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Report

Balancing Markets and their Impact on Hydropower Scheduling

Review of Nordic Market Structures and Relevant Scheduling Methods

Author(s)
Arild Helseth, Marte Fodstad, Arild L Henden

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SINTEF

SINTEF Energi AS
SINTEF Energy AS

Address:
Postboks 4761 Sluppen
7465 Trondheim
NORWAY

Telephone: +47 73597200

www.sintef.no

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ABSTRACT
This report has been prepared in the early phase of the project 'Integrating Balancing Markets in Hydropower Scheduling Methods', and its purpose is two-fold. First, a review of the current Nordic power market design is presented, focusing on the sequences and rules of the various markets. Balancing services and markets are primarily organized per country, and we review the Norwegian and Swedish arrangements. A basic summary of recent historical volumes for these markets is also given to indicate the activity. Second, a literature review on the topic of treating multiple power markets in both short- and long-term hydropower scheduling is given.

PREPARED BY Arild Helseth	SIGNATURE Arild Helseth
CHECKED BY Michael Belsnes	SIGNATURE Michael Belsnes
APPROVED BY Knut Samdal	SIGNATURE Knut Samdal
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1 Introduction

The future European electricity system will be more integrated and will include a larger share of renewable intermittent generation than what is the case today. This development is e.g. driven by a stronger transmission grid, environmental targets set by the European Union and decisions on downscaling of nuclear generation capacity. Tighter market couplings and increased contributions from intermittent generation will call for efficient balancing services, and possibly the development of new products to handle system balancing.

The flexibility of hydropower allows for efficient balancing of intermittent production. By fully utilizing this flexibility, hydropower producers can optimize the use and allocation of available capacity in the different electricity markets. Thus, the value of flexible hydropower generation can be enhanced by participating in multiple markets. The importance of the different types of market products may change significantly from what hydropower producers in the Nordic power market are familiar with. Today, the producers primarily benefit from selling power in the day-ahead market. However, the inherit flexibility of hydropower enables active contribution in balancing markets as well.

Due to the long-term reservoir storage capability in hydropower dominated systems, a producer's resource planning should be done for a relatively long time horizon and with an appropriate representation of uncertainties (primarily market prices and inflow to reservoirs). The planning problem can be defined as a multi-stage stochastic optimization problem. In order to cope with the computational complexity of this problem while modeling a high level of detail, practical hydropower scheduling is normally organized in hierarchical levels. Long-term scheduling models provide end-value targets to shorter-term models, and there is a substantial refinement in time resolution and the level of technical details represented when going from long- to short-term models. Both tools for long-term and short-term scheduling applied in the Nordic power market today limit the market representation to the day-ahead market.

In the research project *Integrating Balancing Markets in Hydropower Scheduling Methods*, we ask how the overall scheduling problem should incorporate the increasing importance of balancing markets, seen from a hydropower producer's perspective. Traditionally, scheduling is done considering a market for trading electric energy[1], and price forecasts used in the scheduling refer to day-ahead (spot) prices. A price-taker hydropower producer will normally pursue the following objective: Maximize expected revenue from the energy market based on the price forecast, taking into account all physical and legislative constraints. In case the balancing markets contribute significantly to the revenue, the objective needs to include contributions from these. How can one find the economic benefit of offering both energy (MWh) and capacity (MW) to markets. The complexity of this challenge can be reduced by carefully considering which markets are the most important and which could possibly be neglected.

The purpose of this report is two-fold. First, it aims at reviewing the current power market designs in Norway and Sweden, particularly emphasizing on the sequences and rules of balancing markets. A basic summary of historical volumes for these markets is also given as a part of this review. Second, a literature review on the topic of treating multiple power markets in both short- and long-term hydropower scheduling is given.

1.1 Terminology

We start by defining and discussing some basic terminology used throughout this report. The terminology is somewhat loosely formulated, and is generally valid for European power markets.

The **day-ahead market (DAM)** is a market offering trade for day-ahead physical delivery. The DAM is centrally cleared and physical obligations may relate to a specific unit (e.g. as in the Iberian market) or a price zone (e.g. as in the Nordic market). The DAM is expected to be the place with the highest turn-over of electricity,

[1] In the rest of this report the term energy should be understood as electric energy.

determining the next day's system dispatch. This is an ex-ante market as it closes several hours before real time. Thus, to ensure physical balance in real time, reserves should be available.

Once the day-ahead market is cleared, the **intra-day market (IDM)** opens for physical energy trade. Here, the market participants can adjust their positions closer to real time. The IDM normally closes one hour before real time.

Ancillary services are services that are fundamental for the quality of a power system, i.e., security of supply, frequency stability, voltage level and voltage stability. These services are sometimes referred to as *system services*. It is generally challenging to provide ancillary services through a normal market mechanism since the need for these services is tied to quality aspects that are considered collective. All consumers within a synchronous grid receive the same frequency, and the voltage quality will basically be the same for consumers within a limited geographical region. Ancillary services are therefore acquired by the transmission system operator (TSO) in order to support the quality on behalf of the consumers. Table 1 lists what is normally considered as ancillary services in the Nordic market (Wangensteen 2007). ENTSO-E also includes black-start capability as an ancillary service (ENTSO-E 2014). Black-start capability is a measure of the capability of restoring a power station to operation without relying on the external electric power transmission network, and is particularly important for systems with a high share of thermal power production. In Wangensteen (2007), grid losses are also mentioned as an ancillary service.

Table 1: Ancillary services in the Nordic Power Market.

Type		Control (Activation)	Time response
Active reserves	**Primary reserve**	Automatic (frequency)	Seconds
	Secondary reserve	Automatic	Minutes
	Tertiary reserve	Manual	15 Minutes
	Load shedding	Automatic (frequency)	Minutes
	Production tripping	Automatic (frequency)	Minutes
Reactive reserves		Automatic (voltage)	Minutes
Reactive generation		Manual	Minutes

In this report we will focus on **Balancing services**, which refer to a subset of the ancillary services listed in Table 1, namely the primary, secondary and tertiary reserves. For the current Norwegian market design these corresponds to the markets for FCR[2], FRR-A[3] and RKOM/FRR-M[4] that are described in detail in Section 2.3.

After the closure of the IDM, the TSOs are responsible for matching supply and demand of electricity in real time. In order to ensure this balance the TSOs need to be able to acquire balancing services, both in terms of capacity (power) and energy. Thus, balancing services concerns both **reserve capacity** and **balancing energy**. The reserve capacity is used to assure system quality, while the balancing energy is used to restore the system's energy balance in real time. A peculiarity of balancing markets relative to the energy markets is that the TSO is the sole buyer in the balancing markets.

When it comes to exchange of balancing services across asynchronous areas, there is a distinct difference between the two services. Exchange of balancing energy is not in principle dependent on the reservation of cross border interconnection capacity, while market designs for exchange of reserve capacity normally will include reservation of cross border interconnection capacity to ensure that the buyer pays for an available service (Doorman et al. 2010). The need for balancing services is dependent on the market design. If it is possible to adjust the market balance closer to real time (e.g. through IDM) the need for balancing services are normally reduced since adaptations to short-term variations become possible. However, it is always necessary to have reserves available in case of contingencies (Wangensteen 2007).

The DAM and IDM concern trading and physical delivery for hourly time periods. Significant system imbalances may occur between IDM market clearing and real-time operation, thus, balancing services are needed to

[2] frequency-controlled reserves

[3] automatic frequency restoration reserves

[4] RKOM is the regulating power options market, FRR-M is manual frequency restoration reserves

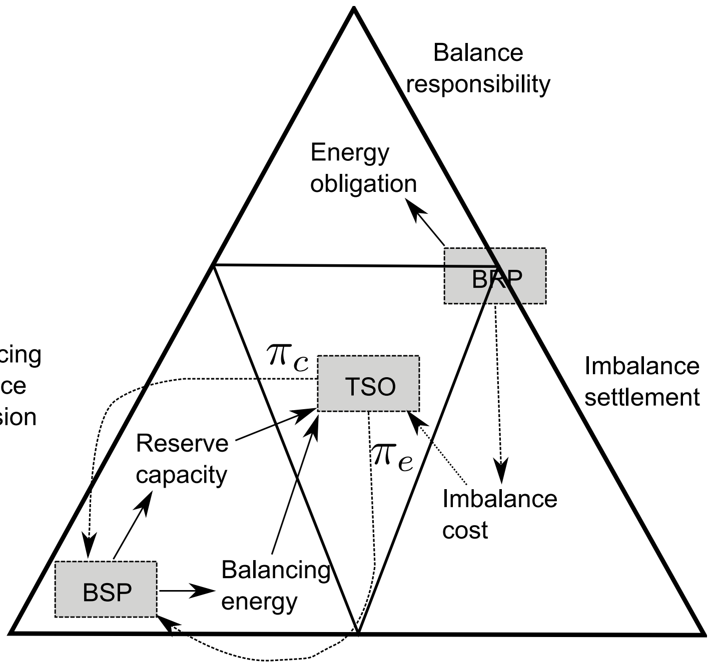

Figure 1: Basic structure of the balancing market.

ensure the instantaneous power balance. The type of balancing services being traded varies between European countries, as do the market sequences and market clearing frequencies. The term **balancing markets** will be used in this work for markets that are designed to provide balancing services, that is both reserve capacity and balancing energy. Since these markets share production resources with the energy markets, characteristics of DAM and IDM are also presented in this report.

Fig. 1, inspired by van der Veen et al. (2010), indicates three main pillars of the balancing market; balance responsibility, balancing service provision, and imbalance settlement. The dotted arrows in Fig. 1 indicate cash flows and the solid drawn indicate obligations and physical deliveries. The figure also points (boxes) to the three main actors involved; the **TSO**, the **Balance Responsible Party (BRP)** and the **Balancing Service Provider (BSP)**. These terms are defined next.

In a liberalised electricity market, the TSO is responsible for maintaining the balance between infeed and outtake of electricity in a control area. Since the TSO does not have production resources of its own, it must acquire balancing resources from players in the electricity market. As actual production and/or consumption deviates from planned production and consumption, the TSO buys balancing resources from producers and large scale consumers to ensure that the system is balanced at all times (Nordic Energy Regulators 2010). In the Nordic region the TSOs are Statnett for Norway, Svenska Kräftnat for Sweden, Fingrid for Finland, and Energinet.dk for Denmark[5].

The BRP concept is used in most European countries. The TSOs sign balancing agreements with BRPs. Each consumption and production point as well as connection point for interconnectors, have to have a unique BRP. Every producer, trader or supplier needs either to be a BRP themselves or have a contract with a BRP. Before the hour of operation, each BRP has a market position or balance, existing of the sum of all its obligations in the form of sales and purchases in organized markets like day-ahead and intraday, and through bilateral transactions. The BRP is generally obliged to try to act in such a way that it complies with this balance in real time, although the strength of this requirement varies between different markets (Doorman et al. 2010). Such obligations are often referred to as energy obligations and can e.g. be communicated between the BRP and TSO in the form of a production plan for some time period ahead in time, see Fig. 1. The BRP bears the economic responsibility for

[5]The Icelandic and Faroeish systems are disconnected from the other system and are therefore usually not seen as parts of the Nordic power system.

the imbalances created by those parties he is representing, and will have to settle his energy imbalances with the TSO ex-post. The BRP often has regulation resources at his disposal, which means that he can act as a player in the balancing markets. This is however not a requirement for being a BRP (Grande et al. 2008).

The TSO will obtain balancing services in terms of reserve capacity and balancing energy from the BSP. Procured capacity ensures availability of balancing services, whereas the actual activated energy is used to restore the system balance in real-time. The BSPs are remunerated according to capacity price π_c paid for procured reserves and the energy price π_e paid for activated balancing energy. In the Nordic area the BSPs are usually BRPs, so the concept of BSP is not frequently used, but in some countries it is possible for non-BRP actors to sell balancing services under certain circumstances (Nordic Energy Regulators 2010).

1.2 Why do we need balancing services?

Balancing services are needed to balance supply and demand at real time operation. More specifically, balancing services are needed to handle:

- Outages of power system components (power plants, transmission facilities, etc.). Such events are hard to predict and may cause severe system disturbances.
- Weather dependent exogenous factors (impacting e.g. demand and intermittent generation). Although forecasting methods continue to improve, weather forecast errors will always exist.
- Structural imbalances caused by the market design. These are imbalances that are due to the discrete time-resolution of DAM and IDM. Obligations may change in large steps in between consecutive hours, whereas load and intermittent production changes are continuous. Both the granularity (hourly time resolution) and time difference between market closure and real time operation leaves behind a need for balancing services.
- Congestions in the power grid that are not explicitly seen by the DAM and IDM. These are treated by use of manually regulated reserves.

2 Nordic Power Markets

The purpose of this section is to give an overview of the different power markets that a producer in the Nordic power market can participate in, covering the DAM, IDM and balancing markets, as defined in the previous section. The balancing markets are primarily organized by nation, and we focus on the Norwegian and Swedish arrangements, and include some volume figures to get an indication on the use of each market. Although both the volume figures and the balancing market regulations will quit fast become “yesterday’s news”, we hope that this review provide insight in the current market status.

There are several ongoing processes within the EU system to harmonize electricity markets, including balancing markets. As an example, the EU commission and the European regulators aims at establishing an internal harmonized market for automatic and manual frequency restoration reserves (FRR-A and FRR-M) within 10 years (Statnett 2014*c*). This development is certainly interesting and relevant in the future development of the balancing markets, but we have chosen not to directly address it here. For more information on the EU harmonization process for balancing markets and the relevant pilot projects under consideration, we refer to a separate project memo prepared by an intern in the SINTEF Energy summer project (Miao 2014).

Regarding the use of volume data for the Norwegian system, we have used two data sources; Statnett’s web pages and Nord Pool spot’s ftp-server. The following data regarding balancing markets are available through these sources:

Statnett:

- turnover and prices for primary regulation (FCR-N and FCR-D)

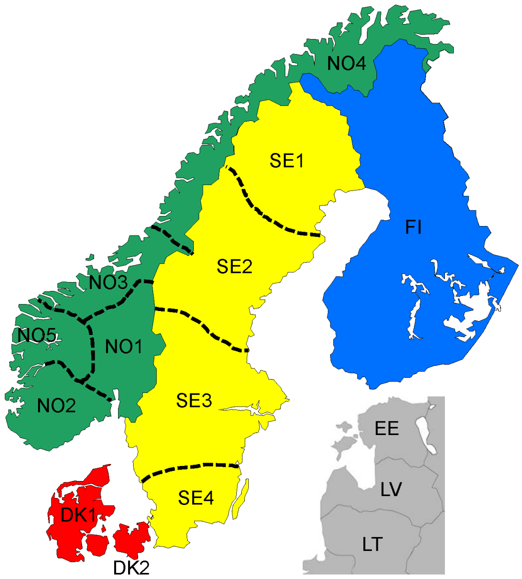

Figure 2: ELSPOT price areas.

- turnover and prices for secondary regulation (FRR-A)
- turnover and prices for reservation of tertiary control capacity (RKOM)

Nord Pool Spot:[6]

- bid volumes in the FRR-M market
- turnover and prices in the FRR-M market
- volumes used for special regulation
- automatically activated reserves

Most of the presented data refer to the year 2013. This was the latest full year of data that we could obtain when writing this report, and given the rapid change in structure of the balancing markets, it seems natural to study this year in particular.

2.1 The Day-Ahead Market (DAM) – ELSPOT

ELSPOT is Nord Pool Spot's (NPS) marketplace for trades in day-ahead physical electricity delivery. ELSPOT was established in 1993 as Statnett Marked AS, serving the Norwegian market only. In 1996, Sweden joined and the exchange changed name to Nord Pool ASA. Later on, Finland and Denmark joined the exchange, and NPS was established as a separate company in 2002. Currently, NPS is owned by the Nordic (Statnett, Svenska Kraftnät, Fingrid and Energinet.dk) and Baltic (Elering, Litgrid and AST) TSOs.

ELSPOT currently includes Norway, Sweden, Denmark, Finland and the Baltic countries. The division into ELSPOT areas, or price areas, is a result of the combination of the TSO's projections of which areas and interfaces that will experience power transmission demand exceeding the grid capacity. Currently ELSPOT comprises 15 price zones, with 5 in Norway, 4 in Sweden, one for each of the Baltic countries, one in Finland and 2 in Denmark. The term 'spot market' will usually refer to this market, which is also the norm in this document.

The market is cleared once a day as an auction with marginal pricing. Market players who want to trade energy on the ELSPOT market, must send their bid volumes and prices to NPS before 12:00 the day before physical

[6] All data are given per hour and per price area

delivery. The time delay between clearing and physical delivery ensures that thermal and nuclear power plants are given sufficient time to plan the up- and down-regulation of production (Bang et al. 2012). The bidding does not refer to individual plants and units, and is thus on portfolio basis for the given price area.

The system price is calculated based on all bids for the entire exchange area for each delivery hour the following day. The bids for buying and selling power are gathered in one curve for supply and one for demand. The intersection point of these curves defines the unconstrained, hourly system price, which serves as a reference price for the entire market. In case any of the resulting flows between price areas exceed their respective maximum capacities in a given hour, the market is split to find valid flow values and separate area prices for that hour.

Trading is based on three different types of orders: single hourly orders, block orders and flexible hourly orders. The largest share of the ELSPOT trading is matched based on *single hourly orders*. In the following we describe the single hourly orders, and refer to (*Nord Pool Spot* 2014) for further descriptions of block orders and flexible hourly orders. A market player specifies the purchase and/or sales order for each hour, represented by a bid curve of price/volume-pairs. Once the price for each hour is determined, a comparison with a player's order for that day establishes the delivery for the player. The minimum requirement for a single hourly order is two price-steps, at minimum price €-500 and maximum price €3000, also known as a price independent order. A price dependent single hourly order may consist of up to 62 price steps in addition to the current ceiling and floor price limits set by NPS. NPS linearly interpolates volumes between each adjacent pair of submitted price steps.

The TSOs require that market players expect no imbalances when bidding into a price area in the spot market, cf. §8 in (Statnett 2013*b*). If a player acts in a way that causes significant imbalances in any direction over time, the TSOs may withdraw its concession to produce. Thus, producers will be risk-averse when it comes to creating imbalances.

In 2013, 84% of all power in the Nordic and Baltic region was traded on NPS, with a total of 348.9 TWh being traded on ELSPOT (*Nord Pool Spot* 2014).

2.1.1 Relation to the Intra-Day and Balancing Markets

The ELSPOT market is often referred to as the spot market, but one may argue that this market is a forward market since the prices market players are finally exposed to are the real-time balancing market prices (Glachant & Saguan 2007). Although the market participants should not expect imbalances at the time of bidding, the time-delay between bidding and physical delivery allows imbalances to occur. When faced with an unbalanced portfolio, e.g. due to changes in weather conditions or (economically) unfortunate production plans, the BRP will in principle have two options:

a. Actively remove the imbalance by trading in the intraday market
b. Await the TSO's balancing service activation and imbalance settlement

2.2 The Intra-Day Market (IDM) – ELBAS

ELBAS (ELectrical Balancing Adjustment Sytem) is an IDM for the synchronous power system in the Nordic area organized by NPS. The ELBAS market was established in 1999 by Finland and Sweden, and Norway joined in 2009. It provides the opportunity for trading intraday power across country borders in the Nordic and Baltic regions, Germany and the Benelux countries (through the NorNed cable) (*Nord Pool Spot* 2014).

After closure of ELSPOT, market players can adjust their positions in the ELBAS market. ELBAS opens at 14:00, following the closing of the ELSPOT auction and publishing of day-ahead prices and trading volumes. Trades in ELBAS are allowed up to one hour before real-time, which gives the participants the opportunity to adjust for imbalances if production and consumption schedules deviate from the volume committed in ELSPOT. Thus, ELBAS functions as an after-market for ELSPOT.

A bid in ELBAS consists of the bid type (sell or buy), a price and a volume for a specific hour and price area. The trading process works as in a stock market, where the participants place their bids anonymously into a trading system. The trading system is developed for continuous trading, allowing the participants to follow the situation on the market, place bids and search trade and cash-flow information. Prices are set according to a pay-as-bid regime and based on a first-come, first-served principle (*Nord Pool Spot* 2014). NPS acts as the only counterpart for all trades on ELBAS, guaranteeing settlement and anonymity.

The trading participants will only see the bids that are available after transmission constraints have been accounted for. Initially, all available transmission capacity is given to the ELSPOT market. The ELBAS cross-border capacity is known when the deadline for filing complaints on the ELSPOT has elapsed and the cross-border capacity that is left after ELSPOT clearing is known. The participants are obliged to report their ELBAS trades to the relevant TSO. After a trade, the available capacities and offers in the entire ELBAS area are updated for market participants.

As with the ELSPOT, the TSO states that all trade in the ELBAS should be done considering the associated BRPs to be in planned balance (Statnett 2013*b*).

The total energy traded in ELBAS in 2012 and 2013 was 3.2 and 4.2 TWh, respectively. The traded volumes in the ELBAS market are rather small. According to Weber (2010), one possible explanation is in the market concentration. Large BRPs can find it advantageous to net imbalances using their own portfolio. The traded volumes are particularly low for Norway. A recent study of the ELBAS transactions in 2012 showed that the share of ELBAS volumes in total generation [7] differs significantly between Norway (0.1%) and Sweden (0.8%) (Scharff & Amelin 2016). Several characteristics may explain this difference. The flexibility in most hydropower producers' portfolios seems to give no obvious preference for correcting imbalances in the ELBAS rather than in the balancing market (regulating power). Scharff & Amelin (2016) also points to the facts that Norway has a lower share of wind power, lower capacity towards the Continental Europa (when ELSPOT trade has been accounted for), and lower export possibilities to the countries with higher balancing prices. One should also note that the two countries had different ELBAS gate closures in 2012 [8].

2.2.1 Relation to Balancing Markets

The ELBAS allows the participants to balance their portfolio by trade before the balancing market is cleared, and thus avoid the higher price spread that one may experience in the balancing markets.

While the balancing markets to a large extent yet remain national or at least confined in synchronous areas, the ELBAS is getting harmonized across borders. Through existing HVDC cables, Nordic hydropower producers have the opportunity to trade with countries outside the Nordic synchronous area. The ELBAS therefore represents an opportunity to trade some of the imbalance volumes, and one can therefore expect that imbalance volumes are shifted between asynchronous power systems. This will in turn have an impact on the volumes seen in the regional balancing markets.

2.3 Balancing Markets

The ELSPOT and ELBAS markets concern trading and physical delivery of energy for hourly time periods. Balancing markets aim at resolving the imbalances that may occur within the operational hours. Availability of and rules for the different types of balancing markets differ between countries within the Nordic market. In the following description we will focus on the Nordic synchronous system, where the four TSOs Statnett (Norway), Svenska Kraftnät (Sweden), Fingrid (Finland) and Energinet.dk (Denmark) are responsible for operational reliability and the balance between production and consumption of electricity. In particular we describe the Norwegian and Swedish markets and arrangements for providing balancing services. Some countries/regions are outside the Nordic synchronous system, but are interconnected through HVDC cables, e.g. Western Denmark. The frequency in Western Denmark is therefore not affected by Nordic imbalances, but this area can contribute to frequency control by delivering regulating power through the HVDC cables, and vice versa.

[7] ELBAS volume is evaluated as $0.5 \times (sales + purchase)$

[8] Sweden had one-hour gate closure in 2012, whereas Norway closed two hours before. Norway adopted the one-hour gate closure in 2013.

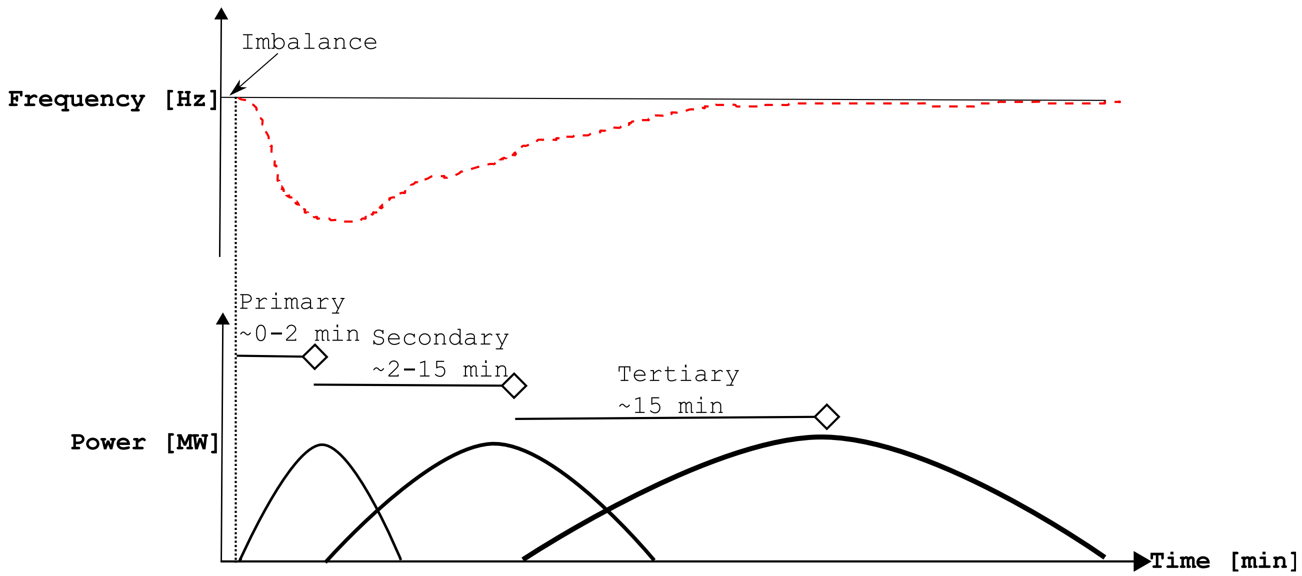

Figure 3: Illustration of activation sequence of different type of reserves (Statnett 2014*c*).

In the following we will describe the sequences and rules for the balancing markets. Much of the material is based on regulations (Statnett 2013*c*,*d*, 2014*d*, SvenskaKraftnät 2014*b*) and other documents (Statnett 2014*c*, SvenskaKraftnät 2012) from Statnett and Svenska Kraftnät. The operational requirements for the Nordic system are defined in a common system operation agreement (ENTSO-E 2013), which e.g. specifies how operational reserves should be maintained and distributed. The three different regulation principles (primary, secondary and tertiary) are illustrated in Fig. 3, and described below. A frequency deviation is caused by an imbalance between generation and demand, and primary, secondary and tertiary reserves are used to sequentially restore the frequency to its nominal value. The figure illustrates that secondary control is used to restore primary reserves, and tertiary to restore secondary.

From the replacement sequence indicated in Fig. 3 it follows that reserves delivered for primary, secondary and tertiary control should be independent. This requirement is pointed out by Statnett in §8 in (Statnett 2013*b*), particularly specifying that each plant's set point (p^{set}) is limited by the physical minimum (P_{min}) and maximum (P_{max}) production capacity and the market obligations (primary p_p, secondary up/down $p_s^{+/-}$ and tertiary up/down $p_t^{+/-}$):

$$P_{min} + \left(p_p + p_s^- + p_t^-\right) \leq p^{set} \leq P_{max} - \left(p_p + p_s^+ + p_t^+\right) \qquad (1)$$

According to the definitions in section 1.1 balancing markets refer to markets designed to provide balancing services. Generally balancing services are divided into three different products/reserve types needed to provide the control principles in Fig. 3. In parentheses the names of the Norwegian products currently corresponding to the general reserve types are given.

- Primary reserves (frequency-controlled reserves, FCR)
- Secondary reserves (automatic frequency restoration reserves, FRR-A)
- Tertiary reserves (manual frequency restoration reserves, FRR-M)

Both primary and secondary reserves are automatically controlled, and are normally characterized as so-called “spinning reserves”. That is, they should be running before called upon. In contrast, the tertiary reserves are manually controlled and do not need to be “spinning“.

The importance of reserve procurement may vary greatly between hydropower- and thermal-dominated systems. Procurement of reserves is generally less critical in systems with a large share of hydropower than it is in typical thermal systems. Hydropower plants can normally be started up in short time and have their best efficiency below maximum production. Thus, when operating at their best efficiency, hydropower plants provide spinning reserve for both up- and down-regulation at low operational cost. Thermal power plants are generally slower to start-up and are most efficient at maximum production, and will thus be more expensive to keep as spinning reserves. However, with an integrated European market in future sight, the separation between hydro- and thermal will become less distinct. The stronger coupling between systems will open for increased exchange of balancing services between systems, and a growing potential for socio-economic benefits stemming from coordinated operation of hydro- and thermal-based systems.

The term “replacement reserves” does not seem to belong to the standard terminology in the Nordic market, and will not be used here. According to ENTSO-E, replacement reserves are used to restore the FRR-M to prepare for additional system imbalances.

2.4 The Primary Reserve Market

Momentary imbalances between supply and demand will firstly be regulated by use of primary regulation reserves. The system frequency is controlled by automatic activation of frequency-controlled reserves (FCR). Such reserves are currently assured by the droop setting in the turbine governors for generators exceeding 10 MVA (Norway). If they are spinning and not already operating at full load, generators respond automatically to changes in frequency according to their droop setting. That is, generators that do not participate in the primary reserve markets will still participate in the primary regulation. The TSOs need to assure that there are enough spinning reserves in the system and that these reserves are geographically distributed so that the risk of overloading the transmission system is limited.

2.4.1 Market Structure – Norway

In previous years, Statnett would ask Norwegian generators to adjust the droop in case of insufficient reserves. In that sense, primary control was considered a free service and there was no market for this type of service. In 2008 two primary reserve markets were established; a weekly and a daily market. These markets are operated by Statnett according to conditions stated in (Statnett 2013*d*). After introducing the marketplace for primary reserves, Statnett decides on a maximal droop setting to ensure a distributed supply of primary reserve from spinning aggregates. The producers can supply more reserves than the required lower limit by decreasing the droop setting or by running more aggregates than originally planned.

Two products are traded in the Norwegian primary reserve market, namely FCR for normal operation (FCR-N) and for contingencies (FCR-D). Both are automatically activated; FCR-N is activated when the frequency is within the ”normal range” (49.90 - 50.10 Hz), whereas FCR-D is activated when the frequency falls below 49.90 Hz. For FCR-N both response directions (up and down) should be available for a given market bid. The FCR-N and FCR-D market products do not only differ in the frequency band, but also in the activation response time.

The division of the primary reserve market in a weekly and daily market is based on an agreement between Statnett and the producers (Statnett 2014*a*), and can be seen as a compromise between the ability to secure sufficient reserves at early phase on the one hand, and the system cost and loss of flexibility in the production system by doing so on the other.

The weekly market only concerns FCR-N and is divided in 6 time periods (combinations of weekday and weekend with daily periods night, day and evening). Bids to the weekly market should be given per price area and should be delivered before Thursday 12:00 for the coming weekend and before Friday at 12:00 for the coming weekdays. The daily market concerns both FCR-N and FCR-D. Bids are given for the type of primary reserve, per price area and per hour for the day-ahead, and should be submitted before 18:00. Both the weekly and daily markets are primarily cleared according to the marginal pricing principle. All accepted bids will then receive the marginal price in NOK/MW/period. Committed capacity in the FCR-N and FCR-D markets should be reserved for this purpose, and should not be affected by the responsible party’s contribution in other markets.

Statnett may deviate from the marginal pricing principle by buying reserves that are priced higher than the marginal price, in order to meet all relevant constraints. Such purchases are referred to as “special purchase”, and are remunerated according to the pay-as-bid principle. Delivery of FCR that has not been a part of the market solution, is referred to as “rest delivery” and is remunerated according to a predefined price set by the TSO. The balance settlement is therefore divided in four categories; the weekly and daily markets, the special purchases and the rest delivery.

2.4.2 Market Structure – Sweden

In 2011 Svenska Kraftnät started procuring primary reserves according to the definitions of FCR-N and FCR-D above. Primary reserve bids should be delivered either the day before (D-1) or two days before (D-2) the day of operation, and can be stated per price area *or* per regulating object. Unlike the case in Norway, Svenska Kraftnät uses the pay-as-bid principle when procuring reserves, and provides guidelines on how to calculate bids. Bids shall be cost-based and provide some margin for profit- and risk premium (SvenskaKraftnät 2010, 2014*b*).

2.4.3 Volumes in the Primary Reserve Market

The delivery (p_p, in MW) of FCR for a specific generator is limited by its rated value (P_N, in MW), frequency band (Δf, in Hz) and droop setting (ρ, in %), according to (2). Δf is 0.1 Hz for FCR-N and 0.4 Hz for FCR-D (Statnett 2013*b*, SvenskaKraftnät 2012).

$$p_p = \frac{2P_N \Delta f}{\rho} \tag{2}$$

The FCR-N reserve requirement is defined per subsystem within the Nordic synchronous system on the basis of annual consumption (total consumption excluding consumption by power plants) in the previous year (ENTSO-E 2013). Table 2 shows the FCR-N requirements per country in the Nordic synchronous area in 2013. The joint requirement for the synchronous system is 600 MW, and the corresponding frequency response [9] is 6000 MW/HZ.

Table 2: FCR-N requirements per country for 2013.

Subsystem	**Annual Consumption [TWh]**	**FCR-N requirement [MW]**
Eastern Denmark	13.7	22
Finland	85.2	138
Norway	130.0	210
Sweden	142.5	230
Synchronous system	**371.4**	**600**

The FCR-D reserve requirement for the Nordic synchronous area is defined according to the dimensioning fault[10] minus 200 MW, that is 1200 MW for the synchronous system. The corresponding frequency response is then 3000 MW/Hz. The FCR-D requirement per subsystem is basically scaled according to the dimensioning fault of the subsystem. A list of the dimensioning fault and the corresponding FCR-D requirement for each country in the Nordic synchronous area is provided in Table 3.

In Norway, the daily FCR-N market had the highest activity in terms of procured capacity in 2013. The average procured capacity in the daily FCR-N market (sum for all 5 Norwegian price areas) was 177 MW in 2013. In comparison, the average procured capacity for all price areas in the weekly FCR-N market was 51 MW. The procured capacity in the FCR-D market are primarily allocated on one specific day in 2013. Fig. 4 shows the procured capacity in the daily FCR-N market for 4 of the price areas in Norway (Statnett 2014*a*). There seems to be no obvious system-wide seasonal pattern in the daily market. In contrast, when looking at

[9] frequency response is defined as change in power output due to change in frequency.

[10] dimensioning faults are faults which entail the loss of individual major components (production units, lines, transformers, bus bars, consumption, etc.) and entail the greatest impact upon the power system from all fault events that have been taken into account.

Table 3: FCR-D requirements per country for 2013.

Subsystem	Dimensioning fault [MW]	FCR-D requirement [MW]
Denmark	600	176
Finland	880	259
Norway	1200	353
Sweden	1400	412
Synchronous system		**1200**

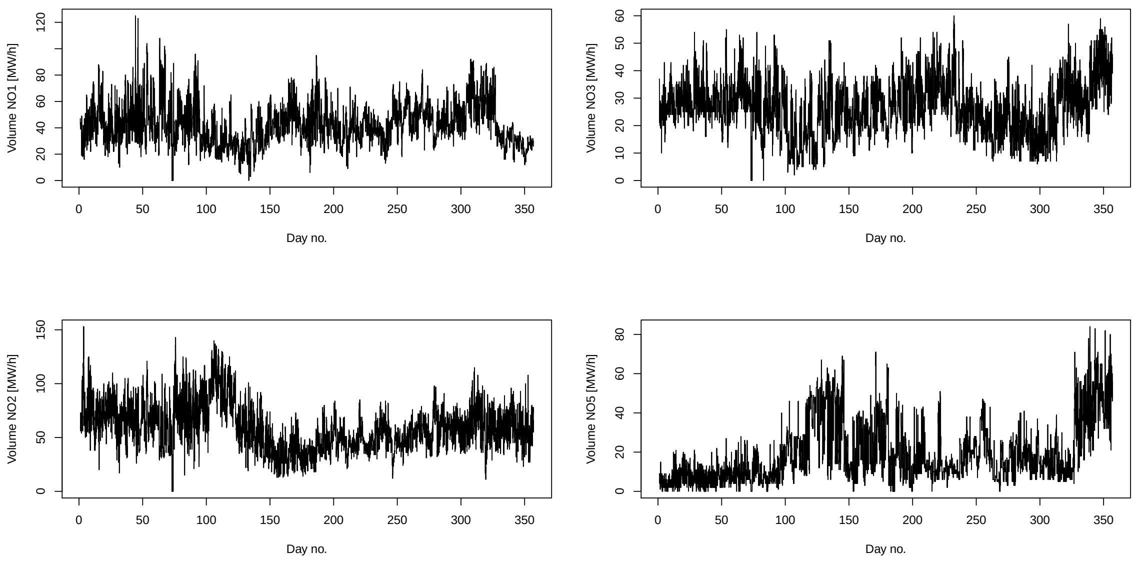

Figure 4: Procured capacity in the daily primary reserve market for normal operation (FCR-N) in Norway ELSPOT areas NO1-NO3 and NO5 in 2013.

the procured capacity in the weekly FCR-N market for the Norwegian NO2 price area in Fig. 5, there is a strong seasonal pattern. Relatively large amounts of capacity are procured at summer time, between weeks 20 and 30. This pattern is seen in the other Norwegian price areas as well, and indicates that in low load periods with low ELSPOT prices, there are clear incentives to ensure sufficient amounts of spinning reserve at an early phase. In other parts of the year, there is sufficient amounts of spinning aggregates that will contribute to primary control. Consequently, the TSO does not need to procure reserves through the weekly market. The average daily procured capacity in the two different markets is plotted in Fig. 6. It shows how volumes are moved from the daily to the weekly market to meet the system requirement during summer and autumn.

2.5 The Secondary Reserve Market

If frequency imbalances lasts for minutes, the secondary regulation reserves will take over, releasing the primary regulation reserves so that these are available in case of new outages and/or imbalances. An arrangement for secondary reserves was initiated in Norway in 2008, and later on led to the introduction of a system service termed automatic frequency restoration reserves (FRR-A) in 2013. The FRR-A system service concerns the synchronous systems and is currently managed through a single load frequency controller located in Statnetts SCADA system. The controller will, based on frequency measurements, send set points to the individual generators contributing in the FRR-A arrangement. These signals are directly communicated to generators on the Norwegian side, and will go through the responsible TSO if sent to neighboring countries (Statnett 2014*c*). In contrast to the activation of primary reserves, FRR-A activation is based on adjusting the generator's setpoints.

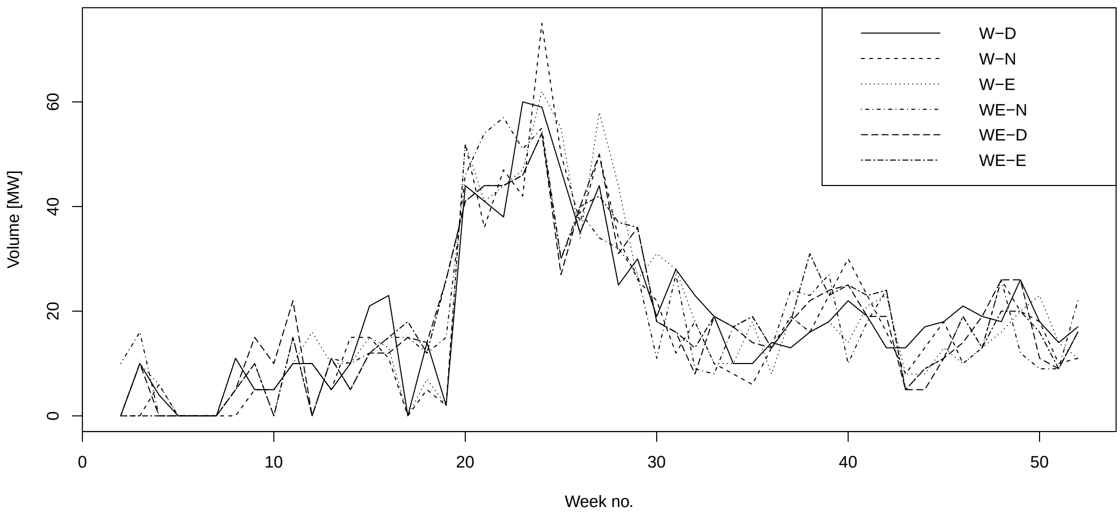

Figure 5: Procured capacity in the weekly primary reserve market for normal operation (FCR-N) in Norway ELSPOT area NO2 in 2013.

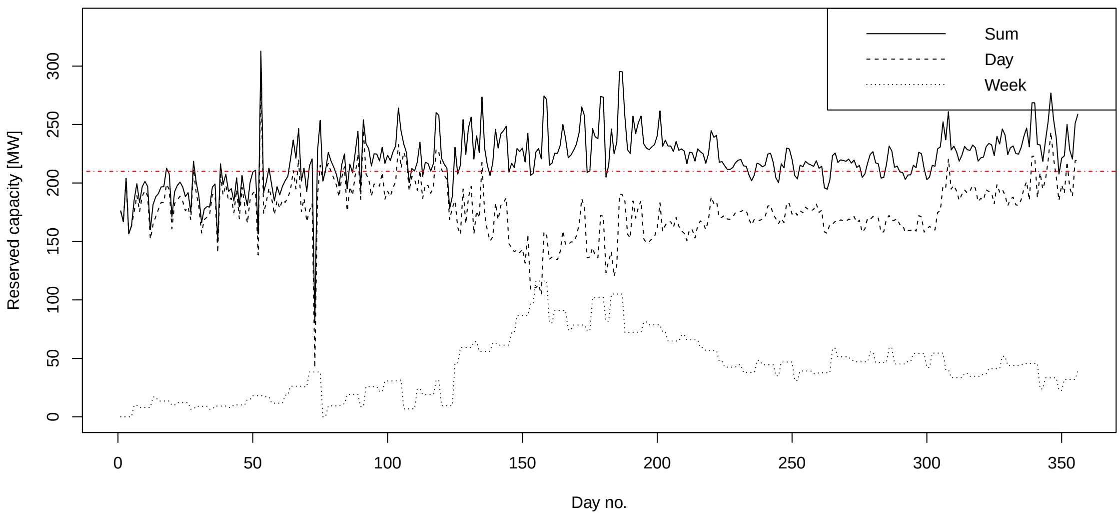

Figure 6: Sum of procured capacity in the weekly and daily FCR-N markets in 2013. Data points are average values per day. Capacities in the two markets are shown as dotted lines and the sum as a solid-drawn line. The horizontal line shows the FCR requirement for Norway in 2013.

Thus, for a power producer to participate in the FRR-A market, the generator units need control systems that can receive signals from the TSO and automatically adjust their setpoints. The FRR-A should be fully activated within 120 seconds.

The frequency quality in the Nordic system has decreased the last decade. According to Statnett, the frequency of periodes in which the frequency is outside the normal range (49.9 - 50.1 Hz) has increased alarmingly the last 10-15 years. According to (Statnett 2014*c*), it is reasonable to assume that the introduction of the FRR-A service has contributed to moderate this trend the later years. In that sense, the newly established arrangement for secondary reserves serves to improve the operational reliability in the Nordic power system and allow for an increased level and exchange of renewable energy (Statnett 2014*a*).

The procurement of secondary reserves is currently carried out individually per country. The procurement of FRR-A implies an increase in system operation cost, and the cost of reserves may vary significantly between the countries in the Nordic market. Consequently, there is a potential socio-economic benefit in joining the national markets, and the Nordic TSOs work on establishing a common Nordic FRR-A market. The "Hasle pilot", which is further discussed in section 2.5.4, can be seen as a step in this direction. In the future we expect increased exchange of automatic reserves across overseas cables. In their concession application for preparation of cables to Germany and Great Britain, Statnett assures that the intention is to enable interchange of up to 300 MW automatic reserves across each of the two cables (Statnett 2013*a*).

2.5.1 Market Structure – Norway

The Norwegian secondary reserve market was established to ensure that sufficient amounts of FRR-A are available in the system. Reservation of capacity is done through weekly auctions. Bids for the week-ahead should be delivered before Thursday 10:00, and should specify the country, type of regulation (up- or down), capacity offered (between 5-35 MW, blocks of 5 MW) and time period (3 periods, covering night, day and evening). The market is cleared according to the marginal pricing principle, and bids are either rejected or fully accepted. All accepted bids will then receive the marginal price in NOK/MW. The TSO estimates the activated energy, and this volume should be subtracted from the production imbalance and priced according to the FRR-M price in the direction of the regulation. Thus, in contrast with the pricing of activated tertiary reserves, activated FRR-A is priced according to the more favorable one-price system, see section 3.2 for further explanations.

Committed capacity in the FRR-A market should be reserved for this purpose, and should not be affected by the responsible party's contribution in other markets. Furthermore, at the time of bidding the producer shall inform the TSO about which station or group of stations that shall cover the bid volumes. Note also that the regulations state that the market player should be able to document the calculation of bid prices upon the TSOs request. If Statnett finds specific bids that do not conform with socio-economic efficient market pricing, these bids may be suspended (Statnett 2014*d*). It is pointed out in (Statnett 2014*d*) that this market is not yet mature and that the current regulations are likely to change in the future.

2.5.2 Market Structure – Sweden

Similarly to the Norwegian market for FRR-A, the Swedish market has a weekly tendering process. Bids for the upcoming week (Saturday to Friday) should be delivered before Thursday at 10:00, and shall be submitted per hour with 5 MW in each block, and have separate bids for up- and down regulation. The Swedish FRR-A is a pay-as-bid market and it is pointed out in (SvenskaKraftnät 2014*a*) that Svenska Kraftnät pay-as-bid remuneration is applied primarily due to the expected low liquidity in the introductory phase of this market. Pricing of activated FRR-A energy is similar to the Norwegian market. Unlike the case in for FCR, we could not find defined guidelines on how to calculate bids in FRR-A (SvenskaKraftnät 2014*b*).

2.5.3 Volumes in the Secondary Reserve Market

Unlike for the primary reserve markets, there is currently not a clearly defined volume requirement in the FRR-A market. The reserved capacities cleared in the weekly auctions for up-regulation in the Norwegian secondary re-

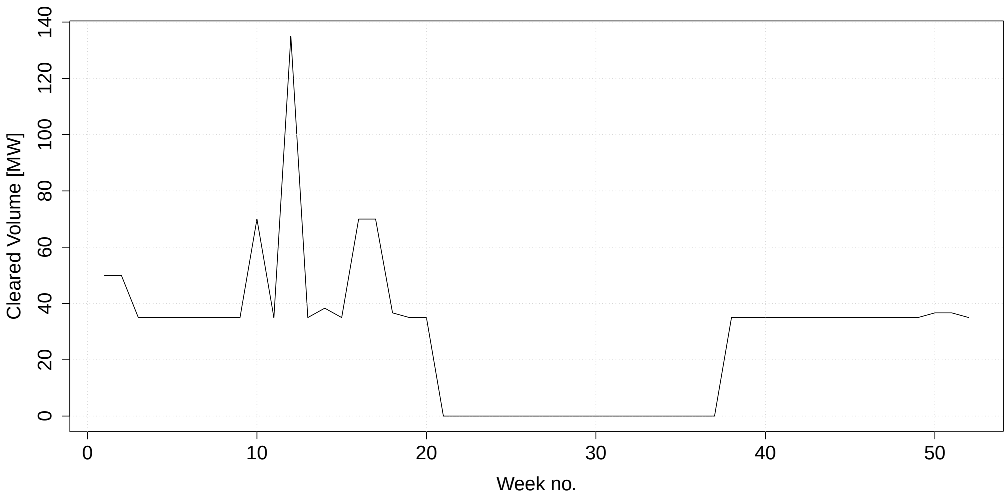

Figure 7: Average weekly volumes in the secondary reserve market in Norway in 2013.

serve market in 2013 are shown in Fig. 7. The volumes shown are averaged over the three time blocks (night, day and evening). There are small differences in volumes between time blocks and negligible differences between up- and down-regulation. In weeks 6-20 the total Nordic FRR-A volume was no lower than 100 MW, and in some weeks the volume increased to 200-350 MW (Statnett 2014*c*). The TSOs distributed the volumes per country according to the FCR-N requirements, see Table 2. Note that the Nordic TSOs decided to stop the FRR-A market for a period from the summer to the first part of the autumn in 2013. This decision was made because of the limited availability (number and capacity) of units suitable for providing FRR-A, due to the hydrological condition. The volume boundaries were adjusted upwards by Statnett in the first half of 2014, giving a corresponding increase in cleared volumes for Norway in that period.

2.5.4 Pilot Projects

During fall 2014 Svenska Kraftnät and Statnett ran a pilot project, named ”Hasle-piloten”, where the two countries established a shared FRR-A market place. First, the national markets where cleared as described above. Then the two TSOs compared bid curves and ran a socio-economic analysis in order to decide on the FRR-A volume to exchange and the cross-zonal capacity to be reserved. The reserved cross-zonal capacity for FRR-A was then subtracted from the available capacity provided to the ELSPOT (Statnett 2014*b*). The primary objective of the pilot project was to check if a joint market would reduce the total cost and increase the socio-economic surplus compared to each countries having separate markets (Statnett 2014*a*).

The fourth HVDC connector between Norway and Denmark, named SK4, is another interesting pilot project. A capacity of 100 MW out of a total capacity of 700 MW is allocated exchange of FRR-A from Norway to Denmark. The expected FRR-A price is higher in Denmark than in Norway, and the reservation of capacity is seen as important for the cable project's profitability. After a tendering process, two producers were contracted as FRR-A suppliers for a five-year period (Montel 2015).

2.6 The Tertiary Reserve Capacity Market

If frequency deviations still persists after activation of bids in the primary and secondary markets, the tertiary regulation reserves will be manually activated by the TSO. Tertiary reserves primarily serves two purposes; to continue the frequency regulation by balancing mismatches between generation and load (and thus release primary and secondary reserves), and to alleviate regional transmission grid bottlenecks. The latter is often referred to as special regulation.

The Nordic market for tertiary reserves is also known as the regulating power market, but will be termed the manual frequency restoration reserves (FRR-M) market in the following to comply to what seems to be the standard international terminology. The FRR-M market is a common Nordic market for trading tertiary reserve energy, and will be presented in more detail in section 2.7. We start by reviewing the approaches for tertiary reserve capacity procurement.

2.6.1 Market Structure – Norway

The TSOs in the Nordic market have different arrangements for securing that sufficient amounts of regulating power will be bid into the FRR-M market. The Norwegian regulating power option market (RKOM) was established in 2000 for this purpose. Both producers and consumers can bid to RKOM, but only for up-regulation (increase in production or decrease in consumption) (Statnett 2013*c*)[11]. Allowing down-regulation is currently considered as an option (Statnett 2014*c*). The accepted set of regulation offers for a given period receive an option payment in NOK/MW/h. By introducing the RKOM market, the Norwegian TSO has succeeded in including a considerable share of reserves from the demand side. As a consequence, load reduction from power intensive industry (e.g. paper mills and smelting plants) is regularly bid into RKOM (Flatabø et al. 2003).

The RKOM is split in two sub-markets; the seasonal and the weekly. The seasonal market will by default cover the winter period from week 45-16, with one time period (5:00-24:00). The weekly market covers two time periods (night 00:00-05:00 and day 05:00-24:00), and bids for the coming week should be placed before Friday 12:00. Trades in the weekly market are based on the expected state of the power system, primarily the forecasted demand and exchange with neighboring countries. Statnett has divided Norway in three geographical regions based on structural bottlenecks and distribution of reserves. Bids should be stated per region, with a price and volume for up-regulation. The market bidders are encouraged to indicate the geographical location of the units intended to cover the bid volume, but this is not an requirement. Both the seasonal and weekly markets are primarily cleared according to the marginal pricing principle, and market players are remunerated according to the clearing price. Accepted bids in RKOM should conform to the following rules:

- A volume at least the size of the accepted options should be made available in the FRR-M market for period agreed upon;
- Accepted options for production cannot be withdrawn in the FRR-M market and offered in other markets;
- Accepted options for demand can be withdrawn in the FRR-M market in case the demand is reduced.

Thus, the RKOM market itself will not set prices and volumes in the FRR-M market, but will help ensuring that sufficient capacity is made available to the FRR-M market. The RKOM market also serves to ensure that the necessity of keeping reserves is reflected in the ELSPOT price. As discussed in Wangensteen (2007), if one compare the tertiary reserve market (capacity reservation and energy) with normal option pricing, it is equivalent to settling on an option price (reserve capacity premium) without knowing the strike price. That is, the TSO will know the price for keeping tertiary reserves available, but not the price of activating these reserves.

2.6.2 Market Structure – Sweden

For the other countries in the Nordic power market, Denmark has adopted a similar option market as the Norwegian, whereas Sweden and Finland procure reserves through bilateral contracts in what is referred to as strategic reserves or peak-load arrangements. In Sweden Svenska Kraftnät contract generation capacity and consumers for the winter period (mid November - mid March) through a tender. About 2000 MW is procured, and these reserves should only be used in case the market cannot otherwise attract sufficient capacity. Parts of the procured capacity can be offered in the ELSPOT and FRR-M markets, but the bids are then priced higher than all regular bids. Such peak-load arrangements can be criticized for being economically inefficient and for their

[11] Statnett has updated RKOM regulations for the season 2014/2015. The major change is the splitting what was one uniform product in two; "RKOM high-quality" and "RKOM with limitations", as described in (Statnett 2014*e*). The regulations described in this text still apply.

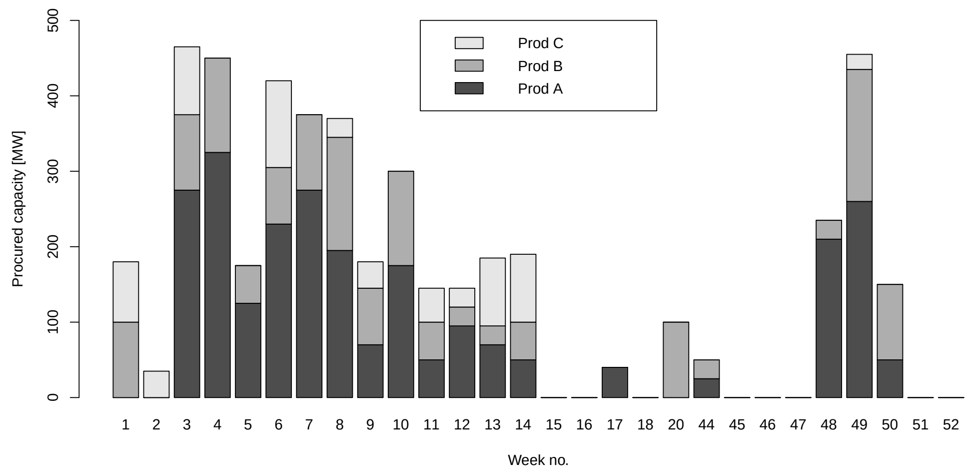

Figure 8: Committed production capacity in the weekly RKOM market for 2013. Regions A-C correspond to southern, mid and northern Norway.

loose connection to the existing market structure. For this reason, Svenska Kraftnät aims at phasing out the peak-load arrangement within 2020 (SvenskaKraftnät 2011).

2.6.3 Volumes in the RKOM market

According to the Nordic System Operation Agreement (ENTSO-E 2013) regarding operation of the interconnected Nordic power system, each of the countries has an individual requirement for available reserves according to dimensioning faults in its subsystem, see Table 3 on page 14. For 2013 this corresponds to requirements of 1200 MW and 1400 MW for Norway and Sweden, respectively. In addition, the Norwegian TSO has decided to ensure that an additional amount of 800 MW can be made available through the RKOM market. Regarding the weekly procurement, Statnett evaluates the requirement for the coming week based on a forecast of the power balance and an assessment of the need for reserves. Fig. 8 shows the production capacity reserved in the weekly RKOM market in 2013. Note that the consumption capacity is generally larger, but we focus on production capacity in this report. The majority of production capacity is reserved in area A, which corresponds to southern Norway. These numbers should be seen in relation to the reserved capacities in the seasonal market, shown in Table 4 for year 2013.

Table 4: Committed capacities (production and consumption) in the seasonal RKOM market for the two seasons related to 2013.

	Capacity [MW]			
Weeks	**Area A**	**Area B**	**Area C**	**Sum Norway**
45-52	44	287	540	871
1-15	67	187	380	634

2.7 The Tertiary Reserve Energy Market

The FRR-M market is a common Nordic market for manually activated frequency restoration reserves. It is open for both up-and down regulation from production and consumption. Participants should be able to respond on 15 minutes notice and deliver non-interruptible power for at least one hour. The common Nordic FRR-M market was introduced in 2002 and is based on cooperation between the Nordic TSOs within the Nordic synchronous area. Statnett exchanges regulating power with the other Nordic TSOs through a common regulating power bid list, often referred to as the NOIS[12] list (Nordic Energy Regulators 2010). Bids on the NOIS list are activated according to price order, with the exception of bids confined behind grid bottlenecks. The Nordic TSOs use the FRR-M market to ensure that supply and demand balance at the hour of real time operation, and one can therefore argue that energy prices from the FRR-M market are the de-facto spot prices.

Bids should state a price (integer divisible by 5 NOK), the power dedicated for up- or down-regulation, and the desired time slot (minimum one hour), and should be sent to the TSO at latest 45 minutes before real-time operation. Multiple bids can be sent, which will give a stepwise bid curve, as opposed to bid curves in Elspot which are linearly interpolated. Both production and consumption can contribute. Bids should be given per station or station group or per consumption site. Thus, the producer cannot aggregate all its bids into one single bid curve as it was done in Elspot and Elbas markets. The product is priced per Elspot area. The lowest (resp. highest) price for up- (resp. down-) regulation is the closest 5 NOK over (resp. under) the corresponding area price from Elspot. That is, there are *price caps* and *price floors* provided by the Elspot prices. At the time of bidding in the FRR-M market, each player knows his accepted volumes and the prices from the Elspot market. The FRR-M market is normally cleared according to the marginal pricing principle. Deviations from this principle are made in case of system problems. In such situations, omitted bids will not be compensated. Furthermore, bids accepted out-of-order will be compensated according to the pay-as-bid principle and tagged ‘special regulation’. Statnett points out that commitments in other markets should not prevent the market players to deliver according to the FRR-M commitment. Conversely, activation of a down-regulation bid in the FRR-M should not involve shutting down aggregates so that commitments in the FCR or FRR-A markets are challenged.

When activating regulating power, Statnett will activate bids as special regulation to relieve grid bottlenecks before resolving potential frequency-related problems. The regulation should be activated in more than 10 minutes in order to be price setting, and the price is set by the highest priced activated bid disregarding special regulations. The FRR-M prices are also used when pricing activated energy from the FRR-A market, and is used together with the Elspot area prices in the remuneration settlement of BRPs, cf. Section 3.

2.7.1 Volumes in the Tertiary Reserve Energy Market

Since the balancing markets discussed so far are capacity markets, the figures presented on volume have represented procured or committed capacity. As the FRR-M market is an energy market, one should be careful when comparing the values presented here with the above figures. Fig. 9 presents the manually activated energy for up- and down regulation for the NO2 price area in 2013. The total amounts of up- and down regulation for NO2 in 2013 were 0.14 and 0.38 TWh, respectively. For comparison a total of 0.54 TWh was used for up-regulation and 1.12 TWh for down-regulation in the Norwegian system in 2013. The distribution per price area in both Norway and Sweden is shown in Table 5. Although most of the time there is either up- or down-regulation, there may be hours were the price area is regulated in both directions. We found no obvious seasonal patterns when studying the manually activated reserves.

In theory, since market players are obliged to plan their portfolios in the Elspot and Elbas in balance, it seems natural to expect that the probabilities for up- and down regulation are equal, and that the FRR-M prices should be symmetric around Elspot price. However, Table 5 shows significantly higher down-regulation volumes, which also seems to be the trend in the rest of Europe. Although interesting, we decided that a discussion of the reasons for this asymmetry was outside the scope of this report.

2.8 Systematizing Markets and their Sequences

In this subsection we try to summarize the sequences and the basic properties of the various markets in Norway and Sweden. Based on the market description in the previous subsections, one can arrange the market and their clearing in a time-sequence, indicating the decision stages that a producer will have to relate to. The market

[12] Nordic Operational Information System.

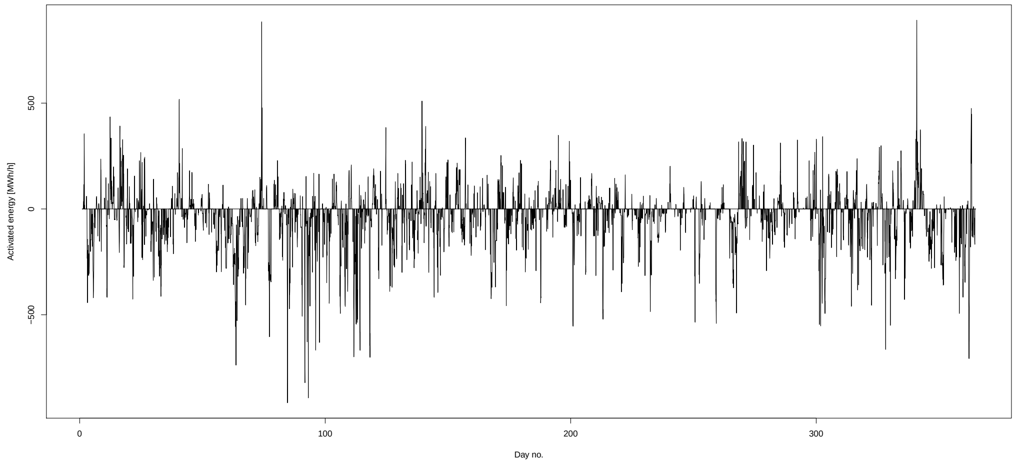

Figure 9: Activated energy in the FRR-M market in NO2 in 2013. Up-regulation is positive, down-regulation is negative.

Table 5: Manually activated energy for up- and down-regulation per Elspot area in Norway and Sweden in 2013.

Price area	**Activated energy [TWh]**	
	Up	**Down**
NO1	0.12	-0.17
NO2	0.14	-0.38
NO3	0.06	-0.08
NO4	0.06	-0.13
NO5	0.16	-0.36
Sum Norway	**0.54**	**-1.12**
SE1	0.19	-0.37
SE1	0.22	-0.58
SE1	0.08	-0.14
SE1	0.01	-0.01
Sum Sweden	**0.50**	**-1.10**

sequence for the Norwegian market is shown in Table 6. The sequences differs slightly in the Swedish case, see Table 7.

From Tables 6 and 7 one can conclude on the following:

- Capacity is basically procured before clearing of the Elspot, e.g. through the RKOM, FCR-N week and FRR-A markets in Norway, and FCR D-2 and FRR-A in Sweden.
- There is also possibilities to offer capacity to the market after knowing the outcome of the Elspot. These possibilities exists in the daily FCR-N/D markets (Norway) and FCR-N/D D-1 (Sweden).
- Elspot clearing for a given hour is known at the time of bidding in the FRR-M market for that hour. Since the FRR-M price is closer to real-time operation, it can be seen as the 'real' spot price.

After the Elspot prices are published and the accepted bids are set, the producers must send their production plans for the next day to their respective TSO before 19:00 every day. These plans should comprise information about planned production, regulating strength and available reserve per station group and per hour for the next

Table 6: Time-sequence for the different markets in Norway.

				October	Thursday	Thursday	Friday	Day-1	Day-1	Hour-1	Hour-0:45
					10:00	12:00	12:00	12:00	18:00		
Market	**Period**	**Resolution**	**Commodity**								
RKOM season	Winter	Season	Capacity	✓							
FRR-A	Week	N/D/E	Capacity		✓						
FCR-N week	Weekend	N/D/E	Capacity			✓					
RKOM week	Week	N/D	Capacity				✓				
FCR-N week	Weekday	N/D/E	Capacity				✓				
ELSPOT	Day	Hour	Energy					✓			
FCR-N/D day	Day	Hour	Capacity						✓		
ELBAS	Cont.	Hour	Energy							✓	
RKM	Hour	Hour	Energy								✓

Table 7: Time-sequence for the different markets in Sweden.

				Summer	Thursday	Day-2	Day-1	Day-1	Hour-1	Hour-0:45
					10:00	15:00	12:00	18:00		
Market	**Period**	**Resolution**	**Commodity**							
Peak-load arr.	Winter	Season	Capacity	✓						
FRR-A	Week	Hour	Capacity		✓					
FCR-N/D D-2	Day	Hour	Capacity			✓				
ELSPOT	Day	Hour	Energy				✓			
FCR-N/D D-1	Day	Hour	Capacity					✓		
ELBAS	Cont.	Hour	Energy						✓	
FRR-M	Hour	Hour	Energy							✓

day (Statnett 2013*b*). Changes to the production plan should be updated as they occur and at latest 45 minutes before physical operation.

A summary of the different rules and regulations associated with the different balancing markets is provided in Table 8. The second column states the geographical belonging of a bid, the third indicates whether bids are per station group, the fourth states if there should be separate bids for upward and/or downward regulation, and the last column states the pricing principle

3 Imbalance Settlement

The imbalance settlement is done after the hour of delivery, when actual production and consumption has been measured. First, the TSOs settle imbalances between countries. Aftewards, each TSO settles imbalances within BRPs and BSPs in its respective country. We focus on the national settlement in this chapter.

Recall from Section 1.1 and Fig. 1 that the BRP bears the economic responsibility for the imbalances created by those parties he is representing, and needs to settle this with the TSO. Therefore, through the imbalance settlement, the costs of the TSOs are retrieved from the BRPs. The imbalance settlement was harmonized for the Nordic countries (NORDEL) in 2009 (Statnett 2009). Thus, there is a common definition of which cost

Table 8: Properties for the different balancing markets in Norway and Sweden.

Market	Bids refer to	Bid located to	Direction of regulation	Pricing principle
Norway				
FCR-N week	price area	price area	symmetric	marginal pricing
FCR-N/D day	price area	price area	symmetric	marginal pricing
FRR-A	country	station group	up and down	marginal pricing
RKOM week	price region	price reg.[a]	up	marginal pricing
RKOM season	price region	price reg.[a]	up	marginal pricing
FRR-M	price area	station group	up and down	marginal pricing
Sweden				
FCR-N/D D-2	–	–	symmetric	pay-as-bid
FCR-N/D D-1	–	–	symmetric	pay-as-bid
FRR-A	country	country	up and down	pay-as-bid
Peak-load arr.	country	country	up and down	
FRR-M	price area	station group	up and down	marginal pricing

[a] Station group specification invited

elements that should be included in the imbalance settlement, and which pricing principles that should apply.

3.1 Pricing Systems

For each BRP, two types of imbalances are calculated per price area; one for production and one for trade and consumption. BRPs having production in their portfolio will relate to two balances, and BRPs without production will relate to one balance (Statnett 2009). In the Nordic market the two types of imbalances are priced differently. The production imbalance is priced according to the *two-price system* whereas the consumption imbalance is priced according to a *one-price system*.

The two pricing systems differ as shown in Table 9, where π_{SP}, π_{BM}^{+} and π_{BM}^{-} are the spot and the FRR-M prices for upward and downward regulation, respectively. According to market rules, $\pi_{BM}^{+} \geq \pi_{SP} \geq \pi_{BM}^{-}$. In the two-price system, the BRP's imbalance is priced differently depending on whether it is contributing to restore system balance or not. If a BRP is undersupplied (negative imbalance) and the system is oversupplied (needs down regulation), he will be charged the spot price rather than the FRR-M price for downward regulation π_{BM}^{-}. Conversely, if the BRP is oversupplied (positive imbalance) and the system is undersupplied (needs up regulation), he will receive the spot price rather than the FRR-M price for upward regulation π_{BM}^{+}. In both cases the imbalances support the needs of the system, and the BRP is "penalized" for being unbalanced by receiving the least favorable price. Therefore, the BRP is given a clear economical incentive to comply with the submitted production plan, and the TSOs have reduced the probability of not being able to balance the system. In the one-price system, imbalances that support the needs of the system will receive the FRR-M price rather than the spot price. Consequently, the economical risk of being a BRP is lower in the one-price system, which is expected to lower the barrier for retailers and end-users to contribute as BRPs.

3.2 Production Imbalance

A BRP being responsible for production can have a production imbalance, comprising actual production, production plans and both automatic and manual regulations.

$$\boxed{Production\ Imbalance = Measured\ Production - Planned\ Production + Regulation(prod.)}$$

Table 9: Imbalance settlement pricing systems.

	BRP imbalance	System balance	
		negative	positive
One-price system	negative	π_{BM}^{+}	π_{BM}^{-}
	positive	π_{BM}^{+}	π_{BM}^{-}
Two-price system	negative	π_{BM}^{+}	π_{SP}
	positive	π_{SP}	π_{BM}^{-}

Generally, the production imbalance will state how much the measured production deviates from the submitted production plan, corrected for active regulations. The planned production refers to the last submitted production plan from the BRP. The active regulations, that is the activated energy stemming from accepted bids in the different balancing markets, contribute to the active part of the imbalance. What is left in the production imbalance is often referred to as the *passive* imbalance.

An updated production plan per station group should be submitted to the TSO no later than 45 minutes before real time. By settling the production imbalance according to the two-price system, producers are prevented from taking speculative positions. This can be illustrated by an example. Suppose a producer in one hour is producing less than his planned production. The producer has already sold the planned production, and will now have to enter the market in order to be in balance. If the system is over supplied, the producer supports the system, the balancing price will be lower than the spot price and the producer can buy back his deficit at spot price. However, if the system is under supplied, the price of balancing power will be higher than the spot price, and the producer will pay more for his deficit than what it was sold for. Clearly, the producer will have no obvious incentive to create a passive imbalance as it will only receive the spot price for supporting the system imbalance.

At this point it is worth noting that the Norwegian TSO clearly states that BRPs should arrange their trades in the ELSPOT market so that they expect to be in balance. Trade in subsequent markets should serve to restore the BRP's planned balance (Statnett 2013*b*, § 8).

3.3 Trade and Consumption Imbalance

All BRPs will be settled according to their trade and consumption (TAC) imbalance. This imbalance expresses the deviation between consumption and active consumption regulation on the one hand, and trade and planned production on the other.

$$\boxed{TAC\ Imbalance = Planned\ Production - Measured\ Consumption + Trade + Regulation(cons.)}$$

The term 'Planned Production' has the same meaning as in the production imbalance, whereas the term 'Trade' relates to the BRPs total trade comprising bilateral trade and trade at both ELSPOT and ELBAS. The imbalance is corrected for activated energy related to accepted bid for reduced consumption (down regulation) in the FRR-M market. For a BRP with no consumption and pumps[13], the TAC imbalance should be zero, indicating that planned production is in balance with obligations bilaterally, in ELSPOT and in ELBAS. Since the TAC Imbalance is priced according to the one-price system, the imbalance is traded according to the FRR-M price dictated by the regulating state (up/down) in the relevant price area.

The use of two different pricing systems for production and TAC imbalance will in some cases provide producers with an economic incentive to move an imbalance from the unfavourable two-price system to the one-price system used in the TAC imbalance. Consider a wind power producer selling 100 MWh in the ELSPOT market, but only manages to produce 90 MWh, leaving a production imbalance of 10 MWh and a TAC imbalance of 0 MWh (planned production = 100 MWh, Trade = 100 MWh). Depending on the regulating state in the price area, the production balance will be charged either the spot price or the FRR-M up-regulation price. By updating

[13] see Statnett (2009), appendix 2 for treatment of pumps.

the production plan at the latest possible time (45 min) before physical operation and avoiding trades in Elbas, the producer will most likely have a better prognosis (closer to 90 MWh) and may be able to shift parts of the imbalance over to the consumption imbalance [14]. It is however questionable whether this practice is in-line with the TSOs regulations.

4 Literature Review

4.1 Overview

In this section we will review literature on hydropower scheduling, focusing on what properties are modelled both for the production system and the market operation. Even though the distinction is not an absolute one, we separate the presentation in two parts, short-term and long-term models. Short-term typically means model horizons of days or weeks with the creation of operational schedules and market bids as important aims. Long-term models is at least seasonal, often multi-annual, and often motivated by the creation of water value functions or other means of long-term resource allocation.

Our main interest is on trade rooted in a physical hydropower production system, so we limit our review to research treating physical markets rather than financial markets. Most European physical markets are set up so that generators are self-scheduling and bid their resources to multiple markets that are cleared in sequence, as thoroughly discussed for the Nordic case in Section 2. For this reason it makes sense to talk about *co-optimization* or *coordinated bidding*, i.e. optimization that takes subsequent markets into account, as opposed to *separate* or *sequential* bidding/optimization. The following presentation will focus on research on co-optimization, even though some single market models are mentioned when these are found particularly relevant in a hydropower perspective. We will not include work where market designs with centralized dispatch, as opposed to self-scheduling, is a decisive property for the results.

The day-ahead market is the largest market for power trading in most regions, including the Nordic. This is also reflected in the research community with a large literature on day-ahead power scheduling and bidding problems, see Li et al. (2011) and Steeger et al. (2014) for recent reviews. As the market arrangements for intraday and balancing markets become more harmonized across countries and mature in terms of regulations and liquidity, one can expected the trade in these markets to increase. In this context, Klæboe & Fosso (2013) presents a literature review on optimal bidding in sequential physical power markets. Emphasis is put on spot, intraday and real-time energy markets, and do not cover the reservation of capacity. It is argued that, from a theoretical point of view, the optimal bidding strategy is found when taking all subsequent market into account when bidding in the first market. The profit gained and flexibility used in the first market is then balanced against the opportunities in the subsequent markets. It is pointed out that the existing literature regarding coordinated bidding is not very rich, the comparisons with separate bidding are few, and the few results reported indicate that the gain of coordinated bidding is not very high Klæboe & Fosso (2013).

A few recent papers present well organized reviews on the treatment of multiple markets in hydropower scheduling schemes. Scharff et al. (2014) presents and overview on the decision-making process for a power generating company in the Nordic power market. The sequential trading decisions taken by the producers and the type of tools applied are systemized. These decisions are related to the market sequences for both energy and balancing power market in the Nordic context. It is concluded that, due to the variety of trading possibilities, most of them being interdependent, mathematical models can only provide limited decision support. Including more decision steps in current stochastic modelling tools will dramatically add complexity to these.

4.2 Short-Term Models

Most papers on hydropower co-optimization describe short-term models. Tables 10–12 summarizes some characteristic features of papers that will be presented in more detail in the following.

[14]The sum of production imbalance and TAC imbalance do not change, but the planned production is updated and this term is a part of both imbalances

Table 10: Short-term models in literature - modeled markets.

	DAM	IDM	Primary reserve	Secondary reserve	Tertiary reserve	Imbalance settlement
Aasgård et al. (2014)	✓					
Belsnes & Fosso (2005)					✓	
Boomsma et al. (2013, 2014)	✓				✓	✓
Chazarra et al. (2014)	✓			✓		
De Ladurantaye et al. (2007)	✓		✓	✓[a]		
Deng et al. (2006)	✓		✓	✓[a]	✓	
Faria & Fleten (2011)	✓	✓				
Fjelldal et al. (2014)	✓		✓	✓		
Fleten & Kristoffersen (2007)	✓					✓
Olsson & Söder (2005)					✓	
Ugedo et al. (2006),Ugedo & Lobato (2010)	✓	✓		✓		
Vardanyan, Amelin & Hesamzadeh (2013) Vardanyan, Söder & Amelin (2013) Vardanyan & Hesamzadeh (2014)	✓				✓	

[a] non-spinning reserve

In Olsson & Söder (2005) the bidding of a price-taking producer in the FRR-M market is modeled as a multi-stage stochastic program, provided the day-ahead commitment. The bidding is done for each consecutive hour as a individual stage. A non-linear, continuous and convex bidding curve is considered. Upward and downward regulation is sampled from individual ARIMA-price processes, with additional binary stochastic processes indicating whether regulation is activated in each direction. The hydro scheduling problem models a cascade of reservoirs with constant head, piecewise linear production function, constant water value and no start-stop costs.

Belsnes & Fosso (2005) presents an alternative method for decision aid to bid hydropower capacity in the FRR-M market [15]. An optimization model based on successive linear programming (SHOP) is used to optimize the hydro-power schedule to comply with the Elspot plan. Based on these results, the regulating costs are estimated by using the cost-recovery principle, which in principle forms a lower limit for bids in the FRR-M market. This principle can be expressed as follows. Let us say that the revenue (R) for a producer equals the immediate income from selling power (p) in the spot market at price (π) minus the loss of inventory expressed by the water value (κ) and efficiency (η):

$$R(p, \eta) = \pi p - \frac{\kappa p}{\eta} \tag{3}$$

A commitment in the FRR-M market will lead to a change in generation output and efficiency and possibly involve costs (S) related to start-up of units. Thus, there will be a revenue loss (ΔR) in the spot market which can be used as a reference point when pricing bids in the FRR-M market:

$$\Delta R(p, p^0, \eta, \eta^0) = \pi \left(p - p^0\right) - \kappa \left(\frac{p}{\eta} - \frac{p^0}{\eta^0}\right) + S \tag{4}$$

A supplement to this work is presented in Belsnes et al. (2013), where the implementation of different FCR-N and FCR-D constraints in the SHOP model is elaborated. This work assumes that the water values are unaffected by the activity in the balancing markets, and the model does not consider the impact of activation on the reservoir balances. A similar principle is applied for the FRR-A market in Gebrekiros et al. (2013).

[15] referred to as real-time market in the article

Table 11: Short-term models in literature - market modeling assumptions. '-' means 'not relevant'

	Bidding modeled	Price taker or maker	Price uncertainty	Reserves activated	Activation uncertainty	Risk attitude
Aasgård et al. (2014)	Bidding	Taker	✓	-	-	Neutral
Belsnes & Fosso (2005)	Derived bids	Taker				-
Boomsma et al. (2013, 2014)	Bidding	Taker&maker	✓	✓	✓[a]	Neutral
Chazarra et al. (2014)	Allocation	Taker		✓		-
De Ladurantaye et al. (2007)	Bidding	Taker	✓[b]		-	Neutral
Deng et al. (2006)	Allocation	Na	✓	(✓)	✓	Neutral
Faria & Fleten (2011)	Bidding	Taker	✓	-	-	Neutral
Fjelldal et al. (2014)	Allocation	Taker		(✓)[c]		-
Fleten & Kristoffersen (2007)	Bidding	Taker	✓	-	-	Averse
Olsson & Söder (2005)	Bidding	Taker&maker	✓	✓	✓[a]	Neutral
Ugedo et al. (2006),Ugedo & Lobato (2010)	Constrained allocation	Maker	✓[d]		-	Neutral
Vardanyan, Amelin & Hesamzadeh (2013) Vardanyan, Söder & Amelin (2013) Vardanyan & Hesamzadeh (2014)	Bidding	Taker	✓	✓	✓	Neutral

[a] By price difference
[b] DAM only
[c] Secondary reserve income, but not water consumption
[d] Through residual demand curve

Table 12: Short-term models in literature - physical modeling assumptions and problem class. ‘WV’ means ‘water value’

	Start/ stop	Variable head	# reser- voirs	# gene- rators	Inflow uncertainty	End-of-horizon modelling	Pump	Problem class
Aasgård et al. (2014)	0/1	Post proc.	7	6	✓	WV func.		MILP
Belsnes & Fosso (2005)	Approx.		9	13		Const. WV		MINLP
Boomsma et al. (2013, 2014)			2	2		Const. WV		MILP
Chazarra et al. (2014)	0/1		1	1		Target level	✓	MILP
De Ladurantaye et al. (2007)	0/1	✓	4	6		WV func.		MINLP
Deng et al. (2006)	Na	Na	Na	Na		Const. WV		LP
Faria & Fleten (2011)	0/1		3	7		WV func.		MILP
Fjelldal et al. (2014)	0/1		Na	Na		Const. WV		MILP
Fleten & Kristoffersen (2007)	0/1		2	2		WV func.		MILP
Olsson & Söder (2005)			3	3		Const. WV		convex NLP
Ugedo et al. (2006),Ugedo & Lobato (2010)			Na	8		WV func.	✓	MILP
Vardanyan, Amelin & Hesamzadeh (2013) Vardanyan, Söder & Amelin (2013) Vardanyan & Hesamzadeh (2014)			3	1	(✓)	Const. WV		MILP

Deng et al. (2006) model co-optimization of a hourly energy market and four reserve markets (up-, and down-regulation, spinning and non-spinning reserves) according to the Californian market structure. They emphasize the importance of representing the market uncertainty, both in terms of price uncertainty and uncertainty in reserve activation[16]. A stochastic multi-stage model is presented where each stage represent a sequence of consecutive hours with simultaneous allocation to all markets. The hydropower production system is simplified, among others without hydraulic connections. Reservoir target levels are enforced both within the model horizon and at the end of horizon. A case study is performed with a one month model horizon with hourly resolution and four stages. Evaluation in a simulator shows that the stochastic model performs 0.97% better than the expected value model on average.

A two-stage stochastic programming model for optimizing bidding strategies in the day-ahead market is presented in Fleten & Kristoffersen (2007). The first-stage is used to decide on a bidding curve before day-ahead prices are known. In the second stage the accepted bids and the actual production is found for each day-ahead price realization. Differences between the accepted bids and scheduled volumes are penalized in the imbalance settlement phase. The modelling is applied to a cascaded hydropower system and includes details limiting the flexibility of the producer, e.g. time-delays, start-up costs.

An extension of Fleten & Kristoffersen (2007) is presented in Aasgård et al. (2014), where a stochastic model for bid optimization is tested through a simulation procedure. The stochastic bid model relates to the day-ahead market and sees uncertainties in spot prices and inflows. The modelling is applied to a cascaded hydropower system and includes details limiting the flexibility of the producer, e.g. time-delays, start-up costs.

Faria & Fleten (2011) build on a similar two-stage model structure and biddig model technique as Fleten & Kristoffersen (2007) to consider coordinated decisions in the spot and Elbas markets. The model comprise physical details for a hydropower system, including time delays, start-up costs, water value cuts for end reservoir valuation and simplified head relationships. Spot and Elbas prices are treated as stochastic variables. The first stage concerns bidding in the spot market, whereas the second stage considers trading in the Elbas market and operation of the production system. Despite the hourly structure of Elbas, all Elbas trading is collapsed into a single decision stage. To comply with market rules the expected Elbas volume is required to be zero for each spot realization. The model is tested on a part of a water course in Norway, and it was found that the coordinated bidding do not significantly improve expected income compared to pure spot bidding.

Boomsma et al. (2013) extends the two-stage model by Fleten & Kristoffersen (2007) into a three-stage model adding the balancing market as an intermediate stage. This gives a model for coordinated bidding in spot and balancing markets, resembling the Nordic market structure. The first and second stages concerns the spot and balancing market bidding, respectively. The spot prices are known at the time of bidding in the balancing market. Similarly to Faria & Fleten (2011)'s treatment of Elbas the hourly decision stages of the balancing market is approximated with a single decision stage. This is justified by assuming no operational uncertainty in that period (i.e. outages, reservoir inflows, etc.). Finally, the third stage consists of imbalance settlement and operation of the production system. The model structure balances the risk of not being dispatched in the balancing market with the value of postponing the bidding decision until the balancing market to reduce uncertainty. It is shown that there is a small added value of a coordinated bidding model as long as the imbalances are settled according to a two-price system.

Boomsma et al. (2014) extends the Boomsma et al. (2013) work further into a multi-stage model with hourly decision stages for balancing market bidding, imbalance settlement and operation. The lacking value of co-ordinated spot and balancing market bidding in a one-price imbalance settlement regime is confirmed, while substantial added value is observed with coordinated bidding with a two-price system.

Vardanyan, Amelin & Hesamzadeh (2013), Vardanyan, Söder & Amelin (2013) and Vardanyan & Hesamzadeh (2014) builds on the same model on coordinated spot and balancing market bidding. The problem is represented in a two-stage model and as opposed to the model of Boomsma et al. (2014) imbalances are not allowed. Vardanyan, Amelin & Hesamzadeh (2013) and Vardanyan, Söder & Amelin (2013) sample market prices from ARIMA models, while Vardanyan & Hesamzadeh (2014) sample from mean revering jump diffusion processes. They describe the balancing market activation state with a Markov model, allowing for none,

[16] Denoted 'market participation' in the referenced paper.

single or dual-directional activation in each hour. The original model shows extreme bidding patterns where maximum production capacity is offered in the balancing market, either as up or down-regulation. This is not seen as expected behavior in real operations, and Vardanyan, Amelin & Hesamzadeh (2013) and Vardanyan, Söder & Amelin (2013) evaluate different modeling alternatives to achieve more moderate and realistic bidding patterns. Vardanyan, Amelin & Hesamzadeh (2013) also evaluate the importance of modeling the uncertainty in spot price and inflow, and concludes that price uncertainty has the larger influence on VSS[17]. Vardanyan & Hesamzadeh (2014) seeks to improve the approximation of the hourly decision process of the balancing market. Rather than a single decision stage for all 24 hours of the balancing market they solve the model in a rolling horizon setup over four iterations giving balancing market price updates every sixth hour. Tests on a Swedish three-reservoir system for one day shows a 3.3% profit improvement when the balancing market is included compared with spot-trade only.

A bidding model considering spot market and reserve bids in the 2h-ahead market of Ontario, Canada was presented in De Ladurantaye et al. (2007). It makes a distinction between spinning and non-spinning reserves, and bids for both markets and for a given time-period are submitted synchronously. Activation of reserves are not represented. Non-convex head effects are treated with successive linear programming. The model is compared with two similar models: a deterministic model and a stochastic model without bids where the quantity is set prior to knowing the price. The results show, as expected, increased profits when bidding is included, and that the size of the improvements depend on the scenario tree structure, the price volatility and the water value relative to the market price.

Ugedo et al. (2006) present a model for coordinated bidding that is evaluated in a case study for the Spanish market in Ugedo & Lobato (2010). The market sequence represented by the model is the day-ahead, the secondary reserve and the intra-day market. They use a stochastic programming model that initially captures all three markets, and are re-run for a subset of the markets as time evolves and obligations in the first markets are fixed. A portfolio of thermal, hydropower and pumping units are modeled, including binary variables to represent start/stop and pumping/turbining for thermal and pump units. For each market either oligopolistic or perfect competition can be assumed. The oligopolistic behavior and the market uncertainty are represented with stochastic residual demand curves that are represented by linear approximations in the optimization model. The description of the stage structure is somewhat unclear. The mathematical formulation indicates one stage per market combining the stochastic outcomes for different markets all-to-all. The model allocates energy and capacity to each market, and bidding curves are post-calculated based on the price-quantity pairs of each scenario. The allocations are restricted to conform with the requirement of non-decreasing sales bids and non-increasing purchase bids as prices increases. The case study in Ugedo & Lobato (2010) shows structural changes in the allocations to different markets under coordinated optimization of the markets relative to a sequential optimization, where day-ahead allocation becomes less aggressive to give room for reserve allocation while the with-in market is used for balancing the obligations with the production portfolio capabilities.

The master thesis in Lindsjørn (2012) outlines a model for sequential allocation of capacity in reserve markets and spot market production in the Norwegian market. The modelling of all three reserve markets is described, and the reserved capacity is withdrawn from the spot market. This work considers a short time period with constant water values and do not model activation of reserves.

A hydro scheduling problem co-optimizing spot and either primary or secondary reserve market is presented in Fjelldal et al. (2014). The scheduling model sees both markets simultaneously with no uncertainty. Besides capacity allocation, the effect of activated energy on income but not on water consumption is considered by predefined delivery factors for the secondary reserve market. Examples from Switzerland and Norway illustrate how these reserve markets impact the optimal production patterns. In most test instances reserve market obligations are committed, which gives fewer unit stops and less production in the capacity min and max limits to correspond to the reserve requirements. Both reserve markets are found to improve profits relative to a spot-only model. The impact of balancing markets on the scheduling strategy is discussed, but not modeled.

Chazarra et al. (2014) present a model for a pumped storage hydropower plant operating in the Spanish day-

[17] VSS = value of stochastic solution, that is, the difference between first stage decisions of the expected value solution and the stochastic solution evaluated on the same scenario tree, see Birge & Louveaux (1997)

ahead and secondary reserve market. Both capacity reservation and water consumption due to reserve activation are modeled. The power plant is modeled with binary variables describing pumping/turbining and on/off-modes and bounds on energy production and consumption in the different modes. The model is deterministic which implies a perfect information model that gives an upper bound on the profits that can be achieved in real operation. Evaluation on realized prices in Spain for 2012-2013 shows an added value of variable-speed pumps relative to conventional pumps due to the regulation capabilities in pumping mode. It also shows that the income from capacity reservation covers more than 95% of the total income for all pumps tested.

4.3 Long-Term Models / Market Models

In the research project WILMAR, a fundamental market model was established Meibom et al. (2006), known as the joint market model. This model analyzes multiple markets by combining technical and economical aspects, based on an hourly description of generation, transmission and demand. The amount of wind power available is treated as a stochastic parameter. Four markets are considered: day-ahead markets for spot and primary reserves, and intra-day markets for regulating power and secondary reserves. The sequential market's clearing processes are simulated by sequentially solving a three-stage stochastic program. In the first sequence, covering hours 12:00-15:00 the day-ahead, the obtained first-stage decision concerns activities in both the day-ahead markets. In the remaining sequences, the day-ahead market decisions are given as input, and the first-stage decisions concern the two intra-day markets. The model is based on LP and represents linearized start-up costs of generators, see Barth et al. (2006). The coupling to the long-term strategic operation of hydropower reservoirs is provided by a separate model Ravn (2006), through water values. The two models see the same system boundary, but differ e.g. in that the long-term model does not consider unit commitment. Moreover, the long-term model does not seem to include reserve capacity procurement. As pointed out by the authors, ideally the long- and short-term models should be solved simultaneously, but this was not done in this project. Instead the two models are solved in weekly sequential steps, where water values from the long-term model is passed to the short-term model, and reservoir levels are passed the other way. This interplay can be calibrated to account for systematic deviations in price levels between the models.

A chain of models for combining the long-term hydrothermal scheduling and the sequence of procuring and activating regulating power is described in Jaehnert & Doorman (2010). Unlike the traditional market sequences, the procurement phase succeeds the day-ahead market clearing in this model. For a given time step, the EMPS model is run first to obtain a market clearing for the day-ahead market. Subsequently, reserves are procured to ensure that a target level is available. After procuring reserves, imbalances are simulated using load and wind forecasting errors. Reserves are then activated to bring the system to balance. There is no feedback from the reservation and activation of regulating power to the strategy computation (water values) in the EMPS model. Thus, in this chain of models, the impact of procuring reserves will not be reflected in the day-ahead prices.

In the SINTEF project "Competence Building Capacity Shortage"[18] 2002-2005, substantial work was done to study and model the central approaches for solving the peaking capacity problem in restructured power systems, see Doorman et al. (2005) for a summary. Of particular relevance for this project, we mention the model developed in Wolfgang et al. (2004) for the purpose of simulating the behaviour of different agents in a market with capacity reservation, spot- and balancing markets. A power producer agent is modeled with a three-stage decision process, finding strategies for the RKOM, spot and RK markets successively. The agent's decision process is solved by use of dynamic programming, where the demand is considered stochastic.

Several authors have decomposed the planning problem into intra- and inter-stage problems. This was first suggested in Pritchard et al. (2005), and further discussed in e.g. Lohndorf et al. (2013). Roughly speaking, the inter-stage problem will take care of the longer-term and strategic decisions, e.g. how much water to use in a given week. The intra-stage decisions concerns more detailed decisions with much finer time-resolution. In a recent publication, Abgottspon & Andersson (2014) presented a model for medium-term hydro scheduling considering participation in both the spot market and secondary control market. The authors emphasize that short-term flexibility is not correctly captured in linear energy-only models. In this model water values are

[18] Financed by The Research Council of Norway

computed using stochastic dynamic programming (SDP) on a higher-level optimization problem. The daily schedules are found in a lower-level formulation by solving a stochastic mixed-integer problem. Both inflows (weekly) and market prices (daily) are considered stochastic variables in the lower-level problem. The key challenge here is the interaction between the two problem layers. In their approach Abgottspon & Andersson (2014) enforces a volume requirement obtained from the higher-level problem for all leaf nodes in the scenario tree of the intra-week problem. Thus, the use of water will not depend on the intra-week scenarios being realized. Furthermore, the method does not allow uncertainty modeled in the higher-level problem to depend on the modeling in the lower-level problem.

In Rajaraman et al. (2001) the general self-scheduling problem is modeled considering sales of energy and reserve capacity for a risk-neautral price-taking producer. Both energy and reserve capacity prices are modelled as discrete Markov chains. Temporal ties are treated in a stochastic dynamic programming framework. The article is is didactic and focuses on simple examples for a thermal plants scheduled for a short period. However, the presented modeling technique can easily be incorporating in the calculation of water values.

In Ortner & Graf (2013) a fundamental market model considering unit commitment in spot, secondary and tertiary reserve markets is presented. The model is based on linear programming and uses observed volumes from secondary and tertiary markets as demand.

5 Conclusions

This report was prepared in the early phase of the project 'Integrating Balancing Markets in Hydropower Scheduling Methods'. The purpose of it has been to; a) review the current Nordic power market design and; b) review literature on the topic of treating multiple power markets in both short- and long-term hydropower scheduling.

Regarding the balancing markets, we find that the operating rules and regulations have been frequently updated during the latest years. The reader should therefore be aware that the market information may not be up-to-date when reading this report.

The literature review serves as a background for the scientific work within the project. There are two important findings from the literature review. First, we find that many researchers have recently addressed the multi-market problem in short-term hydropower scheduling or bidding models. Although the importance of treating multiple markets vary greatly between reviewed studies, we think that this topic will be important in the future development of operational short-term scheduling or bidding models. Second, there are relatively few published approaches for evaluating the impact of considering multiple markets in long- and medium-term hydropower scheduling tools. In that sense, our initial assumption when initiating this project has been strengthened through an extensive literature review. There is clearly a need for consistent modeling tools and approaches in order to quantify the impact of balancing markets in hydropower scheduling methods.

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