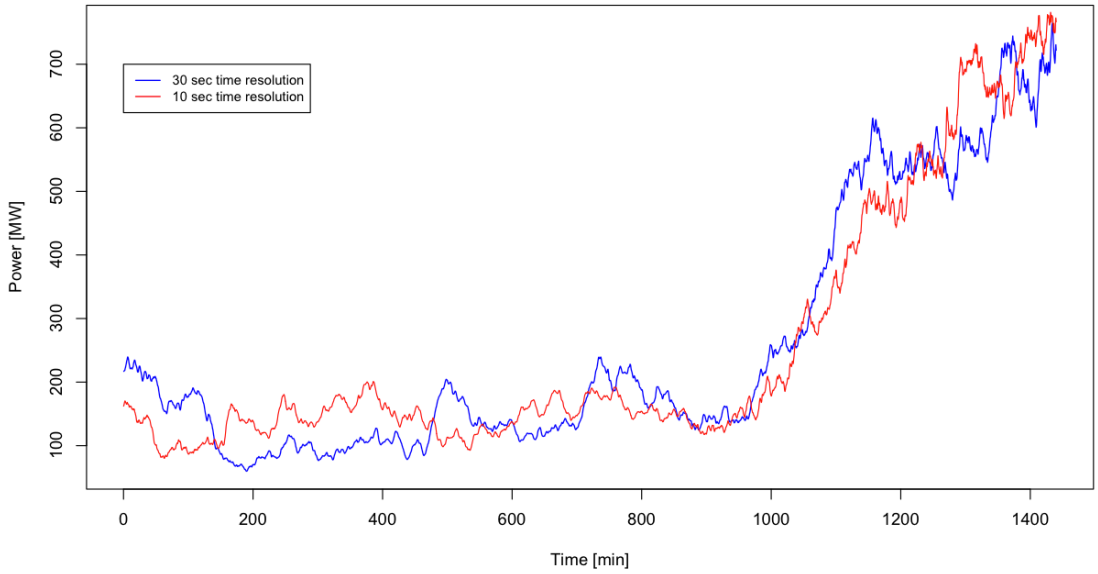


Figure B.3: Total power profiles for the production side, simulated using different time resolutions by mean of CorWind

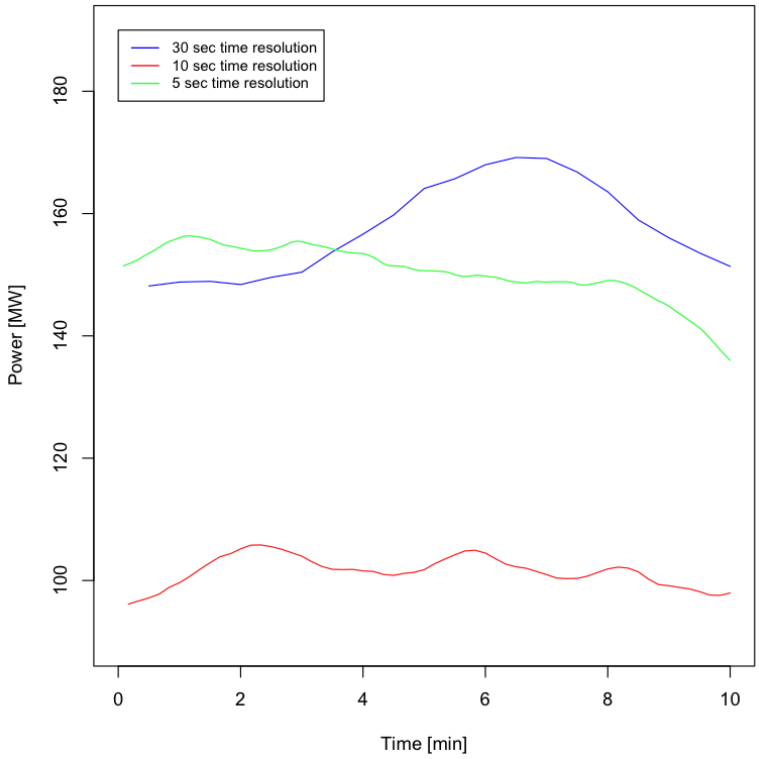


Figure B.4: Close-up of the total power profiles for the production side, simulated using different time resolutions by mean of CorWind

Appendix C

Codes selection

The simulation study of this thesis has been performed by mean of suitable scripts developed by the author using the software environment for statistical computing and graphics R©. This chapter provides some examples of these scripts. Following, examples of the XML file developed to provide the input data to the CorWind model are included.

```
TCR0101<-read.delim2("TCR_2014-01-01.txt",header=TRUE,dec=".")

attach(TCR0101)
capacitypayment0101<-Capacity.price
offeredpower0101<-Offered.power
energyprice0101<-Energy.price
product0101<-Productname
award0101<-Award
detach(TCR0101)

l1<-length(which(award0101=="yes"))
l2<-which(award0101=="yes")
power0101<-rep(0,l1)
price0101<-rep(0,l1)
j=1
for (i in l2) {
    power0101[j]=offeredpower0101[i]
    price0101[j]=capacitypayment0101[i]
    j=j+1
}
```

Figure C.1: Example of a code created in R© to analyse the German data of Tertiary Control Reserves downloaded from the TSOs' internet platform

```
##### Germany Tertiary Reserves #####

### Functions ###

fneg_0004<-function (op,cp,p) {
    A<-cbind(op,cp)
    l<-length(which(p=="NEG_00_04"))
    l1<-length(p)
    B<-matrix(0,nrow=l,ncol=2)
    C<-matrix(0,nrow=l,ncol=2)
    D<-matrix(0,nrow=(l+1),ncol=2)
    k=1
    for (i in 1:l1) {
        if (p[i]=="NEG_00_04") {
            B[k,1]=A[i,1]
            B[k,2]=A[i,2]
            k=k+1
        }
    }
    for (i in 1:l) {
        j=which.min(B[,2])
        C[i,1]=B[j,1]
        C[i,2]=B[j,2]
        B[j,2]=100000000
    }
    w=2
    for (i in 1:l) {
        D[w,1]=D[i,1]+C[i,1]
        D[w,2]=C[i,2]
        w=w+1
    }
    return(D)
}
```

Figure C.2: Example of a code created in R© to select and organize the data downloaded in order to create the supply curves

```
##### Function to generate the demand power profile #####

power_profile<-function(rho,sig,ndim) {
    zv<-rnorm(ndim,0,sig)
    xv<-rnorm(1,0,sig)
    for (i in 1:ndim) {
        xv<-c(xv,(rho*xv[i-1]+sqrt(1-rho^2)*zv[i]))
    }
    return(xv)
}


##### Superimposition of two time-series with a first-order correlation #####


rho1=0.95       # for the profile highly correlated in time
rho2=0.2        # for the fluctuations to add on top of the first profile

for (i in 1:lh) {
    profile1=power_profile(rho1,sigma[i],ndim)
    profile2=power_profile(rho2,1,ndim)
    energy_neutral_demand_power_profile[,i]=profile1+profile2
}

```

Figure C.3: Code created in R© to generate the total demand energy-neutral power profile

```
##### POWER CAPACITY METRIC #####

pcm_qhour=array(0,c(3,lq,mrkp))


for(i in 1:mrkp) {
    for(k in 1:lq) {
        pcm_qhour[1,k,i]=max_individ_en_qhour_pp[1,k,i]/
 sum(max_individ_en_qhour_pp[1,k,])*cost_qhour_6[k]
    }
}


for(i in 1:mrkp) {
    for(k in 1:lq) {
        pcm_qhour[2,k,i]=max_individ_en_qhour_pp[1,k,i]/sum(max_individ_en_qhour_pp[1,k,])*100
    }
}

vet=seq(from=1,to=lq,by=4)
for(i in 1:mrkp) {
    for(k in vet) {
        if (pcm_qhour[1,k,i]!=0 && pcm_qhour[1,(k+1),i]!=0 && pcm_qhour[1,(k+2),i]!=0 &&
 pcm_qhour[1,(k+3),i]!=0) {
            pcm_qhour[3,k,i]=(pcm_qhour[1,k,i]+pcm_qhour[1,(k+1),i]+pcm_qhour[1,(k+2),i]
 +pcm_qhour[1,(k+3),i])/(mean_individ_qhour_pp[1,k,i]*0.25+mean_individ_qhour_pp[1,(k
 +1),i]*0.25+mean_individ_qhour_pp[1,(k+2),i]*0.25+mean_individ_qhour_pp[1,(k+3),i]*0.25)
            pcm_qhour[3,(k+1),i]=pcm_qhour[3,k,i]
            pcm_qhour[3,(k+2),i]=pcm_qhour[3,k,i]
            pcm_qhour[3,(k+3),i]=pcm_qhour[3,k,i]
        }
    }
}

```

Figure C.4: Example of a code created in R© to implement the power capacity metric

```xml
- <TaskRequest SchemaVersion="1.0">
    <StartDateTime>2001-05-16T02:30:00</StartDateTime>
    <EndDateTime>2001-05-16T02:50:00</EndDateTime>
    <TimeResolutionSeconds>2</TimeResolutionSeconds>
    <RandomSeed>3</RandomSeed>
  - <Points>
      <Point Name="HornsRev2" Long="7.582" Lat="55.6" InstalledCapacity="209.3" PC_ID="NormalizedParkPC" D_Area="6.482"/>
      <Point Name="Anholt" Long="11.208" Lat="56.598" InstalledCapacity="399.6" PC_ID="NormalizedParkPC" D_Area="12.153"/>
    </Points>
  - <PowerCurves>
    - <PowerCurve ID="NormalizedParkPC">
        <PowerCurveItem WindSpeed="2.82" Power="0"/>
        <PowerCurveItem WindSpeed="3.25" Power="0.00762"/>
        <PowerCurveItem WindSpeed="3.77" Power="0.022555"/>
        <PowerCurveItem WindSpeed="4.26" Power="0.0372"/>
        <PowerCurveItem WindSpeed="4.76" Power="0.05765"/>
        <PowerCurveItem WindSpeed="5.25" Power="0.08182"/>
        <PowerCurveItem WindSpeed="5.75" Power="0.10944"/>
        <PowerCurveItem WindSpeed="6.25" Power="0.142825"/>
        <PowerCurveItem WindSpeed="6.75" Power="0.183545"/>
        <PowerCurveItem WindSpeed="7.25" Power="0.231545"/>
        <PowerCurveItem WindSpeed="7.75" Power="0.28778"/>
        <PowerCurveItem WindSpeed="8.25" Power="0.352435"/>
        <PowerCurveItem WindSpeed="8.75" Power="0.42517"/>
        <PowerCurveItem WindSpeed="9.25" Power="0.5106"/>
        <PowerCurveItem WindSpeed="9.75" Power="0.6086"/>
        <PowerCurveItem WindSpeed="10.25" Power="0.71175"/>
        <PowerCurveItem WindSpeed="10.74" Power="0.81385"/>
        <PowerCurveItem WindSpeed="11.24" Power="0.907"/>
        <PowerCurveItem WindSpeed="11.74" Power="0.971"/>
        <PowerCurveItem WindSpeed="12.25" Power="0.9949"/>
        <PowerCurveItem WindSpeed="12.75" Power="0.99915"/>
        <PowerCurveItem WindSpeed="13.25" Power="0.9997"/>
        <PowerCurveItem WindSpeed="13.75" Power="0.99965"/>
        <PowerCurveItem WindSpeed="14.24" Power="0.9995"/>
        <PowerCurveItem WindSpeed="14.74" Power="0.99965"/>
        <PowerCurveItem WindSpeed="15.23" Power="0.9997"/>
        <PowerCurveItem WindSpeed="15.73" Power="0.99975"/>
        <PowerCurveItem WindSpeed="16.23" Power="0.99945"/>
        <PowerCurveItem WindSpeed="16.73" Power="0.99965"/>
        <PowerCurveItem WindSpeed="17.23" Power="0.99975"/>
        <PowerCurveItem WindSpeed="17.73" Power="0.99975"/>
        <PowerCurveItem WindSpeed="18.24" Power="0.99945"/>
        <PowerCurveItem WindSpeed="18.74" Power="0.9995"/>
        <PowerCurveItem WindSpeed="19" Power="0.999531"/>
        <PowerCurveItem WindSpeed="22" Power="0.999883"/>
        <PowerCurveItem WindSpeed="23" Power="1"/>
        <PowerCurveItem WindSpeed="26" Power="0"/>
      </PowerCurve>
    </PowerCurves>
  </TaskRequest>
```


Figure C.5: Sample XML script used to pass all the parameters to CorWind in order to simulate the actual power observations

```
- <TaskRequest SchemaVersion="1.0">
    <StartDateTime>2014-03-01T00:00:00</StartDateTime>
    <EndDateTime>2014-03-01T23:59:59</EndDateTime>
    <TimeResolutionSeconds>1</TimeResolutionSeconds>
    <FluctuationRandomSeed>3</FluctuationRandomSeed>
    <ForecastRandomSeed>5</ForecastRandomSeed>
  - <Points>
      <Point Name="HornsRev2" Long="7.582" Lat="55.6" InstalledCapacity="209.3" PC_ID="NormalizedParkPC" D_Area="6.482"/>
      <Point Name="Anholt" Long="11.208" Lat="56.598" InstalledCapacity="399.6" PC_ID="NormalizedParkPC" D_Area="12.153"/>
    </Points>
  - <PowerCurves>
    - <PowerCurve ID="NormalizedParkPC">
        <PowerCurveItem WindSpeed="2.82" Power="0"/>
        <PowerCurveItem WindSpeed="3.25" Power="0.00762"/>
        <PowerCurveItem WindSpeed="3.77" Power="0.022555"/>
        <PowerCurveItem WindSpeed="4.26" Power="0.0372"/>
        <PowerCurveItem WindSpeed="4.76" Power="0.05765"/>
        <PowerCurveItem WindSpeed="5.25" Power="0.08182"/>
        <PowerCurveItem WindSpeed="5.75" Power="0.10944"/>
        <PowerCurveItem WindSpeed="6.25" Power="0.142825"/>
        <PowerCurveItem WindSpeed="6.75" Power="0.183545"/>
        <PowerCurveItem WindSpeed="7.25" Power="0.231545"/>
        <PowerCurveItem WindSpeed="7.75" Power="0.28778"/>
        <PowerCurveItem WindSpeed="8.25" Power="0.352435"/>
        <PowerCurveItem WindSpeed="8.75" Power="0.42517"/>
        <PowerCurveItem WindSpeed="9.25" Power="0.5106"/>
        <PowerCurveItem WindSpeed="9.75" Power="0.6086"/>
        <PowerCurveItem WindSpeed="10.25" Power="0.71175"/>
        <PowerCurveItem WindSpeed="10.74" Power="0.81385"/>
        <PowerCurveItem WindSpeed="11.24" Power="0.907"/>
        <PowerCurveItem WindSpeed="11.74" Power="0.971"/>
        <PowerCurveItem WindSpeed="12.25" Power="0.9949"/>
        <PowerCurveItem WindSpeed="12.75" Power="0.99915"/>
        <PowerCurveItem WindSpeed="13.25" Power="0.9997"/>
        <PowerCurveItem WindSpeed="13.75" Power="0.99965"/>
        <PowerCurveItem WindSpeed="14.24" Power="0.9995"/>
        <PowerCurveItem WindSpeed="14.74" Power="0.99965"/>
        <PowerCurveItem WindSpeed="15.23" Power="0.9997"/>
        <PowerCurveItem WindSpeed="15.73" Power="0.99975"/>
        <PowerCurveItem WindSpeed="16.23" Power="0.99945"/>
        <PowerCurveItem WindSpeed="16.73" Power="0.99965"/>
        <PowerCurveItem WindSpeed="17.23" Power="0.99975"/>
        <PowerCurveItem WindSpeed="17.73" Power="0.99975"/>
        <PowerCurveItem WindSpeed="18.24" Power="0.99945"/>
        <PowerCurveItem WindSpeed="18.74" Power="0.9995"/>
        <PowerCurveItem WindSpeed="19" Power="0.999531"/>
        <PowerCurveItem WindSpeed="22" Power="0.999883"/>
        <PowerCurveItem WindSpeed="23" Power="1"/>
        <PowerCurveItem WindSpeed="26" Power="0"/>
      </PowerCurve>
    </PowerCurves>
  </TaskRequest>
```


Figure C.6: Sample XML script used to pass all the parameters to CorWind in order to simulate both actual power observations and forecasts

Acronyms

ACER	Agency for the Cooperation of Energy Regulators
AS	Ancillary Service
CI	Cost Indicator
CorWind	Correlated Wind
CRI	Cost Ratio Indicator
DK1	Western Denmark
DTU	Denmark Technical University
EC	European Commission
ENTSO-E	European Network for Transmission System Operators for Electricity
ERGEG	European Regulators Group for Electricity and Gas
EU	European Union
FCR	Frequency Containment Reserves
FER	Fonti di Energia Rinnovabile
FRR	Frequency Regulation Reserves
Hz	Hertz
IEM	Internal Energy Market
IGCC	International Grid Control Cooperation
ISO	Independent System Operator
LFC	Load-Frequency Control
MTU	Market Time Unit
MW	Megawatt

MWh	Megawatthour
NERC	North America Electric Reliability Council
PJM	Pennsylvania - New Jersey - Maryland Interconnection
PR	Primary Reserve
PCR	Primary Control Reserve
reBAP	Germany uniform Balancing Energy Price
RES	Renewable Energy Source
RG	Regional Group
RR	Replacement Reserve
SR	Secondary Reserve
SCR	Secondary Control Reserve
SO	System Operator
TR	Tertiary Reserve
TCR	Tertiary Control Reserve
TSO	Transmission System Operator
UCTE	Union for the Coordination of Transmission of Electricity
VI	Volume Indicator

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