INTERMITTENCY AND PRICING FLEXIBILITY IN ELECTRICITY MARKETS

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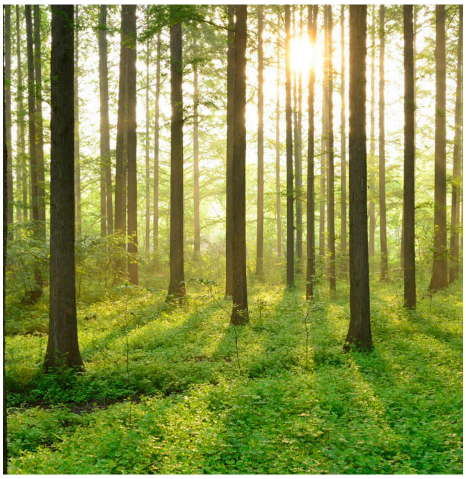

EFORIS

ELMARKNADENS FUNKTION OCH ROLL I SAMHÄLLET

Energiforsk

Intermittency and Pricing Flexibility in Electricity Markets

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Foreword

EFORIS, Function and role of the electricity market in society, is a research program on electricity market design. The program was initiated by Energiforsk and involves dozens of highly reputable Swedish and international researchers.

These are the results and conclusions of a study on Intermittency and Pricing Flexibility in Electricity Markets. The study was carried out by Jūratė Jaraitė, Andrius Kažukauskas, Runar Brännlund, Chandra Kiran and Bengt Kriström at Umeå University. The author/authors are responsible for the content.

Sammanfattning

Hur kan ökad intermittent kraftproduktion i det svenska elsystemet hanteras på ett mer marknadsorienterat och kostnadseffektivt sätt? I denna rapport hävdar vi att användandet av marknadsmekanismer är det mest naturliga och effektivaste sättet att få den flexibilitet i elsystemet som är nödvändig. I princip kommer lämpligt utformade marknader att ge de incitament som behövs för att kostnadseffektivt integrera intermittent elproduktion, såväl på kort och lång sikt. De viktigaste utmaningarna för framtida elmarknadsdesign handlar därför om att utforma erforderliga marknadsmekanismer - till exempel prissättning av flexibilitet - som stimulerar flexibiliteten i systemet. En transparent och samstämmig marknadsbaserad mekanism, som vi argumenterar för, kommer att underlätta effektiva investeringar för att säkra den långsiktiga stabiliteten och tillförlitligheten i det svenska elsystemet.

Det övergripande syftet med studien är att identifiera kunskapsbrister och föreslå de mest fruktbara framtida forskningsinriktningarna, sett i en svensk kontext. De flesta miljö- eller energipolitiska förslagen, och debatten kring dessa, bygger i stor utsträckning på ex-ante-analyser. Tyvärr finns det få analyser ex-post av effekter och konsekvenser till följd av energi- och klimatpolitik. Bristen på ex-postanalyser hindrar sannolikt effektivt beslutsfattande på många sätt, särskilt genom att det gör det svårt att identifiera specifika aspekter av tidigare politik som har visat sig vara effektiv. Därför är en fullständig ex-postbedömning av den svenska ”dagen före”- och balansmarknaden avgörande för att bedöma effektiviteten hos dessa marknader. En analys av dessa marknader bidrar också till att förstå i vilken grad nuvarande marknadsdesign förväntas integrera intermittent kraftproduktion på ett bra och effektivt sätt, och därmed även till att identifiera potentiella förbättringar på dessa marknader i syfte att förbättra förmågan att på ett kostnadseffektivt sätt integrera ökande mängder av intermittent kraft. Vi identifierar relevanta forskningsinriktningar för att analysera de svenska elmarknaderna i relation till prissättning av flexibilitet. Vi "skrapar på ytan" vad gäller tillgängliga datakällor och, baserat på analyser av dessa data, försöker vi ge tentativa svar på några av våra föreslagna forskningsfrågor.

Så vitt vi vet finns det inga studier som noggrant granskar och analyserar prisbildningen på intradaghandeln på Nordpool, och därmed prispremien på den svenska intradagmarknaden. I princip bör prispremien, definierad som skillnaden mellan intradagpris och dagenförepris (spotpris), vara positiv eftersom den extra flexibilitet som erhållits genom att skjuta upp transaktionen närmare leveranstiden förmodligen är värdefull. Vi finner emellertid att i genomsnitt är de timvisa premierna negativa i alla svenska prisområden under de fem senaste åren. Premierna tenderar dessutom att minska i alla svenska prisområden. Båda dessa observationer är förbryllande ur ett marknadsperspektiv. Vi menar att det är av stor vikt att förstå varför dessa premier tenderar att vara negativa och fallande över tid, vilket implicerar att den flexibilitet som erbjuds inte tycks värdesättas. Vi rekommenderar därför en djupare analys av prisasymmetrier på denna marknad med hjälp av (state-of-the-art) ekonometriska modeller. Kopplat till detta visar vi också att det finns en tydlig skillnad mellan teoretiskt förväntad volym och den

faktiska handeln på intradagmarknaden. Det indikerar att likviditeten på den svenska intradagmarknaden fortfarande är låg. Vi anser att det är viktigt att bättre förstå varför likviditeten är så låg på denna marknad och varför, med tanke på vindkraftsproduktionen som den största intermittenta kraftkällan, denna marknad inte återspeglar absoluta fel i vindprognoser. Om marknadsaktörer föredrar att använda andra strategier för att minska sina obalanser är det viktigt att förstå vilka dessa strategier är, och om de är kostnadseffektiva.

På balansmarknadssidan finner vi också några oväntade resultat som bör undersökas ytterligare. För det första har volymerna på den svenska balansmarknaden inte ökat utan snarare tenderat att minska, samtidigt som vindkraftskapaciteten har ökat snabbt. Med minskade uppregleringspremier och volymer kan investeringarna, i denna för elsystemet viktiga flexibilitetsrelaterade marknad, minska i framtiden. Vi betonar vidare vikten av framtida utvärderingsforskning ex-post för att bättre förstå hur det ökande absoluta vindprognosfelet absorberas av elmarknaden. Bättre förståelse kring detta kan få betydande konsekvenser för utformningen av balansmarknader i framtiden.

Sammanfattningsvis har den ökande andelen av intermittent kraftproduktion hittills inte lett till några större utmaningar i det svenska elsystemets flexibilitet tack vare riklig kraftproduktion i form av inte minst kärn- och vattenkraft. Med mindre eller ingen kärnkraftsproduktion kan den ökade andelen av förnybar energi emellertid öka trycket för ökad flexibilitet. Utfasningen av kärnkraftverk är således en av de största utmaningarna för hela det svenska elsystemet. För att förstå de potentiella konsekvenserna av utfasningen av kärnkraften för de svenska balans- och andra flexibilitetsrelaterade marknader, är ett förslag att undersöka effekterna av faktiska, tvingade och planerade, kärnkraftverksavbrott på svenska elmarknader.

Ytterligare förslag till relevanta forskningsinriktningar för att analysera de svenska elmarknaderna relaterat till flexibilitet sammanfattas i följande punkter:

- Det är nödvändigt att bättre förstå och uppskatta de nödvändiga incitamenten (kostnader) för teknisk förändring för att låsa upp ytterligare flexibilitet i det svenska elsystemet genom att belysa och analysera internationella erfarenheter.
- För elmarknadsaktörer som handlar på sekventiella marknader med skillnader i prisnivåer och riskexponering är det relevant att analysera energiföretagens potentiella fördelar och vilja att samordna sina bud på dessa marknader genom att ha en enda handelsplattform.
- Givet de något oklara effekterna på prisvolatilitet till följd av ökad andel intermittent kraft så finns ett tydligt behov av mer detaljerad ex-postanalys av den svenska och nordiska elmarknaden med avseende på effekter av mer intermittent kraft.
- Tidigare empiriska studier som syftar till att identifiera effekter av intermittent kraftproduktion på dagens elpriser är huvudsakligen inriktade på kortvariga, väsentligen väderstyrda, fluktuationer i intermittent effekt. Detta tillvägagångssätt är inte användbart för att förstå de långsiktiga effekterna, dvs hur kapacitetsuppbyggnad av intermittent effekt påverkar marknaderna och därmed investeringar i annan kraftproduktion. Följaktligen finns det behov av

studier som utvärderar kapacitetseffekterna till följd av ökad intermittent kraftproduktion.

- Det är nödvändigt att undersöka hur kraftpriset varierar över hela dygnet och över säsongerna och orsakerna till detta och hur kraftproduktionen responderar på dessa fluktuationer. Det ger oss en bättre förståelse för hur utvecklingen av intermittent kraftproduktion påverkar kraftpriser och vinster från olika typer av teknologier som används endast under ett fåtal timmar.
- Det finns behov att undersöka de svenska elproducenternas lönsamhet för att få bättre förståelse för incitamenten för nuvarande och framtida investeringar i olika typer av kraftgenererande teknik.
- Den övergripande effekten av mer volatila men lägre genomsnittliga kraftpriser på lönsamheten för olika kraftgenereringsteknologier är oklar och behöver undersökas närmare.
- Elmarknaderna är föremål för snedvridningar och misslyckanden på marknaden, t.ex. som följd av olika typer av subventioner för energiresurser eller specifik kraftgenererande teknik. Effekterna av dessa snedvridningar på såväl dagenföremarknaden som intradag- och balansmarknader behöver undersökas närmare.

Summary

How can increasing intermittent power generation in the Swedish electricity system be managed in a more market-oriented and cost-efficient way? We argue that market mechanisms are the most natural means for obtaining the needed flexibility in the electricity system. In principle, appropriately designed markets will provide the incentives needed to cost-effectively integrate intermittent power generation in both the short and the long run. The key challenges involved in future electricity market design therefore pertain to designing requisite market mechanisms— such as pricing aspects of flexibility – that incentivise the provision of flexibility in the system. A transparent and coherent market-based mechanism, we argue, will facilitate efficient investments towards securing the long-term stability and reliability of the Swedish electricity system.

Our main objective is to identify knowledge gaps and to suggest the most fruitful future research directions for the Swedish context. Most environmental or energy policy/market proposals and debates are largely based on *ex ante* analysis. Unfortunately, there is little *ex post* assessment of performance of environmental-energy policies and related markets. The lack of *ex post* analyses is likely to hinder effective policy making in many ways, in particular by making it difficult to identify (specific aspects of) prior policies that have proven (in)effective. Hence, a complete *ex post* assessment of the Swedish wholesale and balancing market functioning is crucial to determine the effectiveness of these markets in attaining their major objectives. An assessment of these markets will help understand the degree to which the current market design manages to efficiently integrate intermittent sources, and identify potential improvements to these markets to enhance their ability to cost-effectively integrate increasing amounts of intermittent generation. We identify relevant research directions for analysing the Swedish electricity markets in relation to pricing flexibility, "scratch the surface" of available data sources and, based upon analysis of these data, provide answers to some of our suggested research questions.

To the best of our knowledge, there is no study that scrutinizes intraday price formation and price premium in the Swedish intraday market. In principle, the intraday price premium, defined as the difference between intraday price and day-ahead price, should be positive, since the added flexibility obtained by postponing the transaction closer to the delivery hour is presumably valuable. However, we find that, on average, the hourly intraday premia are negative in all Swedish electricity pricing zones over the previous five years. Furthermore, premia tend to decline in all Swedish electricity bidding zones. Both aspects are puzzling from a market design standpoint. We suggest that it is crucial to understand why these premia have been decreasing and why the provision of flexibility afforded by this close-to-real-time market has not been rewarded. For this purpose, we recommend analysing price asymmetries in this market by using state-of-the-art econometric models. We also show that there is an apparent discrepancy between theoretically expected trading volume and actual trading volume; this may imply that liquidity on the Swedish intraday market is still low. We believe it is important to better understand why liquidity is so low in this market, and why, in view of wind

generation being the major intermittent generation source, this market does not reflect the development of absolute wind forecast error. If market participants prefer to use other strategies to reduce their imbalances, it is important to understand what these strategies are and whether they are cost-effective.

On the balancing market side, we also find some unexpected results, which should be further investigated. First, trading volumes on the Swedish balancing market have not been growing and have in fact tended to decline, while wind power generation capacity has been increasing rapidly. With decreasing up-regulation premia and volumes, investment in this key flexibility-related market may decline in the future. We further stress the importance of future *ex post* research to better understand how the increasing absolute wind forecast error is absorbed by the electricity market. Better understanding of this relationship may have significant implications for the design of balancing markets for the future.

Altogether, the increasing share of intermittent power generation has not to date challenged the flexibility of the Swedish power system in any substantial way, thanks to abundant hydro-power generation. However, with less or no base-load nuclear power generation, the increasing share of variable renewable power may exert greater pressure on Swedish markets for flexibility. Thus, the phase-out of nuclear power plants is one of the biggest challenges for the whole Swedish electricity system. To understand the potential consequences of this phase-out for the Swedish balancing and other flexibility-related markets, one suggestion is to examine impacts of actual forced and planned nuclear power plant outages on the Swedish electricity markets.

Our additional suggestions for relevant research directions for analysing the Swedish electricity markets in relation to pricing flexibility are summarised below:

- There is a need to better understand and estimate the required incentives (costs) for technological change to unlock additional flexibility in the Swedish electricity system by analysing international experience.
- For electricity market participants trading in sequential markets with differences in price levels and risk exposure, it is relevant to analyse the potential benefits and willingness of energy firms to coordinate their bidding across these markets by having single trading platform.
- Given the inconclusive results on the effects of intermittent power generation on electricity price volatility, there is a clear need for more detailed *ex post* analysis of the Swedish and Nordic electricity markets.
- Previous empirical studies aiming to identify effects of intermittent power generation on day-ahead electricity prices mainly focus on short-run, largely weather-driven, fluctuations in intermittent power output. This approach is not useful to understand the long-term effects, i.e. how capacity additions to intermittent power affect the markets. Consequently, there is a need for studies evaluating the capacity effects of intermittent power generation.
- There is a need to examine how the power price response varies *across hours* of the day and across seasons. Ultimately, this could allow us to better understand how intermittent power generation developments affect power prices and profits of different kinds of power plant generators that operate during a subset of hours.

- Investigating the past profitability of the Swedish power producers to obtain better understanding of the incentives for current and future investments into different types of power generating technologies.
- The overall effect of more volatile but lower average power prices on the profitability of different power generating technologies remains unclear, and needs more investigation.
- Electricity markets are subject to market distortions and failures, such as different types of subsidies for renewable energy resources or specific power generating technologies. The effects of these distortions upon the Swedish wholesale and balancing markets need to be investigated.

List of content

Introduction[1]

Background and motivation

In 2016, the Swedish Parliament decided that by 2040, at the latest, Sweden will have a 100 percent renewable electricity production system. This means that renewable electricity generation in the form of bioenergy and intermittent power, such as wind and solar power, have to be significantly expanded in order to replace non-intermittent sources such as nuclear power. In any case, the share of generation from intermittent sources will need to rise from approximately ten percent today to about 40-50 percent in 2040. It is expected that this will have considerable effects on the Swedish electricity markets in the sense that it will require a substantial increase in the demand for flexibility, i.e. the ability of the overall electric system to respond to changes in the balance between supply and demand.

Given the 100 percent renewable electricity target for Sweden and the recent significant technological transformation in the Swedish electricity system, there is a need to re-evaluate the design of markets responsible for flexibility. Two particular questions will need to be answered for assessing the design aspects of energy markets: first, whether, and if so how, should they be modified to accommodate the increasingly intermittent nature of power generation; and second, how can more efficient trading of intermittent energy sources be achieved.

Our main objective and goals

This report provides an overview of the existing knowledge base arising from both the actual experience in the Swedish (and other countries') electricity markets and leading academic research, with a view, ultimately, to answering the questions posed above. Our **main objective** is to identify knowledge gaps and suggest relevant research directions for analysing the Swedish electricity markets in relation to pricing flexibility.

To achieve our key objective, our report mainly focuses on three goals:

- First, describing **recent trends and developments** in the electricity market design, with a particular focus on Sweden;
- Second, providing an overview of the academic literature and a preliminary data analysis of the Swedish electricity markets where, we believe, relevant **knowledge gaps** exist;
- Third, identifying **future research directions** that, in our view, may be followed by academics and market practitioners alike to yield insights directly applicable to the question of electricity market design for Sweden.

[1] We thank Nils-Henrik M. von der Fehr, Richard Green and Michael Pollitt for their advice and suggestions, which we received before starting writing this report. We are extremely grateful to the members of the Steering Committee of the EFORIS research program for their detailed and constructive comments and suggestions. We also greatly benefited from the discussions with members of CERE and Chloé Le Coq. We are solely responsible for all remaining errors and mistakes.

Our focus

This study mainly focuses on the existing Swedish markets for **flexibility** and how these markets have coped so far with integrating the increasing share of intermittent renewable energy sources, largely **wind power** for Sweden. By flexibility we mean the ability of the power system to respond to rapid changes in power consumption and production. This study therefore does not address certain aspects, including: flexibility across all elements of the Swedish power system (for example, the transmission grid); the overall adequacy of the entire power system; questions of whether the current market design can achieve "sufficient" reliability; and the costs and benefits of integrating a higher share of intermittent renewable energy sources in the near future (which is an explicit policy goal and is taken as given).[2]

We argue that markets constitute the most natural means of providing flexibility to the electric system and that, in principle, well-functioning markets should be able to provide the right incentives for balancing power supply and demand both in the short and long term. The report focuses on **Swedish energy-only markets**, their recent design trends, developments and actual performance in integrating wind power in electricity mix. The transformation of the Swedish electricity markets cannot be analysed separately from Nordic-Baltic markets or even an increasingly integrated European electricity market context. Where necessary, therefore, experience from other European power markets is discussed.

Ex ante vs. ex post

Most environmental or energy policy/market proposals and debates are largely based on *ex ante* analysis. Unfortunately, there is little *ex post* assessment of performance of environmental-energy policies and related markets. The lack of *ex post* assessment is likely to hinder effective policy making in many ways, in particular by making it difficult to identify (specific aspects of) prior policies that have proven (in)effective. Hence, a complete *ex post* assessment of the Swedish wholesale and balancing market functioning is crucial to determine the effectiveness of these markets in attaining their major objectives. An assessment of these markets will help understand the degree to which the current market design manages to efficiently integrate intermittent sources, and identify potential improvements to these markets to enhance their ability to cost-effectively integrate increasing amounts of intermittent generation. We identify relevant research directions for analysing the Swedish electricity markets in relation to pricing flexibility, "scratch the surface" of available data sources and, based upon the analyses of these data, provide answers to some of our suggested research questions.

[2] Some of the related issues are analysed and discussed in a parallel study by Bergman and Le Coq (2019) within the same EFORIS program. These issues include "missing money problem," appropriate capacity mechanisms for Sweden, financial markets for hedging electricity price risks, the continuing integration of the Swedish electricity markets into European electricity markets, the role of transmission and distribution system operators, design of renewable energy support systems and other relevant issues for safeguarding security of supply.

Structure of the report

In the first part of this report, we provide an overview of the major developments related to intermittent renewable electricity in Sweden, and explain the main policies that have shaped these developments. In the second part, we discuss the specific question of flexibility, using data on the Swedish system (in)flexibility and experience of accommodating intermittent renewable energy so far. In the third part of this report, we briefly review the structure of electricity markets for flexible power generation. Finally, in the fourth, fifth and sixth parts of the report, we analyse flexibility pricing issues in the Swedish day-ahead, intraday and balancing markets, respectively.

1 The developments of VRE generation in Sweden

In this part of the report, we review the latest developments in variable renewable electricity (VRE) generation in Sweden (section 1.1) and explain the main renewable energy targets (sections 1.2) and policies (section 1.3) that have shaped these developments. Finally, we discuss the future of VRE expansion in the context of the changing policy environment and the increasing likelihood of Swedish nuclear power capacity phase-out after the year 2040 (section 1.4).

1.1 VARIABLE RENEWABLE ELECTRICITY GENERATION IN SWEDEN

Figure 1.1 shows a composition of electricity production (net) in Sweden from 1970 to 2016. It is evident that most electricity in Sweden has been produced by hydropower and nuclear power generators. For instance, during the period 2006-2016, on average, hydropower and nuclear power constituted 45% and 40% of total electricity production, respectively. The share of wind power increased from 0.7% to 10.2% over the period. Projecting the current generation from VRE (detailed in sec 1.2), and assuming that total generation will remain at about 150 TWh per year, it is likely that the contribution of wind generation will increase to 20% by the end of 2020 and to 30% by the end of 2030.

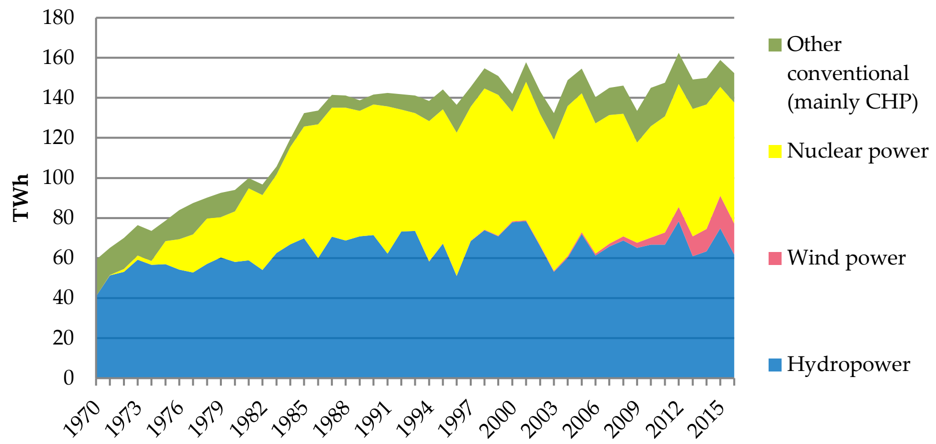

Figure 1.1. Electricity production mix in Sweden, 1970-2016

Sources: Swedish Energy Agency (2018a) and own calculations.
Note: The production of electricity used for own consumption is not included.

Figure 1.2 shows that the share of installed wind power capacity is higher than the share of wind power generation in Sweden. For instance, in 2016, the share of installed wind power capacity was 16.3%, while the share of wind power was only 10.2%. These statistics reveal the fact that wind is a variable source of energy, meaning that operating wind turbines do not produce electricity at all times. This explains why capacity factors of wind turbines are much lower than those of conventional electricity generating technologies. In general, the capacity factor tells how much wind power a wind turbine can generate in a year compared to its nameplate capacity.

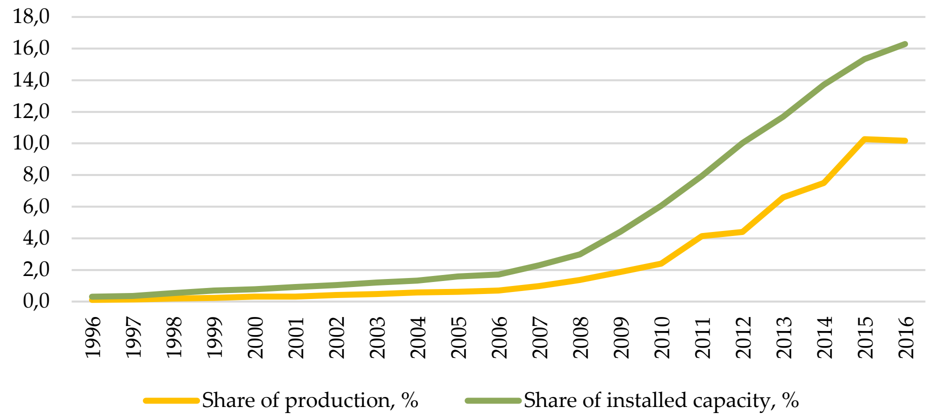

Figure 1.2. Shares of wind power capacity and production, 1996-2016

Sources: Swedish Energy Agency (2018a) and own calculations.

In Figure 1.3 we present a roughly estimate of aggregate annual capacity factor for Sweden during the period 2006-2016. Over this period, the aggregate capacity factor has increased from 19.5% to 27.1%. If we assume that, on average, weather conditions are the same throughout the years, this change of almost 8% in the capacity factor reveals the fact that utilization of wind turbines does not only depend on wind conditions but also on technical design features of wind turbines. We expect that the average capacity factor of the Swedish wind power park will increase in the near future as technical characteristics of recently approved wind power parks imply much higher capacity factors, many of them ranging between 40-50% (Swedish Energy Agency, 2018b).

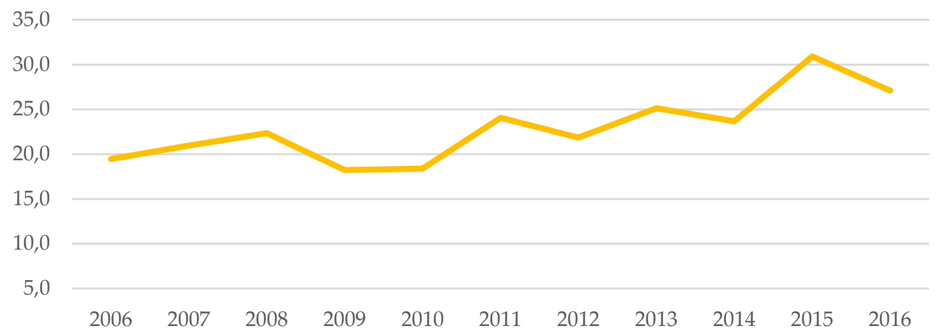

Figure 1.3. Capacity factor of installed annual wind power capacity in Sweden, 2006-2016

Sources: Swedish Energy Agency (2018a) and own calculations.

1.2 RENEWABLE ELECTRICITY TARGETS AND PROGRESS IN ACHIEVING THEM

In Sweden as well as in the other EU countries, the major support for VRE generation was initiated by the EU Directive 2001/77/EC (European Parliament and Council, 2001) and kept going with the so-called "20-20-20" climate change and energy sustainability goals in the Europe 2020 strategy (European Commission, 2010). Consequently, a number of other EU directives have come into force related to VRE support and promotion.

With respect to the production and promotion of energy from renewable sources in the EU, the Renewable Energy Directive 2009/28/EC requires the EU to fulfil at least 20% of its total energy needs with renewables by 2020 – to be achieved through the attainment of individual national targets (European Parliament and Council, 2009). The Directive specifies national renewable energy targets for each country, taking into account its starting point and overall potential for renewables. These targets range from a low of 10% in Malta to a high of 49% in Sweden. EU countries set out how they plan to meet these targets and the general course of their renewable energy policy in national renewable energy action plans.

The Swedish Parliament has adopted a *national* overall target for renewable *energy* of 50%, i.e. one percentage point above the binding national target in accordance with the Renewable Energy Directive 2009/28/EC (Government Offices of Sweden, 2010). In the context of renewable *electricity*, the initial opinion of the Government of Sweden was that the share of renewable energy in electricity consumption, defined as gross final consumption of electricity from renewable sources divided by gross final consumption of electricity, should be at least 63% (8 356 ktoe or 97.2 TWh). According to Sweden's progress reports with respect to the Renewable Energy Directive 2009/28/EC, the overall Swedish renewable *energy* target was reached in 2012, whereas the target of renewable energy in the area of *electricity* was achieved in 2014 (Government Offices of Sweden, 2013, 2015).

Despite this, the Government of Sweden has continued with ambitious climate and clean energy goals and, in June 2016, it announced the new national climate policy framework, which has the long-term aim that Sweden will have net zero emissions of greenhouse gases (GHG) into the atmosphere by 2045. This goal will be supported by more efficient energy use and Sweden's transition to a carbon-free energy system. More specifically, the aim is to increase energy efficiency by 50%, i.e. a decrease of energy use per unit of GDP by 50%, by 2030 compared to 2005, and to reach 100% renewable electricity production by 2040.

The specific goals for new renewable electricity generation are set out in the context of the Act on Electricity Certificates which in May 2003 established a Swedish tradable green certificate (TGC) scheme to support the expansion of electricity production from renewable energy sources and peat (Sveriges Riksdag, 2003). The current Swedish national goal is to finance 30 TWh of new renewable production by 2020 compared to the year 2002 (Sveriges Riksdag, 2011).

The Swedish TGC scheme was enlarged by the entry of Norway into the scheme in January 2012 (Sveriges Riksdag, 2011). Since then, Sweden and Norway have a common market for tradable green certificates and a common target, which initially was to expand the production of renewable electricity in the order of 26.4 TWh from January 2012 until the end of 2020. In April 2015, this common target was increased by an additional 2 TWh to 28.4 TWh. Norway agreed to finance 13.2 TWh of renewable electricity expansion, whereas Sweden – 15.2 TWh. Note that renewable electricity generating units that started operating before January 2012 and are eligible for receiving tradable green certificates are not contributing to this common target, but rather to the national one.

In June 2017, the Act on Electricity Certificates 2011 was updated to expand the Swedish national target by additional 18 TWh from 2022 till 2030 (Svensk författningssamling, 2017). The enhanced ambition will be financed by Sweden. This also means that, in principle, the TGC scheme in Sweden should be extended until 2045.

According to the Norwegian Water Resources and Energy Directorate and Swedish Energy Agency (2018), from the beginning of 2012 to the end of 2017, 20.3 TWh of new expected renewable electricity was generated under the common Swedish-Norwegian TGC scheme. This means that only 8.1 TWh are left to achieve the common target of 28.4 TWh by the year 2020.

The national target of 30 TWh by 2020 is also within reach. In 2017, 24.1 TWh of Swedish renewable electricity production were financed by the TGC system (Swedish Energy Agency, 2018a). Also, it is expected that the new national target of additional 18 TWh between 2021-2030 will be achieved well ahead in time. Therefore, in June 2017, the Swedish Energy Agency received an assignment from the Ministry of the Environment and Energy (2017) to propose a "stop-mechanism" related to the new 2030 target (*in Swedish*, stoppmekanism kopplad till det nya målet 2030). This assignment should be completed by the end of the year 2018 and it is expected that the rules concerning the "stop-mechanism" will be announced in spring 2019.

1.3 MAJOR POLICIES FOR PROMOTION OF RENEWABLE ELECTRICITY EXPANSION IN SWEDEN

Renewable electricity generation in Sweden has been promoted by a mix of policies for almost three decades. Some of these policies are national, some are regional, while others are established at the EU level. In the Swedish National Action Plan for the promotion of the use of renewable energy in accordance with Directive 2009/28/EC (Government Offices of Sweden, 2010), it is stated that "*General economic instruments, such as carbon dioxide tax, international emissions trading and certificates for renewable electricity are fundamental to the long-term energy policy*." In what follows, we provide a brief overview of these policies.

1.3.1 The Swedish TGC scheme and the common Swedish-Norwegian TGC scheme

The Swedish TGC system came in to force on 1 May 2003. In January 2012, Norway joined the market (the national Swedish and the common Swedish-Norwegian targets and progress in reaching those targets are described in section 1.2). Renewable electric capacity installed after 1 May 2003 receives TGCs for a maximum of 15 years (one TGC for each MWh of renewable electricity produced). Electricity retailers and energy intensive industries are obliged to buy a certain share of TGC in relation to their total electricity sales or consumption, respectively. The percentage requirement (see Figure 1.5) is given by law for every year until the system ceases (Sveriges Riksdag, 2003).

TGCs are registered on renewable electricity producers' on-line accounts in Cesar (Swedish registry) and NECS (Norwegian registry). TGCs are traded either directly between two parties, such as electricity producers and/or electricity retailers, or through brokers. Each issued TGC is valid until the system ceases, meaning that both renewable electricity producers, and retailers that are obliged to meet their individual TGC quotas, and other third parties can store and trade TGCs at a later point in time.

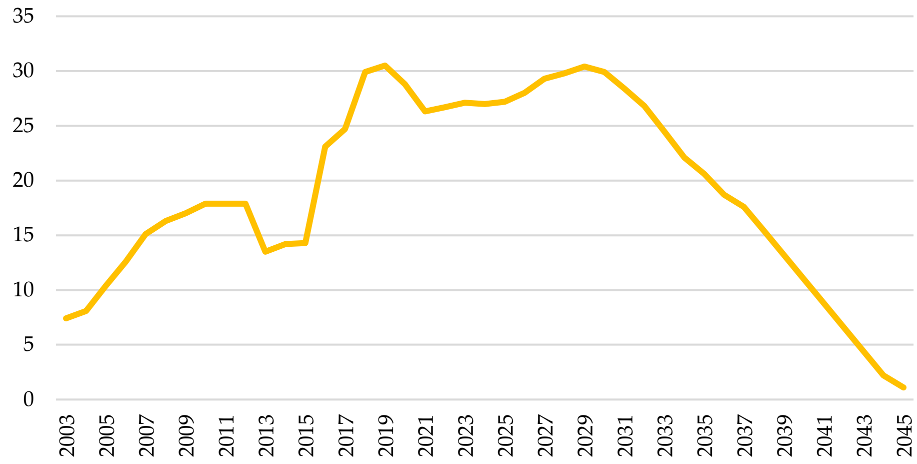

Figure 1.4. Required share of power consumption from renewable sources since the implementation of the Swedish TGC system

Source: Swedish Energy Agency (2019).

Currently, market participants have information on TGC prices from two sources: two national TGC registries (Cesar and NECS) and various brokers (e.g., Svensk kraftmäkling). A market TGC price provided by brokers gives an indication of the value of TGCs for a given period. An average volume-weighted registry TGC price reflects the value of TGC transactions registered during a historical period. Thus, the registry TGC price cannot be treated as the market TGC price (Swedish Energy Agency, 2017). Because of this, many market participants have been using the market TGC price as a reference price.

In September 2018, the average monthly spot price of TGCs stood at SEK 250 (see Figure 1.5). It is noticeable that TGC price was much lower in 2017 and during the first three months of the year 2018, when the average monthly sport price of TGCs was at SEK 66 and SEK 86, respectively. This drop in TGC price could be explained by market expectations that the national and common Swedish-Norwegian targets for renewable electricity generation will be reached sooner than later. On the other hand, this does not explain the recovery of TGC price since mid-2018. We argue that this price development could be explained by a surge in price of carbon in the

EU – it increased from around EUR 8 in January 2018 to around EUR 21 in September 2018. This might suggest that the regional Swedish-Norwegian TGC market is more tied together to the EU ETS market than initially assumed. Certainly, this claim requires deeper empirical investigation. Some interesting analytical insights related to the relation between the EU ETS and Swedish-Norwegian TGC markets are provided in a study by Schusser and Jaraitė (2018).

Figure 1.5. Dynamics of TGC spot monthly average price in SEK, January 2005 – September 2018

Source: Svensk Kraftmäkling (http://www.skm.se/priceinfo/history/).

Figure 1.6 presents the developments of new renewable electricity production which was financed by the TGC system from 2003 until 2017. It is evident that, in 2017, 24.1 TWh were produced by renewable electricity generators. Most of this electricity was generated by wind mills – 17 TWh. Electricity generation based on bio fuels is the second largest renewable electricity source financed by the TGC system, although it has been shrinking since 2013. From Figure 1.6 it is also clear that even though the TGC system is technology neutral, meaning that it provides the same level of support to electricity produced by various renewable electricity generators, only negligible amount of solar power (74 GWh in 2017) was financed by the TGC system. This development could be explained by the fact that costs of solar power technologies are still rather high and that the current price of TGC certificate is too low to encourage significant solar power expansion. Acknowledging this, Sweden has introduced additional subsidies to support electricity generation by solar power.

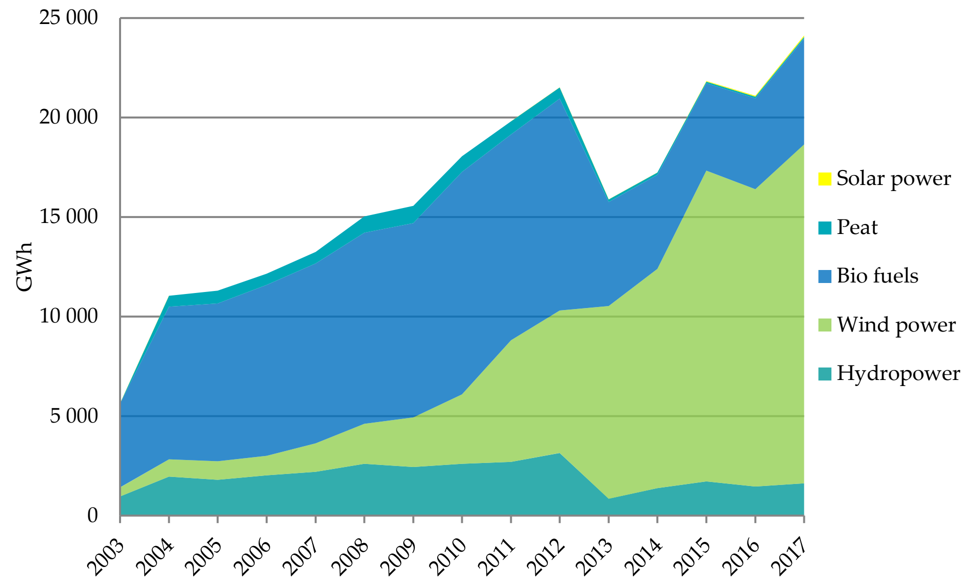

Figure 1.6. Renewable electricity production in Sweden financed by the TGC system, 2003-2017

Source: Swedish Energy Agency (2018a)

1.3.2 The EU ETS

As a member state of the EU Sweden has been covered by the EU's Emissions Trading System (EU ETS) since January 2005. The EU ETS is one of the largest downstream cap-and-trade schemes in the world. A "cap" is set on the total amount of certain GHG emissions that can be emitted by the largest GHG emitters in the system. The cap is reduced over time so that total GHG emissions fall. Within the cap, firms receive or buy emission allowances (EUA) which they can trade with one another as needed. The limit on the total number of EUAs available in the market ensures that they have a value.

The EU ETS is a downstream emissions trading system regulating the direct sources of GHG emissions including energy intensive industries, power plants, and other combustion installations with a rated thermal input exceeding 20 MW (European Parliament and Council, 2003). It covers about 12,000 installations, representing approximately 50% of the EU's GHG emissions.

In Sweden, the main sectors included in the EU ETS account for 35% of the country's total CO_2 emissions (Löfgren et al., 2014). These sectors correspond to the energy sector (15% of total Swedish CO_2 emissions), the metal industry (8%), the mineral industry (6%), refineries (4%), and the pulp and paper industry (3%). According to Jaraitė et al. (2013), in 2012 the number of Swedish installations included in the EU ETS was 853, corresponding to 264 firms as some firms owned several installations.

The EU ETS is organized into trading phases: the first was from 2005-2007, the second period, corresponding to the commitment period of the Kyoto Protocol, was from 2008-2012. The third trading period runs from 2013-2020; and the fourth trading phase starts in 2021 and will continue until the end of 2030. Today, there is a clear communication from the European Commission that the EU ETS should remain a key instrument to achieve additional carbon emission reductions as suggested in in the EC’s low-carbon economy roadmap (European Commission, 2011).

The EU ETS is now in the third phase, which is rather different from phases 1 and 2. In phases 1 and 2, an EU-wide cap on emissions was a product of national caps. In phase 3, a single harmonized EU-wide cap is set centrally. Another important feature of phase 3 is that auctioning is the default method for allocating allowances (instead of free allocation in phase 1 and 2), and harmonized allocation rules apply to the allowances still given away for free.

In phase 3, 636 industry installations in Sweden have been allocated free emission allowances. No free allocations has been given to Swedish power generators which have been covered by the EU ETS since the start of the cap-and-trade mechanism (IEA, 2013). The rationale for removing free allocation for power generators is based on the fact that, in terms of CO_2 emissions, power generation is the largest sector in the EU ETS. According to the conventional wisdom, the power generating sector is credited with having most of the low-cost emission abatement opportunities in the EU ETS. This, and the fact that power generation is not directly exposed to international competition– allowing for passing on of additional costs to consumers without loss of output and market share – are the main reasons why, in phase 1 and 2, many EU member states allocated fewer allowances to this sector compared with the other sectors covered under the EU ETS, and why, in phase 3, auctioning was introduced as the default method for allocating allowances for the power generating sector.

Figure 1.7 shows the development of the spot price of carbon dioxide allowances measured in EUR per ton of CO_2. On the 22th of October, 2018, carbon price stood at 19 EUR/tCO_2 and it is expected that it will remain at this level or even higher throughout phases 3 and 4 since the cap on GHG emissions is made tighter every year. Currently, the overall number of allowances declines at an annual rate of 1.74%. From 2021 onwards, the annual rate will be 2.2%.

Another important factor that has recently sustained the price on CO_2 emissions are short- and long-term measures – namely, “back-loading” of auctions and a market stability reserve – that have been (and will be) dealing with a surplus of emission allowances in phases 3 and 4. The surplus of allowances is largely due to the economic crisis (which reduced emissions more than anticipated) and high imports of international credits. This has led to lower carbon prices and thus a weaker incentive to reduce emissions. The market stability reserve, which started operating in January 2019, has to objectives: to address the current surplus of allowances and to improve the EU ETS’ resilience to major shocks by adjusting the supply of allowances to be auctioned. The reserve operates entirely according to pre-defined rules that leave no discretion to the Commission or EU member states in its implementation (for more see European Commission, 2019).

Figure 1.7. Carbon price in the EU ETS, from 7 April 2008 to 22 October 2018

Source: https://sandbag.org.uk/carbon-price-viewer/.
Notes: Closing ECX EUA Futures prices, Continuous Contract #1. Non-adjusted price based on spot-month continuous contract calculations. Raw data from ICE via Quandl.

1.3.3 The Swedish carbon tax

A Swedish carbon tax was implemented in 1991, alongside an already existing energy tax, and it remains a cornerstone of Swedish climate policy. Over time, the carbon tax has increased in importance, contributing to a broad range of environmental and climate objectives. For example, it provides incentives to reduce energy consumption, improve energy efficiency and increase the use of renewable energy.

The carbon tax is levied on all fossil fuels in proportion to their carbon content, as carbon dioxide emissions released in burning any fossil fuel are proportional to the carbon content of the fuel. It is therefore not necessary to measure actual emissions, which greatly simplifies tax administration. Emissions from combustion of biofuels are not taxed, based on the assumption that biofuels are carbon neutral.

The carbon tax was introduced at a rate corresponding to SEK 250 (EUR 26) per ton of fossil carbon dioxide emitted, and has gradually been increased to SEK 1 150 (EUR 120) in 2018 (Government Offices of Sweden, 2018). By increasing the tax level gradually and in a stepwise manner, households and businesses have been given time to adapt, which has improved the political feasibility of tax increases. Since the tax is very high (World Bank, 2018) and Sweden is a small open economy, there has been quite some concern about the competitiveness of some energy-intensive industries and, hence, a series of reduced tax rates have been applied to sectors that are open to international competition. For example, Brännlund and Lundgren (2010) show that during the period 1990–2004, the effective carbon tax rate was on average 11 EUR/tCO_2; the carbon tax varied considerably across sectors, ranging from about 4 EUR/tCO_2 in the wood product sector to almost 15 EUR/tCO_2 in the food sector.

Since January 2011, the entire Swedish industry within the EU ETS has been fully exempt from the carbon tax. The same exemption has applied to combined heat and power production (CHP) from 2013 onwards. From 2005 to 2012, some partial exemptions applied. For instance, in 2012, CHP plants only paid 7% of the carbon tax (for more details see IEA, 2013). A lower tax rate has historically been applied to industry outside the EU Emissions Trading System (EU ETS). As of 2018, however, the industry rate outside the EU ETS is the same as the general rate (Government Offices of Sweden, 2018).

The carbon tax is imposed "upstream" in the fossil fuel supply chain regulating firms that produce or import fuels that generate carbon dioxide emissions. Therefore, though the tax applies to the fuel used by most industrial and energy-producing activities in the economy, the carbon tax is only filed and paid to Skatteverket (the Swedish tax authority, STA) by firms referred to as authorized warehouse or stock keepers. In 2012, according to Coria and Jaraitė (2018), there were 223 firms registered as authorized warehouse keepers by the STA. These firms sell fuel to final consumers, adding the carbon tax to the price their customers pay. They may use fuel themselves too, paying the tax payments related to their consumption.

1.4 THE FUTURE OF VRE GENERATION

From a reading of different reports regarding the future expansion of VRE in Sweden, it is evident that there is a good amount of clarity regarding major developments and policies until 2030. Given the targets of renewable electricity and assuming that wind power will largely be the technology fulfilling these targets, it is reasonable to predict that the share of wind power in the total electricity production in Sweden will be close to 30% by 2030.

It is more difficult to predict the generation mix in Sweden beyond 2030 since there are many uncertainties in place, such as: the timing of the full phase-out of nuclear power capacity; the policies in place to support further expansion of VRE; technological developments affecting the costs of wind and other VRE technologies; and finally, the societal acceptability of the increasing number of onshore wind turbines.

Nevertheless, despite these uncertainties, it is anticipated that the capacity of wind power will continue increasing even beyond 2030. For instance, the modelling exercise in a recent report from the IEA and NER (2016) shows that the greatest increase in electricity production capacity is seen for wind power. This growth can be supported even further by increasing flexibility through various flexibility sources. Especially, adding local flexibility options makes it easier to balance wind power locally, which leads to fewer investments in the internal Swedish power grid. Table 1, which summarizes some of the results from this report, shows that under Baseline scenario by 2040 wind power capacity will measure 18 656 MW, by 2050 – 23 156 MW.

Table 1. Simulated wind power capacity in Sweden, 2020-2050

Year	Scenario	Onshore, MW	Offshore, MW
2020	Baseline	5 210	215
	Flex	5 210	215
2030	Baseline	11 514	215
	Flex	14 943	215
2040	Baseline	18 656	215
	Flex	24 072	215
2050	Baseline	23 156	215
	Flex	31 377	215

Source: Adapted from IEA and NER (2016, p. 170).
Notes: In Baseline scenario, a range of flexible technologies are available: co-generation plants, large heat pumps, heat storage in district heating systems and hydrogen storage. In Flex scenario, flexibility is increased by introducing flexible demand from buildings, industry, transport and fuel production. Under both scenarios it is assumed that nuclear power will be phased out after 2040.

Figure 1.8, which shows the simulated composition of electricity generation in Sweden, underlines the importance of wind power after the Swedish nuclear fleet is expected to live out its technical lifetime after 2040. This development shows that in 2040 the share of wind in the Swedish generation mix will be 24% and it will increase to 41% in 2050. In other words, it is expected that wind power will fully replace nuclear power in a 30-year time horizon. This scenario relies on the assumption that some flexibility measures will already be in place (see notes regarding Baseline scenario under Table 1) meaning that the future expansion of wind generation significantly depends on investments in various flexibility measures.

In the next part of this report, we review the current status of flexibility in the Swedish power system and analyse data on the (in)flexibility issue in relation to rapid expansion of VRE and flexibility potential in Sweden. The following major questions are addressed in the next part: (i) Are there any signs that the current Swedish electricity system has difficulties in integrating the rapidly increasing share of wind power? (ii) Is the current system flexible enough and, if not, what aspects of electricity markets may be modified to enhance flexibility?

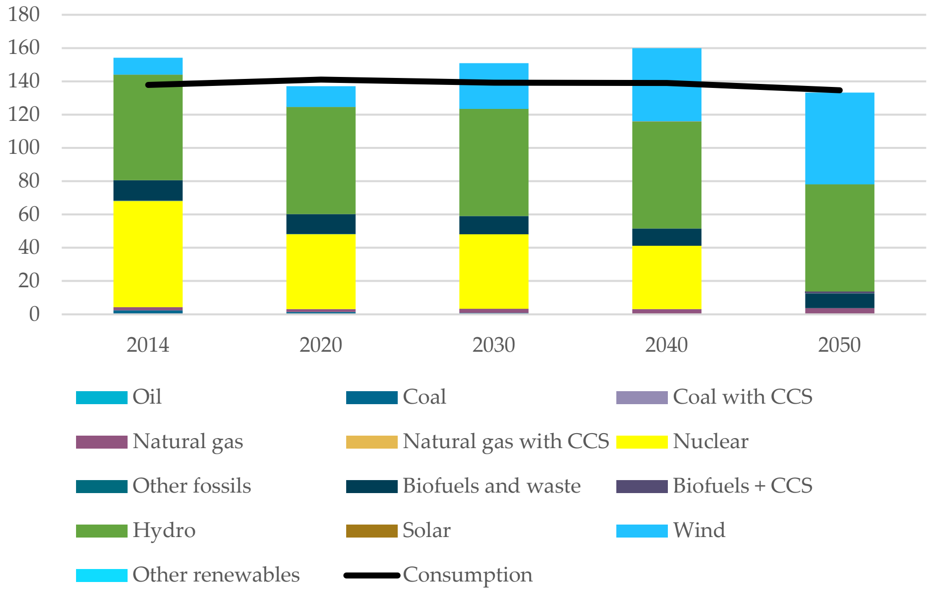

Figure 1.8. Simulated development of electricity generation in Sweden, 2014-2050

Source: Adapted from IEA and NER (2016, p. 173).

Notes: In this scenario (CNS-B), a range of flexible technologies are available: co-generation plants, large heat pumps, heat storage in district heating systems and hydrogen storage. It is assumed that nuclear power in Sweden will be phased out after 2040.

2 The status of power system (in)flexibility

The technology mix in Sweden and the neighbouring countries is dominated by hydropower, which provides regulating and balancing services for the relatively low current level of VRE. Therefore, flexibility is not at present a major issue in Sweden. However, as we wrote in the first part of the report, VRE are expected to play an increasing role in the years to come, especially after the anticipated closure of nuclear plants. This will increase the demand for more flexible power system. However, it is worth asking if one can detect signs indicative of a strain on the *current* power system consequent to increasing wind power generation. If so, these signs can provide some suggestive indications for the power system's flexibility in the near future, if regulatory frameworks remain similar. Thus, in this part of the report, we briefly overview several important indicators of (in)flexibility of the current Swedish power system (sections 2.1–2.4) and discuss the potential of flexibility resources in Sweden (section 2.5).

As the signs of power system inflexibility are somewhat easier to detect than the ones of flexibility, we investigate the following three potential signs of inflexibility[3] in the Swedish power system:

1. The increasing **demand for power ramping capacities** in relation to higher wind penetration.
2. Difficulty balancing electricity power demand and supply, resulting in **frequency excursions**.
3. **Price volatility** and increasing occurrences of **negative market prices,** which may indicate limited system flexibility in terms of availability of ramping (up or turning down) and limited demand flexibility.

2.1 INCREASING DEMAND FOR SYSTEM RAMPING CAPABILITIES

VRE generation can increase the need for flexibility in the electric system. If wind power generation is low during hours when the demand for power increases very steeply (e.g., the early hours in the mornings), then there is a greater demand for *ramping up* capabilities, exerting pressure on a system that may not be ready for significant power variation. "Ramping" means the ability of generating facilities to start and stop power generation on command. This type of flexibility feature in generating units is essential in managing variability in power loads.

In the case of no wind power, conventional generators must be ready to ramp up power. An impact of wind power unavailability in the early morning hours on the system operation is indicated in Figure 2.1. This figure shows the net load (i.e. the total load minus wind generation) *changes* between 5am and 6am at monthly extremes, which can be interpreted as the maximum need for ramping-up capabilities. Figure 2.1 shows that the potential need for ramping-up capabilities

[3] Significant VRE curtailments, which occur when VRE generation is not needed, can also be viewed as yet another sign of inflexibility of the system. However, to our knowledge, VRE curtailments are very rare in Sweden, and so curtailment is not further discussed in this report.

has been increasing. For example, in one particular day in December 2017, between 5am and 6am, if no wind power had been produced during this specific hour, the system operator would have to be able to ramp power up by as much as 2 500 MW within that hour, while in January 2011, the maximum need for ramping-up capabilities between 5am and 6am stood at around 2 200 MW.

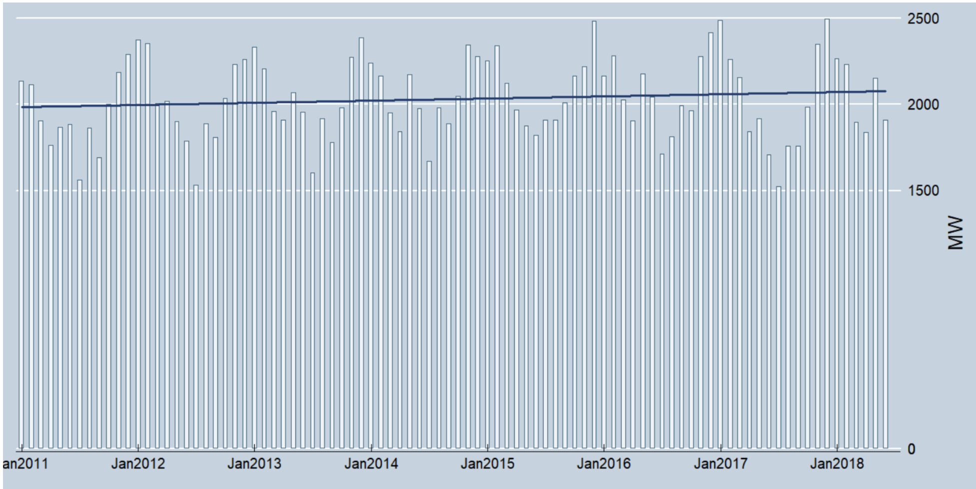

Figure 2.1. Monthly maximum need for ramping-up capabilities to meet net load between 5am and 6am (if wind is not available at that time).

Sources: Based on own calculations using the data from the Swedish Energy Agency.

2.2 GRID FREQUENCY EXCURSIONS

Another potential indicator of increasing inflexibility in the Swedish power system can be a difficulty in balancing electricity demand and supply in real time, resulting in frequency excursions or deviations from the fixed frequency of supply. At all times, the power supply and demand for electricity have to be in balance and the electrical frequency of the grid has to be kept close to 50 Hz. The difficulty of balancing demand and supply results in frequency deviations from the nominal 50 Hz value. Grid frequency deviations are harmful not only for consumer electric appliances but especially to thermal power plants and various industrial activities. If grid frequency drops too low, some of these plants will be forced to disconnect from the grid in order to protect their machinery. If this is a case, it will cause further drop in electrical frequency resulting in further excursions of grid frequency due to the increased mismatch between supply and demand. This situation can lead to eventual controlled blackouts. Thus, frequency deviations are an important measure of power system operating flexibility and reliability. The objective of grid frequency control is to make sure that this does not happen.

With increasing VRE penetration, there appears to be growing challenges for grid frequency control. The deviations of the Nordic grid frequency have been gradually increasing during the last decades. Figure 2.2 shows that the balancing control quality of the Nordic countries has been declining. If this trend continues, this can become a challenge for system operators' ability to maintain reliable operations (Nordic TSOs, 2018).

There are a few explanations for the increasing frequency deviations. For example, according to Weissbach and Welfonder (2008), increasingly deregulated wholesale electricity markets have led to more activity on the supply side (starts and stops), especially around hour shifts, since electricity is bought and sold in blocks of one hour. These step-wise power changes lead to greater power imbalances around the hour shifts causing large unintended frequency deviations with a negative impact on the control performance of power plants and power system. According to Saarinen (2014), another potential reason for these larger deviations is that the share of VRE has increased in the overall power supply and that has exacerbated the above-mentioned effect of the deregulation of wholesale electricity markets. Thus, frequency quality is predicted to decline in the future due to the expected increase in power generation from intermittent energy sources and due to the expected decline in both flexibility capacity and inertia (Copenhagen Economics, 2017; Fingrid, 2016).[4]

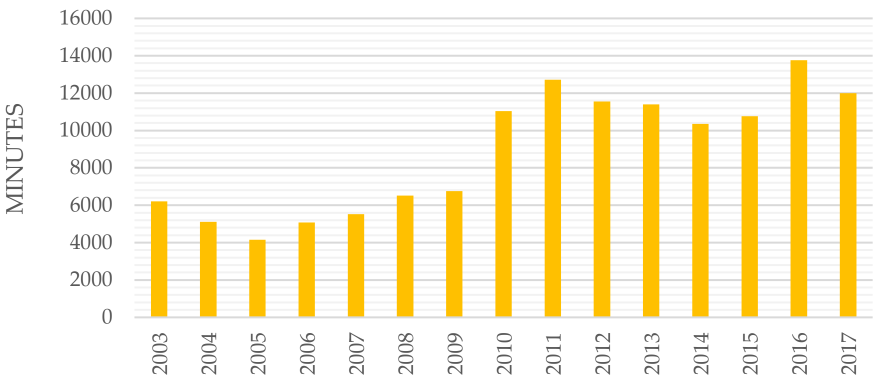

Figure 2.2. Frequency deviations (>50.10 Hz or <49.90 Hz) in minutes per year

Sources: Nordic TSOs (2018)

A report by Nordic TSOs (2018) suggests that one of the ways to reverse this trend of deteriorating frequency control is to have smaller bid-sizes, for example, 15 minute bids in the wholesale electricity markets. We discuss this issue in parts 4 and 6 of this report.

2.3 NEGATIVE ELECTRICITY PRICES

According to Cochran et al. (2013), the variability and uncertainty of VRE could lead to increased electricity price volatility. Furthermore, the low marginal costs of VRE at times could result in extended periods of near-zero or even negative marginal electricity prices, particularly during times when load is relatively low (and difficult to increase) and VRE resources are plentiful. Negative electricity prices can occur in electricity markets without VRE but they may be exacerbated as renewable energy penetration increases.

When the demand for electricity is low and not so flexible base-load plants dominate the power system, it can make sense for these power plants to accept

[4] The increasing frequency deviations point for a need for assessing VRE impacts on the operational side of balancing electricity supply and demand. We leave this analysis for future work.

negative electricity prices for a limited period of time if that saves start-up costs, so they can offer their capacity for subsequent hours. In addition, negative electricity prices can also be caused by VRE power plant operators who might be prepared to accept negative electricity prices in order to maintain their claim for subsidies (e.g., tradable green certificates). This means that VRE power plant operators should accept negative electricity prices up to the amount of their expected subsidy amount (e.g., TGC price).

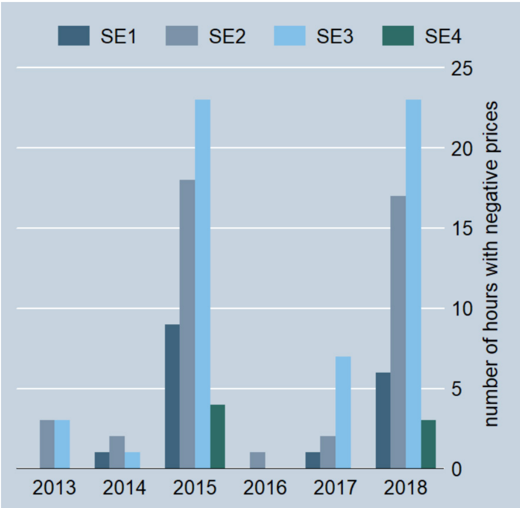

Figure 2.3. Number of hours with negative electricity prices in the Swedish intraday market

Sources: Based on own calculations using the data from Nord Pool.

To see if this is the case for Sweden, we look at the occurrences of negative prices in the Swedish *intraday* market (in the last five years negative prices did not occur in the Swedish day-ahead market). Figure 2.3 shows the number of hours with negative prices in the intraday market for each electricity bidding zone. It is evident that there was a sharp increase in the frequency of negative prices in 2015 and 2018.[5] In contrast to Sweden, negative prices were more frequent in countries with higher VRE penetration, e.g. in Germany or Denmark. The stochastic concurrence of low load and high VRE production are the main explanations for the increased occurrence of negative prices in Germany and Denmark (Höfling et al., 2015). In Sweden, negative prices have also coincided with higher than usual wind production hours. For example, in electricity bidding zone SE3 in 2015, the 23 negative price hours coincided with the hours when wind production was 70% higher than the average for the year (3 000 MWh vs. 1 800 MWh).

2.4 ELECTRICITY PRICE VOLATILITY

The volatility of electricity price depends on many factors. According to Benini et al. (2002), they include fuel prices, hydro-power generation, demand elasticity, network congestion and specific market rules, and finally availability of generating units (e.g., the presence of wind). Since there will always be some uncertainty

[5] Data for the year 2018 are restricted to days prior to 12 June, when the Nord Pool introduced the XBID, which allows for intraday cross-border trading across 13 European intraday markets.

regarding the weather, there will be ambiguity about the precise electricity generation from wind power plants. This may result in jumps in the electricity prices. The increased volatility of electricity price due to VRE expansion may indicate limited availability of ramping (up or turning down) and limited demand flexibility in the power system.[6]

Many international studies on the impacts of VRE on electricity price volatility indicate increasing electricity price uncertainty and volatility due to increasing penetration of VRE (see more detailed literature review in Part 4). However, the results for the Nordic market are inconclusive. Thus, there is a need for more detailed research on the Nordic power markets, in particular, on the Swedish market, which is currently dominated by hydro and nuclear power plants.

Figure 2.4 shows the hourly electricity price developments in the balancing, day-ahead and intraday markets in the Swedish electricity biding zone SE3. In spite of rapid VRE expansion between 2013 and 2017 in this zone, we do not observe any obvious changes in electricity price volatility in all electricity markets during this period. However, one needs to do an appropriate statistical investigation to see if this is really the case. In Part 4 of this report, we investigate the impact of VRE on electricity price volatility in the Swedish day-ahead market in a more rigorous way.

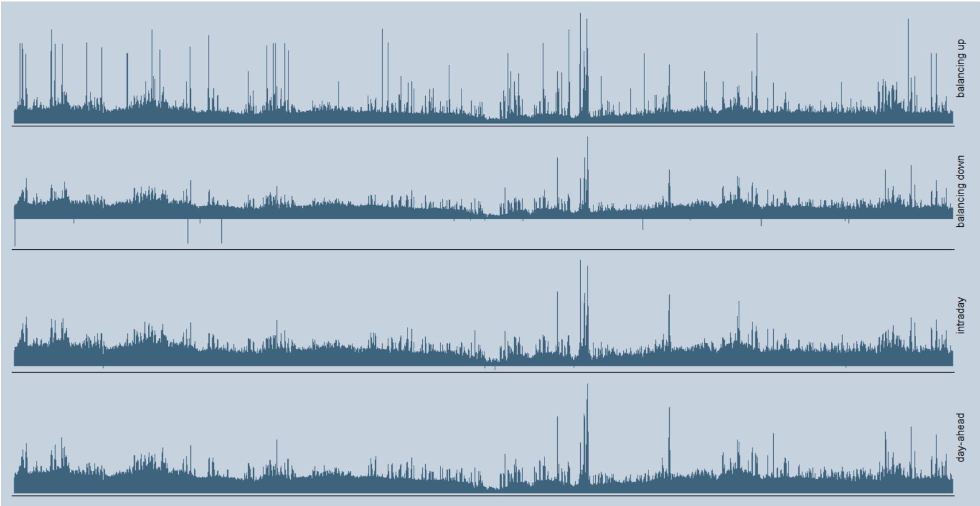

Figure 2.4. The hourly price developments in balancing (up and down), intraday and day-ahead markets in the Swedish electricity biding zone SE3, 2013-2017

Sources: Based on own calculations using the data from Nord Pool.

2.5 POTENTIAL OF FLEXIBILITY RESOURCES

After looking at the indicators of inflexibility in the Swedish power system, in this section, we discuss and assess the potential of flexibility resources available in the Swedish power system in the near future.

[6] It is noteworthy that price volatility is not necessarily a negative thing. It is only *excess* price variability that can be considered as being bad, and the word "excess" is largely a systemic/political consideration. We have more discussion on how price volatility may affect electricity markets in positive and negative ways in the next parts of this report.

Generally, the power system has two main ways to respond to future potential changes related to higher penetration of VRE. One option is to adapt to future challenges by using "the correct" incentives on the supply side to invest in or keep flexible fast-ramping power plants to withstand increasing sharp variations in the net load. Another option is the promotion of demand-side flexibility by hourly dynamic electricity pricing and other measures to encourage customers to shift their power usage from high-demand to low-demand times, smoothing out unwanted fluctuations. Figure 2.5 outlines the framework for analysing these flexibility options on the supply and demand sides.

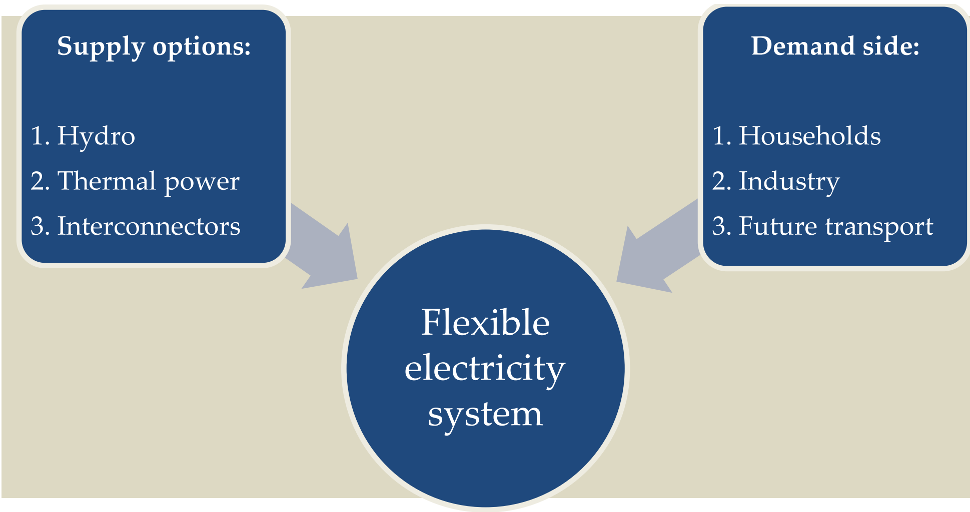

Figure 2.5. The flexibility options on the supply and demand sides for the Swedish power system

In consideration of the supply side options, Figure 2.6 provides average daily profiles for the load, generation and cross-border trade in electricity by each hour in Sweden. It is evident that hydro power generation follows very closely the load profile by responding to the changes in consumption and providing all necessary flexibility to the system. It is also evident that wind and nuclear generation are not at all responsive to the changes in consumption over the day. Moreover, on average, wind power mills tend to generate less power when it is needed the most. Thermal power plants (mainly CHP plants) are more responsive to demand changes than wind or nuclear plants. However, CHP generation profiles match with consumption profiles somewhat less than hydro power generation profile does. Gas turbines are rarely used – mainly to provide the ramping-up generation in the critical early morning hours.

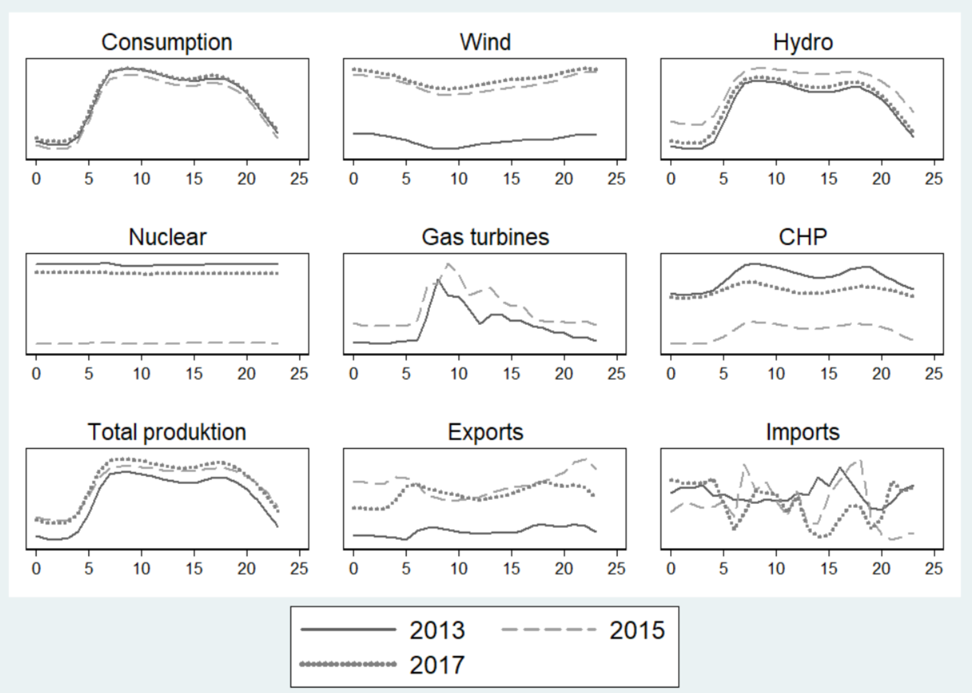

Figure 2.6. Daily profiles of electricity consumption, exports, imports and electricity production by technologies by hour (annual averages) in Sweden

Sources: Based on own calculations using the data from Nordic/Baltic FTP server
Notes: The scale of the vertical axes are not provided intentionally.

On the supply side, hydropower plants present the greatest current and future potential to provide system flexibility. These plants are generally highly flexible by their capabilities to adjust power generation within minutes. Hydropower plants can store energy in their reservoirs, so it can be used later when needed. Hydropower plants can reduce their production when there is plenty of wind and increase production when there is a scarcity of power. In this way they act as storage of VRE generated in the Nordic countries and other neighbouring European countries.

Increased flexibility of thermal power plants can also be an important way to accommodate increasing share of VRE. As discussed and indicated above, it is expected that the increasing amounts of VRE will lead to increased variations in both net load (see Figure 2.1) and electricity prices, and thermal power plants may want to adjust their generation to avoid low electricity prices at the times of higher generation from VRE. Therefore, it is essential that thermal power plants can be technically capable to adjust their generation in line with more volatile prices. Key technical parameters are minimum load levels, start-up cost and ramping up and down rates. The Danish power system presents an interesting case how thermal power plants have managed to adjust their technical parameters to become more flexible energy generators over recent decades (Ea, 2015). For example, Danish coal power plants can run at 10-20% load compared to the normal 45-55% (e.g., as in Germany). It is clear that the optimisation of technical parameters in the Danish thermal power plants has been driven by high penetration of VRE. However, the realisation of the additional flexibility potential in thermal power plants requires the provision of appropriate incentives. For future research, there is a need to better understand international experiences and assess the incentives (costs) for the required technological adoption by the Swedish thermal plants in order to unlock additional potential flexibility.

Interconnectors can be also seen as another important way to share flexibility resources between neighbouring regions and to smooth out wind power intermittency in the region. On the other hand, interconnectors may put additional stress on the Swedish power system's flexibility as it is likely that it will be affected by both the shrinking availability of flexibility resources and the increasing demand for flexibility in the neighbouring power systems, such as in Finland and Denmark, where several flexible power generators have been pushed out from the wholesale and balancing markets.

While the supply side can provide additional flexibility to the system by expensive investments in new power plants or interconnectors, the demand side can potentially offer cheaper flexibility resources. Figure 2.7 illustrates how additional flexibility resources on the supply side can be relatively more expensive option than flexibility resources implemented on the demand side.[7]

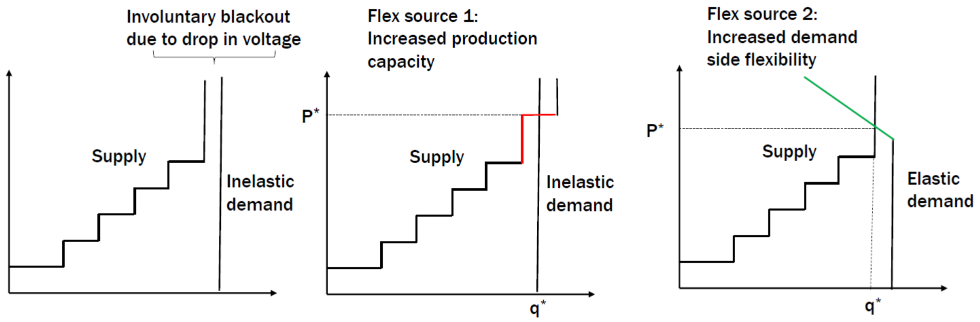

Figure 2.7. Illustration how equilibrium can be reached using flexible production and consumption.

Source: Ei (2018)

Traditionally, electricity consumption has been viewed as inelastic to price at least in the short run. The presence of a historically persistent demand inelasticity implies that there are market failures and barriers to become a more active consumer in electricity markets. The basic problem is that firms and households fail to make socially optimal decisions when prices fail to signal the true resource scarcity, information is incomplete, or consumers fail to pay attention.

The paper by Broberg and Kazukauskas (2015) discusses a series of market failures that appear in discussions relating to the inelastic electricity demand. The list of market failure is not exhaustive, but includes those we see as essential: (1) average electricity price contracts; (2) transaction costs of searching and finding the ways

[7] At the one end, the predictable part of power variability (e.g., windy evenings and nights) can be targeted by the usual dynamic power pricing. On the other end, the unpredictable part will need newer tools, such as remote load control, aggregation of loads, sufficient customers who can rapidly ramp their demand up and down.

for being active and price responsive consumer; (3) incomplete information about the benefits of being active market participant and (4) limited attention to electricity bill as it is usually a relatively small share of total household expenditure. To increase demand elasticity, electricity market efficiency and enhance welfare, well-targeted policy and technological solutions are needed to eliminate or alleviate these market failures. In the near future new technological developments (e.g., smart meters, increasing presence of prosumers, electricity storage in EVs, appliances connected to networks etc.) may help to alleviate and overcome these market barriers.

An example of technology that can alleviate demand-side flexibility is a remote load control technology, which could, with consent from the customer, remotely control parts of the customer's electricity appliances based on the simple setting customized by each consumer. The time of electricity usage and level could be remotely adjusted based on price signals from electricity markets and/or network. This technology could be also used to control electricity usage based on frequency deviations in the electricity system. In this way the customer could, for example, offer her heating load or stored electricity in her electric vehicle as an automatic control resource in the regulation of grid frequency.

As we have showed and discussed above, increasing ramping needs, system frequency deviations and potential electricity price volatility indicate the increasing demand for flexibility in the Swedish power system. Accessing the potential of the currently available flexibility resources is critical for considering future investments. Some countries invest in interconnection capacities to manage the variability and forecasting errors of VRE production, while others focus on national solutions, such as thermal power plants with flexibility characteristics, or the conversion of hydro power stations to operate in more flexible pumped hydro storage mode. Flexibility options tend to be different in different countries.

Below we suggest an analytical framework that one can use to assess whether a particular power system has enough flexibility to accommodate the increasing share of VRE. Figure 2.8 presents a simplistic but rather informative "flexibility chart" of the Swedish power system. The concept of similar "flexibility charts" was developed by Yasuda et al. (2013). This chart highlights what types of flexibility resources Sweden currently has in relation to wind power (orange line), which is measured in terms of maximum utilized capacity over the last 5 years (in MW). The chart shows the installed capacity of each potential source of flexibility, i.e. "nameplate" capacity (green line). However, since capacity does not map directly to flexibility, the size of the green area should be taken with caution, i.e. the charts only highlight the potential of flexibility sources. The yellow line represents the *actual maximum* utilized capacity of each flexibility source over the last 5 years. The differences between the yellow and green points represent the unutilized potential capacities for flexibility whether because they were not profitable to be utilized in the last years or because these spare capacities were technically unavailable.

From the "flexibility chart" it is evident that Sweden has a variety of options to cope with the increasing demand for flexibility. However, hydropower plants are the most utilized option to provide flexibility relative to the other resources. Also, Sweden has a significant interconnection capacity (imports) to exchange flexibility with other countries. These interconnectors could be used, if needed, even to a greater extent. However, some international lines are not fully utilized presumably because of higher flexibility costs in some neighbouring countries. Thermal power plants (mainly CHP plants) are the third largest source of flexibility. One can expect that in the future these plants could play a larger part in flexibility provision if incentives are right for needed investments to change technical plant parameters as it was done in Denmark. Gas turbines provide little capacity in Sweden, and they are not used extensively or frequently. Finally, the demand side has a huge estimated capacity for flexibility, however, it is still the least exploited flexibility resource for many above-discussed reasons.[8]

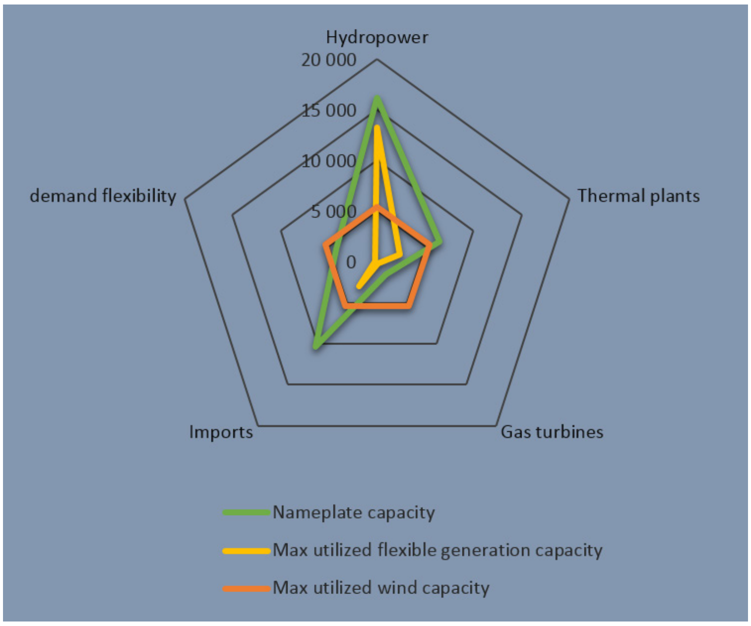

Figure 2.8. Power system flexibility chart for Sweden

Sources: Based on own calculations using the data from Nordic/Baltic FTP server, Ei (2017), Energiföretagen Sverige (2017) and (IEA & NER, 2016)

In a nutshell, our simplistic flexibility chart suggests that much more wind power generation could be accommodated in Sweden with the currently available flexible technologies, of which the hydropower capacity is the most important. However, there are physical limitations to the flexibility of hydropower plants. Grid constraints also limit access to hydropower balancing. Looking ahead, it will be necessary to identify low-cost resources of flexibility, such as demand response, stronger coupling to neighbouring countries and the use of new technologies (e.g. electricity storage or electric vehicles).

[8] The average capacity potential for demand-side flexibility (from both households and industry) was calculated by using figures taken from by Ei (2017). The *technical* potential means the potential that a customer has, and that could be activated with the right incentives and technology. A large proportion of this technical potential exists among household customers in detached homes using electric heating. This potential is available during one to three hours per day (IVA, 2015). The "technical potential" of demand-side flexibility has to be taken with caution here as the estimates do not rely on the realities of economic conditions.

2.6 DISCUSSION AND DIRECTION FOR FUTURE RESEARCH

After investigating the signs of inflexibility in the current Swedish power system we conclude that, thus far, the Swedish power system has proven capable of incorporating increased variability and uncertainty related to the increasing share of VRE. Furthermore, our analysis of the potential flexibility sources suggests that greater wind power generation could be accommodated in the system with the currently available flexibility technologies and mechanisms, such as flexible hydropower capacity, interconnectors, demand-side flexibility and flexible thermal power plants.

As for future research, there is a need to understand better and estimate the required incentives (costs) for technological change on both the supply and demand sides to unlock additional potential flexibility in the Swedish power system. This can be done by investigating international experience of inducing such technical changes. The early stages of still manageable VRE penetration levels are good time for researchers, regulators and industries to prepare for future challenges by making necessary *ex post* analyses. These analyses should facilitate decision-making for cost-effective investments needed to achieve additional flexibility in the future.

In the remaining parts of the report, we focus on electricity markets as the key tool to achieve the cost-efficient and flexible power system. Well-designed electricity markets ought, at least in theory, to signal whether there is a demand for investments in flexibility. We discuss and investigate whether the Swedish electricity markets do in fact provide signal for the scarcity of flexibility sources, and whether the current market design is fit to provide the necessary information (price signal) about such demand for flexibility.

3 Markets for flexibility

As detailed in the introduction, in this report, we restrict our analysis of flexibility to markets for power. We argue that, in general, markets provide a natural place and incentives for flexible resources to trade in and, in principle, well-functioning markets should give incentives for balancing power supply and demand both in

In the Swedish power system, flexibility in the wholesale (day-ahead and intraday) and balancing markets has not been an issue due to significant hydropower capacity (relative to current VRE capacity), which is extensively used to secure grid frequency stability and competitive wholesale and balancing markets. However, the low electricity prices in recent years in the day-ahead market, low liquidity in the intraday market and the shrinking balancing market may discourage entry of additional flexible resources in the future. Furthermore, it is likely that flexibility in the Swedish power system will be affected by both the availability of flexibility resources in the neighbouring countries and the increasing demand for flexibility in the neighbouring power systems, such as in Finland and Denmark.

In this part of the report, we will describe the current structure of Swedish power markets (section 3.1) and the incentives to provide flexibility to and to trade in balance in these markets (section 3.2).

3.1 THE STRUCTURE OF THE SWEDISH POWER MARKET

The Swedish power market consists of two wholesale electricity markets – the day-ahead and intraday markets – and a balancing market. Currently, the Swedish *day-ahead* market is fully integrated in the Nordic/Baltic wholesale electricity market, called Nordic-Baltic Nord Pool, which encompasses the day-ahead markets of four Nordic countries (Denmark, Finland, Norway and Sweden) and three Baltic States (Estonia, Latvia and Lithuania). The Swedish *intraday* market is part of Nord Pool Intraday trading platform, which from the 12th of June 2018 has been supported by the European Cross-Border Intraday Market (XBID) solution, through which customers can trade in 13 intraday markets, which encompass the Nordic, Baltic, German, Luxembourg, French, Dutch, Belgian, and Austrian markets (Nord Pool, 2018b). The Swedish *balancing* market is part of the Nordic Regulation Power Market (RPM), which is a tool for the Nordic TSOs in Denmark, Finland, Sweden and Norway to perform the balancing (The Nordic TSOs, 2016). Below we describe each market in greater detail.

3.1.1 Day-ahead market

In Sweden, as in other Nordic countries, electricity is mainly traded in the day-ahead Nordic-Baltic Nord Pool market – about 90% of all electricity that is produced in the Nordic region is traded on this market, while the remaining 10% are traded bilaterally (Ei, 2016). In general, the Nordic-Baltic day-ahead market plays an important role in other electricity markets. For example, the day-ahead price of electricity is used as a reference price for many financial electricity contracts and as a starting point for deriving prices in balancing markets.

In Nordic-Baltic Nord Pool, market actors submit their buying and selling bids for the next day no later than 12 noon (see Figure 3.1). The bids specify how much, at what price and in which electricity bidding areas[9] each actor wants to buy/sell electricity in each hour of the next day. When all bids have been submitted, the power exchange summarizes all bids in the supply and demand curves for each area and each hour, and the price of electricity for each area and each hour of the next day is set by the intersection of the supply and demand curves (Nord Pool, 2018a). This price is defined as a spot price or as a marginal price, which means that all bids that are activated must trade at the derived spot price, irrespective of their initial price offers. Marginal pricing implies that the spot price of electricity is determined by the "merit order" – the sequence in which power stations contribute to the electricity market, with the cheapest offer made by the power station with the smallest running costs setting the starting point.

It is also important to note that the Nordic-Baltic Nord Pool day-ahead market takes into account the price floor and price ceiling approved by the regulators. The current price floor is -500 EUR/MWh and the price ceiling is 3000 EUR/MWh. This implies that the formation of the electricity price in this day-ahead market will be distorted and will not reflect the true value of the lost load in situations of extreme scarcity. To the best of our knowledge, up to now, neither the price floor nor price ceiling have been breached.

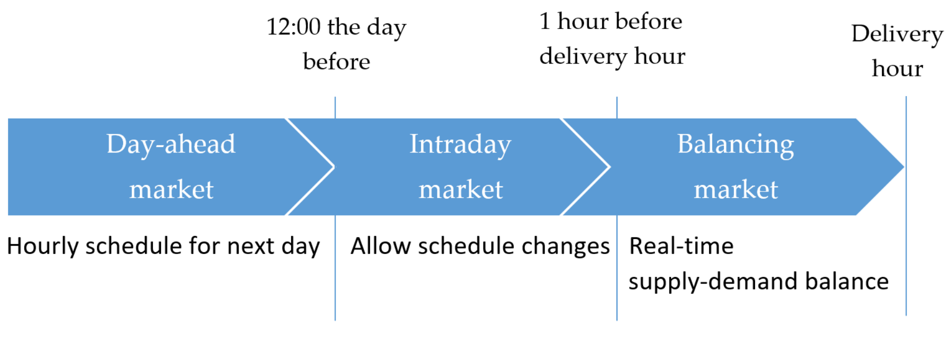

Figure 3.1. Market structure of the Nordic power market

Source: Authors' own illustration based on information from Nord Pool power exchange.

3.1.2 Intraday market

After the day-ahead price calculations, precise figures for unused cross-border transmission capacities are provided by the TSOs to the Nord Pool intraday market, where market actors are able to continue to trade and to balance their portfolios if load or production forecasts turn out to be inaccurate.[10] As we wrote above, from the 12th of June 2018, the Nord Pool intraday market has been supported by the XBID solution, which allows for intraday cross-border trading across 13 European intraday markets. Cross-border trades are only possible if there is enough allocated capacity between the areas (Nord Pool, 2018b).

[9] The Swedish day-ahead market is divided into four electricity bidding areas: SE1, SE2, SE3 and SE4.
[10] Of course, bilateral trading is another option.

In Sweden as well as in the other Nordic countries, the trading volumes on the intraday market are relatively small, compared to the day-ahead market, but this might change with the increasing share of VRE generation and the recent enlargement of the Nord Pool intraday market. We will expand on this in Part 5 of this report.

Trading on the *Nordic* Nord Pool intraday market opens at 2pm on the day before and closes one hour before the delivery hour.[11] Selling/buying bids submitted to this market must contain the hour and location of delivery, volume and price. Currently, on *Nordic* Nord Pool intraday market, actors enter into hourly or user-defined block contracts, where the price is set on a first-come first-served basis, meaning that both producers and suppliers can see the list of available bids for selling/buying of electricity and can simply choose the one they are willing to accept. Hence, trading on the Nordic Nord Pool intraday market is continuous.

3.1.3 Balancing market

While the wholesale power markets ensure the planned balance of supply and demand, they do not ensure operational security of the power system in real-time. This responsibility falls on the Swedish TSO, Svenska kraftnät, which is liable for balancing consumption and generation at every instant.

The balancing services in Sweden consist of several products: Frequency Containment Reserves (FCR), automatic Frequency Restoration Reserves (aFRR) and manual Frequency Restoration Reserves (mFRR). These products are activated to contain and restore the grid frequency. Additional manual balancing capacity is procured for winter periods (in *Swedish*, effektreserven) and for large unexpected frequency interruptions (in *Swedish*, störningsreserven). Detailed information about these reserves can be found on Svenska kraftnät's website (Svenska kraftnät, 2018a).[12]

In what follows, we will focus on mFRR, which is the main balancing resource in the Nordic and Swedish power system (The Nordic TSOs, 2016). mFRR is used for power balancing and to handle congestions both during normal operations and when faced with a disturbance. When activated, it replaces both remaining FCR and aFRR activations and brings frequency back to the target. It is expected that mFRR will continue to be the main balancing resource in the system. mFRR is known as the Nordic Regulation Power Market (RPM), which is a common market for the four Nordic countries (Denmark, Finland, Norway and Sweden).

In the RPM market, voluntary upward-regulating and downward-regulating bids are submitted to the Nordic RPM 14 days before the delivery hour at the earliest. Bids can be adjusted up to 45 minutes before the delivery hour (Svenska kraftnät, 2018b). The Nordic RPM uses marginal pricing, which means that all activated upwards regulation bids are priced the same as the most expensive activated bid

[11] Opening and closing times varies across countries participating in XBID. For more see Nord Pool (2018b).

[12] For purpose of our report it might be useful to describe the relative size of all balancing services and the frequency with which they have been used over the recent years. Unfortunately, the lack of data hindered any meaningful analysis of this aspect.

(the principle of "cheapest bid first"). Sometimes, exceptions have to be made due to transmission limitations or the time required before the resource is fully activated. Divergences from the principle of "cheapest bid first" are called special regulations (The Nordic TSOs, 2016). Only balance responsible parties (BRP) can submit bids; this applies to both production bids and bids for consumption reduction. According to the Swedish Ediel registry, there are about 30 BRPs in Sweden (Ediel, 2018).

Apart from volume (MWh) and price (SEK/MWh or EUR/MWh), the bids shall include information about geographic location and how quickly a bid can be fully activated. Bids must therefore be made per regulation object. The minimum bid volume per hour is 10 MW in all electricity areas, apart from SE4, where the requirement for minimum bid is 5 MW.

The maximum permitted price for upward regulation bids is 5 000 EUR/MWh. Regulating power prices are not available in real time, but are published by Nord Pool power exchange within an hour after the end of the operating hour. The price of the last activated bid will be the hourly price for the entire Nordic market if there is no congestion. When congestion occurs between two electricity bidding areas in the operational phase, the Nordic TSOs jointly determine when the areas no longer can be mutually regulated. Consequently, the separation of regulating prices occurs (The Nordic TSOs, 2016).

3.2 INCENTIVES TO PROVIDE FLEXIBILITY AND INCENTIVES TO TRADE IN BALANCE

To understand different actors' incentives to provide flexibility in the wholesale and balancing markets and incentives to trade in balance on the day-ahead and intraday markets it is important to understand how flexibility is rewarded in these markets and how imbalance prices are set in the Swedish power system.

Owners of flexible resources receive income streams from selling flexibility in the wholesale and balancing markets. The market value of flexibility on the day-ahead market depends on the level of the spot price, and daily as well as seasonal volatility of the spot price of electricity. In principle, flexibility provision on the intraday and balancing markets should be rewarded with a positive price premium. This means that flexibility provided closer to the delivery hour should be valued more than flexibility provided on the day-ahead market, implying that the price premium is larger in the balancing market than in the intraday market. In summary, this means that flexibility providers are not explicitly paid for the flexible capacity they provide or possess, but for actual provision of electricity. The value of flexible capacity is implicitly reflected in the market price of electricity, be it in the wholesale or balancing markets. Because of these features, the Swedish electricity market is treated as an "energy-only" market.

In Sweden, as in other Nordic countries, all parties that cause an electricity imbalance on the production or consumption sides are charged imbalance prices. The main principle for the pricing of imbalances is to reflect the value of the activations used to balance out the imbalances. The imbalance price is determined as the hourly marginal price of activated bids for balancing purposes in the Nordic Regulation Power Market (The Nordic TSOs, 2016).

Different price models are applied, depending upon whether imbalance occurs in production or consumption. A two-price system is applied for the imbalance in production (defined as the difference between measured production and production plan). Purchase and sales of imbalance power will be settled at different prices.

If the imbalance of a producer has the same direction as the total imbalance on the market (thus increasing total imbalance), the producer is charged the regulating market price; if the producer's imbalance has the opposite direction than the total imbalance (thus reducing total imbalance), the producer is charged the day-ahead market price of the area. In the hours with no active mFRR regulation, imbalances still appear for individual players in the market and the price charged in this case is the area day-ahead market price.

In the one-price system, which is used when consumption imbalance occurs (i.e. when there is a mismatch between measured consumption, trade and production), the purchase and sales prices of imbalance power are identical. During an up-regulating hour, the price of imbalance power is the up-regulating price, and during a down-regulating hour, the price of imbalance power is the down-regulating price. If no regulations have been carried out during an hour, the price of imbalance power is the area day-ahead market price.

Imbalance pricing encourages actors in the Swedish power system to bid very close to expected production/consumption in the day-ahead market and to resolve the remaining imbalances in the intraday market, in which, as we wrote above, electricity prices should be lower than regulating electricity prices that are used to charge imbalances.

In the remaining parts of this report, we present each electricity market's recent developments and trends and show whether, and if so how, these markets have been effected by the increasing share of VRE and the implications of these changes for flexibility provision in the future. In carrying out this task, we refer to experiences from other European markets and provide some insights from the academic literature. We also identify a number of research needs related to intermittency of electricity and flexibility in the area of energy economics.

4 Developments in the Swedish day-ahead market

In the context of the increasing share of VRE generation, and hence expected higher demand for flexibility, the role of electricity day-ahead markets is increasing in importance. Day-ahead markets are designed to be the least-cost option to match supply and demand in electricity systems, i.e. to reduce the demand for required flexibility. Thus, even if intraday and balancing markets are other key markets for pricing flexibility, it is desirable that day-ahead electricity markets contribute as much as possible to balancing supply and demand.

In this part of the report, we present the Swedish day-ahead market's recent developments and trends and we look at whether, and if so how, this market has been affected by the expansion of VRE. The plan of this part of the report is as follows: first, we present a comprehensive overview of the relevant literature on impacts of VRE expansion on electricity price and its volatility (section 4.1), followed by an empirical analysis of the effects of VRE on electricity price and its volatility in the Swedish day-ahead market (section 4.2). Second, we analyse how the profitability of the largest electricity companies in Sweden has been affected by their asset portfolios of various power generating technologies (section 4.3). The results of this analysis will shed more light on what kind of power plants have been profitable in the last decade and whether one could expect more investments into flexible electricity generation technologies in the future. Finally, we discuss our empirical results, knowledge gaps and provide some directions for future research and some implications for the design of future day-ahead markets (section 4.4).

4.1 LITERATURE REVIEW OF VRE EFFECTS ON THE MERIT ORDER AND PRICE VOLATILITY

Sweden as well as other Nordic and European countries have recently experienced a decade of low electricity prices. In Sweden, the day-ahead price has fallen by about 40% over the period 2006-2017 (see a trend line in Figure 4.1). This drop in prices could be explained by various supply and demand factors, but it has been argued that, in Sweden, the lowering of the day-ahead prices could be mainly explained by the so-called "merit order effect" caused by an increased supply of cheaper electricity from renewable energy sources in combination with lower demand (Hirth, 2018).

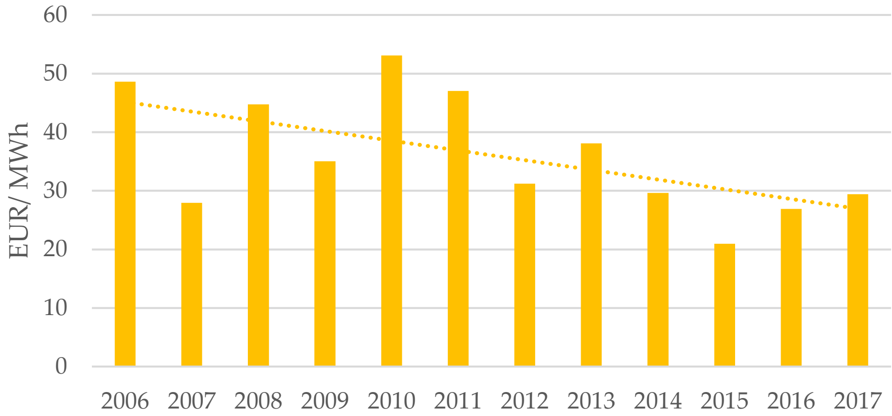

Figure 4.1. Average day-ahead spot prices in Nord Pool

Sources: Based on own calculations using the data from Nordic/Baltic FTP server.

The electricity price in the Nord Pool day-ahead market is determined by the point where the supply of electricity, represented by the merit order curve, equals the demand for electricity. The cheapest offer made by power plant sets the starting point for the merit order. Power from renewable installations such as wind turbines and photovoltaic installations has to be sold on day-ahead market too, but these suppliers have almost no operating costs (since they do not need fuel or much labour). When generation from VRE increases, it generally leads to reduced production from thermal generation sources due to their higher operating cost. Figure 4.2 below illustrates the effects of an increase in wind power generation on system price, which is called the merit order effect. Depending on the elasticity of demand, total power generation will change as well.

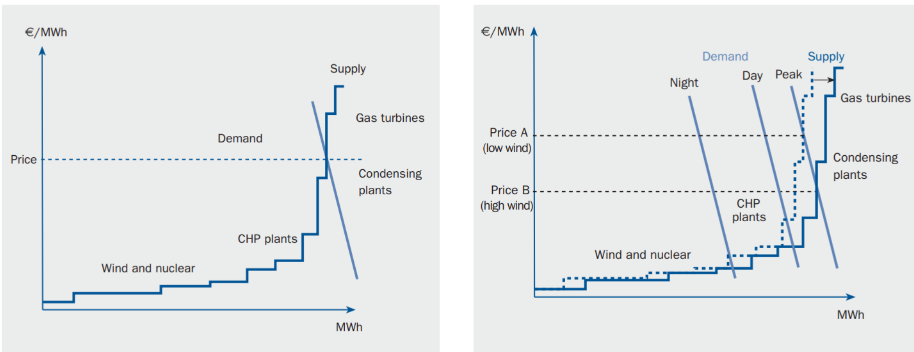

Figure 4.2. "Merit order" and wind power effects on price at peak and off-peak hours

Source: Pictures are taken from Morthorst and Awerbuch (2009).

A large branch of the energy economics literature discusses this merit order effect caused by the increasing share of VRE (Gil et al., 2012; Hirth, 2018; MacCormack et al., 2010), and there are a number of studies providing empirical evidence for the merit order effects in various European countries, for example: Germany and Austria (Cludius et al., 2014; Ketterer, 2014), Italy (Clò et al., 2015), Spain (de Miera et al., 2008; Gelabert et al., 2011; Pereira et al., 2017), Denmark (Jónsson et al., 2010), Ireland (O'Mahoney & Denny, 2011). While these studies differ in terms of econometric approach, types of renewable sources, country analysed or frequency of their data used, they all conclude that increasing VRE generation has led to reduced day-ahead electricity prices.

The increasing share of VRE affects the provision of flexibility via its effect on day-ahead electricity prices in two opposing ways. On the one hand, VRE expansion may lower the day-ahead electricity prices and potentially reduce the profits of flexibility-providing thermal power plants. On the other hand, VRE generation may significantly affect electricity price volatility and create profit opportunities for flexibility providers. Which effect is prevailing in a particular day-ahead market is an empirical question.

The effects of VRE generation on power price volatility have been explored in various empirical studies. One strand of the literature argues that increasing penetration of VRE should actually diminish volatility in power prices (see Couture & Gagnon, 2010; Doherty et al., 2006), as electricity source diversification in VRE could lead to less volatile prices. However, most of empirical studies based on data from the European power markets do not support such claims. For example, the impact of VRE on electricity price level and volatility is investigated in a recent study by Pereira et al. (2017). They estimate the effect of wind power generation and hydro reservoir levels on the electricity price in Spain. The Spanish case is interesting for the Swedish context since, in addition to having become more exposed to intermittent wind power due to the increase in wind power capacity, Spain, like Sweden, has also a relatively large hydropower sector. Their results suggest that wind power generation has a negative effect on price level but positive effect on price volatility. A similar study by Ketterer (2014) on the German electricity market finds similar results, namely that the level of electricity price decreases and its volatility increases as wind power generation expands. Clò et al. (2015) also report a similar finding for the Italian electricity market.

However, there are only few empirical studies on the impacts of increasing VRE generation on electricity price volatility in the Nordic electricity markets. Some of these studies provide somewhat different results. For example, Mauritzen (2010) studies the impact of wind power on price volatility in Denmark and concludes that while higher wind power generation had the negative impact on *intraday* price volatility, volatility in the longer run (measured in average daily prices) increased. This study is somewhat complimented by an analysis of Rintamäki et al. (2017), who compare electricity markets in Denmark and Germany. They conclude that wind power and other zero-marginal cost technologies cause German *intraday* price volatility to increase, and Danish *intraday* price volatility to reduce. The authors pinpoint that the access to flexible generation capacity and differing wind power generation patterns as the main contributing reasons for these differences. Specifically, in Germany, wind power generation occurs more frequently at off-peak hours, while Denmark has better access to the hydropower reservoirs in the other Nordic countries.

Given the abundance of hydropower plants in the Nordic countries and inconclusive results on VRE effects on electricity price volatility, there is a clear need for more detailed *ex post* analysis of the Swedish and other Nordic electricity markets, in particular, of their day-ahead markets. In the next section, we provide a simple analysis, where we investigate the presence of merit order and price volatility effects associated with the increasing share of VRE in the Swedish day-ahead market. The Swedish day-ahead market is interesting due to its large hydropower capacity, which could lead to effects different from those reported for other countries.

4.2 ANALYSIS OF THE EFFECTS OF VRE ON MERIT ORDER AND PRICE VOLATILITY

Our empirical analysis, among the few of its kind for Sweden to our knowledge, aims to answer two distinct questions. The first question is whether the merit order effect is observed in the Swedish day-ahead electricity market. The second question is whether the increasing share of wind power affects electricity price volatility in the day-ahead market.

To answer these questions, we use a generalized autoregressive conditional heteroskedasticity (GARCH) model.[13] We mainly follow the methodological frameworks of Pereira et al. (2017) and Ketterer (2014). In our analysis, we use a simplified theoretical framework by assuming that the electricity day-ahead price in the Swedish electricity bidding zones (P_t^e) depends mainly on the amount of electricity generated by wind turbines in Sweden ($Wind_t$), the available water stock in hydropower reservoirs in the Nordic countries ($Hydro_t$), biofuel (wood chip) prices (P_t^{wood}), nuclear power generation in Sweden (Nuc_t) and the forecasted electricity demand in Sweden ($Load_t^{prog}$). A reduced form regression model, which is derived from the electricity demand and supply functions (see Appendix A.1), looks like this:[14]

$$\log(P_t^e) = \beta_0 + \beta_1\log(Wind_t) + \beta_2\log(Hydro_{t-1}) + \beta_3\log(P_t^{wood}) + \beta_4\log(Nuc_t) + \beta_5\log(Load_t^{prog}) + \epsilon_t \tag{4.1}$$

Hourly electricity day-ahead prices in EUR/MWh are collected from Nord Pool for the period January 2015-June 2018. Observations of hourly wind power production and consumption forecasts (both measured in MWh) are also collected from Nord Pool for the same period. Electricity consumption forecasts, a proxy variable of electricity demand, is used to control for economic activity and other weather-related changes. The use of forecasted consumption instead of actual consumption helps us to avoid some econometric issues, such as endogeneity problems. The weekly data on the water stock in hydro reservoirs (measured in GWh) is available at Nord Pool. The stock of water in hydro reservoirs is included in the model since hydropower is the main flexible power generating method to balance the Swedish electricity system. We expect this variable to correlate negatively with both electricity price level and electricity price volatility. We use one-week-lagged

[13] The generalized autoregressive conditional heteroskedasticity (GARCH) process is an econometric term developed in 1982 by Robert F. Engle to describe an approach to estimate volatility in financial markets.

[14] This is a very simplified model to explain electricity price formation in Sweden. In the future research one should expand this model to include other control variables, such as prices of EU ETS allowances, coal prices, constrained grid transmission lines and other factors.

hydro reserves to avoid endogeneity problems. In our analysis, we include wood chip prices (measured in SEK/MWh) collected from SCB on quarterly basis to control for thermal power generation, which is mainly based on biofuels such as wood chips. Finally, we include nuclear power generation (measured in MWh) to control for base-load power supply.

For our research purposes we estimate simultaneously two GARCH models.[15] The first model (Equation 4.1) describes the factors driving the level of day-ahead electricity prices. The second model is slightly different in the sense that it is the day-ahead electricity price variance that is explained by the same explanatory variables. The variance of the error term of the price level model (Equation 4.1) in period t is denoted by h_t, and the variance equation error term is e_{t-1}^2. The variance equation can be written as:

$$h_t = \gamma + \gamma_1 \log(Wind_t) + \gamma_2 \log(Hydro_{t-1}) + \gamma_3 P_t^{wood} + \gamma_4 \log(Nuc_t) + \gamma_5 \log(Load_t^{prog}) + \gamma_6 e_{t-1}^2. \quad (4.2)$$

Table 4.1 shows the effects of wind power generation on both electricity price level (panel A) and its volatility (panel B). It is evident that wind power generation has negatively affected day-ahead electricity prices in all electricity bidding zones in Sweden. A coefficient between -0.077 and -0.087 means that one percent increase in wind power generation is associated with 0.077-0.087 percent decrease in day-ahead electricity prices in the Swedish electricity bidding zones. Based on our results, we can conclude that the merit order effect is present in the day-ahead market not only at the Nord Pool system level but also in each Swedish electricity bidding zone. These results are in line with the previous studies.[16]

Table 4.1. Wind generation effects (percentage change) on electricity price level (panel A) and electricity volatility (panel B) in the day-ahead markets of four electricity bidding zones in Sweden (SE1-SE4) and the Nord Pool (SYS)

	(1)	(2)	(3)	(4)	(5)
VARIABLES	SYS	SE1	SE2	SE3	SE4
Panel A: Price level effects (mean equation)					
Wind Generation	-0.053***	-0.077***	-0.077***	-0.083***	-0.087***
Hydro Reservoir	-0.248***	-0.225***	-0.224***	-0.191***	-0.186***
Demand	1.069***	1.182***	1.183***	1.308***	1.424***
Nuclear	-0.021***	-0.179***	-0.179***	-0.213***	-0.208***
Price of biofuel	3.643***	2.788***	2.776***	2.834***	1.899***
Panel B: Price volatility effects (variance equation)					
Wind Generation	0.942***	2.274***	2.277***	2.436***	2.678***
Hydro Reservoir	-0.398***	-1.872***	-1.871***	-1.552***	-1.966***
Demand	-11.68***	-13.34***	-13.36***	-13.91***	-13.82***
Nuclear	1.372***	2.306***	2.310***	2.561***	2.214***
Price of biofuel	-42.69***	-31.92***	-31.90***	-30.29***	-26.42***
No of obsv.	47,634	47,634	47,634	47,634	47,634

Standard errors in parentheses, *** p<0.01, ** p<0.05, * p<0.1

[15] For our purposes we have estimated separate models for each electricity bidding zone by assuming independence among them. In the future research, one could do better estimations by dropping this assumption.

[16] For example, see Cludius et al. (2014), de Miera et al. (2008) and Gelabert et al. (2011).

The signs of the coefficients of the remaining control variables seem to be in line with our expectations giving us confidence in our model specification. As expected, the higher demand forecast and higher biofuel (wood chips) prices are positively correlated with day-ahead electricity prices, and the larger hydro reserves and nuclear generation tend to correlate negatively with day-ahead electricity prices.

Panel B of Table 4.1 provides the results from the variance equation, where day-ahead electricity price volatility is the dependent variable. The demand forecast, price of wood chips and hydro reservoirs are negatively and significantly correlated with electricity price volatility. The coefficient sign for hydro reservoirs is in accordance with the expected outcomes, as the higher level of water reservoirs implies greater potential for electricity market balancing. For wind power generation, the positive coefficient suggests that higher production of wind power leads to higher electricity price volatility. This result is in line with the results of the previous studies examining other energy markets (e.g., see Clò et al., 2015; Ketterer, 2014; Pereira et al., 2017).

However, it is necessary to expand this analysis to account for the imports and exports of electricity. According to Copenhagen Economics (2016), to date, the increased production of wind power in Sweden has resulted in an increase in net exports, which were facilitated by the expanded cross-border transmission capacity. It would be also valuable to expand this type of research by covering other electricity markets and longer time-spans, so that the overall effects of VRE generation on electricity prices in day-ahead, intraday and balancing markets could be clearer.

Previous empirical studies attempting to identify VRE effects on day-ahead electricity prices mainly focus on short-run, largely weather-driven, fluctuations in VRE output. This approach is not useful to understand long-term VRE effects, i.e. how capacity additions affect the markets. The rationale for more *ex post* research on new VRE capacity additions instead of generated VRE output is that the focus on *capacity* helps to better understand the long-term effects on the electricity markets. Renewable energy capacity utilization (production) levels differ a lot over time. Thus, the presence of high volatility in capacity utilization data, mainly because of weather and other factors, makes it inadequate for studying these long-term effects.

Moreover, existing studies largely focus on estimating the *average* change in the day-ahead electricity price. There is a need to examine how electricity price response varies *across hours* of the day and across seasons. Ultimately, this could allow us to better understand how VRE developments affect electricity prices and profits of different kinds of power plant generators that operate during a subset of hours (Bushnell & Novan, 2018).

In order to understand how wind power generation affects day-ahead prices across hours of the day (in terms of EUR per MWh), we estimate the hourly effects of wind power generation on the Nord Pool's system electricity price by ordinary least square (OLS), controlling for the amount of electricity generated from wind sources, the available water stock in hydropower reservoirs in Nordic countries, biofuel (wood chip) prices, nuclear power production in Sweden, the forecasted demand for electricity in Sweden and the monthly and seasonal effects.[17] In Figure 4.3 we provide the estimated coefficient from this regression. These estimates indicate a substantial variation in the effect of wind power upon the day-ahead electricity price across hours. The negative price effect of wind generation tends to be much larger in the critical morning and early evening peak hours. This result suggests that peak-load power generators with high variable costs might face difficulties in the future, when the share of wind power generation is predicted to increase even further.

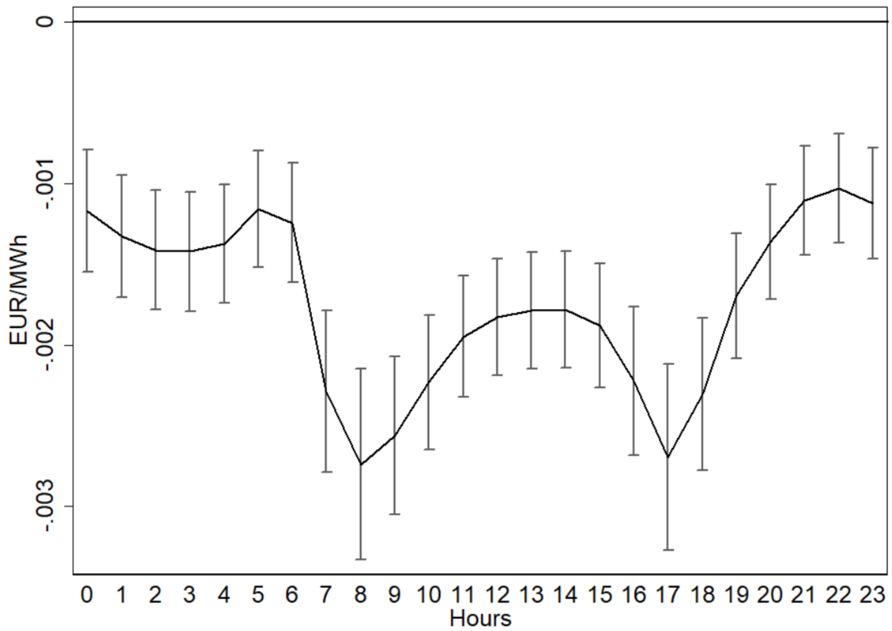

Figure 4.3. Wind power generation effects (EUR/MWh) on day-ahead electricity prices across hours

Sources: Based on own estimations using the data from Nordic/Baltic FTP server

In a nutshell, our analysis indicates that wind power generation not only reduces the day-ahead electricity price but also tends to increase its volatility. This conclusion holds across our various econometric specifications used and across all Swedish electricity bidding zones.

On the one hand, an implication of our results is that low and volatile electricity prices might decrease or delay investment decisions in new flexible power capacity, which might be needed to counterbalance intermittent nature of wind power and other VRE generation. The situation of increasing VRE capacity, low electricity demand growth in Sweden and neighbouring countries and limited potential to export surplus electricity may result in reduced power generation or even capacity of power plants operating at the top of merit order (Copenhagen Economics, 2016).

[17] This time we use a linear model in order to measure wind power effects in terms of EUR per MWh.

On the other hand, somewhat higher electricity price volatility in relation to increasing VRE penetration, i.e. more frequently higher electricity prices, may create opportunities for flexible power plants to make profits in these peak hours.[18] What the overall effect of lower average but more volatile electricity prices on the profitability of different power generating technologies is remains unclear.

In the next section, we look at the past profitability of the largest Swedish electricity producers to get better understanding about the incentives for current and future investments into different types of power generating technologies.

4.3 PROFITABILITY AND FLEXIBILITY IN SWEDEN

Investments in flexible power generating technologies may become more important and may play a key role in enabling further cost-efficient deployment of VRE. Investments in flexible power capacity may be needed at least as a back-up for expanding VRE production. However, some flexibility-related investments may have been delayed by the current market conditions and regulations. The key barriers to such investments may have been the low day-ahead electricity prices and stagnating electricity demand resulting in the insufficient rate of return on this type of investment. In this section, we assess the profitability of these potential investments, which may be necessary to meet the future flexibility demand.

Growth in electricity demand has historically been a key driver for investments in the electricity sector. However, current investments in power generating capacity appear mainly to be policy driven (e.g., VRE support schemes). Meanwhile, electricity demand growth has become too weak to act as a driver for investments in power generating assets across the EU (Nuffel et al., 2017). For example, in Europe, the demand for electricity has flattened in 2007-2012, compared to an annual growth rate of 2.7% since the 1970s (WEF, 2015). The total consumption of electricity in the EU is expected to increase slightly in the medium and long term, partly because of an increase in the use of electricity for heating (heat pumps), cooling and transport (electric vehicles). ENTSO-E estimates an annual growth rate in electricity consumption in Europe of 0.9% between 2016 and 2025, with an even more sluggish growth rate in Sweden (ENTSO-E, 2015). A study by IVA (2017) estimates that the total use of electricity in Sweden will change from 130 TWh in 2013 to 128–165 TWh beyond 2030, depending on different scenarios.

Apart from stagnating electricity demand, the low electricity prices in the Swedish day-ahead market is driven by a massive development of subsidized VRE generation with low variable costs (see our analysis in section 4.2). Taken together, this has led to lower profitability on unsubsidized already realised investments in power generation capacity, which then may have discouraged new investments in conventional and more flexible electricity generating capacity. In other words, VRE subsidies may simply have increased total capacity to inefficiently large levels. In the absence of VRE subsidies, total capacity may have been lower and that may have been the efficient solution.

[18] As price volatility is likely to increase in the future, the policy makers may not be able to increase the current price ceiling of 3000 EUR/MWh if it starts binding. This may result in "missing money" issue. For more detailed discussion on this aspect see a report by Bergman and Le Coq (2019).

Figure 4.4 shows that, in the EU, the overall return on capital invested in electricity generating utility companies fell from about 10% in 2006 to 5% in 2013. Low day-ahead prices in combination with stagnant electricity demand and rapid expansion of VRE suggest that the overall return on conventional thermal plants is not high enough to justify significant capital expenditures in most EU markets.

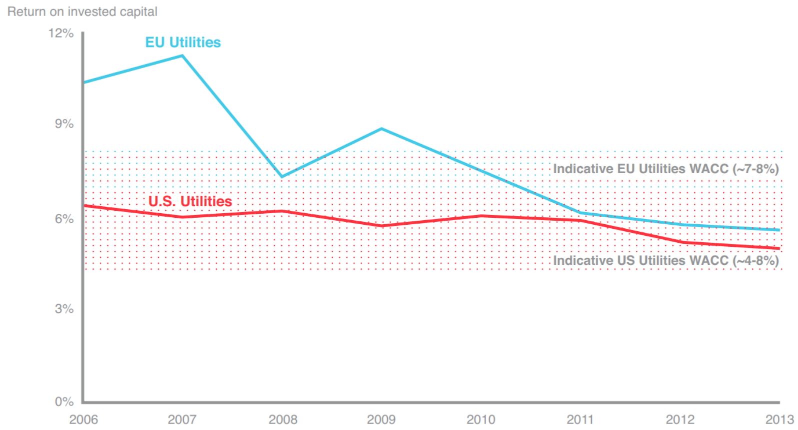

Figure 4.4. Returns on invested capital in EU and US utilities in 2006-2013

Source: WEF (2015).

In Figure 4.5 we present developments in the Nordic day-ahead electricity prices and profitability of the largest Swedish energy firms during the previous ten years. It is evident that electricity price fluctuations had a large effect on the profitability of these firms – the average turnover-weighted profitability has been on the decline for years up until 2015. More importantly, from 2012 the average return on capital employed (ROCE)[19] has dropped below what is required (6-8%) for large energy firms in Sweden (see more details about required cost of capital, WACC, for different types of energy firms in the report written by Sweco, 2016). In 2016 and 2017, electricity prices, and therefore, the profitability recovered, and so did the ROCE ratio, which reached the minimum required WACC levels in 2017.

[19] Return on capital employed (ROCE) is a profitability ratio, which tells how effectively a company is using its capital. Return on capital employed is useful for investors to decide whether this capital-intensive energy company would be good enough to invest into.

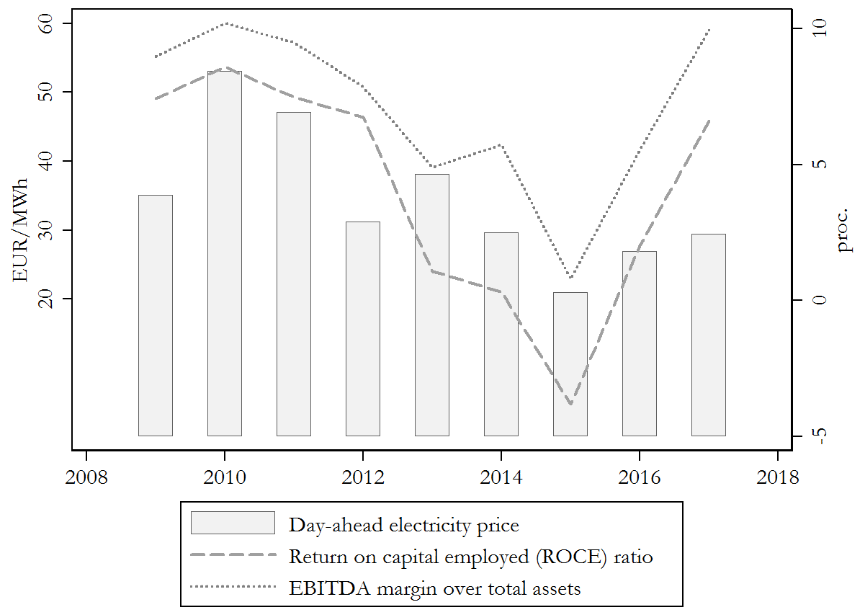

Figure 4.5. Weighted average (by turnover) profitability of the largest 24 electricity producers in Sweden and the Nord Pool system's day-ahead electricity prices

Sources: Amadeus database, Energiföretagen Sverige, Nordpool and own calculations.

Which power generation technologies are profitable for these large Swedish energy firms? To determine the relationship between the profitability and technology types of power plants owned by these firms, we use a naïve econometric estimation.[20] We have data for a sample of 24 Swedish energy firms, which, in total, own about 80% of the Swedish power generating capacity. We assume that the firm's profitability is a function of various power generating technologies measured in terms of capacity, electricity price, employee number and other unobservable time-invariant factors:

$$profit_{it} = \alpha + \beta_1 wind_{it} + \beta_2 hydro_{it} + \beta_3 nuc_{it} + \beta_4 therm_{it} + \beta_5 price_{it} + \beta_6 size_{it} + \mu_i + \varepsilon_{it},$$

where $wind_{it}$, $hydro_{it}$, nuc_{it} and $therm_{it}$ terms denote the shares of wind, hydro, nuclear and thermal power plants in the total firm capacity, respectively, in each year. For example, in 2017, Umeå Energi AB had the shares of 66%, 9.5% and 24.5% in hydro, wind and thermal power capacity, respectively. α is a constant term; μ_i are the firm-specific unobserved heterogeneity fixed effects; ε_{it} is an error term; and $size_{it}$ is the number of employees to control for the changes in firm size over time.

Our sample covers the electricity generation companies for the period 2009-2017. The data on power capacities by technology owned by the Swedish energy companies in Sweden was acquired from Swedenergy (Energiföretagen Sverige).[21]

[20] It is worth noting that this regression is merely illustrative, since, in reality, firms' *expectations* about profitability drive the changes in the share of each technology. In addition, one should control better for firm size changes over time.

[21] Swedenergy is a non-profit industry and special interest organization for companies involved in the supply, distribution, selling and storage of energy, mainly electricity, heating, and cooling. Swedenergy

Our analysis is restricted only to the electricity generating firms that are the members of Swedenergy (they represent about 80% of the total power capacity in Sweden). The Amadeus (Bureau van Dijk) database is a central data source for our profitability measures.[22] In addition to the ROCE ratio, we use two other measures of profitability. The first one is a ratio of operating revenues before interest and taxes over total assets (EBIT). The second is the ratio of earnings before interest, taxes, depreciation and amortization over total assets (EBITDA). The advantage of EBITDA over EBIT ratio is that EBITDA does concern more with cash flow without taking into account substantial one-off asset write-offs.

Table 4.2 presents the results of our analysis. They show how power capacity mix have affected the average profitability of the selected energy firms in the last decade. The effects of the specific power generation technology (or rather its share) on the profitability measures are expressed in terms of having more hydro, thermal or nuclear power capacity instead of wind power capacity. We find that having one percent more hydro power capacity instead of having the same capacity of wind power in the capacity portfolio resulted in 0.49% higher ROCE profitability measure. We get a similar positive result (0.39%) for having higher share of thermal power capacity but the effect is less statistically significant. Meanwhile, higher capacity “exposure” to nuclear technology instead of wind leads to slightly negative profitability (this result is statistically insignificant though).

Table 4.2. Capacity mix effects on the profitability of the selected energy companies in Sweden instead of having wind power capacity

	(1)	(2)	(3)
VARIABLES	EBIT	EBITDA	ROCE
Hydro capacity share	0.190*	0.216**	0.485***
	(0.101)	(0.101)	(0.168)
Thermal capacity share	0.213	0.209	0.391*
	(0.130)	(0.129)	(0.208)
Nuclear capacity share	0.0297	-0.0343	-0.00991
	(0.269)	(0.269)	(0.414)
Electricity price	0.0991**	0.0844**	0.120**
	(0.0390)	(0.0387)	(0.0596)
Number of employees	0.000571	0.000437	0.000652
	(0.000476)	(0.000473)	(0.000725)
Number of observations	174	172	172
R-squared	0.113	0.104	0.127
Number of firms	24	23	24

Standard errors in parentheses; *** p<0.01, ** p<0.05, * p<0.1.

Given that hydro and thermal power plants tend to be more flexible than wind or nuclear power plants (see Figure 2.6), in general, our results suggest that the

has a total of 400 members, which includes state-owned, municipal, and private companies as well as associations within the energy sector.

[22] This database includes firm level accounting and other data in a standardized financial format. The general sources for the Amadeus are national official public bodies in European countries.

decision to keep or to invest in existing or new more flexible power plants has so far been a good strategy for the average power company in our sample.

In the above-presented rather simple *ex post* analysis, we provide some insights into how the composition of power capacity may affect future investments. However, there is still a need for more thorough analyses. Future investment incentives are influenced by many more factors than we have covered in our analysis. Ultimately, firms' incentives to invest in various kinds of power generating technologies are determined by how profitable a plant is *expected* to be during its future economic life-time. These expectations can depend on past profitability but also on assumptions about the future market conditions. The required return on investments is also determined by the investor's risk preferences, ownership, financing opportunities, past decisions and energy/climate policies.

In our analysis, we have focused on the aggregate firm profitability measures. This means that these measures are also affected by firm revenues generated from other activities than power generation. The reports by Ei (2016) and Sweco (2016) have discussed some of these issues, but there is still a large scope for more detailed empirical research on these matters. In particular, there is a need to better understand how electricity price volatility in the day-ahead market affects power firms' profitability depending upon whether their own more or less flexible power plants.

Based on our results from Table 4.1 we can expect that the occurrence of very low and very high electricity prices will be more frequent. This is likely to reduce the need for conventional base-load power plants, whereas the demand for flexible peak-load power plants may well increase. The results of our profitability study (see Table 4.2) further supports such expectations.

As already detailed in section 4.1, two scenarios may be envisaged, based upon the effect of VRE on electricity prices and investments. On the one hand, larger fluctuations in electricity prices may result in more uncertainties about future revenues of electricity producers, which may result in higher required rate on return for risk averse investors and delay the required investments in flexible power generating capacity. On the other hand, high electricity price volatility may act as a driver for investments in flexible capacity. It is difficult to predict which one of the scenarios will play out. Hence, there is a clear need to assess how electricity price volatility have affected and will affect investment decisions of Swedish power generating companies.

4.4 DISCUSSION: WIND POWER, FLEXIBILITY AND DAY-AHEAD MARKET IN THE SHORT AND LONG TERM

Because of imperfect information, market mechanisms are needed to ensure efficient allocation of resources. We know from Akerlof's (1978) *lemons* example that private and uncertain information can cause markets to fail. Furthermore, Myerson and Satterthwaite's (1983) theorem shows that independently distributed private information about value and cost will lead to inefficient allocation of resources. Thus, good market design matters. However, good market design is not "one size fits all." It must be sensitive to the details of the context (Klemperer, 2002). In this section, we consider day-ahead market design issues and how we can fine-tune the current Nord Pool day-ahead market design to achieve the overarching purpose of providing reliable power at least-cost to final consumers both in the short- or long-run perspectives.

The efficiency of day-ahead markets in the short run

According to Cramton (2017), the first key objective of day-ahead markets is a short-run efficiency, i.e. making the best use of existing power generating resources. One of the ways the short-run efficiency of trading power can be improved is by increasing granularity in the day-ahead market to more closely follow actual ramping power. The purpose of shorter trading and delivery intervals is to provide market participants further opportunity to reduce imbalances with less need for regulatory intervention. There are several options for more sophisticated structures for flexibility that have already been demonstrated in other international electricity markets. This change in the day-ahead market design could help market participants by providing to them a closer approximation of the true price of flexibility. This could help to incentivise adequate investments and production decisions to make the system more flexible in a more cost-effective way. Thus, it is necessary to understand the key benefits and costs of having shorter trading and delivery intervals as a basis for day-ahead and other electricity markets. Benefits and costs of shorter trading and delivery intervals are widely analysed in several recent reports and studies, and thus, below, we briefly summarise the key findings of these analyses.

At the hour shift, the power imbalance can change significantly, or "jump", from one minute to the next. These jumps can be quite significant. Figure 4.6 illustrates the jump at the hour shift. For example, in Figure 2.1 we showed that in winter days there can be a significant need for ramping-up capacity of up to 2500 MW per hour, if wind resource is not available. In these critical winter morning hours, when the power system already faces steep ramping-up situations, additional imbalance "jumps" at the hour shift can create additional stress on the power system. As VRE penetration increases in the future, there is an increasing probability that these "jumps" at the hour shifts will become larger, and the finer trading time resolution is likely to reduce these jumps. A study by Copenhagen Economics (2017) provides an estimate that, in Sweden, the average imbalance jump around hour shifts can be reduced by about 18% by having 15-minute trading intervals.

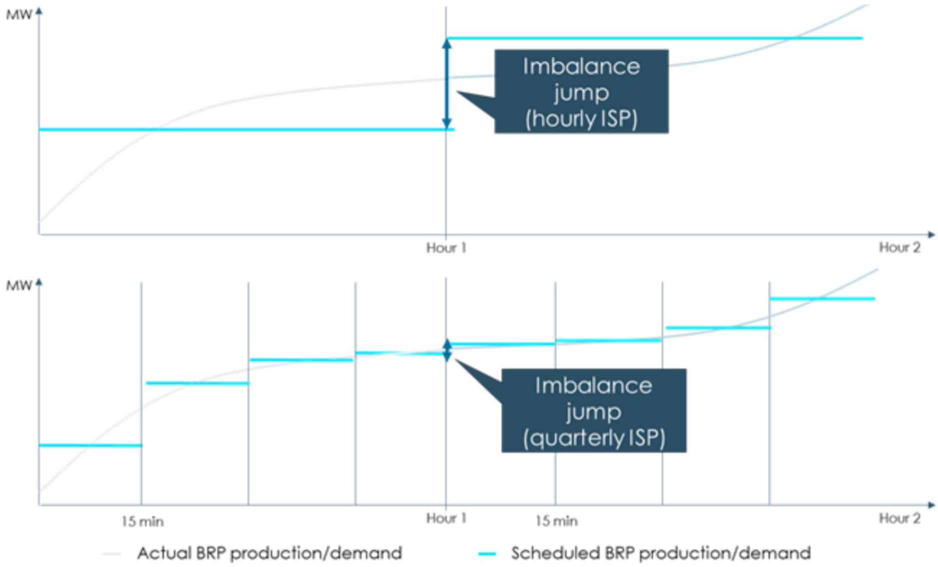

Figure 4.6. Imbalance "jumps" can be reduced by 15-minute trading intervals

Source: Picture is taken from Copenhagen Economics (2017).

An important additional longer-run benefit of 15 minutes interval trading is that it could encourage future investments in more flexible power generation plants. This market design change will favour flexible power plants that can easier adjust their power generation to VRE scheduling in the day-ahead market.

To sum up, most of the reviewed reports and research papers advocate the introduction of contracts with shorter durations. Previous studies expect benefits of 15-minute trading to accommodate increasing VRE production (Copenhagen Economics, 2017; Riesz & Milligan, 2015). On the other hand, some studies discuss potential issues arising from a more granular discretisation (Märkle-Huß et al., 2018). For example, there are technical market optimisation challenges in implementing 15-minute trading periods in the day-ahead market, as a number of intervals increases from 24 to 96. Thus, one may consider these 15-minute trading intervals only for the critical hours.

We believe that there is a knowledge gap about *ex post* effects of shorter trading and delivery intervals on electricity markets, in particular, on day-ahead markets. Previous studies are mainly based on simulations, simplified calculations, discussions or theoretical frameworks. Thus, there is a need for more rigorous *ex post* empirical evaluations in this area. These analyses should aim to investigate effects of finer trading time resolution on day-ahead markets in terms of electricity prices, its volatility and trading volumes.

The efficiency of day-ahead market in the long run

The second major objective of proper day-ahead market design, according to Cramton (2017), is a long-run efficiency to ensure that the market provides the proper incentives for efficient long-run investments. In principle, efficient long-run investment decisions should rely on the "right" day-ahead market prices. If market participants bid truthfully and there are no other major distortions, then the day-ahead market will achieve an efficient welfare-maximising outcome. However, this may not always be achieved in reality. Electricity markets are subject to market distortions and failures, such as all sorts of subsidies for energy resources or specific power generating technologies. Effects of such distortions in the Swedish day-ahead market still need to be investigated in the future research. In Sweden, one of the biggest market distortions, among many others, is subsidies to the specific power generating technologies.

Large subsidies are currently funnelled to VRE generation. On some days, Sweden produces more than 40% of its electricity from wind. In turn, subsidised wind power creates not only unfair competition in the day-ahead market (the merit order effect), potentially higher prices for final consumers, but also a negative externality for the whole electricity system in terms of costs for providing flexibility and adequacy. According to the Swedish Energy Agency (2016), new wind power together with other renewable power are likely to be subsidised until 2045 (see Part 1 of the report for more details). The important question is how this market distortion affect other electricity market participants, and how we can improve current market design to counter-balance the distortionary effect of VRE in the future. In order to counter-balance the subsidy-induced distortionary effects, first, we need to better understand which market participants are affected most.

Who pays for the subsidies to VRE?

In Sweden, electricity retailers are obliged by law to buy renewable electricity as part of their overall electricity portfolio in the form of tradable green certificates (TGCs). The price of TGC varies over time depending on supply and demand conditions, and it was about 20 EUR/MWh during the last decade (see Figure 1.5). Electricity suppliers' costs of buying these certificates are included in electricity bills of final electricity users. TGC price of 20 EUR/MWh (1 TGC is given for 1 MWh of green electricity produced) corresponds to an estimated average cost of about 4 EUR per MWh for all electricity consumers in Sweden.[23] However, it is obvious from our analysis of wind power effects on the day-ahead market's merit order (see Table 4.1) that electricity bill increase due to the subsidy is partly offset by the negative effect of having more wind power generation on the electricity price, i.e. the so-called "merit order effect."

Our naïve econometric estimations show that an increase in wind power generation of 1 MWh in 2017 can be associated with a decrease in wholesale electricity prices of about 0.002 EUR. In 2013-2017, wind turbines produced, on average, about 1600 MW in one hour. This means that electricity supplied by wind power plants decreased electricity prices by about 3.2 EUR/MWh in 2017. Thus, while final electricity users paid for wind capacity expansion via the TGC scheme (about 4 EUR/MWh more in 2008-2017) they ended up paying considerably less for their electricity because of the merit order effect.

Our estimation is a very rough and illustrative way to understand the distributional effects of having the TGC scheme in Sweden. Johansson and Kriström (2019) develop a general equilibrium cost–benefit rule to assess changes

[23] This information is available at http://www.energimyndigheten.se/fornybart/elcertifikatsystemet/om-elcertifikatsystemet/elkundens-bidrag-till-fornybar-elproduktion/.

in quantity-based subsidy schemes that support renewable electricity generation. They apply this rule to Sweden's existing TGC market, taking into account "trickle-down" effects, such as a loss of value-added tax income in the rest of the economy and environmental costs (i.e. externalities from electricity generation that are not currently internalised). They first present an *ex post* estimate, i.e. the welfare consequences of having scrapped the existing TGC system (from 2003 to 2017) and then an *ex ante* analysis of extending the TGC system to 2045. Overall, they find net present value gains from removing the subsidy scheme, taking into account externalities, "trickle-down" effects and public finance repercussions. There are also important distributional consequences of having the TGC system in operation. Apparently, TGCs cause considerable redistribution from electricity consumers to owners of green power plants.

Due to lack of data, the issue of power grid stability has been omitted from this study by Johansson and Kriström (2019). Taking into account the effects of "green" certificates on overall power system stability could be a direction for future research. According to Mount et al. (2012), even modest wholesale electricity price drops can cause "hidden system cost" by endangering the profitability of conventional power plants that are needed to maintain reliability of electricity supply when intermittent renewable energy sources are absent. In Figure 4.5, we presented how the profitability has changed for the large Swedish energy firms with assets, which are dominated by base-load power plants. It is evident that lower electricity prices have had a large effect on the profitability of these firms, and that the financial burden of electricity price drops is particularly large for companies owning less flexible base-load power plants (e.g., nuclear power plants). To make things worse for base-load power plants, in Sweden, there is another market-distorting subsidy that is funnelled to keep large flexible power reserves in operation (in Swedish, effektreserven). These subsidies further squeeze the profitability out of the Swedish energy companies that rely on the base-load power plants.

Given these distortions, one might argue that it is unlikely to expect the efficient welfare-maximising outcome in the Swedish day-ahead market. There is a need to review the regulatory framework governing how the power from subsidised VRE and reserves is traded and used. It is necessary to ensure that market-distorting subsidies affect the functioning of the day-ahead market as little as possible. Thus, there is a need for better understanding the extent of these distortions in the Swedish electricity system, and ways to minimise the negative effects of these distortions for the whole society.

One way to minimise the distorting effect of VRE subsidies is by giving conditional subsidies. In the current scheme, RES-based power plants receive electricity certificates whenever they produce electricity, even when electricity prices are close to zero or even negative. If the price of TGC is high enough, the renewable power generating plant can sell its electricity profitably despite the negative market price of electricity. One way to solve this problem and to increase the overall electricity market efficiency, is not to issue "green" certificates when electricity price is negative or below the pre-determined price level. This has also been proposed in the report by the Swedish Energy Agency (2016). Another alternative, which was proposed in the report by IVA (2016), is to replace the current TGC system with a "price-premium" subsidy (a certain percentage of the electricity price). This VRE support measure would give incentives to invest in capacity that can be used during the periods when the demand is high. This option would be beneficial for bio-based power plants.

The future long-run market design should also provide incentives for generators to keep sufficient amounts of reliable power and/or storage capacity. The key issue for the future is the pricing of capacity, and the consequences of seemingly insufficient capacity adequacy. Energy-only markets, as in Sweden, rely solely on price signals from wholesale and balancing markets to induce sufficient investments in resources to meet the abrupt changes in electricity consumption and production. The challenge with the energy-only market is that it typically takes several years to build new generation capacities. If there is adequacy or flexibility issues in the market, there may be capacity markets which can serve as an insurance policy and coordination device to better optimize future investments in needed capacity. While the general theory of energy-only markets suggests that the optimal number of power plants should be able to recover their costs, Joskow (2008) gives a number of reasons why this may not happen in practice. However, capacity markets are difficult to design and operate. Pollitt and Anaya (2015) and Newbery (2016) discuss some of the issues related to capacity markets in the European perspective, and Copenhagen Economics (2016) has a deep discussion on this matter for the case of Sweden. As currently Sweden has little or no issues with capacity shortage, system reliability or lack of flexible capacity, the capacity market mechanism is only relevant in the not-so-near future. Currently, to safeguard the stability and reliability of the Swedish power system it is more important to strengthen the design of day-ahead and other electricity markets and to maintain the stable regulatory environment in order to reduce uncertainty for future investments.

Electricity systems always require flexibility, and this flexibility has been rewarded in different ways. The recent rapid increase in VRE capacities has not changed this. Thus, the electricity system only needs to ensure its adequate ability to fully remunerate flexibility. In the next parts of the report (Parts 5 & 6), we will look at whether the other Swedish electricity markets – namely intraday and balancing markets – provide adequate price signals for having more flexible power generation capacity.

5 Developments in the Swedish intraday market

There is a common understanding that the role of intraday markets is likely to increase with the increasing share of intermittent renewable power generation. Well-functioning intraday markets may well lower societal costs of wind power integration and may directly benefit wind power producers who otherwise have to use other balancing strategies or to trade their generation imbalances at a higher cost in balancing markets. The theoretically implied positive premium (Soysal et al., 2017) in the intraday market should also adequately reward flexible generators for their timely contribution to power system security, thus making it profitable for them to stay in this market.

Yet, there is a lot of evidence showing that many European intraday markets, including the Nordic intraday market, are illiquid and hence might be inefficient and result in higher costs of imbalances (Weber, 2010). Historically, the volume of trade on the Nordic intraday market has been relatively low, especially, compared to that in the Nord Pool's day-ahead market. The low liquidity in the Nordic intraday market has led to concerns that many potential market participants may have been discouraged from participating in this market. According to Ei (2017), currently, the intraday market is used primarily by balance responsibility parties, which are mainly big power producing companies, even if there is no requirement to be a balance responsibility party in order to participate in the intra-day market.

This part of the repot proceeds as follows. First, we provide a short review of the literature concerning renewable power and functioning of intraday electricity markets (section 5.1). Second, we briefly analyse the question of liquidity in the Swedish intraday market in the very recent periods in order to understand whether problems related to liquidity documented in prior studies persist (section 5.2). Third, we examine the premium in the Swedish intraday market and discuss the implications for flexibility provision in the future (section 5.3). Finally, we identify relevant knowledge gaps related to the Swedish intraday market and propose future research directions that may be explored by academics and policy practitioners alike (section 5.4).

5.1 BRIEF OVERVIEW OF THE LITERATURE ON INTRADAY MARKETS

According to Scharff and Amelin (2016), there are different reasons why intraday trading is attractive to market participants. First, it offers a possibility to reduce the imbalance costs (which are unknown *ex ante*) to which electricity consumers/producers are exposed to when supplying/consuming more or less energy than they planned. According to Pogosjan and Winberg (2013), among Swedish balance responsible parties, this is the main motivation for intraday trading. Second, intraday markets give a possibility to optimize own production/consumption schedules, for example, by buying electricity to reduce generation in an own power plant that would be costlier to run. Last but not the least, intraday trading can also be used as a venue to sell flexibility of own production/consumption to other market participants who need this flexibility and are willing to pay for it. Without intraday trading, this flexibility might not be utilized because flexibility on intraday and balancing markets can have different characteristics. Balancing markets usually have higher requirements on balancing bids in terms of minimum bid size, activation times and purely physical fulfilment. This means that not all flexibility identified by market participants during the intraday trading period can be offered on the balancing market. In consequence, intraday markets provide a venue to access this flexibility and, hence, they should be regarded as complements rather than substitutes to balancing markets.

Despite these three economic motivations to participate in intraday trading, it is still puzzling why liquidity on intraday markets has been so low, especially now when the share of VRE generation is increasing, which we recall implies not only higher demand for flexibility but also provides greater opportunities for flexibility providers.

Weber (2010) was among the first to assess liquidity in several European intraday markets in France, Germany, Nordic, Spain and the UK. He defines liquidity as the ease of trading a particular good and the fact that a single transaction in this good can significantly affect its value. The ease of trade is defined as an increasing function of the number of market participants and the number of trades. Therefore, the actual trading volume is used as an indicator to measure liquidity. Weber (2010) compares the trading volumes across the selected intraday markets and concludes that, historically, liquidity in these markets has been rather low. For example, in the intraday market, which at that time encompassed Sweden, Finland and Denmark East, the trading volume stood at 1.6 TWh in 2007, which corresponded to only 0.3% of the total electricity consumed in the same year. Interestingly, in the case of the German intraday market, Weber (2010) compares the actual liquidity to the potential liquidity, which he defines as the required short-term adjustments. He concludes that the potential trading volume on the German intraday market should have been at least two times larger than the actual trading volume.

Scharff and Amelin (2016) also postulate the view that, in principle, there should be a clear correlation between VRE generation and trading activity in the intraday market. They analyse trading on the intraday market during the period March 2012-February 2013. During this period the intraday market included eight countries (Belgium, Denmark, Estonia, Finland, Germany, Norway, Sweden, and the Netherlands). Their hypothesis only holds in the case of Denmark, which had the largest share of wind power and traded most energy on intraday market in relation to its generated energy. However, this hypothesis does no explain why Finland with lowest wind power penetration had a half as high share of intraday market volume as did Denmark, with wind penetration multiple times that of Finland.

The Spanish intraday market has exhibited high trading volumes relative to the Nordic and other European intraday markets. J. Chaves-Ávila and Fernandes (2015) argue that high liquidity is a result of different Spanish electricity market regulations that incentivise market actors to participate in the Spanish intraday market. The actual intraday market design is another explanation of high trading activity in this market, where six auctions during the day of delivery itself are carried out.

Weber (2010) provides several possible explanations for poor liquidity. A first reason could be ineffective market design. For example, he argues that an auction-based intraday market design (e.g. in Spain) not only allows for flexible intraday trading opportunities and bundling of liquidity in dedicated auctions, but also is likely to lower the overall transaction costs. The reason being that it lowers the price risk for trading on the intraday market, which presumably is much higher in less transparent pay-as-bid intraday markets, where market participants may fear that their purchases or sales would affect the market price, and cause losses relative to the undisturbed price level. In short, it means that poor market design may become a self-sustaining phenomenon, as the absence of liquidity may reduce the trust in intraday markets.

Market structure can also have other effects upon trading volumes in the intraday market. For instance, J. P. Chaves-Ávila et al. (2013) argue that low liquidity on intraday markets could be explained by most power generators' willingness to commit their production long ahead of time because of start-up costs and generation planning. This explanation is valid for base load plants and other thermal generation plants but not for wind generators, who would benefit from participation in intraday markets that allow them to adjust their production commitments to updated forecasts. However, Mauritzen (2015) finds that in the case of Denmark, wind power generators behave asymmetrically with respect to wind forecast errors: wind power shortfalls increase the probability of intraday trading, while wind power surpluses make intraday trading less likely. Furthermore, Henriot (2014) suggests that poor liquidity in intraday markets may result from a rational behaviour of participants as he shows that the oscillating nature of wind forecasts can deter the players from trading in intraday markets provided it is not too expensive to procure energy in balancing markets.

While a high level of liquidity has been viewed as a standard criterion for an effective intraday market, some scholars argue that an optimal intraday market should not target a high trading volume per se, because economic agents behave according to the incentives that they receive from price signals (Henriot, 2014; Karanfil & Li, 2017). While sympathetic to this point of view, we nonetheless believe that improved wind forecasts and higher demand for balancing should eventually be reflected in this market, meaning that higher shares of VRE generation should lead to an increase – not necessarily proportionally – in trading activity in the intraday market. Additionally, as we wrote above, intraday markets are important not only for actors who are responsible for imbalances but also to other market participants who are willing to offer flexibility in own production/consumption. In this respect, easily accessible and well-functioning intraday markets are essential to access this flexibility. Moreover, well-designed and well-functioning intraday markets are important to prevent the abuse of market power (Borggrefe & Neuhoff, 2011).

Karanfil and Li (2017) suggest that another approach to analyse efficiency and functionality of intraday markets is through causality tests. That is, they recommend that instead of focusing on the level of liquidity or intraday trade volumes, it is better to consider causality between price signals and market fundamentals. If causality between the two can be established in a certain intraday market, it is reasonable to conclude that this market is effective and sufficiently liquid. Karanfil and Li (2017) test this approach in the case of Denmark and find that the Danish intraday market, which is part of the Nordic intraday market, is functioning as intended, since wind and conventional generation forecast errors are the two fundamental factors that drive the intraday prices, apart from the day-ahead prices.

Having these studies in mind, in what follows, we provide a quick look at the latest developments in the Swedish intraday market.

5.2 RECENT STATUS OF LIQUIDITY IN THE SWEDISH INTRADAY MARKET

In this section, we analyse the Swedish intraday market and we compare its actual trading volume to its hypothetical potential trading volume, i.e. a trading volume that would have been observed if all or most power imbalances were traded in the Swedish intraday market. Note that our aim is not to determine the balancing reserves *ex ante* and to calculate "the required physical adjustment capacity," as done by Weber (2010) and Hagemann and Weber (2015) in the case of the other European intraday markets, but to provide a simple back-of-the-envelope calculation of the potential trading volume on the Swedish intraday market.

We will assume that there are three unforeseen major sources for deviations between day-ahead plans and actual power delivery: load forecast deviations, wind power forecast deviations and unplanned *forced* power plant outages. The sum of the absolute load and wind power forecast errors and the forced power outages will give us an idea of the hypothetical potential trading volume, which we will contrast with the actual trading activity on the Swedish intraday market during the period 2015-2017. This exercise will allow us to answer at least three questions. First, which source of deviation does contribute most to the overall demand for balancing? Second, has the absolute wind forecast error been increasing because of the increasing share of wind power in the Swedish electricity mix? Third, to what extent is the intraday market used to trade in power imbalances? In other words, can we detect correlation between imbalances and intraday trading activity?

In Figure 5.1, we plot the annual positive and negative load forecast errors, the annual positive and negative wind power forecast errors, the annual forced power plant outages and the annual trading volumes, all measured in TWh. When considering all Swedish bidding zones, it is evident that the potential trading volume stood between 6-7 TWh during the period 2015-2017.[24] The absolute load forecast error is the major source of imbalance between the day-ahead forecast and actual power delivery. However, it was rather stable during the period under consideration (around 3 TWh/year). The absolute wind forecast error increased from 1.36 TWh in 2015 to 1.79 TWh in 2017 – a change of 32%. This increase is noteworthy when compared to the fact that the production of wind power during this period increased only by ten percent – from 15.38 TWh in 2015 to 16.88 TWh in

[24] January 2015 was excluded from the analysis due to data unavailability.

2017 (see Figure 5.2). This means that the absolute wind power forecast error per unit of wind power produced increased by about 20%. It is also important to note that it is the negative wind forecast error (overestimation) that contributed to this increase.[25]

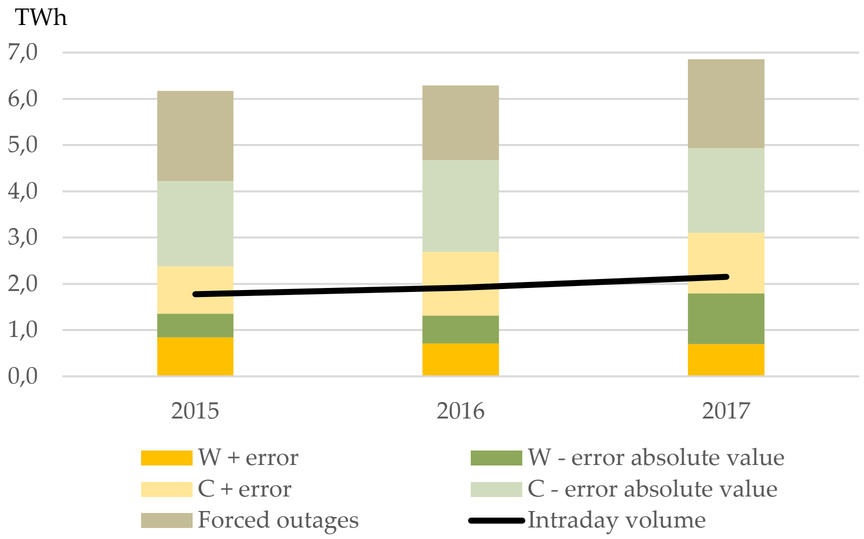

Figure 5.1. Potential vs actual trading volume in the Swedish intraday market, 2015-2017

Sources: Based on own calculations using the data from Nord Pool.

From Figure 5.1 it is evident that the potential trading volume is considerably higher than the actual trading volume on the Swedish intraday market, which ranged from 1.78 TWh in 2015 to 2.15 TWh in 2017. Similar dynamics could be observed across all four Swedish electricity bidding areas. However, the absolute wind forecast errors are more prominent in the areas SE2 and SE3, where they grew by more than 30% from 2015 to 2017 (see Figure 5.3). Yet, this increase in the absolute wind forecast errors is not reflected in trading activity on the Swedish intraday market – trading volumes in SE2 and SE3 areas stood at around 0.5 TWh and 1 TWh, respectively, during the years 2015-2017 (see Figure 5.3).

[25] Lower (higher) penalties for imbalances in the case of down-regulation (up-regulation) events may encourage wind power producers to overestimate their production. In 2017, the cumulative *negative* wind production errors (overestimation) were almost double the size of the cumulative *positive* wind power production errors (underestimation).

Figure 5.2. Wind power production and wind power forecast errors (-/+) in Sweden, 2015-2017

Sources: Based on own calculations by using the data from Nord Pool.

All in all, we can conclude that there is an apparent discrepancy between the expected trading volume and the actual trading volume, and this may imply that liquidity on the Swedish intraday market is low. It is very likely that this discrepancy remains even if we consider other strategies to reduce imbalances, such as a netting of imbalances within producers' and suppliers' own portfolios.[26] This option, for instance, is possible for large power producers who act as balance responsible parties and control several generation units within the same electricity bidding area. However, ownership of wind power production is far less concentrated, meaning that small wind power producers have clear incentives to participate in the intraday market to resume their imbalances.

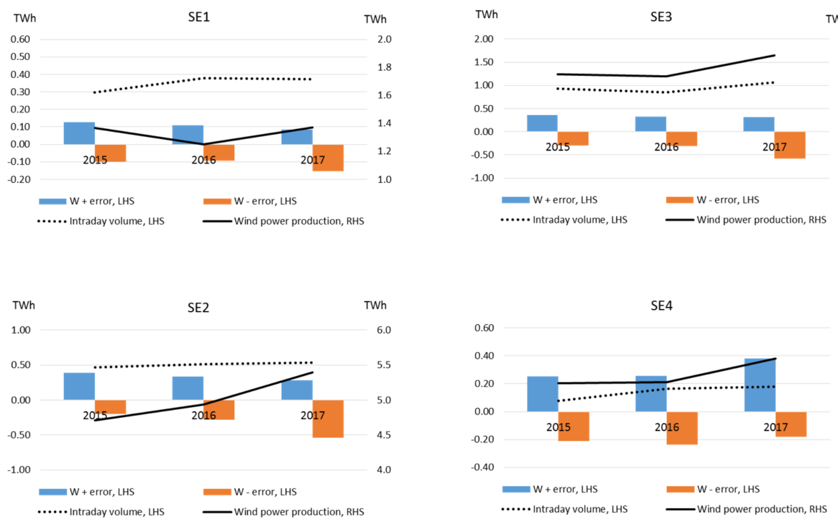

Figure 5.3. Wind production, wind forecast errors and intraday volumes across Swedish electricity bidding zones, 2015-2017.

Sources: Based on own calculations using the data from Nord Pool.

[26] Unfortunately, at the time of writing this report we could not find reliable information on the extent of other imbalance-reducing strategies, such as imbalance netting in the Swedish power system. Hence, we leave the question of the net size of imbalances in the Swedish power system for future research.

5.3 PREMIA IN THE SWEDISH INTRADAY MARKET

To fully understand the functioning and attractiveness of intraday markets, it is important to examine the formation of prices in these markets. One way to do it is to analyse the price premia of intraday over day-ahead prices and to investigate how they respond to total load adjustment needs and other fundamental intraday price drivers. If there is credible evidence showing that the intraday price premium in a certain intraday market does not respond to load adjustments (be they on the production side or the consumption side), one may perceive that this market is not functioning as expected and that actors solve their power imbalances either in regulating power markets or by applying other balancing strategies.

In principle, the intraday price premium, defined as the difference between the intraday price and the day-ahead price, should be positive, as we expect flexibility provided closer to the delivery hour be valued more. Additionally, according to Soysal et al. (2017), this premium should increase with the need for total load adjustment and it may even be asymmetric. Asymmetry in intraday price premia implies that premia for positive load adjustments are larger than those for equally-sized negative load adjustments. A positive load adjustment means a need for an upward adjustment (e.g., overestimation of wind power production or underestimation of consumption in the day-ahead market). A negative load adjustment implies a need for a downward adjustment, which occurs, for example, in the case of excess generation from wind power sources and/or an overestimation of consumption in the day-ahead market).[27]

The existing literature provides conflicting evidence regarding symmetry of the intraday price premium. For instance, Soysal et al. (2017) find that, in the Nordic intraday market (includes all price areas of Denmark, Estonia, Finland, Latvia, Lithuania, Norway and Sweden), intraday price premia are asymmetric, while a recent study by Sekamane (2018) concludes that there are no asymmetries in price premia in this market (which includes price areas DK1, SE2 and SE4). It seems to us that the devil lies in the details and that the choice of data sample as well as empirical strategy significantly affects the results of these studies. Since, to the best of our knowledge, there is no study that scrutinises intraday premium formation in the Swedish intraday market only, in what follows, we provide a quick look at this issue to motivate further research in this area.

Figure 5.4 shows four scatter plots of hourly day-ahead prices and of hourly intraday prices across four Swedish electricity price areas during the period 2013 – 12 June 2018.[28] It is evident that the both prices are correlated and that in some instances the intraday price is higher than the day-ahead price, while in other instances the intraday price is lower than the day-ahead price. This implies that intraday price premia could be positive as well as negative. While one might

[27] The result of intraday price asymmetry is implied by some modelling assumptions. For more details please refer to Soysal et al. (2017).

[28] We chose 11 June 2018 as the final data date due to the fact that from the 12th of June 2018 the Nord Pool intraday market has been supported by the XBID solution, which allows for intraday cross-border trading across 13 European intraday markets.

hypothesise that premia are negative for negative load adjustments and positive for positive load adjustments, this hypothesis requires further investigation.

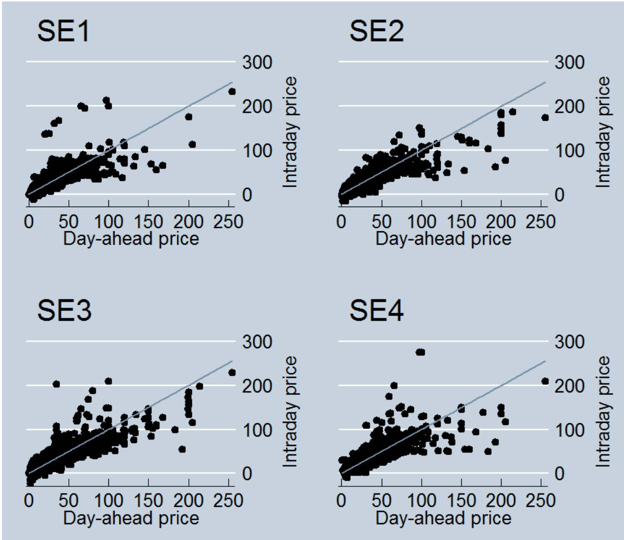

Figure 5.4. Hourly day-ahead electricity prices versus hourly intraday electricity prices across Swedish price areas, 1 January 2013–11 June 2018

Sources: Based on own calculations using the data from Nordic/Baltic FTP server.
Notes: Hours without intraday trades are excluded.

Table 5.1 shows that, on average, hourly intraday premia are negative in all Swedish electricity pricing zones during the period 2013-2018 (12 June). Average hourly premia range from -137.6 EUR/MWh to 177.4 EUR/MWh. Standard deviations indicate that intraday premia are more volatile in SE1 and SE4 electricity prices areas. Figure 5.5 shows dynamics of the annual average hourly premia across all electricity pricing zones. It is evident that, on average, the negative premia tend to get even larger in all zones during the period 2015-2018 (11 June).

Table 5.1. Descriptive statistics of hourly day-ahead electricity prices, intraday electricity prices and intraday premia, all in EUR/MWh, 2013–11 June 2018

Variables	Mean	Std. dev.	Min	Max	No of obs.
Intraday price (SE1)	30.25	10.29	-12	234.1	28,699
Intraday price (SE2)	30.02	10.44	-15.75	188	41,817
Intraday price (SE3)	30.50	11.25	-21.84	229.3	44,049
Intraday price (SE4)	32.84	12.05	-10	275	21,838
Day-ahead price (SE1)	31.17	10.24	0.320	255.0	28,699
Day-ahead price (SE2)	31.16	10.56	0.320	255.0	41,817
Day-ahead price (SE3)	31.50	11.13	0.320	255.0	44,049
Day-ahead price (SE4)	32.95	11.67	0.590	255.0	21,838
Premium (SE1)	-0.927	4.567	-105.1	134.6	28,699
Premium (SE2)	-1.143	3.976	-130.0	62.64	41,817
Premium (SE3)	-0.993	4.300	-137.6	167.3	44,049
Premium (SE4)	-0.114	5.705	-133.5	177.4	21,838

Sources: Based on own calculation using the data from Nordic/Baltic FTP server.
Notes: Hours without intraday trades are excluded from the descriptive statistics of all variables. Intraday hourly prices are volume weighted.

The negative intraday premia are puzzling for us, and it needs to be further investigated. We can only speculate that the negative premia may be a result of the imbalance settlement penalties, which, on average, are much higher for the hours of up-regulation than instead of the hours of down-regulation (for more details see Part 3 and Part 6 of the report).

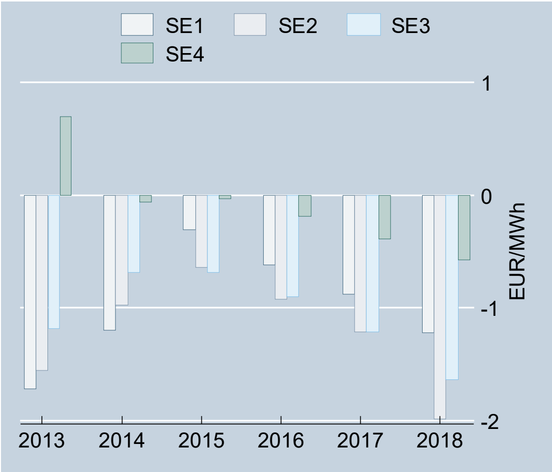

Figure 5.5. Average hourly intraday premia across the Swedish electricity bidding areas, 2013–11 June 2018

Sources: Based on own calculations using the data from Nordic/Baltic FTP server.
Notes: Hours without intraday trades are excluded.

The trimmed distributions of the intraday price premia in each Swedish electricity pricing zone are summarised by the histograms in Figure 5.6. To understand whether there is asymmetry in intraday price premia we present two histograms for each electricity pricing zone. One is for the case when there is expected need for an upward power adjustment (i.e., a power deficit occurring when there is overestimation of wind power production or underestimation of consumption in the day-ahead market) and a histogram of premia for hours when there is expected need for a downward power adjustment (i.e., a power surplus occurring when there is overproduction of wind power and overestimation of consumption in the day-ahead market). We expect intraday premia to be larger during power deficit hours than during power surplus hours.

From the histograms of the intraday premia presented in Figure 5.6, it is difficult to detect any asymmetry, implying that both positive and negative premia occur during expected power deficit hours or during expected power surplus.[29] Nevertheless, this argument requires further scrutiny and research for confirmation.

[29] One could use Kolmogorov-Smirnov method to test the similarity of these distributions

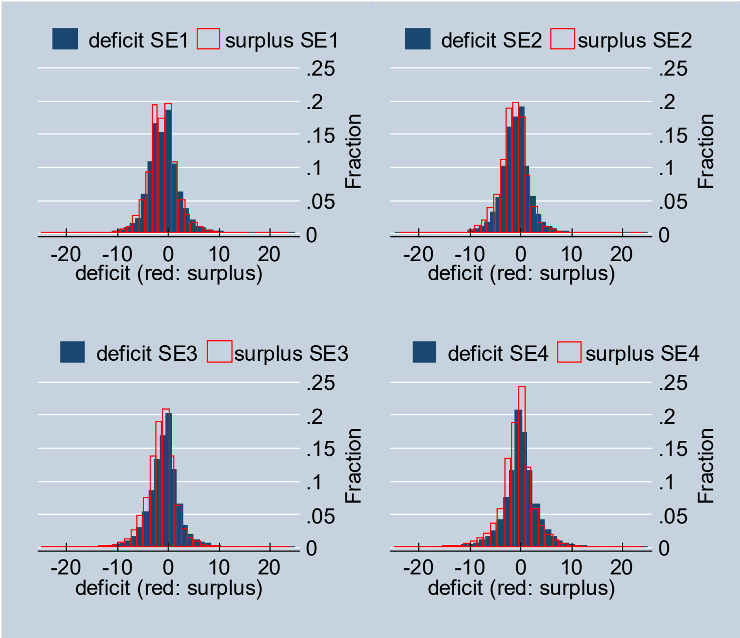

Figure 5.6. Histograms of the hourly intraday price premia across the Swedish electricity price areas, 2013 – 12 June 2018

Sources: Based on own calculations using the data from Nordic/Baltic FTP server.

All in all, our descriptive analysis suggests that, to date, the role of the Swedish intraday market in providing flexibility has not been very important. This is supported by two descriptive observations. First, trading volumes on the Swedish intraday market have been growing more slowly than the absolute wind forecast error. Second, flexibility provision in the Swedish intraday market, on average, has not been rewarded. This points to the fact that the Swedish power system has had sufficient access to cheap flexible capacity to deal with power imbalances. On the other hand, negative average intraday price premia may have discouraged flexibility providers from participating in this market, and instead have directed them to offer flexibility in balancing markets or to resort to other mechanisms. We will explore this issue in Part 6 of this report.

5.4 KNOWLEDGE GAPS AND FUTURE RESEARCH QUESTIONS

In general, we would like to emphasise that the Swedish intraday market and its role in power balancing and flexibility provision have been largely overlooked by the research community. This could be explained by the fact that the share of VRE has been relatively low when compared to the shares of VRE in other power systems, such as the ones in Denmark, Germany or Spain. In any case, there is need for empirical studies on the functioning of the Swedish intraday market, especially in the context of the currently rapidly increasing share of VRE generation and capacity in the Swedish power system. Below, we identify knowledge gaps and provide some research directions on the functioning of the Swedish intraday market.

On liquidity

We think that the most urgent research question related to the Swedish intraday market is why is liquidity is so low? And why are the developments of the absolute wind forecast error not reflected in this market? Can low liquidity be explained by other strategies used by market participants to reduce their imbalances (e.g., imbalance netting)? Or is this result driven by market fundamentals, such as high transaction costs, market concentration and other market inefficiencies or barriers? Or are the Swedish energy-only markets (wholesale and balancing markets) designed in such a way that they do not provide sufficient incentives for agents to participate in the intraday market? Hence, when considering the expansion of variable renewable power in the Swedish power system, an important question is whether the intraday market can be relied on for accommodating increasing power imbalances induced by increased share of VRE and in this way lower the final electricity cost for consumers? Can the Swedish intraday market compete with other balancing products that earn a capacity revenue or maybe are very flexible and hence may offer lower energy prices on the reserve markets than on the intraday markets? In any case, more research is needed to assess the optimal combination of intraday and balancing market designs and to investigate other non-market-related balancing strategies. This could be done by comparing cost and prices between intraday markets, balancing markets and other balancing products as well as by investigating costs and benefits of other non-market-related balancing strategies. Furthermore, for monitoring of market power and other strategic behaviour it is important to assess trading behaviour of different agents that operate in the wholesale and balancing markets. This type of analysis requires availability of transparent information about wholesale and balancing market actors, their technologies and bid prices (Borggrefe & Neuhoff, 2011).

An example of such analysis is a recent study by Karanfil and Li (2017) who suggest a new approach to examine the functioning of the intraday electricity market by testing causality among its fundamental components. They apply this method only to the case of Denmark for the period from January 1, 2012 to May 31, 2014. Hence, it would be useful to extend their analysis to other European power systems, such as the ones in Sweden, Germany, Spain and others.

Another suggestion is to derive an analytical benchmark model that would measure the intraday adjustment needs (i.e., theoretical trading volume) under consideration of fundamental intraday market drivers, market concentration and portfolio internal netting (e.g., see a study by Hagemann and Weber (2015). This derived theoretical trading volume, when compared to the actual trading volume on the intraday market, would allow one to assess the efficiency of the intraday market and also to better understand the intraday market's structure (e.g., competitive vs. oligopolistic). In addition, this model would allow simulating how intraday adjustment needs will change in the future when the share of VRE production increases. This type of model requires reliable information on extent of internal imbalance netting and other "off-market" balancing strategies, which could be obtained from the Swedish TSO or by surveying the Swedish balance responsible parties who are most likely to perform most of internal netting within their portfolios.

On premia and flexibility provision on the intraday market

In relation to the Swedish intraday price premia, it is crucial to understand why premia have been decreasing and why the close-to-real-time markets for flexibility provision have not been rewarded. For this purpose, we recommend an analysis of price asymmetries in this market by using state-of-the-art econometric models.

Gate closure time and improvement of forecasts

There is some discussion regarding moving the intraday gate closure time as close to real-time as possible. We decided not to provide a discussion on this topic as we believe it to be the TSO's role to decide whether the benefits of shortening the gate closure time outweigh operational costs of introducing and maintaining such a gate. Also, it is important to understand whether there is need for shortening the gate closure time and whether market participants have access to forecast tools that would allow them to produce close-to-real-time power production and consumption forecasts allowing them to benefit from the shortening of the gate closure time, issues outside the scope of our report.

Intraday vs. balancing markets

The intraday market is one part of the energy-only electricity market system in Sweden. Even though these markets function independently they are highly interrelated, making it is difficult to analyse the formation of intraday prices independently of those of the other markets. Most studies on intraday price formation take into account the role of day-ahead prices as clearly there is a high correlation between prices in the day-ahead market and prices in the intraday markets. However, the role of regulating markets is often neglected and, clearly, as we show in Part 6 of this report, flexibility providers have more incentives to operate in balancing markets than in intraday markets. While this is currently not an issue, the balancing market might dominate the intraday market in the future, calling into question the existence of the intraday market. It is a possibility that this may lead to an increase in the overall costs of resolving power imbalances and ultimately lead to higher electricity bills for final costumers. Consequently, it is important to understand whether the intraday market acts as a substitute or as a complement in providing flexibility services and how the role of the intraday market should change in the future.

6 Developments in the Swedish balancing market

The intraday and balancing markets are together the designated markets for pricing flexibility in the context of increasing VRE generation. The balancing market is a real-time market, ensuring that balancing prices reflect power scarcity in real time. Design features of the intraday and balancing markets envisage them acting in conjunction with each other (whether as substitutes or as complements). The key characteristic determining the difference between the balancing and intraday markets is that the former usually has higher requirements, in terms of minimum bid size, activation times and purely physical fulfilment, on bids. This means that not all flexibility identified by market participants during the intraday trading period can be offered on the balancing market. Therefore, intraday markets provide a natural venue to provide and access this type of "limited" flexibility. In this respect, intraday markets may be regarded as complementing the balancing markets.

In this part of the report, we focus on the impacts of VRE on the Swedish balancing market.[30] More specifically, we are interested in price incentives that this market provides to flexible power providers. The remainder of this part proceeds as follows. First, we provide an overview of the literature related to the effects of VRE on balancing markets (section 6.1). We then complement the literature review with an empirical analysis of the Swedish balancing market (sections 6.2 and 6.3). The chapter concludes with a summary of policy implications and future research directions (section 6.4).

6.1 EFFECTS OF VRE PENETRATION ON THE BALANCING MARKET

We provide an overview of the literature with a focus on effects of VRE integration on balancing markets in terms of *volumes* and *costs*. It is generally accepted that with an increasing share of VRE, absolute forecast errors are likely to increase, resulting in higher balancing service costs as more power plants have to be operated in more flexible ways to balance electricity supply and demand.

A series of quantitative studies have investigated the impact of VRE on additional *volumes* of balancing services. These, largely simulation-based, studies tend to confirm the expectations that balancing power volumes increase with the level of VRE penetration (see an overview of these studies provided by Brouwer et al., 2014; Holttinen et al., 2011; Ren et al., 2017). For example, Holttinen et al. (2011) report that, if only hourly variability of wind is taken into account, the impact on additional balancing power volumes is 0.5–4% of installed wind capacity at wind penetrations levels below 10% of gross electricity demand. Hydropower dominant power systems, such as in Sweden and other Nordic countries, tend to have lower

[30] The Swedish balancing market is only part of the Nordic balancing market. Hence, for more comprehensive analysis on how the Swedish balancing market copes with integrating the higher share of VRE one may prefer to analyse the whole Nordic balancing market.

expected additional required balancing capacities than power systems dominated by thermal power technologies for balancing.

Next, we look at the literature related to the effect of VRE penetration on balancing *costs* in Sweden and other countries. Hirth et al. (2015) provide a good literature review on this topic.[31] They divide the reviewed studies into two categories, based on whether balancing cost estimates were obtained using market-based prices or simulated by models. The main quantitative evaluations of total balancing costs are shown in Figure 6.1. They find that several market-based studies report rather high balancing costs. All other cost estimates, which are based on simulations, are below 6 EUR/MWh.

Not surprisingly, studies of hydropower-dominated power systems show low balancing costs. Hydropower dominant power systems possess inherent flexibility in generation, and the potential for energy storage in hydro reservoirs make them well-suited to integrate wind power. Agile hydropower plants can successfully mitigate the effects of increasing VRE integration (Acker et al., 2012). Thus, hydropower-dominated power systems can typically deliver balancing services at lower costs than power systems dominated by thermal plants. In the case of Sweden, Carlsson (2011) estimates that balancing costs of integrating wind power at 12% penetration rate is about 1.6 EUR/MWh, which are well below balancing cost estimates for thermal-power-dominated systems (see Figure 6.1).

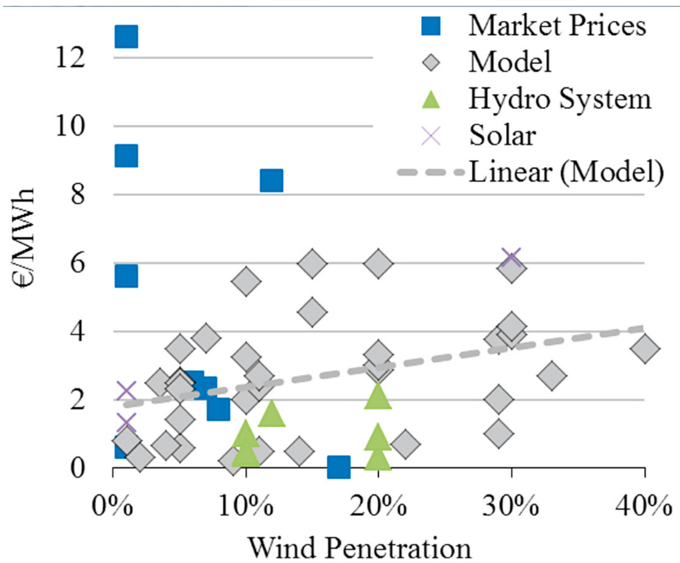

Figure 6.1. Balancing cost estimates for wind and power from market prices (squares) and model prices (diamonds) for wind and solar power (crosses)

Source: Hirth et al. (2015).

In summary, although studies disagree about the size of the effect of VRE expansion on balancing costs, all models show a trend of increasing balancing cost swith increasing VRE penetration. In section 6.3, we empirically test this finding

[31] Here we follow the *balancing cost* definition of Hirth et al. (2015) who define balancing costs as the marginal costs of deviating from announced generation schedules, for example, due to forecast errors. These costs should be reflected in price spread between day-ahead and real-time balancing prices.

for the case of Sweden, and we find no evidence of increasing balancing costs. Contrary to expectations, we find that balancing costs might have been recently decreasing with higher wind power penetration level. Before investigating this finding in more detail, in the next section, we examine the latest trends in trading volumes in the Swedish balancing market and investigate how these volumes were affected by VRE generation.

6.2 THE EFFECT OF VRE PENETRATION ON BALANCING MARKET VOLUMES

In Part 5 of this report, we highlighted that, in Sweden, there are three unforeseen major sources of stochastic deviations[32] between day-ahead plans and actual power delivery: load forecast deviations, wind power forecast deviations and unplanned forced power plant outages. The sum of absolute load, wind power forecast errors and forced power outages gave us an idea of the potential trading volume in the intraday market, which we have contrasted with the actual trading activity on the Swedish intraday market. Hirth and Ziegenhagen (2015) also discuss the above-mentioned stochastic sources of power imbalances and they add a deterministic cause of power imbalances that is relevant only for the balancing market (see Table 6.1).

While stochastic processes include unplanned outages and forecast errors, deterministic processes are deviations between the stepwise schedules and continuous physical variables. Deterministic sources of system imbalances are predictable. At the hour shift, the imbalance can change significantly, or “jump”, from one minute to the next depending on market design of trading intervals. These jumps can be quite significant (e.g., Figure 4.6 illustrates the jump at the hour shift). Copenhagen Economics (2017) study provides an estimate that, in Sweden, an average imbalance jump around hour shifts can be reduced by about 18% by introducing finer 15-minute trading intervals in the intraday or day-ahead markets.

Table 6.1. Major causes of system imbalances

Stochastic	Deterministic
Forecast errors of VRE generation	Schedule leaps or “jumps”
Forecast errors of load	
Nuclear plant forced outages	
Other unplanned plant outages	

In panel A of Figure 6.2, we plot the absolute annual (positive and negative) load forecast errors, the absolute annual (positive and negative) wind power forecast errors and the annual trading volumes in the Swedish intraday and balancing markets, all measured in TWh. It is evident that the absolute wind forecast error significantly increased from 1.36 TWh in 2015 to 1.79 TWh in 2017 – a positive

[32] There are two aspects of VRE that are worth noting: one is the variability over a time period (day/month/season), which is largely predictable (deterministic); the other is the randomness of wind for any given day, which has a stochastic component.

change of 32%. At the same time, the traded balancing power volume decreased from 1.84 TWh in 2015 to 1.56 TWh in 2017 – a negative change of 15%. Similar dynamics in traded balancing volumes can be observed across all four Swedish electricity bidding areas (see panel B in Figure 6.2). These empirical observations seem to contradict the theoretical expectations, which we have summarised above.

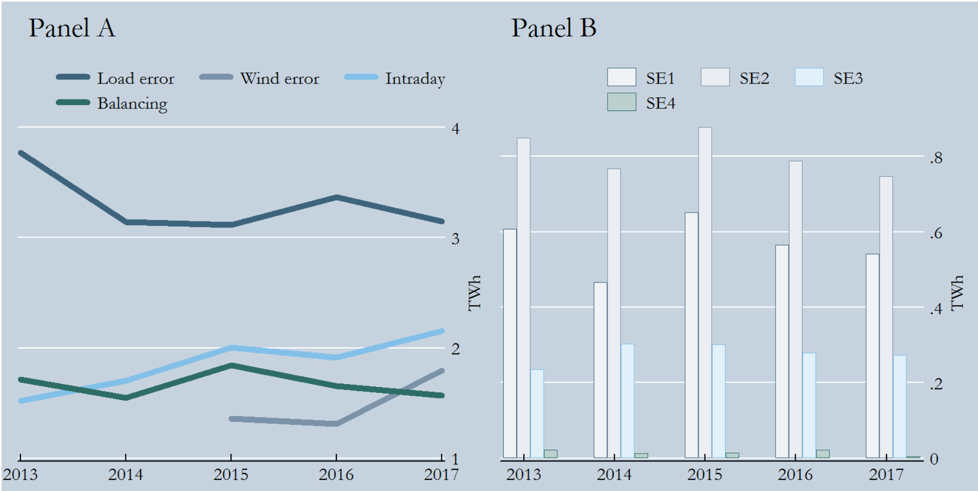

Figure 6.2. Panel A: Trading volumes in the Swedish balancing and intraday markets and major stochastic causes for trading imbalances (wind and load forecast errors), 2013-2017. Panel B: Trading activity in the Swedish balancing market across electricity bidding zone, 2013-2017.

Sources: Based on own calculations using the data from Nordic/Baltic FTP server.

Of course, the trend of decreasing balancing volumes in the last couple of years does not mean that the future increase in VRE capacity will reduce balancing needs. It could be that, for example, the liquidity of intraday market is improving (see more discussion in Part 5), and imbalances caused by stochastic wind forecast errors are traded there, instead of using more expensive way of paying for imbalances through the balancing market (this seems to be the case by looking at panel A in Figure 6.2). Another plausible explanation is that power companies become better in managing their imbalances by netting them instead of paying punitive imbalance prices. Thus, one needs to make in-depth *ex post* analyses to understand better the effects of wind power expansion on the balancing and intraday markets as well as on other balancing strategies, such as imbalance netting. If netting is a prevalent balancing approach, then it is important to understand motivations and costs of this balancing strategy. Another important question is to what extent the Swedish power system can rely on imbalance netting within power generators' portfolios.

We found no *ex post* studies that try to explain the declining trading balancing volumes in the context of the increasing absolute forecast errors. It is surprising that such a phenomenon is also present in Germany (Hirth & Ziegenhagen, 2015) and other countries. Brouwer et al. (2014) also find that balancing reserves did not increase in Denmark, Spain, and Portugal either, despite considerable VRE expansion in these countries. Hence, there is a clear need for more detailed *ex post* analyses on VRE impacts on balancing markets not only in Sweden. Below, we provide a preliminary analysis, where we explore some short-run impacts of VRE expansion on trading volumes in the Swedish balancing and intraday markets.

By using simple econometric techniques and by controlling for seasonal and hourly effects, we find that the absolute wind power forecast error (positive and negative) did have a positive effect on the hourly traded volumes in both the balancing and intraday markets. Figure 6.3 summarises our estimations. It is evident that the impact in terms of the required MWh to balance wind power is getting smaller in both markets. According to our estimates, in 2015, the impact of 1 MWh of wind power forecast error was associated with an increase of 0.2 MWh in the traded volumes in the balancing and the intraday markets. However, in 2017, the same size of wind power error had a much smaller impact on both markets. A plausible explanation of decreasing wind power impact on balancing volumes is that power companies become somewhat better in managing their imbalances by netting. It could also be related to some technological improvements or increased capacity of interconnectors. Thus, one needs to make more comprehensive *ex post* analyses to investigate the causes of these findings.

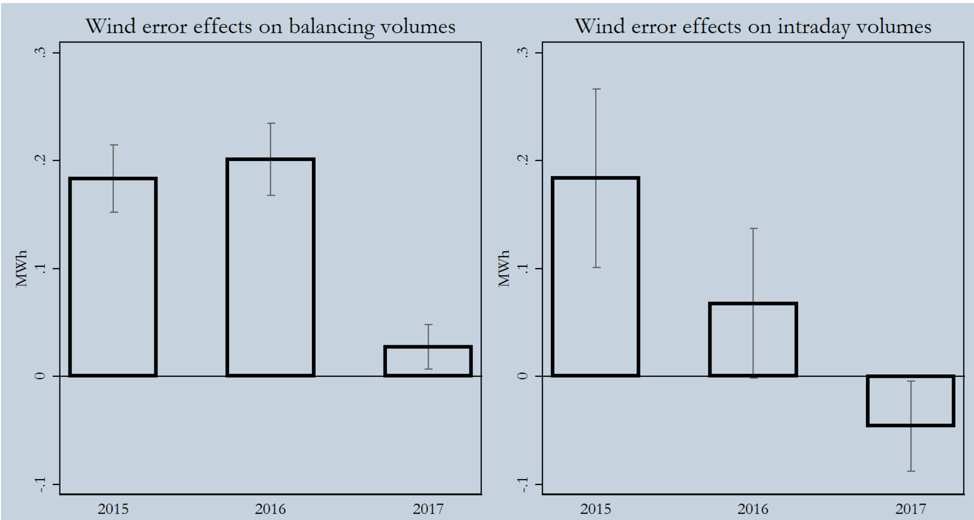

Figure 6.3. Short-run (hourly) wind forecast error effects (of 1 MWh) on trading volumes (in MWh) in the Swedish intraday and balancing markets

Sources: Based on own estimations using the data from Nordic/Baltic FTP server.
Note: The bar graphs include 95% confidence intervals.

6.3 THE EFFECTS OF VRE ON BALANCING MARKET PRICES

To understand the functioning and attractiveness of balancing markets, it is important to examine price formation in these markets and the effect of VRE expansion on these prices. One way of understanding price formation is to analyse balancing price premia over the day-ahead price and to investigate how they respond to the increasing share of wind power. If there is credible evidence showing that balancing price premia and volumes in a certain balancing market do not respond to increasing absolute wind forecast errors, one may perceive that this market is not functioning as expected and that actors solve their power imbalances by applying other balancing strategies. In addition, we examine price formation for balancing services across all Swedish electricity bidding zones and disentangle between situations of up- and down-regulation. We investigate the impacts of VRE generation on balancing prices by examining hourly trading data from 2013 to 2017.

First, we investigate balancing price formation in relation to day-ahead prices. In Figure 6.4, we present scatter plots of hourly day-ahead prices and of hourly balancing prices for both up and down regulation across four Swedish electricity bidding areas during the period 2013 – 2017.[33] It is evident that both prices are quite correlated but not so much as intraday and day-ahead prices. It seems that balancing prices for up-regulation tend to be more volatile when day-ahead prices reach about 20 EUR per MWh and more. For instance, when electricity production becomes scarcer in the day-ahead market, one can expect that the premium for up-regulation will increase and be more volatile. Meanwhile in the case of down-regulation we see different price formation pattern. Prices for down-regulation tend to stay flat after day-ahead prices reach about 50 EUR per MWh. The pattern of day-ahead and balancing prices in Nord Pool is also analysed by Skytte (1999). He also finds this asymmetric price formation pattern for up- and down-regulation that may encourage VRE producers to be strategic in their bidding on the wholesale markets.

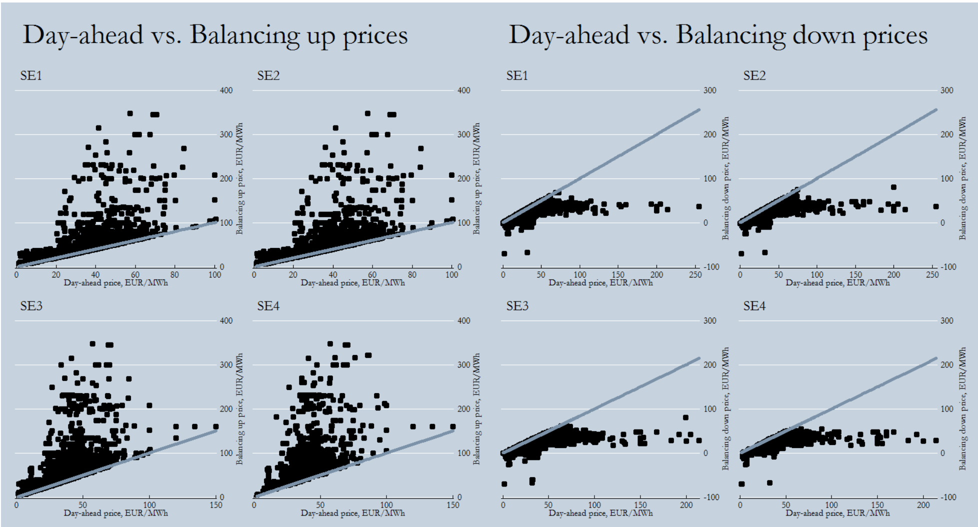

Figure 6.4. Hourly day-ahead prices versus hourly up- and down-regulation prices across Swedish electricity bidding areas, 2013–2017

Sources: Based on own calculations using the data from Nordic/Baltic FTP server.
Notes: Hours without trades are excluded; few observations for hours with prices higher than 500 EUR/MWh and smaller than -500 EUR/MWh were excluded.

If one wants to better understand balancing markets and the motivation of electricity producers to participate in them, one should consider the relative size of

[33] Up-regulation in the balancing market means a need for an upward adjustment (e.g., because of the underestimation of wind power production or underestimation of consumption in the day-ahead market). Down regulation in the balancing market implies a need for a downward adjustment, which occurs, for example, in the case of overproduction of wind power and overestimation of consumption in the day-ahead market).

balancing markets. The size of the Swedish balancing market in terms of value is still only a fraction of the Swedish day-ahead electricity market. According to our estimates, in 2017, the total balancing market size for both up and down regulation was 45 million Euros, which is only about 1% of the total value of electricity bought in Sweden through Nord Pool power exchange (it corresponds to about 0.33 EUR per MWh).

Figure 6.5 shows a downward trend in the balancing market size in value terms since 2013. The size of the Swedish balancing market, and hence the total balancing costs, for up- and down-regulations have decreased by about 30% since 2013. In other countries, the size of balancing costs is also quite low. For example, in Germany, Hirth and Ziegenhagen (2015) estimate that balancing cost are about 0.77 EUR/MWh. Rebours et al. (2007) report the range for balancing costs being 0.5–5% of the day-ahead market in other countries. The cost of balancing is even lower, if we consider the opportunity costs of trading electricity in the day-ahead market instead of reserving power capacity for the balancing market. Hence, a better way to evaluate balancing costs is to consider premia electricity producers receive on the day-ahead prices.

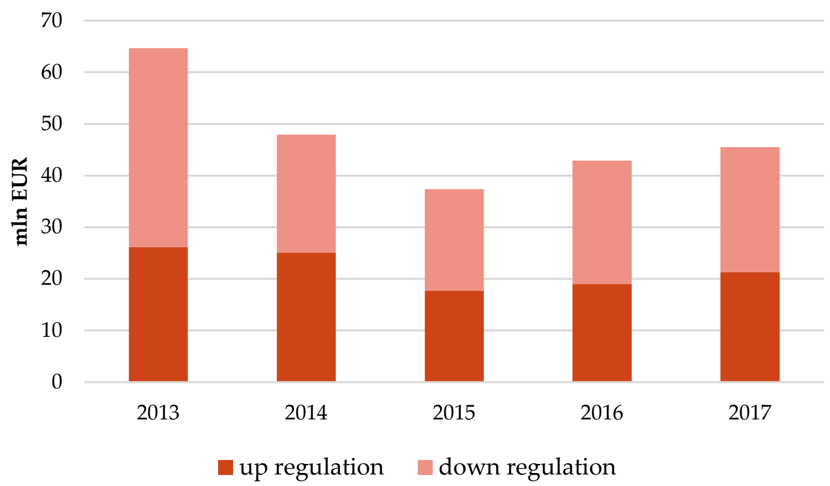

Figure 6.5. Market size of the Swedish balancing market, 2013-2017

Sources: Based on own calculations using the data from Nordic/Baltic FTP server.

In principle, balancing price premium (or spread) for up-regulation, defined as the difference between balancing price and day-ahead price, should be positive (it is negative for down-regulation). One should expect that flexibility feature (capacity to provide up-generation very close to delivery hour) has to be valued by real time markets. Table 6.2 provides the descriptive statistics of price spreads for regulating services across four Swedish electricity bidding zones, disentangling between situations of up- and down-regulation, based on hourly trading data from 2013 to 2017. A higher up-regulation spread means, on the one hand, higher revenues for balancing power supplying market participants, and on the other end, higher balancing costs for imbalanced parties. Meanwhile, a larger down-regulation spread means lower revenues for participants providing such service and lower balancing costs for imbalanced parties.

Table 6.2. Descriptive statistics of hourly balancing premia (spreads), all in EUR/MWh, 2013–2017

VARIABLES	Median	Mean	Std. dev.	Min	Max	No of hours
			Up-regulation premia			
Premium (SE1)	3.61	6.975	25.57	0	1,973	10,553
Premium (SE2)	3.43	6.348	22.90	0	1,973	13,336
Premium (SE3)	3.88	9.398	30.63	0	1,909	9,240
Premium (SE4)	20.19	39.94	54.17	0	589.8	1,081
			Down-regulation premia			
Premium (SE1)	-5.36	-6.520	5.791	-185.3	0	17,144
Premium (SE2)	-5.25	-6.373	5.882	-185.3	0	20,708
Premium (SE3)	-5.86	-7.585	7.467	-185.3	0	12,447
Premium (SE4)	-9.49	-14.06	15.40	-185.3	0	1,710

Sources: Based on own calculations using the data from Nordic/Baltic FTP server.

Although hourly premia for up-regulation can reach up to 2000 EUR/MWh, the average hourly premium range from 6.4 EUR/MWh to 39.9 EUR/MWh for up-regulation and from -14 EUR/MWh to -6.4 EUR/MWh for down-regulation, depending on electricity pricing areas. Balancing prices in the pricing areas SE3 and SE4 are much higher than in the pricing areas SE1 and SE2. Standard deviations indicate that up-regulation spreads are more volatile than spreads for down-regulation, as it was visible in Figure 6.4.[34]

Figure 6.6 shows dynamics of the annual average hourly spreads across all electricity pricing zones. It is generally considered that with the increasing share of VRE and/or increasing absolute forecasting error, the price differential between balancing-up prices and day-ahead prices is likely to increase. This would result in higher profits for power generators with flexible power technologies and would create incentives for new generators to enter balancing markets. However, in the case of the Swedish balancing market, the average premia for up-regulation were decreasing in all pricing zones (except in SE4) during 2013-2017, while the average premia for down-regulation remained rather stable over the same period. Since 2013, balancing premia for up-regulation have decreased, on average, by nearly 50% in all price zones, except in SE4, which is the smallest balancing market. A possible explanation for decreasing average premia can be better interconnection with neighbouring balancing markets (Norway and Finland). Thus, for the future research on this issue one needs to look at the whole Nordic balancing market to see if these premia are really decreasing.

As discussed above, declining premia for up-regulation has caused the size of the balancing market to shrink (see Figure 6.5). In conjunction with decreasing prices in other electricity markets ("merit order effects"), decreasing balancing market size puts further pressure on flexible power generators in Sweden. Consequently, as the difference between balancing power prices and day-ahead power prices gets lower, VRE operators face lower costs for settling their production deviations by using the balancing market.

[34] Actually, since the up-regulation price levels are higher, higher standard deviation does not necessarily mean higher volatility. Ideally, one would like to look at the inter-quartile ranges.

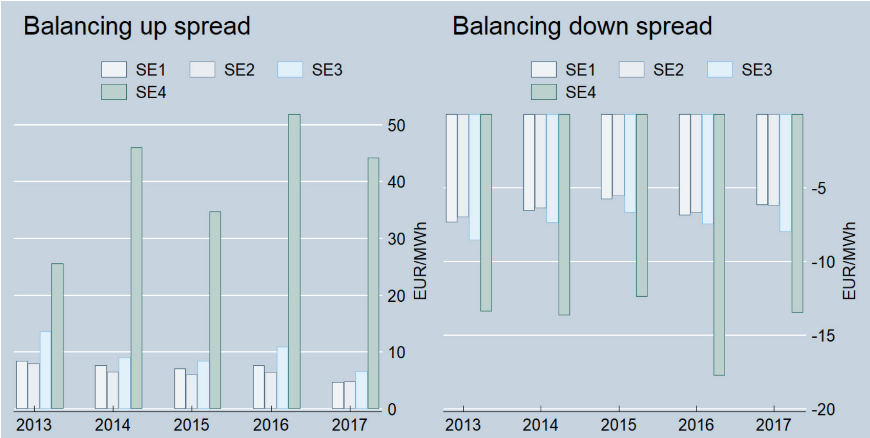

Figure 6.6. Balancing spreads across the Swedish electricity bidding zones, all in EUR/MWh, 2013–2017

Sources: Based on own calculations using the data from Nordic/Baltic FTP server.

Hence, balancing power is currently relatively cheap in Sweden, in particular, in the Northern part of Sweden and when compared to the total cost of the power system. Although balancing capability is considered a major challenge for VRE expansion in Sweden, it remains a small problem, in terms of economics. The fact that balancing costs are in decline as VRE generation increases does not mean that more VRE generation is its cause. This trend only indicates that there is no clear-cut relationship between more VRE generation and higher balancing costs. What is clear is that rapidly increasing VRE share in total generation does not necessarily dominate balancing cost development (Hirth & Ziegenhagen, 2015). Thus, there is a need for more *ex post* research to evaluate the relationship between price developments in balancing markets and VRE capacity expansion, especially, given the fact that most theoretical and simulation studies predict that this relationship is positive (see section 6.1). Below, we "quickly" test the hypothesis that the increasing share of VRE rises balancing costs by estimating the following simple econometric model:

$$P_t^{up\_reg} - P_t^{spot} = \beta_0 + \beta_1 Wind_{share_t} + Y_t + M_t + H_t + \epsilon_t.$$

Using this model we examine the short-run relationship between the premium for *up-regulation* services ($P_t^{up\_reg} - P_t^{spot}$) and the share of VRE generation in total power consumption ($Wind\_share_t$) in each price zone in Sweden. We investigate this relationship by examining hourly trading data from 2013 to 2017. Contrary to theoretical expectations, even after controlling for year-effects (Y_t), monthly seasonality (M_t) and hourly (H_t) fixed-effects, we find a negative short-run relationship between the share of wind power in total power consumption and the premium for up-regulation (see Table 6.3). For example, a 1 percent increase in wind share leads to a reduction in the premium for up-regulation by about 0.2 EUR/MWh. Of course, a more rigorous assessment of this relationship is a promising direction for further research.

Table 6.3. Wind penetration effects on up-regulation premium, all effects in EUR/MWh, 2013–2017.

VARIABLES	SE1	SE2	SE3	SE4
Wind penetration	-0.269***	-0.220***	-0.403***	-0.998**
	(0.0422)	(0.0327)	(0.0543)	(0.390)
Year dummies	yes	yes	yes	yes
Month dummies	yes	yes	yes	yes
Hour dummies	yes	yes	yes	yes
Observations	10,553	13,336	9,240	1,081
R-squared	0.023	0.022	0.039	0.121

Standard errors in parentheses, *** p<0.01, ** p<0.05, * p<0.1

In summary, our analysis suggests that, to date, the costs of providing flexibility in the Swedish balancing market have not been high. In particular, two of our findings from simple empirical explorations support this argument. First, trading volumes in the Swedish intraday market have not been growing, and the increasing absolute wind forecast error has had the positive but somewhat decreasing impact on the volumes traded in the balancing market. Second, average spreads in the Swedish balancing market have been in decline. Decreasing premia for up-regulation may discourage flexibility providers to participate in this market in the future.

6.4 DISCUSSION: MARKET DESIGN ISSUES AND FUTURE RESEARCH DIRECTIONS

One of the key roles of balancing markets is to provide economic incentives for imbalance creators to avoid such imbalances as much as is economically reasonable. Imbalances can be reduced in many ways, such as improved production and load forecasts (technical measures for imbalance management), or by introducing market design features to facilitate imbalance trade before it reaches more expensive (nearly) real-time balancing market. The design adjustment can be 15-minute trading intervals in intraday and day-ahead markets, improving liquidity and attractiveness of intraday markets, and more frequent updating of power production and load forecast.

On the other end, another key role of balancing markets is to create price incentives for balance service providers (e.g., hydropower or gas turbine plants). The market price of balancing power must reflect the actual scarcity of such power in the power system. Only "right" prices will ensure adequate and cost-effective investments into balancing power capacity. For example, Vandezande et al. (2010) show that full-balancing exposure to intermittent technologies is feasible only conditionally on well-functioning balancing markets. For efficient future investment decisions, the electricity system should have a better understanding of the potential needs for new balancing capacities in the near and further future. Thus, it is crucial to understand how imbalances caused by rapid VRE expansion translates into higher price and demand for balancing services. Better knowledge will enable better investment decisions in relation of integrating increasing VRE capacities in the Swedish electricity system.

Based on our analysis in this and the previous parts of the report, we find not much evidence that, to date, the increasing VRE share in Sweden has affected the flexibility of the Swedish power system in any substantial way (thanks largely to abundant hydropower generation). However, in the future, without base-load nuclear power generation and limited entry for new hydropower plants, the increasing share of VRE is likely to exert greater pressure on flexibility of the Swedish power system.

As we showed in Part 4 of the report, the profitability of nuclear power plants and their long-term viability have been negatively affected by low electricity prices in the day-ahead market. Thus, the expected phase-out of old nuclear power plants and limited new investments into new power plants could strain flexible resources in hours with little VRE generation. The phase-out of nuclear power plants is one of the biggest challenges for the Swedish electricity system. To understand the potential consequences of this phase-out for the Swedish balancing and other electricity markets, one needs to examine how actual forced and planned nuclear power plant outages affect these electricity markets.

Davis and Hausman (2016) emphasise two key effects related to the actual big nuclear power plant closure in California. The first-order effect of the plant's closure could be a large inward shift of the electricity supply curve. This lost generation could be made up by operating other generating resources with higher marginal cost. This may also result in more stress for flexibility resources and price volatility in the balancing markets.

It is also important to look at the second-order effects of nuclear power plant closures, which might have significant impact on electricity markets. The binding transmission and other physical constraints of the grid between the North and the South of Sweden mean that it might not be possible to replace the lost power output from decommissioned nuclear power plants (located in the South) by using more abundant generating resources from the Northern part of Sweden.

Another second-order effect of nuclear power phase-out may be the increased market power due to more binding transmission and other physical constraints of the grid between the North and the South. Transmission infrastructure limits the size of the power market and increases the opportunities for non-competitive behaviour, typically in the peak-demand hours. This may especially affect small balancing markets with very few market participants.

Mitigating the potential exercise of market power due to future nuclear power plant closures requires good understanding of price formation in electricity markets. Previous studies on geographic integration of electricity markets have either used theoretical models (e.g., Joskow & Tirole, 2000) or simulations (e.g., Ryan, 2017) rather than econometric analyses (Davis & Hausman, 2016). Tight market conditions in balancing markets during peak-demand hours at the time of nuclear plant outages might create opportunities for certain firms to exercise their market power. Using *ex post* analyses and available data on nuclear power plant outages one could assess whether energy firms have changed their pricing behaviour during nuclear power plant outages. This approach would not prove that energy firms has abused their market power, but at least it could serve as a good indicator of unusual behaviour in these markets at certain times.

The potential exercise of market power in balancing markets will distort the price signal for flexibility, and this will create inefficiencies by providing misleading signals for investment choices. With growing penetration of VRE, balancing services will be increasingly necessary during the hours close to real time and will amplify inefficiencies caused by limited competition. The key issue related to analysing and monitoring market power at individual plant level is unavailability of transparent information. The proper identification of potential market power abuse requires access to information on individual bidding prices as well as a detailed record of the state of the power system.

As the power systems and energy firms are becoming more interrelated across European countries, there is growing need for closer cooperation among institutions (regulators and researchers) across Europe. For an effective market power monitoring, regulators must have access to all relevant market information and researchers must be able to help regulators with analytical capabilities to provide necessary analysis for assessing the efficiency of balancing and other electricity markets.

Another important knowledge gap lies in understanding the actual barriers to trading in balancing markets and the willingness (demand) of energy firms to have a single electricity trading platform, which includes day-ahead, intraday and balancing markets. The issue with the current trading systems is the limited capabilities for energy firms to coordinate their bids between balancing and other energy markets. Currently, balancing services are acquired by Svenska Kraftnät, while electricity in the day-ahead and intraday markets is mainly traded on the power exchange Nord Pool. Smeers (2008) argues that these separate arrangements violate the finance view that day-ahead, intraday and balancing markets are just different stages of a single trading process and hence require a single trading platform. For electricity market participants, who trade in sequential markets with differences in price levels and risk exposure, it is relevant to analyse their potential willingness to coordinate their bidding across these markets. More accessible trading platform might help to have more participants in balancing markets, and therefore, it can help to ensure more robust price signals in these markets.

The Swedish balancing market is also subject to other market distortions, such as subsidies to keep the required rather large flexible power reserve, which may distort market price signals for the provision of flexibility services. The effects of such distortions need to be better evaluated in the future research. If the power reserve distorts the Swedish balancing market, there is a need to review the regulatory framework governing how power from the subsidised power reserve is used and to strive that this reserve affects the functioning of the balancing and other markets as little as possible. Only well-functioning balancing and other electricity markets will ensure cost-effective and flexible electricity systems.

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Appendix A.1

Derivation of the regression model:

Our electricity supply curve below describes a "smoothed" approximation of the underlying marginal cost curve (the merit order curve). We express our supply function approximation in a log-linear model:

$$Q_t^s = \rho_0 + \rho_1 P_t^e + \rho_2 Wind_t + \rho_3 Hydro_t + \rho_4 P_t^{wood} + \rho_5 Nuc_t + \epsilon_t^s$$

Second, electricity demand function can be expressed as follows:

$$Q_t^d = \alpha_0 + \alpha_1 P_t^e + \alpha_2 Load_t^{prog} + \epsilon_t^d$$

In order for the electricity market to clear, the demand has to be equal supply, that is:

$$Q_t^s = Q_t^d$$

When this market clearing condition is stated, we can solve for the electricity price (P_t^e):

$$P_t^e(\alpha_1 - \rho_1) = \rho_0 + \rho_2 Wind_t + \rho_3 Hydro_t + \rho_4 P_t^{wood} + \rho_5 Nuc_t + \epsilon_t^s - \alpha_0 - \alpha_2 Load_t^{prog} - \epsilon_t^d$$

Now we just rename the parameters in front of the explanatory variables (and rearrange a bit) to get a simplified final expression for our reduced-form regression model:

$$P_t^e = \beta_0 + \beta_1 Wind_t + \beta_2 Hydro_t + \beta_3 P_t^{wood} + \beta_4 Nuc_t + \beta_5 Load_t^{prog} + \epsilon_t$$

INTERMITTENCY AND PRICING FLEXIBILITY IN ELECTRICITY MARKETS

How can increasing intermittent power generation in the Swedish electricity system be managed in a more market-oriented and cost-efficient way?

The authors of this report argue that market mechanisms are the most natural means for obtaining the needed flexibility in electricity systems. A complete ex post assessment of the Swedish wholesale and balancing market functioning is crucial to determine the effectiveness of these markets in attaining their major objectives.

This report identifies knowledge gaps and suggests the most relevant ex post research directions and questions for analysing the Swedish electricity markets in relation to intermittency and pricing flexibility.

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