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Future outlook of Swedish hydropower capability to provide flexibility services with a 15 minute trade and settlement period

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Abstract

This thesis evaluates the future outlook of Swedish hydropower's capability to provide flexibility services, particularly mFRR, under changing market conditions. Hydropower has over the years emerged as an important flexibility provider but new *market changes* have raised concerns. The *market change* includes that the Imbalance Settlement Period (ISP) and Market Time Unit (MTU) have been changed from 60 to 15 minutes on mFRR-EAM as well as the implementation of an Activation Optimisation Function (AOF). This thesis therefore investigates how the *market change* and an intermittent operating pattern (including more start and stop cycles, ramping events and operation outside the optimal operating range) affects hydropower production, BSPs (Balance Service Providers) and BRPs (Balance Responsible Parties).

The findings show that the market change affects several aspects of hydropower which have been categorised as technical, market, hydrological and operational. In some cases, the affected aspects are driven by short-term regulation itself, while the market change can amplify the negative consequences. In other cases, the market change introduces new implications. One implication of the market change and intermittent operation is its impact on the local environment and communities. Another aspect is the wear and degradation the intermittent operation causes. By calculations of the related average and marginal cost, indications of how the degradation caused by intermittent operations can be priced in mFRR-EAM are given. However, as intermittent operation of hydropower units significantly shortens the rehabilitation interval, it increases the demand for internal and external resources and can lead to loss of income during standstill. A more intermittent operating pattern followed by the market change also affects the operational aspects as it requires more up- and downregulations of the unit's production. This, along with a potentially higher financial risk due to higher imbalance prices followed by the market change, affects the capability of providing mFRR services. The question is how hydropower producers should and can act upon the market change or whether it may become necessary to withdraw capacity from the mFRR market.

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Sammanfattning

Den europeiska avreglerade elmarknaden står inför förändring när intermittent och förnybar elproduktion utmanar frekvensstabiliteten. För att elnätet ska fungera behöver frekvensen inom det nordiska synkronområdet hålla 50 ± 0.1 Hz och det är när det uppstår obalans mellan produktion och konsumtion som frekvensen avviker från detta värde. För att minska förekomsten av frekvensavvikelser, även vid övergången mellan drifttimmar, kräver en EU-förordning från 2017 att avräkningsperioden för obalanser (ISP, Imbalance Settlement Period) ändras från 60 till 15 minuter. Det innebär att balansansvariga parter (BRP, Balance Responsible Party), som är ekonomiskt och planeringsmässigt ansvariga för att det råder balans i den punkt som balansansvaret gäller, kommer avräknas med kortare tidsupplösning. Förändringen förväntas på sikt möjliggöra att balansenergi kan utbytas mellan flera länder vilket således kommer minska de samhällsekonomiska kostnaderna för stödtjänster (reserver som återställer frekvensavvikelsen) och gynna konkurrensen på stödtjänstmarknaden.

För att möta den europeiska lagstiftningen har Sveriges transmissionsnätsoperatör (TSO) Svenska kraftnät (Svk) ändrat tidsupplösningen för ISP i mars 2025. Samtidigt harmoniserades handelsperioden (Market Time Unit, MTU) på intradagsmarknaden. På så vis kan balansenergi prissättas i samma tidsupplösning som avräkningen. Stödtjänsten och frekvensåterställningsreserven mFRR (Manual Frequency Restoration Reserve) handlas upp till sju dagar innan leverans på kapacitetsmarknaden (CM) och under samma dag som leverans på energiaktiveringsmarknaden (EAM). Utifrån prognostiserade och/eller realtids obalanser mellan produktion och konsumtion kan Svk aktivera mFRR-EAM bud vilket leder till upp- eller nedreglering av produktion, beroende på behovet. För att hantera den förändrade tidsupplösningen på mFRR-EAM har Svk automatiserat budprocessen med en aktiveringsoptimeringsfunktion (AOF).

Hur förändringarna på energiaktiveringsmarknaden påverkar leverantörer av balanstjänster (BSP, Balance Service Provider) och deras möjligheter att erbjuda mFRR är en fråga som bland andra det nordiska energibolaget Fortum ställer sig. Denna fråga är central för Fortum som äger 124 vattenkraftverk i Sverige och Finland då vattenkraften har en betydande roll på stödtjänstmarknaden. Detta tack vare förmågan att kunna korttidsreglera produktionen genom att ändra körmönstret för ett aggregat. Syftet med denna studie är således att undersöka hur vattenkraften påverkas av marknadsförändringen (övergången till 15 minuter ISP och MTU samt implementeringen av AOF) och hur det i sin tur påverkar förmågan till att bidra med kapacitet till mFRR. Studien omfattar både en kvalitativ kartläggning av hur vattenkraften påverkas och en kvantitativ kostnadsmodell som visar på tendenser till hur vattenkraftsanläggningarna kan påverkas av ett mer intermittent körmönster till följd av marknadsförändringen samt hur ett sådant körmönster kan prissättas.

Undersökningen visar att marknadsförändringen påverkar många olika aspekter av vattenkraft vilka har kategoriserats som tekniska, marknadsmässiga, hydrologiska och organisatoriska. En del av dessa aspekter påverkas negativt av korttidsreglering i sig, varpå marknadsförändringen driver på dessa negativa konsekvenser. I andra fall introducerar marknadsförändringen nya konsekvenser.

En följd av marknadsförändringen är att körmönstret av vattenkraftsaggregaten (turbin och generator) blir mer intermittent då frekvensen av start-och stoppcykler, lastförändringar och drift utanför det optimala driftområdet förväntas öka. Det har dels effekter för miljön och

människor och dels leder det till ökat slitage på komponenter och vattenkraftsanläggningar vilket har visat sig förkorta livslängden markant. Vad det ökade slitaget till följd av ett intermittent körmönster kostar har beräknats och ger stöd till hur mFRR buden på energiaktiveringsmarknaden kan prissättas. Däremot innebär det ökade slitaget ett stort behov av underhåll och leder till att renoveringsintervallen av aggregaten klustrar sig. Om flera aggregat behöver renoveras samtidigt kan det vara utmanande för både den egna organisationen och industrins resurser. Dessutom skulle det öka förekomsten av intäktsbortfall under renoveringstiden. Därutöver leder marknadsförändringen till organisatoriska påfrestningar när körmönstret blir mer intermittent. I och med ett ökat fokus på marknaden minskar operatörernas tid till att övervaka och styra vattnet från älvarna ner mot havet. Denna förändring kan i värsta fall få förödande konsekvenser för den lokala omgivningen.

Ytterligare en följd av marknadsförändringen är den ökade ekonomiska risken som uppstår då mFRR marknaden blir mer oförutsägbar med högre obalanspriser samt mer frekventa och oberäkneliga aktiveringar av mFRR bud. Detta leder till att planeringen och allokeringen av resurser blir mer komplex samt som det ökar risken för höga obalansavgifter. Sammantaget visar resultaten från studien på att många aspekter av vattenkraften kan komma att påverkas av marknadsförändringen och en del har bekräftats från och med dess införande i mars 2025. Däremot kan justeringar i marknadsförändringen komma att göras över tid vilket således kan påverka dessa slutsatser. Undersökningen och identifieringen av hur vattenkraften påverkas väcker frågan om vattenkraften bör och kan anpassa sig för att fortsatt kunna leverera stödtjänster och i synnerhet mFRR. Alternativet skulle vara att kapacitet dras tillbaka från stödtjänstmarknaden. Vad betyder i sådana fall det för kraftsystemets förmåga att upprätthålla frekvensstabilitet?

Acknowledgement

This master thesis marks the end of our engineering studies. The last five years have been filled with both challenges and many great memories. Along the way, we have found fields that we feel genuinely curious about and we are excited for what lies ahead of us.

We are very thankful to Fortum for giving us the opportunity to explore such relevant and important questions. We would like to thank all the experts who shared their time, knowledge, and perspectives with us – this thesis would not have been possible without you.

To our supervisors Alessandro Ferraris and Karar Al Obeid, thank you for your guidance, patience and feedback throughout this process. Additionally, thank you to our manager Hans Bjerhag for all your support, structure and warm welcoming to the company.

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Maria Lindström

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Acronyms and own abbreviations

mFRR	Manual Frequency Restoration Reserve
EAM	Energy Activation Market (mFRR)
CM	Capacity Market (mFRR)
MTU	Market Time Unit
AOF	Activation Optimisation Function
ISP	Imbalance Settlement Period
BSP	Balancing Service Provider
BRP	Balance Responsible Party
TSO	Transmission System Operator
Svk	Svenska kraftnät
Imbalance fee	Cost for BRP. Based on the imbalance price.
Unit	Hydropower turbine and generator.
Market change	The transition to a 15-minute Imbalance Settlement Period and Market Time Unit (MTU) at mFRR-EAM as well as the introduction of the Activation Optimisation Function (AOF).

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1. Introduction

Ever since 1996, the electricity and balance power markets have been deregulated, with trading and settlement occurring hourly. To improve power quality across Europe, the European Commission introduced Regulation 2017/2195 that established requirements of changing the time resolution for the Imbalance Settlement Period (ISP). The transition to a shorter time resolution will be beneficial for the grid frequency as it can reduce the occurrence of imbalances in the electrical power grid. Imbalances occur when the production and consumption of electricity differ. The transition to a 15-minute time resolution is expected to reduce structural imbalances that typically occur at the shift between operating hours. Additionally, the market change is meant to efficiently handle the imbalances from the increasing share of variable, weather dependant energy production (Copenhagen Economics, 2017; Svenska kraftnät, 2024a).

In line with the EU-regulation, the Swedish Transmission system Operator (TSO), Svenska kraftnät (Svk), changed the ISP to 15 minutes in March 2025. By aligning the Market Time Unit (MTU) for trading, it is possible for Balance Responsible Parties (BRP) to balance themselves on the intraday market (Copenhagen Economics, 2017). BRPs are financially responsible for maintaining balance between the electricity production and consumption (Energiföretagen Sverige and Svenska Kraftnät, 2025; Svenska kraftnät, 2025a). However, as imbalances still can occur, Svk has the responsibility to maintain a stable grid frequency at 50 ± 0,1 Hz (Energiföretagen Sverige and Svenska Kraftnät, 2025; Svenska kraftnät, 2024b). One frequency regulation service that Svk can activate is mFRR, which stands for manual Frequency Restoration Reserve. At the mFRR Capacity Market (mFRR-CM), the capacity is procured up to seven days before delivery. The balancing energy is then activated close to or in real time at the mFRR Energy Activation Market (mFRR-EAM) (Svenska kraftnät, 2024c). To ensure neutrality in the bid selection and to handle the shorter time resolution, the bid selection at mFRR-EAM became automated by an algorithm called the Activation Optimisation Function (AOF) in March 2025 (NBM, 2024a).

Hydropower plays a crucial role in short-term frequency regulation and the provision of mFRR capacity, mainly due to its ability to store water in upstream reservoirs. This storage capability allows hydropower producers to generate electricity when there is a demand rather than depending on weather such as other renewable energy sources. The ability to regulate production makes hydropower suitable for participation on the mFRR market.. However, the transition to 15 minute ISP and time resolution on mFRR-EAM and the intraday has raised questions about its potential impact on the hydropower system. One concern is if the shortened time resolution will lead to more intermittent operation of the hydropower units. In such case, what impact will it have on the degradation of the hydropower units? Therefore, it is necessary to understand how the *market change* will affect hydropower assets, production and the producers.

A hydropower producer that is interested in how the future capability to provide mFRR capacity is affected by the *market change* to a 15-minute ISP and MTU at mFRR-EAM is Fortum. The Nordic energy company owns and operates 124 hydropower plants in Sweden and Finland (Fortum, n.d.).

1.1 Purpose

The purpose of the thesis is to evaluate the future outlook of hydropower capability to provide flexibility services and in particular mFRR under changing market conditions. This in terms of hydropower production, assets and organisation. The term *market changes* includes the transition to a 15-minute Imbalance Settlement Period and Market Time Unit (MTU) at mFRR-EAM as well as the introduction of the Activation Optimisation Function (AOF).

The first objective is to identify which aspects of the hydropower system that may be impacted by the transition to a 15-minute time resolution. What implications the *market change* has on the identified aspects are analysed on a system-level perspective and is conducted by a qualitative method including interviews and field observations with experts at Fortum in addition to a literature review.

The second objective of this thesis is to evaluate what implication intermittent operation of hydropower units has on the capability of providing flexibility services. An assumption is that the *market change* will lead to a more intermittent operating pattern of the hydropower units due to start and stop cycles, ramping and operation outside optimal operating range. The objective is examined with knowledge from previous studies on how intermittent operation affects hydropower plants and then applies it in the context of the *market change.* Furthermore, the cost of a start and stop cycle has been a relevant question within the field of hydropower for many years and economic calculations have been developed in previous studies. The method used in this thesis is a techno-economic cost model which examines how an intermittent operation affects the units as well as an estimation of the average and marginal costs from such operation pattern.

To examine the two objectives, the following research questions are used:

- How does the *market change* impact the conditions for providing mFRR services from hydropower production in Sweden?
- What implications does an intermittent operating pattern have for hydropower's capability to provide flexibility?

1.2 Delimitations

The scope is limited to the Swedish context and specifically examines how the *market change* may affect Swedish hydropower. The thesis has been done in collaboration with

Fortum Hydro Generation division and no other interviews or data have been collected from other Swedish hydropower producers. As a result, the identified aspects and reflections are based on insights from Fortum's operations and may not fully represent the perspectives or conditions of the broader hydropower industry. Nevertheless, the findings may be relevant to other hydropower producers and countries with similar system characteristics or hydropower dominated portfolios.

As the *market change* was implemented during the course of this thesis, the analysis is based on limited experience which constrains the ability to draw definitive conclusions. While early indications suggest a potential increase in start-stop cycles, ramping events, and operation outside the optimal range, the scenarios used in the cost model are hypothetical.

Even though the focus on the *market change*s is related to intraday trading and mFRR-EAM, it does not include an analysis of bidding strategies. While the market design and activation mechanisms are discussed, the study does not model or evaluate how hydropower producers formulate or optimise their bids. Additionally, some aspects that are raised as an effect of the *market change* are inherent to the nature of short-term regulations, no matter the time resolution. However, the *market change* can amplify the negative consequences of these aspects.

When evaluating the effects of more intermittent hydropower operation, a cost model is used. The model considers the additional wear as lifetime reduction caused by an operating pattern including events such as start up of a unit or increasing/decreasing the power output. The only components considered in the calculations are the turbine and the generator. Two types of turbines are considered, Francis and Kaplan turbines, as they are the most commonly used in Sweden. The calculations do not consider degradation at component level (such as bearings, shaft, runner etc.) but depending on available data, components can be implicitly included as input on the condition of the turbine and generator. Moreover, this approach does not analyse what components of the turbine and generator that are most affected by intermittent operation. This approach simplifies the cost modelling and enables a more general analysis but may overlook variation in how different components are affected by intermittent operation.

1.3 Thesis structure

Section 2 presents background information about electricity production, the energy market, the evolving market conditions and how hydropower can be used for short-term regulation. Section 3 outlines the theoretical background for the techno-economic calculations and in Section 0 the methodology is described. In Section 5, the results of the *market changes'* impact on hydropower providing mFRR services is presented and in Section 6 the results from the techno-economic cost model is given. In Section 7 the results given in Section 5 are further analysed. Thereafter a broader discussion along with future studies is presented in Section 8. The thesis is concluded in Section 9.

2. Background

The Swedish electricity production today is characterised by carbon free nuclear power and renewable energy sources such as hydro, wind and solar power. During the last decade, electricity production from sources such as wind power has entered the production mix and Sweden's generation has thereby increased its dependency of intermittent renewable energy sources (Ekonomifakta, 2024). This has resulted in more volatile electricity prices as the renewable energy sources makes the electricity prices more sensitive to variations in production.

Svenska kraftnät (Svk), the Swedish Transmission System Operator (TSO), is responsible for maintaining a secure and reliable transmission grid. This includes real time balancing between electricity production and consumption as well as developing and adapting the power system to meet future demands (Svenska kraftnät, 2025b). As most of the electricity is produced in the north of Sweden whereas the highest consumption occurs in the south, the transmission capacity in the grid becomes a critical issue. The calculations and allocations of transmission capacity is since October 2024 based on a method called Flow based. The method enables detailed calculations ensuring that the transmission grid is used as efficiently as it can, in order to maximise the transmission of electricity in the grid (Svenska kraftnät, 2024d).

2.1 The electrical power and balance market

Besides the transmission grid, the electricity market which in Sweden was deregulated in 1996, is vital for trading of electricity production and consumption (Sveriges riksdag, 1996). The power market is based on time intervals, seen in Figure 1.

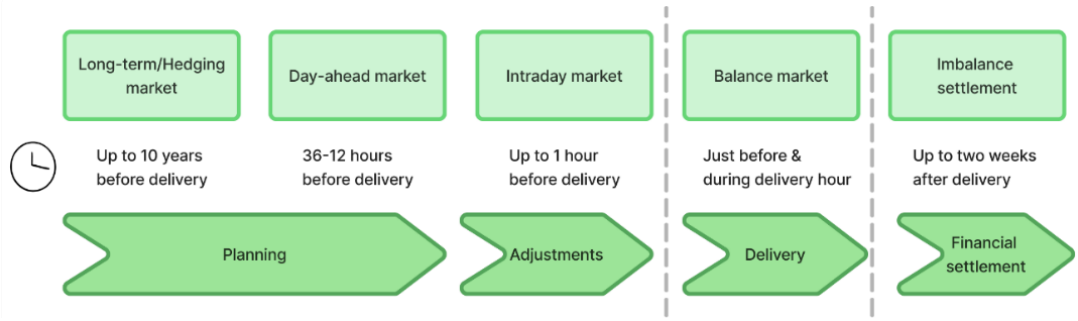

Figure 1. Overview of the electricity market timeline from planning to delivery. Long-term hedging can occur many years before delivery whereas physical trading occurs in the day-ahead market followed by the intraday market closer to delivery. Real-time balancing takes place continuously during the delivery hour. After delivery, imbalances are financially settled. Source: Own interpretation of (Svenska kraftnät, 2024e).

As presented in Figure 1, the long-term market ensures a future deal to a beforehand given price (price hedging) and can be used for risk minimisation (Svenska kraftnät, 2024e, 2023). However, the majority of trading take place at the spot market, also called

the day-ahead market. At the spot market, the volumes are traded based on hourly submitted bids from both buyers and sellers. The price of electricity is based on where the supply and demand curves meet (Svenska kraftnät, 2024f).

The day-ahead market is followed by the intraday market where trading occurs the same day as deliverance. The intraday market is used for adjustments of volumes that have been traded at the spot market as weather or prerequisites of production can change. This enables the BRP who is economically responsible for imbalances, to minimise the risk of imbalance fees (Svenska kraftnät, 2025c). The intraday trading happens both continuously and at three auctions per day (Svenska kraftnät, 2025c).

Although the purpose of the intraday market is to prevent imbalances, it can still occur. In the event of an imbalance, Svk activates ancillary services on the balance market to stabilise the grid. Ancillary services are provided by Balancing Service Providers (BSP) such as energy producers, energy storages and/or facilities that can adapt their consumption based on the demand. BSPs can voluntarily participate with their assets in one or several of these balance markets if they fulfil the requirements in the pre-qualification process ensuring that the technical and regulatory requirements are met for delivering balance energy (Svenska kraftnät, 2022). An variety of assets are necessary as the need differs depending on the type, size and duration of the imbalance.

When ancillary services are activated, the cost falls on the Balancing Responsible Parties (BRPs) who contributed to the imbalance. It follows a so-called polluters pay principle where those who contribute to the imbalance bear its financial consequence (Energiföretagen Sverige and Svenska Kraftnät, 2025; Svenska kraftnät, 2025a). A BRP who is responsible for balancing can at the same time be a balance service provider. The imbalance price is determined by the price of the activated energy bid during that Imbalance Settlement Period (ISP) and the BRPs must pay the imbalance price per megawatt of deviation from their planned production/consumption.

2.1.1 The mFRR market

The manual Frequency Restoration Reserve (mFRR) is an ancillary service used to balance the power system over longer timeframes and is characterised by its ability to provide high capacity. Unlike other ancillary services which require fast response times, mFRR allows for a longer activation time. There are two types of mFRR-markets, the capacity market (mFRR-CM) that was introduced in October 2023 and aims to ensure that there is sufficient balancing capacity available and the Energy Activation Market (mFRR-EAM) where pre-qualified balance service providers omit the same bids as on the capacity market, along with voluntary bids. The accepted bids on the capacity market generate an income for the provider regardless of whether it is activated or not (Svenska kraftnät, 2024c). The need for mFRR capacity is dimensioned to handle the largest contingency that may occur in the electrical power grid (Svenska kraftnät, 2024g).

In Sweden 2023, the total activation volume at mFRR-EAM was 643 GWh of upregulation and 629 GWh of downregulation. In 2024, around 90% of prequalified mFRR capacity in the Nordic power system was provided by hydropower (Svenska kraftnät, 2024c). The companies that have hydropower assets thereby plays a central role in maintaining and restoring power grid stability (Tomé Robles et al., 2024). Especially since the demand of mFRR capacity for both up- and downregulation is expected to increase during the coming five years. For example, according to a forecast of upregulation capacity, the demand is expected to go from around 500 MW in 2025 to nearly 1500MW already in 2026. For downregulation capacity, the demand is expected to go from around 900 MW in 2025, to approximately 1200 MW in 2026 (Svenska kraftnät, 2024c).

2.2 Market change

To enable better frequency control, more effective balancing and more precise market signals, the European commission has set out requirements on changing the time resolution for the ISP to 15-minute intervals across Europe (Commission Regulation (EU) 2017/2195, n.d.). The transition to a 15-minute resolution on the balance market supports grid stability by reducing structural imbalances that typically occur at the shift between each new operating hour (Copenhagen Economics, 2017). Additionally, to manage the increasing share of weather dependent renewable energy sources in the power system, there is a growing need to manage fluctuations and integrate renewable generation in a reliable and cost-efficient way (Svenska kraftnät, 2024a). The requirement is set out in Regulation (EU) 2017/2195,

"*…all transmission system operators shall apply the imbalance settlement period of 15 minutes in all scheduling areas while ensuring that all boundaries of market time unit coincide with boundaries of the imbalance settlement period." (Regulation (EU) 2017/2195, Art. 53(1))*

In accordance with the legislation, Svk introduced a 15-minute ISP and adjusted the market time unit by changing the time resolution on the intraday market and mFRR-EAM from 60 to 15 minutes in March 2025. When the trading and settlement timeframe are aligned, it allows market participants to balance themselves (Copenhagen Economics, 2017). For instance, if an electricity producer is unable to produce according to their production plan they can proactively purchase energy in the intraday market to avoid imbalance fees (Copenhagen Economics, 2017).

Instead of balancing the power system through containing the frequency in the whole Nordic synchronous area, a new balancing model has been implemented that considers the forecasted imbalances for each bidding zone separately (Svenska kraftnät, 2025d). Svk has forecasted a rising demand for mFRR capacity and points out the importance of local resources for balancing services. Up until recently it has been possible to procure much of the balancing energy from Norway when the need was dimensioned based on frequency quality (Svenska kraftnät, 2024c).

To handle the shorter time unit on mFRR-EAM and to ensure neutrality in the bid selection of balancing services, an automatic bid selection algorithm called Activation Optimisation Function (AOF) has been implemented. The AOF schedules energy activation volumes for the upcoming 15 minute interval based on an imbalance prognosis (NBM, 2024a). Unplanned events that fall outside the prognosis are handled through a separate direct activation process, which allows immediate response to unforeseen imbalances in the power system (NBM, 2024a). As a result of the AOF, the system will be regulated at nearly all times and an estimation is that the time no mFRR is activated will drop from approximately 13% to only 0,01% (NBM, 2024b). The *market change* also includes a reduction in the minimum capacity and delivery duration required by BSPs. Previously, the requirement was five Megawatts for one hour. After the change, it has been lowered to 1 Megawatt for 15 minutes for scheduled activations and 30 minutes in the case of direct activations (Svenska kraftnät, 2025e).

The implementation of AOF is one step towards integrating the Nordic balancing markets into a common European market for balancing services, such as the MARI-platform for mFRR. A timeline is presented in Figure 2 over recent changes and steps that were taken before the *market change* implemented in March 2025 as well as future steps towards a European balancing platform.

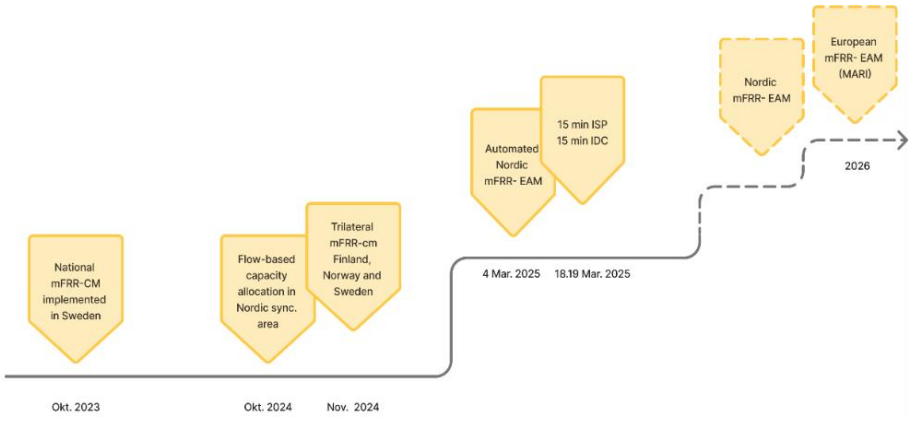

Figure 2. Roadmap over mFRR-market, from implementation of a capacity market in October 2023 and the steps that followed prior to the adjusted 15-minute ISP and MTU in March 2025 as well as planned future steps towards a European platform for mFRR. Source: Own interpretation of (Svenska kraftnät, 2025f).

2.2.1 New terms and conditions on mFRR-EAM

Following the *market change* the number of trading periods increased from 24 to 96 per day. Bid activations are no longer handled manually but by the AOF and BSP providing ancillary services need to send attributes along with the bids that they omit to mFRR-

EAM. It is essential that the physical limitation of the producer's assets are described in a manner that the AOF algorithm can interpret (NBM, 2024a). To deal with the communication with the AOF, a set of bid attributes have been designed. Each bid contains information such as volume, price, direction (up- or downregulation which means an increase or decrease of the production), divisibility and whether the bid is available for scheduled activation, direct activation or both. Additionally, there are bid attributes for more complex information such as technical and conditional linking that includes listing of constraints such as resting time (NBM, 2024a). Resting time is used to account for physical limitations by preventing the reactivation of a unit for a specified period following an activation. In Figure 3 the new terms and conditions on the mFRR-EAM from March 2025 are outlined.

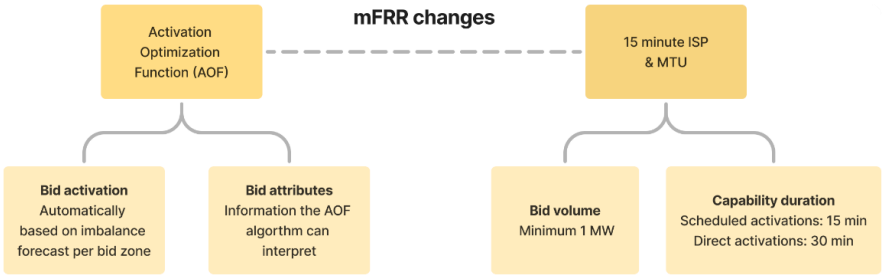

Figure 3. New terms and conditions on mFRR-market from March 2025 that BSP need to manage. Own interpretation based on information from the Nordic Balancing Model and Svk (NBM, 2024a; Svenska kraftnät, 2025g).

Some indications of the *market change* are the increased imbalance prices, the frequency of activations and the unpredictability. Figure 4 shows the imbalance price development in bidding zone SE3 before and after the *market change.*

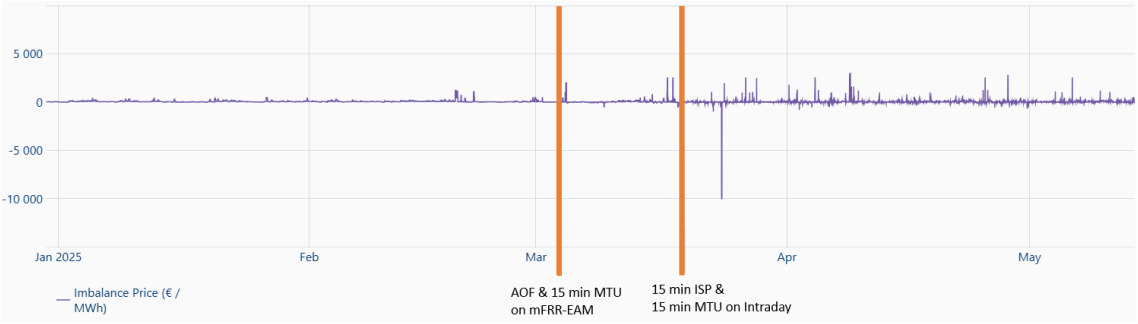

Figure 4. The imbalance price development from January 2025 until the middle of May 2025. The timing for the market changes are marked by two orange vertical lines which included the implementation of 15-minute MTU and AOF on the mFRR-EAM on March 4th followed by the introduction of 15-minute ISP and 15-minute MTU on the intraday market March 18 and 19th. Source: eSett (2025).

Figure 5 shows the imbalance price for SE3 in April 2024, before the *market change* was implemented. It can be compared with the imbalance price for the same bidding zone one year later in April 2025, after the *market change*, in Figure 6.

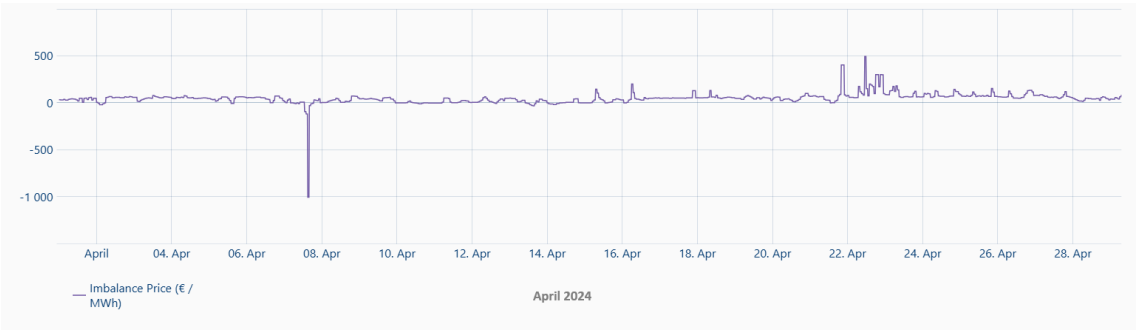

Figure 5. Imbalance prices for SE3 in April 2024 (before the market change). The price volatility and extreme values are limited.

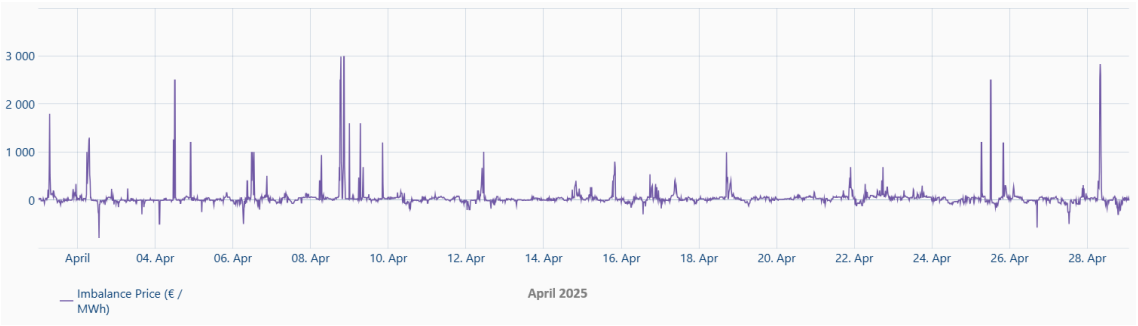

Figure 6. Imbalance prices for SE3 in April 2025 (after the market change). Higher volatility and frequent price spikes, both upward and downwards are visible.

The comparison between Figure 5 and Figure 6 illustrates how the *market change* has contributed to more dynamic imbalance prices with potentially greater risks and opportunities for BRPs. If BRPs are contributing to the imbalances, they risk higher imbalance fees. On the other hand, if BRPs support system balance by overproducing during a deficit or underproducing during a surplus, they may be compensated according to the imbalance price.

2.3 Hydropower

The power in streaming water comes from potential and kinetic energy which derives from the hydrologic cycle caused by wind and solar energy. Therefore, it is considered as a clean energy source since it creates no air pollution, carbon dioxide and no radioactive waste (Lundin, 2021). Most of the installed hydropower capacity for electricity production is located in price area SE1 and SE2, which covers the northern parts of Sweden (Energiföretagen, 2025).

The design of a hydropower plant is unique and based upon the local conditions. Commonly, they include civil structures that enables transportation of water through the

turbine which is connected to a generator (Killingtveit, 2019). Therefore, the hydropower system typically consists of an intake, power unit (turbine and generator) and outlet, which can be seen in Figure 7.

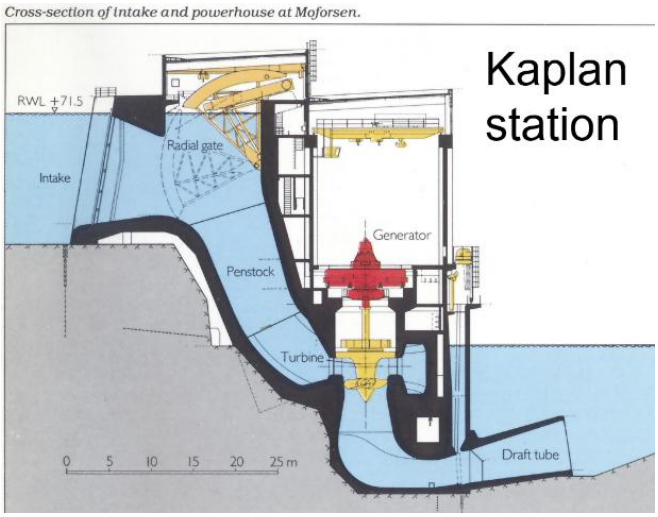

Figure 7. Graphical overview of a hydropower plant. Source: Vattenfall (n.d).

A way to categorise hydropower plants is by the ability to store water. A run-of-river plant has no reservoir and therefore no storage. This makes the generation from a run-of-river plant dependent of the water flow from upstream. A storage hydropower plant has a reservoir where water is stored and thereby also a dam. The design of dam structures depends on the local conditions. The main advantage of hydropower plants with reservoirs is the flexibility it provides for controlling water release and thus the generation of electricity. (Killingtveit, 2019).

To handle for example high water levels in the river or reservoir, spillway gates can be used. In such cases, the water does not pass the turbine (Hannah, 2022). Therefore, spillway gates are important for preventing overtopping of dams during floods. Whether the water is released through the spillway gates or the turbine can depend upon factors such as the prices on the electrical power and balance markets. In a volatile market, spillway gates might be used more frequently. Spillway gates can therefore be used during mFRR downregulation if the water level is too high in the reservoir or in the case that the hydropower plant lack a reservoir.

2.3.1 Hydropower turbines

The turbine converts kinetic energy and in some cases pressure energy, into mechanical power. The turbine is unique for each hydropower plant and can either be an impulse or reaction turbine. The two main types of reaction turbines are Kaplan and Francis. A Francis turbine has a radial-axial flow of water which when it hits the fixed blades makes the turbine spin. The turbine is optimised for operating around the design point but can still adjust the production by varying the flow of water by changing the opening angle of the so-called guide vanes. It is the guide vanes that control and guide the flow

of water into the turbine. Even for a Kaplan turbine, the guide vanes are significant for regulating the flow of water (Wilberforce et al., 2023a, 2023b). However, the Kaplan turbine has a wider operating range as it can also adjust the production by changing the runner blades (Saarinen et al., 2018).

To maximise the energy conversion, the turbine should operate at its best efficiency point (BEP). However, when the efficiency of a turbine is related to the discharge given in percentage of its maximum, a Kaplan turbine has an efficiency above 80% when the discharge is at least 0.5 of the maximum compared to 0.65 for a Francis turbine. Thereby, a Kaplan turbine has a higher efficiency for a wider range of discharges than a Francis turbine, due to the adjustable runner blades (Tiwari et al., 2020). The peak efficiency of the Francis turbine is around 90-95% while it is around 90-93% for a Kaplan turbine (Halder et al., 2021).

2.4 Hydropower for short-term regulation

With the increasing share of renewable energy sources in the power system, imbalances in the grid are occurring more frequently. This has changed the hydropower production to become more flexible, enabling it to provide ancillary services (Saarinen et al., 2018). Therefore, the operating pattern of hydropower units has become more intermittent. These short-term regulations have effects on the local environment and society. In addition, it introduces additional ramping events and an increased frequency of start and stop cycles of the hydropower units (Eggen and Belsnes, 2023).

2.4.1 Start and stop cycles

One way to regulate the production, is by starting and stopping the unit (CEATI International Inc., 2021). However, start ups of the unit causes and accelerates the degradation of the equipment (Bjørkvoll and Bakken, 2002; Eggen and Belsnes, 2023). The mechanical, electrical and thermal stress affects multiple components whereas one is the turbine. Due to dynamic stress caused by mechanical forces the turbine is negatively affected as for example the turbine’s runners experience fatigue (Savin et al., 2023). For the Kaplan turbine the runner bearings are severely affected (Saarinen et al., 2018) while the runners of a Francis turbine is impacted by transverse vibrations (Savin et al., 2021b). Furthermore, structures such as the draft tube and welds in water passages can be negatively affected by start and stop cycles (CEATI International Inc., 2021).

The generator is affected by frequent start and stop cycles, primarily due to thermal cycling which for example causes stress and degradation of the stator insulation (Savin et al., 2023, 2021a). Furthermore, pressure changes between the unlined tunnel and the surrounding rock mass due to intermittent operation can lead to instabilities such as floating, block falls, tunnel collapse (Panthi, 2024). The gates and valves of a hydropower plant can also experience fatigue due to start and stops (CEATI International Inc., 2021).

2.4.2 Ramping

Another way to either increase or decrease the unit's generation is by making load changes. If the turbine can change its load by at least 25% of the nominal power within one minute, the action is referred to as ramping. A ramping event mainly affects the turbine and its runners. However, the stress is considered to be less than what a full start and stop cycle could lead to (Eggen and Belsnes, 2023).

2.4.3 Operation outside normal operating range

Production can also be regulated by running a hydropower unit within different operating ranges. However, as the unit is best suited for operation near the best efficiency point, other ranges above or below the peak efficiency set point will cause extra wear and degradation of the unit due to a higher appearance of cavitation and dynamic stresses (CEATI International Inc., 2021). Especially the Francis turbine is negatively affected by operating ranges as it for example causes cavitation and high pressure pulsations which leads to wear of the turbine (Saarinen et al., 2018).

Each turbine has its unique values of what is considered as low-, part-, normal- and overload due to the design of the runner. Generally, for a Francis turbine, the values are <50% of rated power for low-load, 50-80% of rated power for part-load, 80-100% of rated power for optimal range and 100-110% of rated power for over-load (Interview I.H, Appendix B).

2.4.4 Surge and water hammer

An intermittent operation of the units can increase the appearance of surge and water hammer which can cause degradation of hydropower plants. Water hammer arises due to abrupt changes of water flow at hydropower plants with long pipes, for example during ramping or start and stop events at underground plants (Lupa et al., 2022). Water hammer typically results in a sudden rise in pressure, which can lead to mechanical stress or damage to pipes and other components. However, the pressure might also decrease, which can impose structural stress on components and in severe cases it may result in deformation or collapse. Additionally, under both water hammer and low-pressure conditions, vapor pockets may form and their subsequent collapse can cause wear or damage in both pipes and turbines (Lundin, 2021).

2.4.5 Hydropeaking

The operation of hydropower units can have negative consequences for the environment. A main reason is hydropeaking, which is rapid and frequent changes of the water level and flow. Hydropeaking can for example affect spawning grounds and cause stranding events which both can lead to fish mortality and impact the fish movement and migration. The fluctuations of the discharge can be a stress factor that affects the possibility of fish growth and decrease the aquatic insect richness and

biomass (Bipa et al., 2024). Moreover, hydropeaking tends to affect the sediment in a negative way as the fluctuations in water flow and level leads to erosion particularly near submerged rocks and exposed boulders (Bipa et al., 2024). Hydropeaking also impacts the sub-surface as it increases the spreading and mixing of material. Thereby, hydropeaking affects the water chemically, thermally and hydraulically (Bipa et al., 2024). In addition, hydropeaking events can constitute a risk of public safety. This as sudden changes in velocity and depth of the water can be dangerous for people doing outdoor activities in or near the water ways (Pisaturo et al., 2019).

However, to ensure that the water in regulated water ways is managed safely and efficiently, the Swedish Land and Environment Court has issued water permits. The permits define how the water can be managed in order to consider water resources, safety of people and balancing of various interests of water usage. The permits include for example boundaries of the water level and flow (Sydvatten, 2024).

2.5 Hydropower's operational organisation

The organisation of hydropower producers generally includes traders who buy and sell electricity based on market forecasts, system conditions and available generation capacity as well as operators who controls the hydropower plants. The organisational setup can vary between hydropower BRPs (Fortum, 2025).

Traders reserves certain amount of production capacity for the balance markets by allocating hydropower resources to specific ancillary services from several days ahead up to the day before delivery. At the day-ahead market, traders optimise production schedules and aim to find an optimisation that is as close as possible to what the hydropower plants can produce (Fortum, 2025). Intraday traders then adjust positions closer to real time to account for deviations in consumption forecasts or production plans. Operators are responsible for carrying out production plans and operates hydropower plants, mainly from the control room. Hydropower operators control the power output through various systems and are also responsible for safe water management load (Interview I.D, Interview I.F, Interview I.K, Appendix B).

3. Theory

In this section the theory behind calculating the cost of short-term regulation from hydropower with an intermittent operating pattern is described. An intermittent operating pattern is assumed to lead to increased number of start and stop cycles, ramping events and/or increased operating time outside normal operating range (Eggen and Belsnes, 2023). The theoretical foundation for examining the cost of a more flexible operation builds upon the approach that extra start and stop cycles and ramping events of a hydropower unit will cause stress and degradation leading to a reduced service life and that the wear will not be compensated by increased maintenance (Eggen and

Belsnes, 2023). The cost of extra events can be estimated by both top-down and bottom-up approaches where the latter can be seen as a technical-economical model where potential cost factors are investigated (Savin et al., 2023). By examining the degradation of each individual component, the related cost can be determined (Eggen and Belsnes, 2023)

Hydropower units are designed with specific operating parameters, including the expected share of annual operation, a reference number of start and stop cycles and ramping events as well as a efficiency profile. Therefore, any events that exceeds these design parameters are classified as 'extra' start and stop cycles and ramping events. Each event is assumed to correspond to ΔD hours of operation under normal conditions, meaning that the remaining available operating time will be reduced by ΔD hours for each extra event (Eggen and Belsnes, 2023).

3.1 Cost of start and stop cycles

When calculating the cost of an extra start and stop cycle, the difference between operating time and calendar time must be considered. As a start and stop cycle adds ΔD operating hours to the operating time, the yearly operating time can exceed the total number of hours in a year (8760 hours). To account for this the operating time needs to be adjusted to calendar time using,

$$d(t|\alpha, n, \Delta D) = (\alpha + n \cdot \Delta D) \cdot t \tag{1}$$

where n is the number of start and stop cycles per year, α is the share of the yearly operating time, ΔD is the added operating hours per start and stop cycle and t is the calendar time (Eggen and Belsnes, 2023). The share of yearly operating time α, represents the fraction of the total annual hours (8760) that the hydropower unit is in operation and thereby actively producing electricity.

To isolate the cost of a start and stop cycle, the related operating time under a normal operating pattern can be compared to an intermittent operating pattern. The difference is the increased number of start and stop cycles. The yearly operating time for the normal operating pattern, OT_0 [h/year], is given by,

$$OT_0 = \left(\alpha_{ref} \cdot 24 \cdot 365 + n_{ref} \cdot \Delta D\right) \tag{2}$$

where n_{ref} is the reference (or designed) number of start and stop cycles per year, α_{ref} is the reference share of yearly operating time and ΔD is the operating time loss per start and stop cycle. By multiplying α_{ref} with 24 and 365, the equation converts yearly operating time to operating hours per year (Eggen and Belsnes, 2023).

The intermittent operating time, $OT_{\Delta n}$ [h/year], is calculated by adding the additional operating time caused by extra start and stop cycles to the operating time of the normal

pattern (Bjørkvoll and Bakken, 2002). The intermittent operating time is therefore given by,

$$OT_{\Delta n} = OT_0 + \Delta n \cdot \Delta D \tag{3}$$

where the number of extra start and stop cycles (Δn) is multiplied by the operating time loss per start and stop cycle (ΔD) and added to the operating time for the normal operating pattern (OT_0) (Eggen and Belsnes, 2023).

Hydropower units are periodically rehabilitated to restore them to an 'as good as new' condition. Rehabilitation is performed when the unit reaches the end of its expected operational lifetime. The time period between these rehabilitations is known as the rehabilitation interval and is denoted as T_0 [calendar years]. With a normal operating pattern the rehabilitation interval is given by,

$$T_0 = \frac{T_D}{OT_0} = \frac{T_D}{\left(\alpha_{ref} \cdot 24 \cdot 365 + n_{ref} \cdot \Delta D\right)} \tag{4}$$

where the expected operating lifetime given by the design criteria (T_D) [h] is divided by the normal operating time (OT_0) in Equation 2.

Similarly, the rehabilitation interval at intermittent operation, $T_{\Delta n}$ [calendar years], is given by,

$$T_{\Delta n} = \frac{T_D}{OT_{\Delta n}} = \frac{T_D}{\left(\alpha_{ref} \cdot 24 \cdot 365 + n_{ref} \cdot \Delta D\right) + \Delta n \cdot \Delta D} \tag{5}$$

where the expected operating lifetime (T_D) is divided by the intermittent operating time ($OT_{\Delta n}$).

These equations enable calculations of the average and marginal cost. The average cost is relevant to use if the additional start and stop cycle is due to a changed operating strategy, meaning that there will be an additional start and stop cycle for each day infinitely. The marginal cost, gives the cost of one single additional start and stop cycle and is therefore valuable when the start is a single independent decision due to short-term production planning (Bjørkvoll and Bakken, 2002; Eggen and Belsnes, 2023).

3.1.1 Average cost

The average cost is relevant when the additional start-stop cycles are part of a long-term change in operating strategy (Eggen and Belsnes, 2023). When calculating the average cost, the hydropower unit is always assumed to be in new condition in order to give a general estimation of the long-term cost of changing the operational pattern without considering the current condition (Eggen and Belsnes, 2023).

The undiscounted average cost (c) per additional start and stop cycle is given by,

$$c = \frac{1}{\Delta n} \cdot \left(\frac{R}{T_{\Delta n}} - \frac{R}{T_0} \right) \tag{6}$$

as the difference in annual rehabilitation cost between the intermittent and normal operating pattern can be divided by the number of additional start (starts that are not included in n_{ref}).

Alternatively, the average cost (c) can be calculated based on how much lifetime one start and stop cycle consumes by the following equation,

$$c = R \cdot \frac{\Delta D}{T_D} \tag{7}$$

which considers the operating time loss per start and stop cycle (ΔD), the expected operating lifetime (T_D) and the rehabilitation cost (R).

However, since the rehabilitation interval is expressed in calendar years, the time aspect should be considered by discounting the cost to the present value with an interest rate (r). Assuming that the change in operating strategy is permanent, the intermittent operating pattern is seen as a long-term change of operating strategy and the equivalent rehabilitation interval will follow for an indefinite series of intervals (Eggen and Belsnes, 2023). According to Bjørkvoll and Bakken (2002), the present value of an indefinite series of rehabilitation intervals under intermittent operation $PV_{\Delta n}$ relative to the case with a normal operating pattern PV_0 is given by,

$$PV_{\Delta n} - PV_0 = \frac{R \cdot (e^{-r \cdot T_{\Delta n}} - e^{-r \cdot T_0})}{(1 - e^{-r \cdot T_0}) \cdot (1 - e^{-r \cdot T_{\Delta n}})} \tag{8}$$

and takes into account the rehabilitation intervals at normal (T_0) and intermittent ($T_{\Delta n}$) operation, the rehabilitation cost (R) and the interest rate (r).

To cover the additional rehabilitation cost for Δn extra start and stop cycles as well as for the effect of discounting, the price per additional start and stop cycle (ac) is given by,

$$ac = \frac{1}{\Delta n} \cdot r \cdot \frac{R \cdot (e^{-r \cdot T_{\Delta n}} - e^{-r \cdot T_0})}{(1 - e^{-r \cdot T_0}) \cdot (1 - e^{-r \cdot T_{\Delta n}})} \tag{9}$$

3.1.2 Marginal cost

Unlike the average cost, the marginal cost account for where in the present rehabilitation cycle the extra start occurs by including the time left until the next planned rehabilitation (T_1). The marginal cost (mc) is calculated as the difference in the

discounted value of future rehabilitation costs with and without the additional start. The marginal cost is given by,

$$mc = PV_{start} - PV_0 = \frac{R}{1 - e^{-r \cdot T_0}} \cdot e^{-r\left(T_1 - \frac{\Delta D}{8760}\right)} - \frac{R}{1 - e^{-r \cdot T_0}} \cdot e^{-rT_1} = \frac{R}{1 - e^{-r \cdot T_0}} \cdot (e^{-r \cdot \frac{\Delta D}{8760}} - 1) \cdot e^{-r \cdot T_1} \quad (10)$$

where PV_{start} and PV_0 is the discounted value of all future rehabilitation cost with and without one additional start (Bjørkvoll and Bakken, 2002). The equation takes into account the rehabilitation interval at normal operation (T_0), the rehabilitation cost (R), the operating time loss per start and stop cycle (ΔD), the interest rate (r) as well as the time left until rehabilitation (T_1).

As shown in Equation 10, the additional start reduces the time to the next rehabilitation by $\frac{\Delta D}{8760}$ years. The marginal cost can be simplified to,

$$mc = \frac{R}{1 - e^{-r \cdot T_0}} \cdot (r \cdot \frac{\Delta D}{8760}) \cdot e^{-r \cdot T_1} \quad (11)$$

3.2 Cost of ramping events and operation outside normal operating range

To consider how ramping events affects the unit, the operating time is assumed to be reduced by ΔD_{ramp} hours for each additional ramping event (Eggen and Belsnes, 2023). The hours of lifetime reduction are less for a ramping event than a start and stop cycle. This enables calculations of the average and marginal cost of a ramping event by replacing ΔD with ΔD_{ramp} in Equation 9 and Equation 11.

Furthermore, the effect of operation outside the normal operating range can be considered when calculating the cost related to a start and stop cycle or ramping event. This by adding a stress factor (β_i) for each operational range (α_i). These reflect the wear associated with the different operating ranges. The rehabilitation interval at normal operating pattern considering the operating ranges can be calculated by,

$$T_0 = \frac{T_D}{(\alpha_{normalload} + \alpha_{partload} \cdot \beta_{partload} + \alpha_{overload} \cdot \beta_{overload}) \cdot 24 \cdot 365 + n \cdot \Delta D} \quad (12)$$

which considers operating ranges at normal-load, part-load and over-load. It means that the yearly operating time of the unit can be higher since the share of operating time in different operating ranges ($\alpha_{normalload}$, $\alpha_{partload}$, $\alpha_{overload}$) add operating hours due to the stress factors ($\beta_{normalload}$, $\beta_{partload}$, $\beta_{overload}$). The rehabilitation interval (T_0) is thus shortened under such conditions, even if the calendar time appears unchanged.

4. Qualitative and quantitative methodology

To investigate how the *market change* as well as the introduction of the Activation Optimisation Function (AOF) affects hydropower, a mixed method is used. The aim has been to qualitatively identify potential impacts of the *market change* and understand how the system is affected. To offer additional insights and reinforce the qualitative findings, a techno-economic cost model has been used to calculate the cost of flexibility arising from a changed operating pattern (Creswell, 2018, pp. 205–206).

4.1 Qualitative - Mapping out the system of hydropower

Because of the broad and exploratory nature of this thesis, it was important to gain sufficient knowledge about several different areas and account for various aspects of hydropower that could be affected by the *market change*. The electricity markets, its actors and assets have been treated as an integrated system since there is a high level of complexity in terms of how they interact and impact one another (Barbrook-Johnson, 2022). The mapping of the system included literature and document analysis, field observation and formal and informal interviews. The empirical understanding was further broadened at two industry conferences. One held by SVC (Svenskt vattenkraftcentrum) where the focus was on the latest research including topics about hydropower flexibility and the other conference was held by SwedCOLD concerning flows and water discharge in relation to dam safety. Additionally, interactive webinars from Svk were attended.

To identify aspects and implications of the *market change*, the following areas were considered iteratively:

- The mFRR market, especially the activation logic, actor roles and dependencies.
- Hydropower operation and assets.
- The *market change* and how it affects hydropower production, assets and organisation and possible adaptions.

To present the findings from interviews, documents and the literature review, tables were created based on a categorisation (technical, market, hydrological and operational) of the identified aspect. The tables includes a shorter summary of the findings and to create a structure in the tables the following questions were asked, see Table 1.

Table 1. Structure and questions asked for collecting qualitatively findings.

Identified aspect	Implications
What are the challenges of more frequent short-term regulations?	How or in what way is it a challenge?

A further analysis of the identified aspects was conducted in Section 7. In this section, the findings were discussed per categorisation. The identified aspects were sometimes discussed separately and sometimes in a broader perspective that included multiple aspects. Additionally, potential adaptions have been stated.

In addition, a Venn diagram was created to emphasise a system-level perspective of how the *market change* can influence multiple dimensions of hydropower operations. Venn diagrams can be used to effectively visualise information and interconnections between sets of attributes (EBSCO, n.d.). The diagram points out the complexity and interconnections between the analysed aspects. Moreover, the question of what possibilities the *market change* introduces for hydropower was addressed.

4.2 Quantitative - Cost calculations

To offer additional insights into how an intermittent operating pattern affects the hydropower assets, a techno-economic cost model has been used. The cost model builds upon the theory described in Section 3 and calculates the cost and rehabilitation interval that follows from additional start and stop cycles as well as ramping events. The undiscounted cost model is presented in Section 3 to illustrate the basic logic of the calculation, However, only the discounted model is used for the results, as it better reflects long-term cost implications.

A sensitivity analysis of the cost model has also been conducted. The results from the sensitivity analysis provided a good basis of how the hydropower assets can be effectively managed in order to maintain a good condition of the units. Furthermore, the economic implications derived from the sensitivity analysis can be used to justify the pricing of intermittent operation.

4.2.1 Assumptions for input parameters in the cost model

The parameters and variables used for the economic calculations of what a start and stop cycle as well as ramping event costs can be seen in Appendix A and is built upon the theory described in Section 3.

The value of the rehabilitation cost, R, should be the future value. For the calculations in this thesis, an arbitrary value that corresponds to the present rehabilitation cost have been used. As the calculations are not made for a specific unit but rather as an example of what the cost of an intermittent pattern could be, the exact value is less important for this specific study. The values used for the normal operating pattern (α_{ref}, α_i, $t_{operation}$, $ramp_{ref}$) are based upon historic operating data of a reference unit. The average number of yearly start and stop cycles for the unit (n_{ref}) has been used in the calculations because the technical documentation on the number of designed start and stop cycles was missing. The operating time ($t_{operation}$) is assumed to be independent of an increasing number of start and stop cycles as it is hard to predict how additional start and stop cycles affect the operating time. If additional start and stop cycles results

in longer periods of stops, it is reasonable to assume that operating time will decrease. On the other hand, if the additional start and stop cycle is assumed to increase the operation of the unit it will result in a higher operating time.

Regarding how turbines are affected by operation outside the optimal operating range, both Francis and Kaplan turbines can experience increased wear, although the extent differs between the two designs. Since Kaplan turbines have a wider efficiency range than Francis turbines, such operation is generally less critical for them. To reflect this, the operating time distribution across load ranges (α_i) and associated stress factors (β_i) were only considered for Francis turbines in this study. The value of the stress factors (β_i) are based upon an overall assessment from experts at Fortum and literature (Eggen and Belsnes, 2023). The values of α_i are based on historic operational data.

It is also assumed that the operating time loss (ΔD) is 15 hours for the turbine whereas it is only 10 hours for the generator. The operating time loss for a ramping event (ΔD_{ramp}) is assumed to be less than for a start and stop cycle and is only accounted for the turbine. These values are based upon previous studies and industry references (Eggen and Belsnes, 2023; Bakken and Bjorkvoll, 2002; Nilsson and Sjelvgren, 1997). In addition, Kaplan and Francis turbines have individual values. For a Kaplan turbine, that has more moving parts during ramping than a Francis the time loss is set to three hours while the same parameter is two for a Francis turbine. These values are based on literature and discussed with Fortum's experts. However, it is important to keep in mind that in reality each unit is unique and these numbers should therefore be assessed based upon knowledge and experience about every unit separately. See Table 2 for a summary of the values of operating time loss that were used in the calculations.

Table 2. Operating time loss (in hours) per event and component.

Event	Component	Parameter	Operating time loss [h]
Start and stop	Turbine	ΔD	15
Start and stop	Generator	ΔD	10
Ramping	Francis Turbine	ΔD_{ramp}	2
Ramping	Kaplan Turbine	ΔD_{ramp}	3

The daily number of extra start and stop cycles (Δn) and extra ramping events ($\Delta ramp$) per day were treated as input variables and were varied to explore their impact on the rehabilitation interval as well as the average and marginal cost. Specifically, Δn was set to range between one and five start and stop cycles per day and $\Delta ramp$ between one and ten ramping events per day. These values are not intended as forecasts but rather as

illustrative scenarios used to assess how increased short-term regulation may affect hydropower costs. Table 3 provides an overview of the range of additional events.

Table 3. The scenarios of additional daily start and stop cycles and ramping events over a year that was used to calculate the cost of intermittent operation.

Variable	Min	Max	Event
Δn	1	5	Start and stop cycles per day
$\Delta ramp$	1	10	Ramping events per day

The scenarios were inspired by operational experience at Fortum during the first month with the *market change* as the bid selection by the AOF tended to lead to a more intermittent operating pattern.

4.2.2 Cost model of start and stop cycles and ramping events

The calculations of the cost for a start and stop cycle or ramping event were based on the economic theory described in section 3. Figure 8 provides an overview of the cost model where inputs are to the left and the outputs to the right.

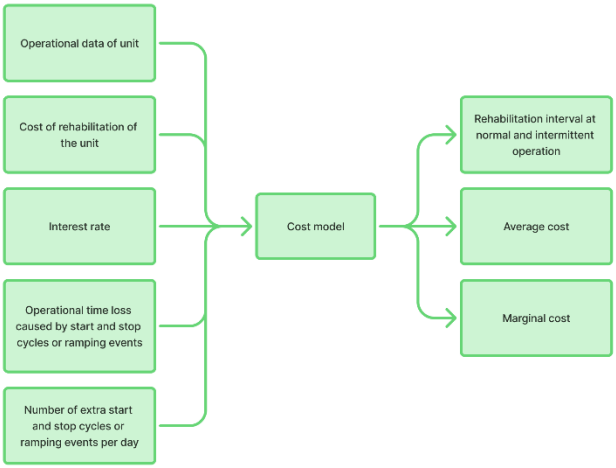

Figure 8. An overview of the economic cost model with inputs to the left and outputs to the right.

Since the model considers the lifetime reduction of a unit caused by an intermittent operation, an evaluation of how additional start and stop cycles as well as ramping events affect the rehabilitation interval was conducted.

Furthermore, the average cost due to additional start and stop cycles and ramping events was calculated across the scenarios given in Table 3. The marginal cost was calculated for one additional start and stop cycle of both the turbine and generator, as well as for

one addition ramping event of the turbine. When calculating the marginal cost, the time until the next rehabilitation is considered as an input parameter.

Consideration of Kaplan and Francis turbine

The cost model was developed in two versions based on the type of turbine. This due to that Francis turbines are more affected by operation outside the normal operating range than Kaplan turbines, which on the other hand, are more stressed by ramping events. This allows cost calculations of units both with a Francis and a Kaplan turbine. The input parameters of the generator were handled in the same way for both hydropower unit set-ups.

In section 3.1, Equation 4 gives how the rehabilitation interval (T_0) can be calculated if the designed total operating hours of the unit is known as well as how many operating hours the unit consumes yearly. To include that operation outside normal operating range impacts the reference operating hours, the calculation of the yearly operating time (OT_0) of a Francis unit was updated. The cost model was divided into two versions, one for a generic Francis turbine and one for generic Kaplan turbine. However, no matter the turbine type, the yearly operating time (OT_0) was updated by also including the reference number of ramping events per year ($ramp_{ref}$) as well as the operating time loss per ramping event (ΔD_{ramp}).

Operating time at normal operation

By updating Equation 2 to consider a Kaplan turbine, the operating time at a normal operating pattern for a Kaplan turbine ($OT_{0\_kaplan)}$ could be derived as,

$$OT_{0\_kaplan} = \left(\alpha_{ref} \cdot 24 \cdot 365 + n_{ref} \cdot \Delta D + ramp_{ref} \cdot \Delta D_{ramp_{kaplan}}\right) \quad (13)$$

which includes the share of yearly operating time based on the design (α_{ref}), the designed/reference number of start and stop cycles per year (n), the operating time loss per start and stop cycle (ΔD), the reference number of ramping events per year ($ramp_{ref}$) and the operating time loss per ramping event for a Kaplan turbine (ΔD_{ramp_kaplan}). By multiplying α_{ref} with 24 and 365, the yearly operating time was given in operating hours.

To account for the additional stress caused by operating a Francis turbine outside its optimal operating, the operating time at a normal operating pattern ($OT_{0_{francis}}$) was for the Francis turbine given by,

$$\begin{aligned} OT_{0_{francis}} = {} & (\alpha_{lowload} \cdot \beta_{lowload} + \alpha_{partload} \cdot \beta_{partload} + \alpha_{normalload} \\ & \cdot \beta_{normalload} + \alpha_{overload} \cdot \beta_{overload}) \cdot 24 \cdot 365 + n_{ref} \cdot \Delta D \\ & + ramp_{ref} \cdot \Delta D_{ramp_{francis}} \end{aligned} \quad (14)$$

where $\alpha_{lowlload}, \alpha_{partload,}\ \alpha_{normalload}\ \alpha_{overload}$ stands for the respective share of yearly operation outside optimal operation and $\beta_{lowload}, \beta_{partload}, \beta_{normalload}, \beta_{overload}$ is the related individual stress factors. Additionally, the operating time loss per ramping event for a Francis turbine is given by $\Delta Dramp\_francis$.

Operating time at start and stop cycles

To calculate the operating time at intermittent operation ($OT_{\Delta n\_kaplan}$) due to additional start and stop cycles, the following equation for the Kaplan turbine was used,

$$OT_{\Delta n\_kaplan} = \left(\alpha_{ref} \cdot 24 \cdot 365 + n_{ref} \cdot \Delta D + ramp_{ref} \cdot \Delta D_{ramp\_kaplan}\right) + \Delta n \cdot \Delta D \quad (15)$$

where Δn is the extra number of start and stop cycles and ΔD is the operating time loss per start and stop cycle. The equation adds the additional degradation due to these extra cycles on top of the reference operating pattern.

The corresponding equation for a Francis turbine ($OT_{\Delta n\_francis}$) was,

$$OT_{\Delta n\_francis} = \left((\alpha_{lowload} \cdot \beta_{lowload} + \alpha_{partload} \cdot \beta_{partload} + \alpha_{normalload} \cdot \beta_{normalload} + \alpha_{overload} \cdot \beta_{overload}) \cdot 24 \cdot 365 + n_{ref} \cdot \Delta D + ramp_{ref} \cdot \Delta D_{ramp\_francis}\right) + \Delta n \cdot \Delta D \quad (16)$$

Incorporating the different operating ranges and the respective stress factors.

Operating time at ramping events

To estimate the effect of additional ramping events on operating time, the following equations were applied. For a Kaplan turbine, the operating time at intermittent operation due to extra ramping events ($OT_{\Delta ramp\_kaplan}$) was given by,

$$OT_{\Delta ramp\_kaplan} = \left(\alpha_{ref} \cdot 24 \cdot 365 + n_{ref} \cdot \Delta D + ramp_{ref} \cdot \Delta D_{ramp\_kaplan}\right) + \Delta ramp \cdot \Delta D_{ramp_{kaplan}} \quad (17)$$

where the extra number of ramping events ($\Delta ramp$) and the operating time loss per start and stop cycle (ΔD_{ramp_kaplan}) was added.

For a Francis turbine, the operating time at intermittent operation due to extra ramping events ($OT_{\Delta ramp\_francis}$) was calculated by,

$$OT_{\Delta ramp\_fancis} = \left((\alpha_{lowload} \cdot \beta_{lowload} + \alpha_{partload} \cdot \beta_{partload} + \alpha_{normalload} \cdot \beta_{normalload} + \alpha_{overload} \cdot \beta_{overload}) \cdot 24 \cdot 365 + n_{ref} \cdot \Delta D + ramp_{ref} \cdot \Delta D_{ramp\_francis}\right) + \Delta ramp \cdot \Delta D_{ramp\_francis} \quad (18)$$

These equations were then used to calculate the reference rehabilitation interval (T_0) in accordance with Equation 4. The intermittent operation rehabilitation interval ($T_{\Delta n}/T_{\Delta ramp}$) is calculated using Equation 5. These intervals are then used as input to calculate the average and marginal cost, as described in Equation 9 and Equation 11.

4.2.3 Values of variables

To evaluate the cost of flexibility, a unit from Fortum's hydropower fleet with a Kaplan turbine was used as a reference. Values on variables were based on historical data accessed through Fortum such as operating time per year (α_{ref}), the mean value of the historical number of start and ramping events per year (n_{ref} and $ramp_{ref}$), the designed total operating hours (T_D) and the number of years left until rehabilitation (T_1). The other parameters are based on premises described in section 4.2.1. All values used as in-parameters can be seen in Table 4.

Table 4. Specified parameters and variables for the hydropower unit used in the cost model that are presented in the result section.

Variable	Unit	Turbine	Generator
R	Euro	4000000	3500000
r	-	0,08	0,08
T_1	Years	31	48
$t_{operation}$	Hours	3185	3185
α_{ref}	-	0,36	0,36
n_{ref}	-	365	365
ΔD	Hours	15	10
$ramp_{ref}$	-	553	-
ΔD_{ramp}	Hours	3	-
T_D	Hours	550000	500000

To evaluate how the cost of flexibility differs between a Kaplan and Francis turbine, a comparative calculation was conducted. The same values of parameters, as in Table 4, have been used except for the α_{ref} and ΔD_{ramp} that have been adapted for a Francis turbine. The operating time loss per ramping event of a Francis turbine was set to

$\Delta D_{ramp} = 2$. By considering the share of operation at different areas (low-, part-, normal-, overload) and the stress factor for each area (see section 4.2.1), the total operating share (α_{ref}) was updated, see Table 5.

Table 5. Yearly operating share with respect to non-optimal power areas; low-, part-, normal- and overload. Relevant for a Francis turbine.

Operating area	α_i	β_i	Equivalent operating share
Low load	0,01	2,00	0,01
Part load	0,03	1,50	0,05
Normal load	0,17	1,00	0,17
Overload	0,15	4,00	0,59
Total operating share per year (α_{ref})	0,36		0,83

4.2.4 Sensitivity analysis of cost model

To evaluate how the various parameters influence the cost model, a sensitivity analysis was conducted. In the sensitivity analysis the value of one parameter at a time was altered to evaluate how the marginal and average cost was affected. The evaluation was accomplished by comparing the percental impact each parameter in the equations had for both the average and marginal cost. It was found that the marginal cost was largely impacted by the time to the next rehabilitation and that the average cost was affected by the rehabilitation interval. How these parameters affect the marginal and average cost was then calculated for three different values of interest rates. It was considered valuable to calculate for different values of interest rates as these values can differ between companies. Values of 6, 8 and 10% were used.

4.3 Data collection process

Both the qualitative and quantitative process have included interviews, field observations and literature reviews for data collection.

4.3.1 Document and literature analysis

To find articles, databases such as Google scholar, Uppsala university library and CEATI member portal were used along with reviewing the reference lists in relevant articles, other reports and papers. The review focused on information about the electricity market, the *market change* and the causes of wear and tear on hydropower assets. However, the review process was iterative and evolved alongside the identification of aspects potentially impacted by the *market change.*

Examples of keywords to find relevant articles: Frequency regulation hydropower, Hydropower for regulation, Regulations impact on hydropower, Short-term hydro scheduling, Hydropower mFRR, Start and stop cost hydropower, Start and stop water hammer, 15-minute market time unit, 15-minute market time unit hydropower, 15-minute imbalance settlement period. Some of these keywords were searched for in Swedish as well.

To ensure scientific quality, peer-reviewed articles were primarily used and especially for the theoretical background. For information related to the electricity market and the *market change*, documents and reports published by Svk and the Nordic Balancing Model (NBM) initiative were used as these are considered authoritative sources in this context. The reference management software Zotero was used to organise and manage articles and documents.

4.3.2 Observations of operational practices and interviews

Two field observations were conducted to understand how hydropower production is traded and managed. By following an intraday-trader, knowledge on the balancing process of a BSP as well as resource allocation on capacity markets, spot-market optimisation and the connection to the actual production plans were gained. Additionally, to get insight into how the operation of hydropower assets are managed, an operation engineer were followed. These observations made it possible to capture real-time responses, routines, processes but also informal communication and interactions.

Interviews with professionals within the hydropower sector have been essential for this thesis. To gain a broad view of how the *market change* impacts hydropower, interviews were conducted with experts working within different areas at Fortum to cover technical, operational, hydrological and market perspectives. The interviews were held in a semi-structural manner, meaning that broader questions and themes were prepared but the respondents were encouraged to resonate freely about the topics that were brought up (Qu and Dumay, 2011). This allowed flexibility to reframe questions and lead to reflections that potentially could have been missed if all questions were set up beforehand.

Each interview started with introducing the respondent to the purpose of the thesis and was then followed by open-ended questions. If there were questions that were left unanswered the respondents were asked to name someone who had knowledge within that area or if there was someone that could be valuable to speak to regarding the research topic. Since both authors were attending each interview, the insights that followed after reflections and reasonings were grounded in the same information to ensure thorough processing of the information. A list of the conducted interviews can be seen in Appendix B.

4.3.3 Limitations of the method

Qualitative data is interpretive and subject to the bias of the researchers own experiences and views and although the intention has been to reflect participants' views accurately and transparently, the analysis is influenced by the authors framing and selection of themes during interviews. This method was successful in such a way that the selection of respondents evolved along the way and the research area grew naturally. The challenge was to stick to the purpose of the thesis.

The insights from the field observation gave important understanding of daily operational challenges and processes at Fortum but the insights are hard to generalise beyond this study partly due to time and place. The timing of this thesis can be seen as a limitation as the *market change* was implemented in March 2025 and many observed effects and concerns are based on early indications and perceptions rather than measured outcomes and established knowledge. However, as the qualitative result of impacted aspects have been mapped out, reflected on and linked to each other in the analysis, this can still provide valuable insights on a system level that gives a good overview of how the *market change* potentially can affect hydropower (Barbrook-Johnson, 2022, pp. 14–16). The qualitative method has also provided insights that complement the techno-economic analysis and help contextualise the broader implications of the *market change.*

The cost model used to quantify the cost and degradation related to start and stop cycles, ramping events and operation outside the optimal operating range is limited to only consider a generator and a turbine. Literature indicates that several components of the hydropower system are influenced by an intermittent operating pattern. Additionally, the generator and turbine were evaluated at the component level as a whole. Thereby, the differences in degradation that the intermittent operation has on different subcomponents like the stator, rotor, runner, guide vanes are not taken into consideration.

Furthermore, the hours of lifetime reduction caused by a start up as well as ramping is based on literature. These values are generic and representative for a general turbine/generator. However, as the unit is unique in its design, the number of hours can in reality differ. Furthermore, the values of time loss are considered to be constant with no regards to where in the rehabilitation interval the event is happening. The potential issue with generic values from literature also applies to the stress factor for a Francis turbine operating outside the optimal operating range. As every turbine, as previously mentioned is unique, the values for stress factors can differ.

5. Results of identified implications for hydropower production, assets and organisation

To assess the impact of the *market change* on hydropower production, assets and organisation, a comprehensive identification and evaluation has been conducted. Note that only the hydropower plants providing mFRR services and thereby used for short-term regulation may potentially face these challenges. Hence, hydropower plants that are not participating in the mFRR market are not affected.

5.1 Technical aspects

Table 6 provides an overview and brief summary of technical aspects that can potentially be impacted by the *market change.* The main cause of the transition that affects the technical aspects is the AOF, as the algorithm will attempt to balance the system even at small deviations and activations may alternate between up- and downregulation across quarters. Some of these aspects are inherent to the nature of short-term regulation, not the *market change* itself. However, the *market change* can amplify the negative consequences of these aspects.

Table 6. Overview of identified technical impacts due to the market change.

Identified aspect	Implications
Efficiency range and restricted operating zones	Need of more flexible operation can lead to operation outside optimal operating range which causes wear. It can be handled by adapting technical specifications when planning new investments of turbines (Interview I.M, Appendix B).
Wear and tear	Lifetime reduction from operation outside normal operating range, start and stop cycles and ramping events are expected to increase with higher flexibility needs (Interview I.A, I.B, I.H, I.K, I.O, I.Q, Appendix B).
Surge and water hammer	An increase of any intermittent operating pattern can increase the risk of water hammer and mass oscillations that cause wear and tear/degradation of technical components (Interview I.K, I.O Appendix B).
Increased use of spillway gates	With downregulations, the use of spillway gates can be more frequent which causes additional wear. In winter conditions this can be problematic because of ice formation on gates (Interview I.Q, Appendix B).
Maintenance	With a changing short-term regulation market that causes lifetime reduction due to more wear and degradation of

	components, the need of maintenance might increase which can lead to insufficient internal and external resources (Interview I.O, Appendix B). In addition, it raises concerns for loss of income during stand still (Interview I.B, I.D, I.F, I.H, Appendix B).

5.2 Market aspects

Table 7 provides an overview and brief summary of market aspects that could potentially be impacted by the *market change*. This is due to the AOF that activates bid per quarter of an hour, resulting in variations between up- and downregulations across quarters as well as attempts to balance the system even at small deviations. The behaviour makes the market and activations unpredictable.

Table 7. Overview of identified market impacts due to the market change.

Identified aspect	Implications
Cost of a start and stop cycle	Uncertainty in how to integrate cost of start and stop cycles in pricing of bids (Interview I.J, I.L Appendix B) .
Resource allocation	More complex to evaluate and predict optimal resource allocation in markets (Interview I.C, Appendix B).
Pre-qualification on unit level	Each unit is required to be pre-qualified to participate in mFRR market and bids on mFRR-EAM are specified per unit. At activation there is no flexibility to change from what asset the ancillary service is provided (Interview I.O, Appendix B). This aspect is more prominent after the *market change*.
Imbalance prices	Activation of higher priced bids can follow from the implementation of AOF (eSett, 2025). That leads to higher imbalance settlement prices and can cause high imbalance fees (Interview I.J, I.K, Appendix B).
Surge and water hammer	Need of resting time due to surge and water hammer effects puts resources/capacity unavailable (Interview I.A, Appendix B). This impacts the ability to control imbalances during the resting time.
Loss of income	At maintenance and rehabilitation the unit is put out of production. If this will occur more often, the accumulated loss

	of income will increase (Interview I.B, I.D, I.F, I.H, Appendix B).
Downregulation	Activations of downregulating bids can lead to increased use of spillway gates and/or operation at non optimal operating range (Interview I.Q, Appendix B)
Volatile market	As the market becomes more volatile, it also becomes more unpredictable. This complicates the market interpretation which can increase the risk of high imbalance fees if the production plan differs from what actually can be produced (Interview I.D, Appendix B).
Grid capacity between bidding zones	The introduction of the Flow based algorithm for calculation of grid capacity gives less space for intraday trading between bidding zones (Interview I.D, Appendix B). Contributes to high imbalance prices and highlights need for production within bidding zone.

5.3 Hydrological aspects

Table 8 provides an overview and brief summary of hydrological aspects that could potentially be impacted by the *market change*. Some of these aspects are inherent to the nature of short-term regulations, not the *market change* itself. However, the *market change* can amplify the negative consequences of these aspects.

Table 8. Overview of identified hydrological impacts due to the market change.

Identified aspect	Implications
Water level and flow rate limits	Rapid adjustments in production, to provide flexibility services, can be limited by regulated water level or flow limits in water permits (Sydvatten, 2024).
Lack of reservoirs in run-of-river plants	Without reservoir there is no way to store water which impacts the possibility to provide ancillary services. Therefore, run-of-river plants are limited by the incoming water upstream (Killingtveit, 2019). After the *market change*, those stations are less suitable for short term regulation (I.S, Appendix B).
Surge and water hammer	Rapid flow changes and pressure changes due to more frequent start and stop cycles as well as ramping events can cause surge in long tunnels and trigger water hammer effects (Interview I.K,

	I.O, Appendix B). Affected units requires resting time (time out of operation) (Interview I.A, I.J, I.K, Appendix B).
Winter conditions	More rapid and fluctuating water levels in reservoirs hinder the formation of a uniform ice layer. Upstream, loose parts of ice can damage parts of the hydropower plant. Downstream, water level fluctuations can increase the risk of ice jam in the river channel (Interview I.S, Appendix B).
Erosion	Fluctuating water flow and water levels (hydropeaking) caused by short term regulations can lead to river bank erosion (Interview I.S, Appendix B; Bipa et al., 2024).
Local communities	Hydropeaking can affect the local community and public safety in a negative way (Interview I.F, I.K, Appendix B; Pisaturo et al., 2019).
Local environment and species	Hydropeaking can affect the local environment and species in a negative way (Interview I.R, Appendix B).

5.4 Operational aspects

Table 9 provides an overview and brief summary of operational aspects that could potentially be impacted by the *market change*. These operational aspects are sensitive to the time of data collection and the limited experience with the *market changes* at that time.

Table 9. Overview of identified operational impacts due to the market change.

Identified aspect	Implications
Surveillance of flow and water levels	Main responsibility for an operator is to transport water in the rivers to the sea in a safe way (Interview I.K, Appendix B). With more frequent activations of bids on mFRR-EAM there is less time for planning and supervision of the water. This can become critical if something unexpected happens where control of water level and/or flow are essential (Interview I.K, Appendix B).
Manual functions in the operator system	The system partly needs to be operated manually, which increase pressure on operators if activations become more frequent (Interview I.A, I.B, I.C, I.K, Appendix B). This leaves less time for production planning and management of water conditions (Interview I.K, Appendix B).

Bid activation	Operators need to be alert of bid activation alarm/signals every 7,5 minutes. Additionally, the operator needs to detect silent signals of deactivation. This causes an increased pressure on the operator to handle both ordinary tasks as water planning and an increased focus of the market (Interview I.K, Appendix B).
Public safety	The operator must consider and handle the safety of individuals during local community events, planned maintenance and reparation of failures. With more activations and increased focus of the mFRR-EAM, there is a risk that these situations will receive less attention (Interview I.F, I.K, Appendix B).

6. Result of cost calculations

This section presents the results regarding the cost of flexibility. The results of a unit with a Kaplan turbine are followed by an comparison of the cost between a Kaplan versus Francis turbine. A sensitivity analysis of the cost model as well implications that emerged from the cost calculations are presented.

6.1 Cost analysis of a unit with Kaplan turbine

To evaluate the cost of flexibility, the economic theory and cost methodology have been implemented for a Kaplan unit with the parameters given in Table 4.

In Figure 9, it is presented how extra start and stop cycles affect the rehabilitation interval of the generator and turbine. With today's operating pattern (zero extra start and stop cycles) the rehabilitation interval is 53 years for the turbine and 73 years for the generator. However, with an intermittent operating pattern, causing one extra start and stop cycle each day over a year, the rehabilitation interval is reduced to 35 years for the turbine and 48 years for the generator. If the intermittent operating pattern results in five extra start and stop cycles each day over a year, the rehabilitation interval is reduced to 15 years for the turbine and 20 years for the generator. For the turbine, this is a 72% reduction of the original interval.

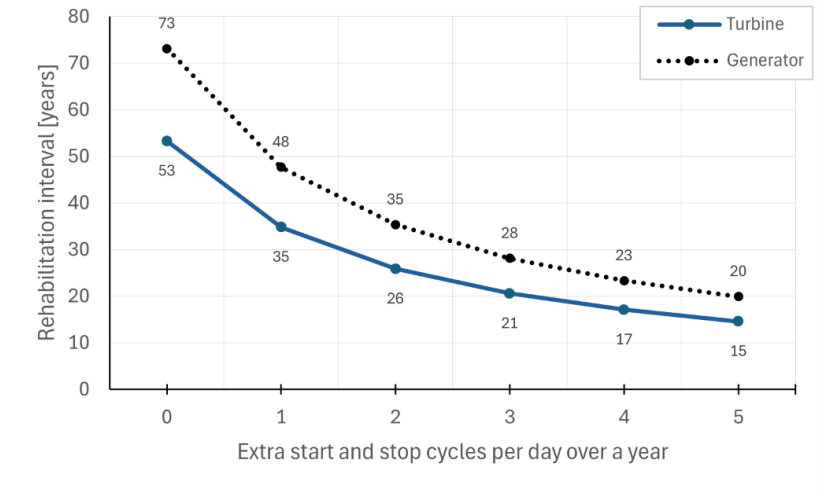

Figure 9. How extra start and stop cycles affects the rehabilitation interval of the generator (black dotted line) and Kaplan turbine (blue solid line).

Figure 10 presents a comparison of how additional start-stop cycles and ramping events affect the turbine's rehabilitation interval across different scenarios. The blue line, representing the rehabilitation interval of the turbine across the five scenarios of extra start and stop cycles, is the same as in Figure 9. However, in Figure 10, it can be compared to how additional ramping events affect the rehabilitation interval. A scenario with one additional ramping event each day over a year, will reduce the rehabilitation interval of the turbine with five years implying a new interval of 48 years. A scenario of five additional ramping events each day over a year will reduce the rehabilitation interval to 35 years. In a scenario of ten ramping events each day over a year, the new rehabilitation interval of the turbine will be 26 years. The conclusion is that additional ramping events reduce the rehabilitation interval of the turbine remarkably less than what extra start and stop cycles does.

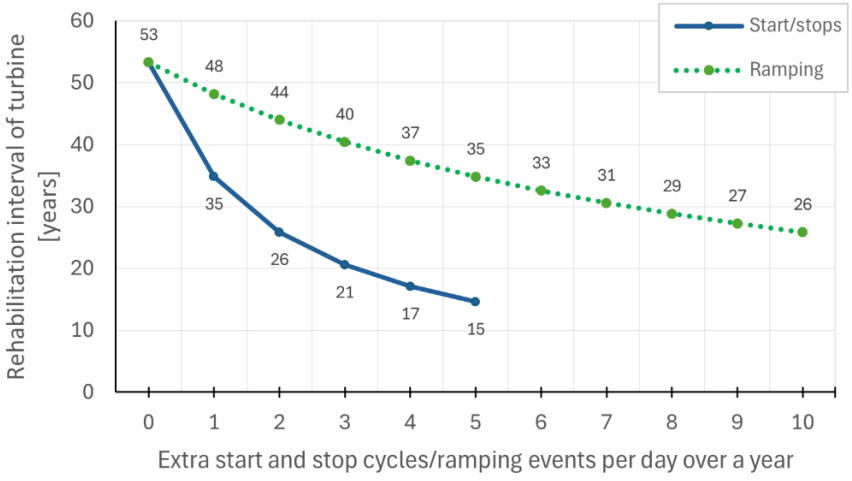

Figure 10. How extra start and stop cycles (blue solid line) or ramping events (green dotted line) affect the rehabilitation interval of the Kaplan turbine.

Regarding the cost aspect of extra start and stop cycles or additional ramping events, Figure 11 illustrates the average cost per event for the scenarios with one up to five extra events each day over a year. Note that the figure includes two y-axes with different scales. The left y-axis represents the average cost per additional start and stop cycle. The grey line indicates the total cost of both the generator and turbine. As shown, the turbine contributes to the majority share of this total cost. Furthermore, the average cost per extra start and stop cycle increases with the number of events per day. This can be explained by the decreasing rehabilitation interval with increasing number of events per day, see Figure 10. The right y-axis gives the average cost per additional ramping event. Across all five scenarios, the average cost per additional ramping event is significantly lower than the corresponding average cost per additional start and stop cycle.

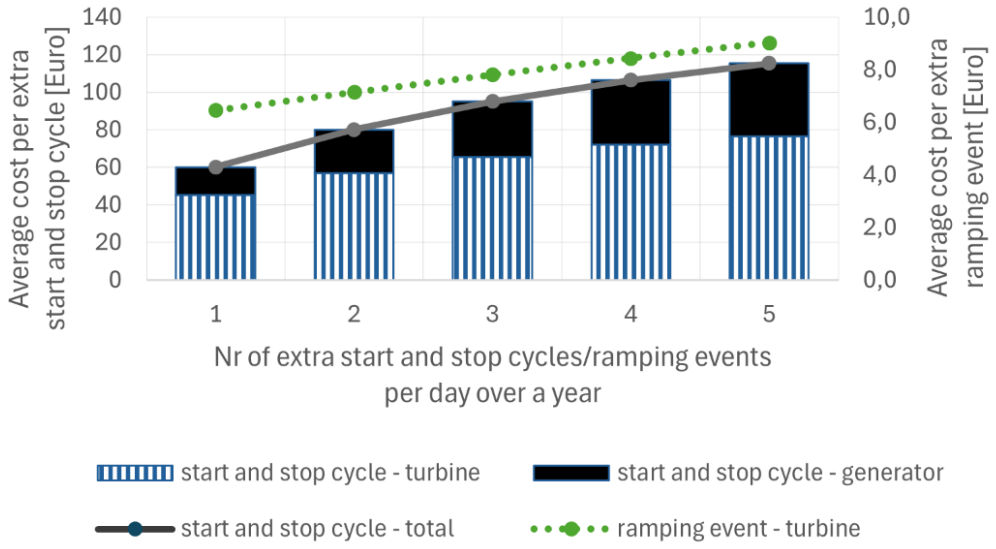

Figure 11. The left y-axis (0–140 EUR) represents the average cost per extra start and stop cycle, while the right y-axis (0–10 EUR) represents the average cost per extra ramping event. The striped blue part of the bars corresponds to the turbine's share and the black to the generator's share. The solid grey line represents the total average cost per start and stop cycle and should be interpreted using the left y-axis. The green dashed line shows the average cost per extra ramping event from the turbine and should be read using the right y-axis.

The marginal cost of one single additional event (start and stop cycle or ramping event) of this unit with a Kaplan turbine is illustrated in Figure 12. The marginal cost of one extra start and stop cycle is 47 euro for the turbine and 7 euro for the generator, giving a total cost of 54 euro. It is clear that the expenses are larger for the turbine since the time to the next rehabilitation is shorter for the turbine than the generator. Additionally, the time loss per start as well as the rehabilitation cost is higher for the turbine. In contrast, the marginal cost of one single additional ramping event is 9 euro. This as a ramping event is considered to cause less reduction of lifetime than one start and stop cycle.

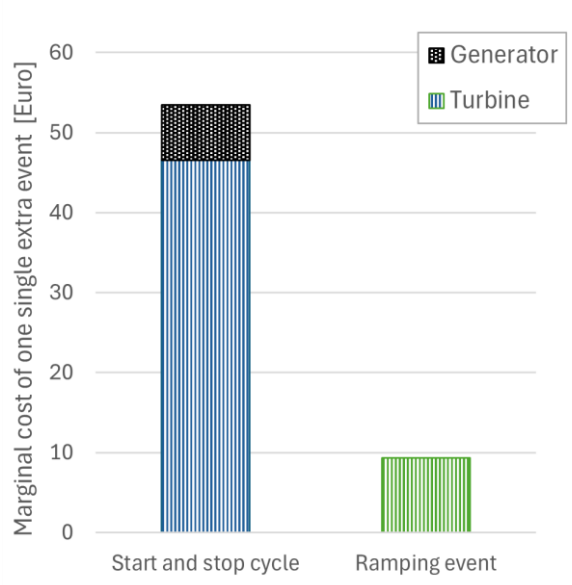

Figure 12. Marginal cost of one single additional event (start and stop cycle or ramping event). The striped blue part of the "start and stop cycle" bar represents the cost that comes from the lifetime reduction of the turbine and the black dotted are costs from the generator. The striped green ramping bar similarly shows the cost from the turbine but no cost from the generator is considered in the scenario of an additional ramping.

6.2 Cost comparison between a Francis and Kaplan turbine

To evaluate how the type of turbine affects the rehabilitation interval and related costs of additional events, a comparison between a unit equipped with a Francis versus Kaplan turbine is presented. As described in section 4.2.1 and 4.2.2, the difference is the time loss per ramping event (ΔD_{ramp}) and the consideration of stress factors (β_i) for operation outside the optimal range.

Given Table 10, the rehabilitation interval at a normal operating pattern differs by 13 years between a Francis and a Kaplan turbine. The difference arises as the Francis turbine has a higher share of yearly operation due to the consideration of operating ranges and its stress factor. The rehabilitation interval for the Kaplan turbine has the same value as given in section 6.1.

Table 10. Rehabilitation interval at normal operating pattern for a Francis and Kaplan turbine.

Variable	Unit	Francis	Kaplan
T_0	Years	40	53

Figure 13 shows an evaluation of how the type of turbine affects the rehabilitation interval with an operating pattern that includes an increase of daily start and stop cycles,

see the left y-axis. The rehabilitation interval becomes shorter for a Francis turbine than a Kaplan turbine across all five scenarios. It is reasonable since the operating share per year is higher for a Francis turbine than a Kaplan turbine. This is as only the Francis turbine consider operation outside the normal operating range and adds stress factors to it.

Note that the diagram in Figure 13 has two y-axis, the right one shows the average cost of one extra start and stop cycle under the five different scenarios of one up to five daily number of start and stop cycles per day throughout the year. As the number of start and stop cycles per day increases, the cost also increases. When the cost increases, there is an opposite trend for the rehabilitation interval. The decrease in time in between rehabilitations leads to a higher average cost per start and stop cycle for both a Francis and a Kaplan turbine. The consideration of operating ranges and related stress factors for the Francis turbine decreases the reference rehabilitation interval since it causes a higher number of yearly operating hours. Therefore, the difference is largest for when an operating strategy is changed by only one or two number of extra start and stop cycles per day. However, when the number of daily events increases above that, the yearly reference operating pattern has less impact on the cost. This as the number of daily extra start and stop cycles and the time loss each start contributes to will be the more dominating term. The time loss each start contributes to is considered to be 15 hours both for the Kaplan and Francis turbine.

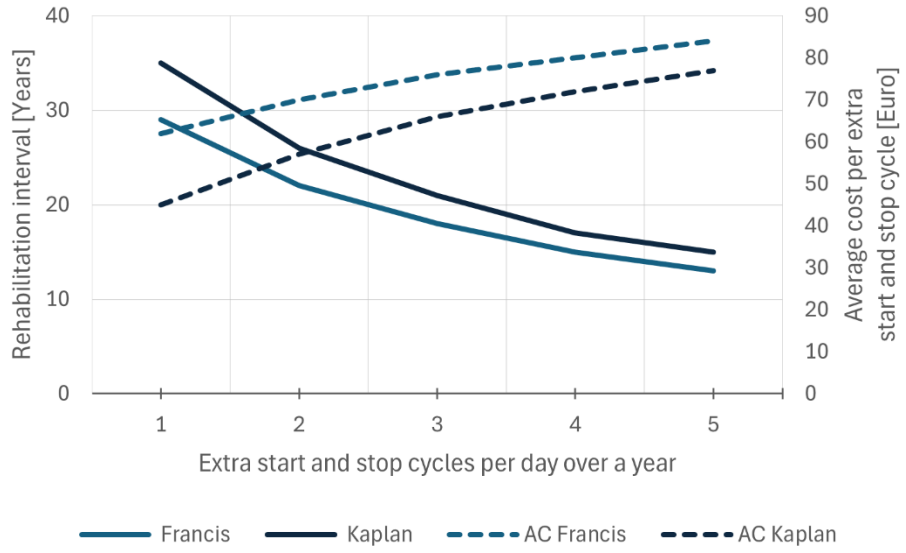

Figure 13. The rehabilitation interval and average cost for a Francis and Kaplan turbine across five scenarios with increasing number of daily start and stop cycles throughout the year. The left y-axis represents the rehabilitation interval and the right y-axis represent the average cost. The dark and light blue solid lines show how the rehabilitation interval is impacted by an increasing number of daily start and stop cycles for a Francis and Kaplan turbine respectively. The dotted dark and light blue lines show the average cost as a function of the number of start and stop cycles.

A similar evaluation has been conducted for an intermittent operating pattern given by additional ramping events, see Figure 14. The same trend of a decreasing rehabilitation interval appears for scenarios with an increase of daily ramping events as with extra start and stop cycles. In comparison, across all five scenarios and both for the Kaplan and Francis turbine, it can be stated that ramping events has less impact on the rehabilitation interval than what start and stop cycles have. Thereby, it can be affirmed that ramping events causes less degradation and wear of hydropower turbines than start and stop cycles. This can be explained by the difference in lifetime reduction that a start respectively ramping causes.

The cost however, starts out lowest for one extra ramping event per day for a Kaplan and is nearly equal to a Francis at two ramping events per day and ends up as the most expensive of the two turbine types with a frequency of three to five daily ramping events. It can be explained by the hours of lifetime reduction per ramping event (three hours for a Kaplan turbine and two hours for a Francis turbine). At first, the yearly operating time is higher for a Francis due to the stress factors results in higher costs per ramping event. However, as the number of ramping events increases, the lifetime reduction parameter becomes more significant. As a ramping event of a Kaplan turbine causes more hours of lifetime reduction than a Francis, it becomes more expensive with the increasing number of extra daily events.

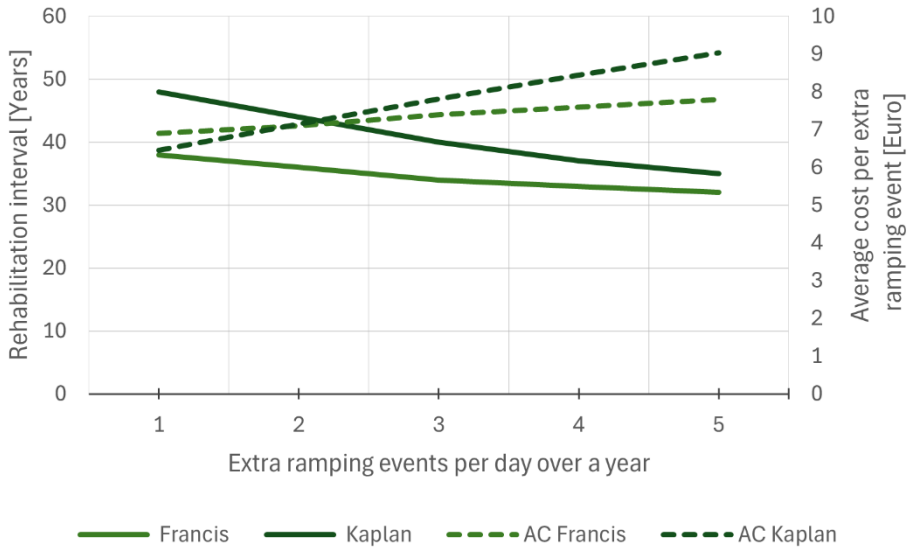

Figure 14. The rehabilitation interval and average cost for a Francis and Kaplan turbine across five scenarios with increasing number of daily ramping events throughout the year. The left y-axis represents the rehabilitation interval and the right y-axis represent the average cost (AC) in Euro. The dark and light green solid lines show how the rehabilitation interval is impacted by an increasing number of daily ramping events for a Francis and Kaplan turbine respectively. The dotted dark and light green lines show the average cost as a function of the number of ramping events per day.

When comparing the average cost of extra daily ramping events and start and stop cycles it is clear that across all five scenarios for both a Kaplan and Francis turbine, it is less expensive with ramping events. This is because ramping events causes less stress and degradation than start and stop cycles.

As discussed previously, the marginal cost is the cost of one single start and stop cycle or ramping event. The marginal cost consider the time left to the next rehabilitation. A comparison of the marginal cost for one additional start and stop cycle respectively ramping event is given between the Francis and Kaplan turbine in Table 11. The marginal cost of a single extra start and stop cycle does not differ that much between a Francis and Kaplan turbine, see Table 10. The reason is that only the rehabilitation interval varies in Equation 11 when calculating the marginal cost related to a start and stop cycle for a Francis and Kaplan turbine.

The marginal cost of one additional ramping event differs with three euro between a Francis and a Kaplan turbine. In this case, the reference rehabilitation interval differs in the same way as described above. The number of hours in lifetime reduction caused by a ramping differs with one hour between the turbine designs. Thereby, it is reasonable that the difference between the marginal cost of a Francis or Kaplan turbine is higher for one extra ramping event than one extra start and stop cycle.

Table 11. The marginal cost for one single additional start and stop cycle or ramping event for both a Francis and Kaplan turbine.

Turbine	MC for one additional start and stop cycle	MC for one additional ramping event
Francis	48	6
Kaplan	47	9

6.3 Sensitivity analysis of cost analysis

Figure 15 illustrates that the marginal cost of the Kaplan turbine with one extra start and stop cycle decreases when the time left until the next rehabilitation of the turbine increases. In the same figure, it is presented how three different values of discount rates (six, eight and ten percent) impact the marginal cost. When the time until the next rehabilitation of the turbine is less than 10 years, the marginal cost of making an extra start and stop cycle is about 250 euro or more for all discount rates.

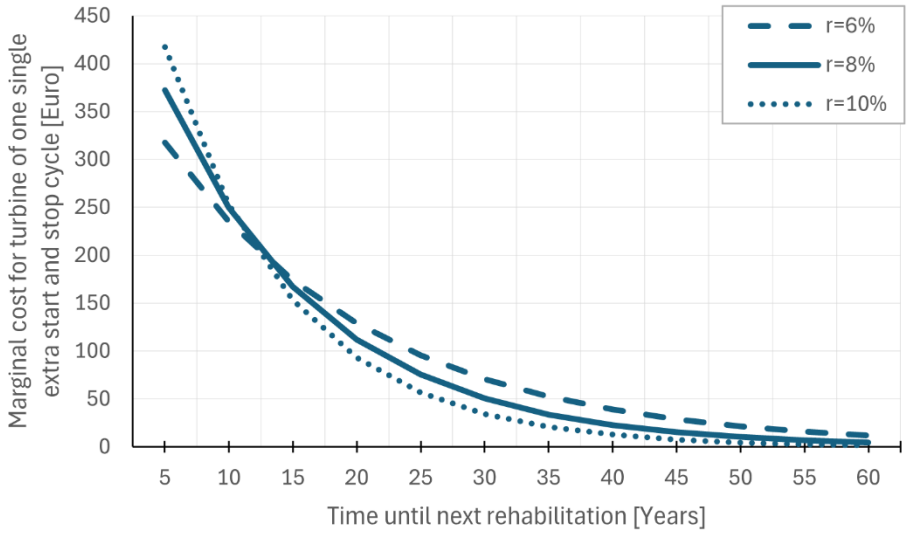

Figure 15. Marginal cost (EUR) of one single extra start and stop cycle for the Kaplan turbine as a function of remaining time until the next rehabilitation, under three different discount rates (r).

When the time until the next rehabilitation is between 10 to 15 years, the dotted and dashed lines that representing different interest rates, intersect and switch places. This indicates that as the time until the next rehabilitation increases, the influence of the discount rate becomes more significant in the marginal cost calculation. When the next rehabilitation occurs in 5 years, the net present value of the marginal cost is high, as the expense occurs soon in time. As the marginal cost is based on a fixed rehabilitation interval, short time left until the next rehabilitation implies that for a higher interest rate the discounting effect has not yet taken hold. The present value is therefore less when the interest rate is low in a case where rehabilitation occurs soon. When the time until the next rehabilitation is between 10 to 15 years, the net present value becomes higher for a lower interest rate as at this time, the effect of having a higher interest rate becomes more vital.

The present value of the marginal cost is reduced noticeably over a longer time horizon (>10 years) for all three discount rates. The marginal cost of an extra start and stop cycle for this Kaplan turbine, at a time when the next rehabilitation is in 50 years or more, converges towards values close to zero for all discount rates. This is because the present value of the cost becomes very small when the expense lies far in the future.

Figure 16 shows the average cost of one start and stop cycle based on a strategy change that involves one extra start and stop cycles per day over a year (in total 365 start and stop cycles per year), with a discount rate of six, eight and ten percent.

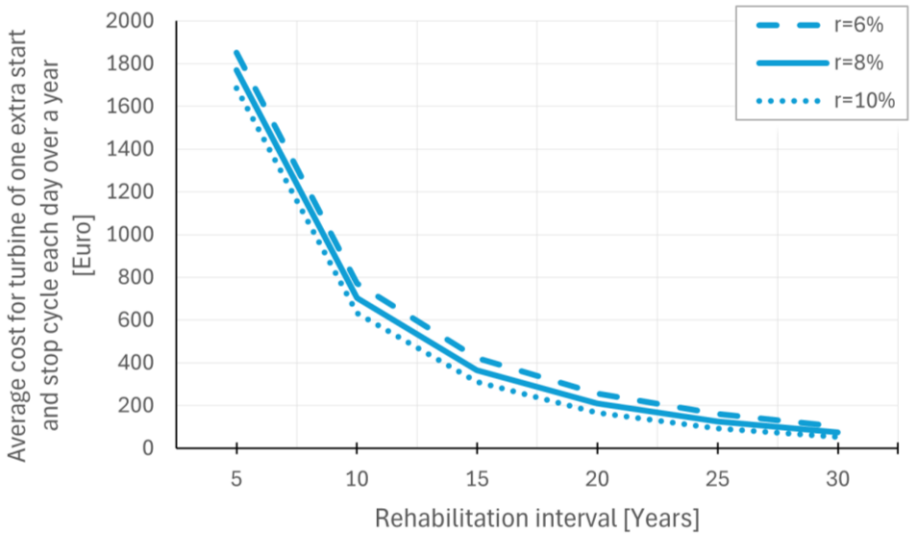

Figure 16. The average cost (EUR) of changing operating strategy for a Kaplan turbine to one where one extra start and stop cycle every day over a year is made, as a function of the rehabilitation interval, under three different discount rates (r).

When calculating the average cost, the Kaplan turbine is considered to be brand new. As seen in Figure 16 the average cost decreases when the rehabilitation interval of the Kaplan turbine increases. When the rehabilitation occurs every five years, the average cost is around 1800 euro with all three interest rates. However, when the rehabilitation interval is between 25 to 30 years, the average cost is just around 100 euro. The total cost of all start and stop cycles throughout the year is given by multiplication with a factor of 365.

Given Figure 16, the slope of the average cost is steepest when the rehabilitation interval is between five to ten years and thereafter the cost gradually drops. An implication is that the rehabilitation interval has a major impact of the average cost. Moreover, the average cost is at any rehabilitation interval highest with six percent discount rate and lowest with ten percent. This as a lower interest rate gives a higher present value.

6.4 Implications of cost analysis for a hydropower producer

From the marginal cost perspective, when considering a single additional event at a certain time in the rehabilitation cycle, an interesting finding is that the cost rises as the unit ages. The time until rehabilitation can therefore be a factor to consider when pricing services from particular units, for example in the short-term balancing market. The marginal cost approach is especially relevant in situations where the additional event is not a part of the long-term planned operational strategy and thus represents an unplanned acceleration of wear of that unit

From the results it is evident that start and stop cycles and ramping events reduces the rehabilitation intervals of the unit which causes a future rehabilitation cost to shift closer

in time, thereby increasing the average cost of an additional start and stop cycle. However, this result does not directly imply that a hydropower producer should avoid additional start and stop cycles or ramping events, it merely gives an indication of how to price their products more accurately on the markets. If the cost of shifting the rehabilitation closer to present time and thereby losing the discounting effect that the rate has on future expenses, is accounted for in the bidding strategy, it can still be reasonable to shift to a more intermittent operating pattern. That is somewhat intuitive as if revenues exceed costs, a profit is generated. There are however more factors to consider, the results highlighted in Figure 9 clearly show that an operating pattern with more start and stop cycle results in shorter rehabilitation intervals. It is worth considering that each rehabilitation results in an income loss during the time when the unit is out of order.

If a more intermittent operational strategy is adopted across multiple units, to respond to the increasing need of flexibility services, it may lead to that rehabilitations cluster due to shortened rehabilitation intervals. The result of clustering puts pressure on the internal resources that participate in the process of planning and managing hydropower rehabilitations.

7. Analysis of identified implications

Each hydropower plant has a unique design. Therefore, the impact of the *market change* will differ from unit to unit and plant to plant for the hydropower plants that voluntary participates at the mFRR market. The potential impact of the *market change* regarding technical, hydrological, market and operational aspects of hydropower, presented in Table 6, Table 7, Table 8 and Table 9 will in this section be addressed more thoroughly.

7.1 Technical implications

There are several technical aspects to consider when evaluating how the *market change* will affect hydropower. When providing flexibility services to the grid, a larger share of the units' operating time can occur outside the optimal operating range (Eggen and Belsnes, 2023). As an example, units running on low load can regulate system imbalances by ramping up production. Operating outside the optimal range causes additional wear, mainly for Francis turbines due to the sharp efficiency curve (Saarinen et al., 2018). However, the Kaplan turbine has a wider operating range as it can also adjust the production by changing the runner blades (Saarinen et al., 2018). This does, on the other hand, mean that Kaplan turbines have more moving parts involved in each load regulation. An extreme type of load change that is considered to be strenuous for hydropower units, is start and stop cycles (Eggen and Belsnes, 2023). Operation outside the optimal range, ramping events and start and stop cycles have increased due to a more intermittent operating pattern followed by hydropower's emerging role as short-term flexibility provider (Eggen and Belsnes, 2023).

Risk and concerns

As intermittent operation causes wear, fatigue and degradation of components, hydropower operators fear that the increasing frequency will cause their units to wear out too fast (Interview I.A, I.B, I.H, I.K, I.O, I.Q, Appendix B). With a 15-minute time resolution on mFRR-EAM and the introduction of the AOF there can be two start and stop cycles or ramping events per hour whereas before the *market change* it was maximum one start and stop cycle or ramping event per hour (Interview I.K, Appendix B). With the algorithm (instead of a human operator at Svk) that balances the system, there is a significant change in behaviour regarding how, when and the duration of bid activations. The change in behaviour have been emphasized by both hydropower traders and operators (Interview I.D, I.J, I.K, Appendix B). The algorithm is less considerate of how hydropower units are activated and deactivated which leads to that operation outside optimal range, ramping events and start and stop cycles are becoming more common.

Except for that intermittent operation causes wear, it can also increase the risk of surge and water hammer due to the rapid changes of the flowing water (Lupa et al., 2022). As water hammer can lead to severe damage of hydropower plants, as mentioned by Lundin (2021), the increasing trend of intermittent operation is troublesome (Interview I.K, I.O Appendix B). Additionally, if the system is downregulated more frequently, the use of spillway gates can increase for hydropower plants providing mFRR, especially at run-of-river plants. Since spillway gates are not designed for frequent use, the wear of the gates might increase due to the *market change*. In addition, if downregulation becomes more common during winter periods, use of spillway gates can be problematic. This is due to that ice formation on gates during can hinder their functionality (Interview I.Q, Appendix B).

Wear and tear, regardless of the reason for its appearance, decreases the lifetime of the affected components and thereby the rehabilitation interval (Eggen and Belsnes, 2023). To avoid breakdown, an owner of the hydropower assets either needs to increase maintenance to compensate for the degradation or rehabilitate the units more often (Eggen and Belsnes, 2023). Besides that maintenance and rehabilitation come with a cost, it also leads to loss of income when the units are unavailable for generating electricity (Interview I.B, I.D, I.F, I.H, Appendix B).

Adaptions

One way to avoid an increased need of maintenance due to the new operating pattern for providing mFRR services, is to re-allocate the resources and/or withdraw capacity from the mFRR-market. This is effective in terms of saving the components lifetime but leads to a decreasing hydropower fleet for providing mFRR services. This can become problematic for grid stability if withdrawal becomes a wider trend among hydropower BSPs since hydropower stands for around 90% of the prequalified mFRR capacity.

One way to adapt to a more intermittent operating pattern is by considering the technical specification when planning new investments of turbines, spillway gates and other components. This is further addressed in Section 8.1.

7.2 Market implications

The EU regulation that required an implementation of a 15-minute ISP also stated that BRPs must have the possibility to balance themselves at the same time resolution. Thereby the 15-minute MTU was introduced and to handle the shorter time resolution, an introduction of the automatic bid selection process through the AOF was necessitated (Svenska kraftnät, 2025h). The changed time resolution of the MTU and/or ISP poses less problems as separate changes but along with the AOF, both expected and less expected challenges appears for hydropower.

The complexity of the *market change* also lies in that earlier changes such as the introduction of Flow based capacity allocation impacts the conditions for how hydropower electricity generation can be traded on the mFRR markets. The available capacity for transferring electricity between bidding zones is now calculated more efficiently for the day-ahead market which then leaves less room for transfer capacity for the intraday market (Svenska kraftnät, 2025g).

When the grid frequency deviates from 50 ± 0.1 Hz, Svk will by the AOF activate mFRR up- or downregulation. BRPs that support system balance by overproducing during a deficit or underproducing during a surplus, are compensated according to the imbalance price. If BRPs instead contributes to the imbalances, they must pay an imbalance fee.

Risk and concerns

The AOF that handles the bid selection on mFRR-EAM has made it challenging for BRPs to position themselves on the market due to an unpredictable behaviour of how it optimises and chooses bids (Interview I.D, I.J, Appendix B). The mFRR market has become more unpredictable in the way that the system has shown tendencies to go from up- to downregulation between quarters, something that was rarely seen before the AOF (Interview I.J, Appendix B). The AOF also regulates on smaller frequency deviations than before. The increased sensitivity together with a shortened MTU results in a system that is regulated by mFRR at almost all times. This was seen already in the testing phase of the Nordic Balancing Market (NBM) (2024b).

This increased sensitivity, coupled with higher imbalance prices and more frequent activations, have made it more difficult, or at least more expensive for BRPs to balance themselves on the intraday market. If a BRP can not match its scheduled production, they must either buy electricity at potentially high intraday prices or accept the imbalance, hoping the system does not require upregulation (Interview I.D, Appendix B). On the other hand, it can be argued for that the mFRR market is now more

predictable since the incentives for BRPs to aim for a more precise balance are stronger (Svenska kraftnät, 2025g). However, hydropower producers face specific constraints since hydropower is not designed for highly frequent and short-duration activations. That complicates participation in both mFRR-CM and mFRR-EAM.

A consequence of the *market change* is that the demand for short-term regulation and mFRR has increased. What is concerning is that the changes that might be beneficial for grid stability is causing problems for hydropower as it leads to a more intermittent operating pattern. As discussed in the section about technical implications and as Eggen and Belsnes (2023) points out, an intermittent operating pattern causes degradation of the hydropower system's components. The concern for increased degradation can cause hydropower production companies to withdraw mFRR capacity. This can be considered as a matter of pricing and that companies can incorporate the cost of degradation into their bidding strategy. However, even if the cost of start and stops cycles and ramping events can be estimated and accounted for, it might be hard to motivate for what bid the cost should be added on to, since it is not always certain if that particular activation requires a ramping or a start-up.

Another reason for capacity withdrawal from the mFRR market is the shift to shorter and more frequent activations. This has increased the appearance of surge and water hammer effects in tunnels of underground plants (Interview I.K, I.O Appendix B). Before the *market change*, when bid activations were handled manually, the mFRR activations of hydropower units typically lasted longer and were less fragmented due to the knowledge of hydropower limitation by operators at Svk (Interview I.J, I.K Appendix B). After the *market change* hydropower producers need to add "resting time" as a bid attribute to avoid damaging hydraulic effects. However, from the perspective of hydropower producers, this attribute has proven problematic. During the resting period, the unit is unavailable for both mFRR activations and internal balancing needs. That means the unit cannot contribute to the BRP's balance management. Respondents from interviews report that the "resting time" attribute has not functioned effectively in practice (Interview I.J, I.K Appendix B). Resting time limits operational flexibility and is not properly designed to deal with hydraulic effects in a way that hydropower producers anticipated. This is discouraging participation on the mFRR markets.

With the introduction of the 15-minute MTU and the AOF, the fact that the bid on the mFRR market is linked to a specific unit, have become more significant. This as there is no flexibility to choose another unit that might be better suited for the moment. For example, Fingrid, the Finnish TSO, allows more flexibility to choose delivery unit later upon an activation (NBM, 2024a). That would be a welcomed alternation in Sweden according to this study (Interview I.O, Appendix B).

Adaptions

The bid attributes that hydropower producers can use along with the bids, need to be improved so that hydropower BRPs can use them to avoid an intermittent operating pattern as it can cause degradation, income losses and higher financial risks on the market. If the bid attributes remains as they are formulated today, hydropower producers might have to withdraw capacity from the mFRR market. Hydropower producers also need to be able to motivate the cost of an intermittent operating pattern by including the cost of degradation in their bids on the mFRR-market.

7.3 Hydrological implications

Regarding the hydrological aspects that can be impacted by the *market change,* some of these aspects are affected by short-term regulation itself. However, the *market change* can cause higher occurrence and/or frequency of the aspects.

When hydropower is used for short-term regulation on mFRR markets, production is either increased or decreased based on the need of up- or downregulation in the grid. The regulation in production can lead to alternating water levels and rapid changes in flow velocity. Bipa et al (2024) describes this as hydropeaking and has examined the environmental and societal impact of it. Hydropeaking does for example affect spawning grounds, the aquatic insect richness and fishes as the habitat is changing. As the *market change* can lead to a more intermittent pattern of the hydropower units, the issue with hydropeaking might grow (Eggen and Belsnes, 2023; Svenska kraftnät, 2024c).

Risk and concerns

If the *market change* leads to higher occurrence of hydropeaking, there is a concern about its negative impact of the local environment. This as hydropeaking can increase the riverbank erosion and have negative effects of the aquatic biodiversity. Moreover, hydropeaking can affect local communities and people (Interview I.F, I.K, Appendix B). According to Bipa et al. (2024), sudden changes of water velocity and depth, can be dangerous for people that are near waterways. It can for example be people doing outdoor activities (Bipa et al., 2024). Therefore, if the *market change* results in more frequent hydropeaking, the public safety will be important to consider as the consequences can be profound. Besides that, water management is also important as it can impact an energy producer’s brand marketing (Interview I.R, Appendix B).

Furthermore, rapid and frequent changes of water level and flow can cause issues during winter as it can hinder the natural formation of a uniform ice layer. Upstream the hydropower plant, loose ice floes in the reservoir or river can damage the hydropower plant, while downstream it can lead to ice jams in the river channel (Interview I.S, Appendix B).

However, water permits at hydropower plants limits, for example, how much the water levels and flow rates are allowed to fluctuate (Sydvatten, 2024). For the aspects

mentioned above, these permits are positive as they constrain rapid changes of water level and flow. Nevertheless, the permits affect the possibility to provide ancillary services to the grid. This can be problematic in times where capacity for short-term regulation such as mFRR is needed more than ever.

Moreover, from a hydrological perspective, the suitability of providing short-term regulation depends on the design of the hydropower plant. For example, run-of-river plants which lacks reservoirs can be less suitable as these hydropower plants are limited by the water from upstream (Killingtveit, 2019). Additionally, without the ability to store water, the only option is to either direct the water through the turbine and produce electricity or to spill the water through the spillway gates. Depending on if the water is let through the turbine or not, the separate waterways are affected which in turn can have negative effects for fish species (Interview I.S, Appendix B). Moreover, as the need of mFRR services is increasing, the need of water storage becomes more crucial as it, according to Killingtveit (2019), allows flexibility in production. To provide regulation of production, run-of-river plants either need to run on low or high efficiency range to be able to ramp up or down production at bid activation, or alternate between production and spilling the water through the spillway gates. Therefore, the *market change* can impact the degradation of turbines and spillway gates especially at run-of-river plants.

Another aspect that depends on the design of the hydropower plant is hydrological effects such as surge and water hammer that can be caused by rapid changes in flow and pressure. As Lundin (2021) describes, water hammer can cause severe damage of both pipes and the turbine. Therefore, it is a big concern that the *market changes* can increase the occurrence of water hammer, surge and other pressure change related issues (Interview I.K, I.O Appendix B). Underground plants with long tunnels and pipes are sensitive to these effects and the *market change* can therefore affect how these plants can participate on the mFRR market (Interview I.K, I.O Appendix B).

Adaptions

Water management is and will continue to be an important aspect to consider for the above mentioned reasons. However, one outcome is that the *market change* might lead to complete withdrawal of units that are sensitive to surge and water hammer from the mFRR market. Run-of-river plants might also be less suitable for providing mFRR services after the *market change*. In addition, the effects of hydropeaking due to the *market change* need to be monitored and mitigated.

7.4 Operational implications

One of the main responsibilities for a hydropower operator is to ensure that the water is safely transported from the rivers to the sea (Interview I.K, Appendix B). Therefore, surveillance and control of flow rates and water levels at various locations are essential

and requires time for production planning and supervision of local information (Interview I.K, Appendix B).

Risk and concerns

The main issue with the *market change* is the time and focus that shifts from managing the water to handle mFRR activations. For an operator, this becomes notable as many of the systems are handled manually. One consequence of the shortened MTU is that activations and deactivations now can occur every 7.5 minutes (Interview I.K, Appendix B). Moreover, the TSO does not send signals for deactivations. This implies that the operator constantly needs to keep track of time and be cautious of silent signals of deactivation. For example, if an mFRR upward bid is followed by a deactivation but the operator does not notice it, the hydropower unit is continuing to produce electricity (Interview I.K, Appendix B). This can create discrepancies between real time production and the production plans sent to the TSO. If the bidding zone then is downregulated that quarter, that imbalance, caused by the discrepancy, can result in an imbalance fee for the BRP. Since the AOF contributes to a system that is regulated more often than before, the financial risk of participating on the mFRR market has increased for a BRP (Svenska kraftnät, 2025g).

Furthermore, when time becomes limited for supervision and surveillance of flow rate and water levels, it can have serious consequences if something unexpected like a power outage or a mechanical failure happens. In a worst-case scenario, it may lead to disastrous consequences. For example, there is a risk that local activities and community events such as ice-skating events may be missed due to the increased amount of information an operator need to manage. In addition, certain maintenance of hydropower plants can require divers and other personnel at potentially hazardous places (Interview I.F, Appendix B). If the market then consumes too much attention there is a risk that personnel and local events are being overlooked. This becomes a matter of public safety as non-expected changes in water flow and levels can have tragic outcomes.

Adaptions

An operator must now manage a more complex and time-sensitive market in addition to their traditional tasks. This introduces a risk of operational overload, especially when activations occur frequently and with limited predictability (Interview I.A, I.B, I.C, I.K, Appendix B). Organisations must adapt to the new conditions and value the work environment. This can include to hire more operators, divide responsibilities and implement control mechanisms to release pressure on the operators. In addition, a needed adaption is to introduce automated IT systems that are centred around operator usability.

7.5 System-level complexity

In Figure 17, a Venn diagram is shown to emphasise a system-level perspective of how the *market change* can influence multiple dimensions of hydropower operations. The diagram points out the complexity of the analysed aspects under each category above. An identified aspect can be categorised differently depending on in what terms it is considered. Additionally, an identified aspect is both affecting and affected by other aspects. The complexity also lies in that the outcome of the *market change* depends on decisions and actions in multiple categories.

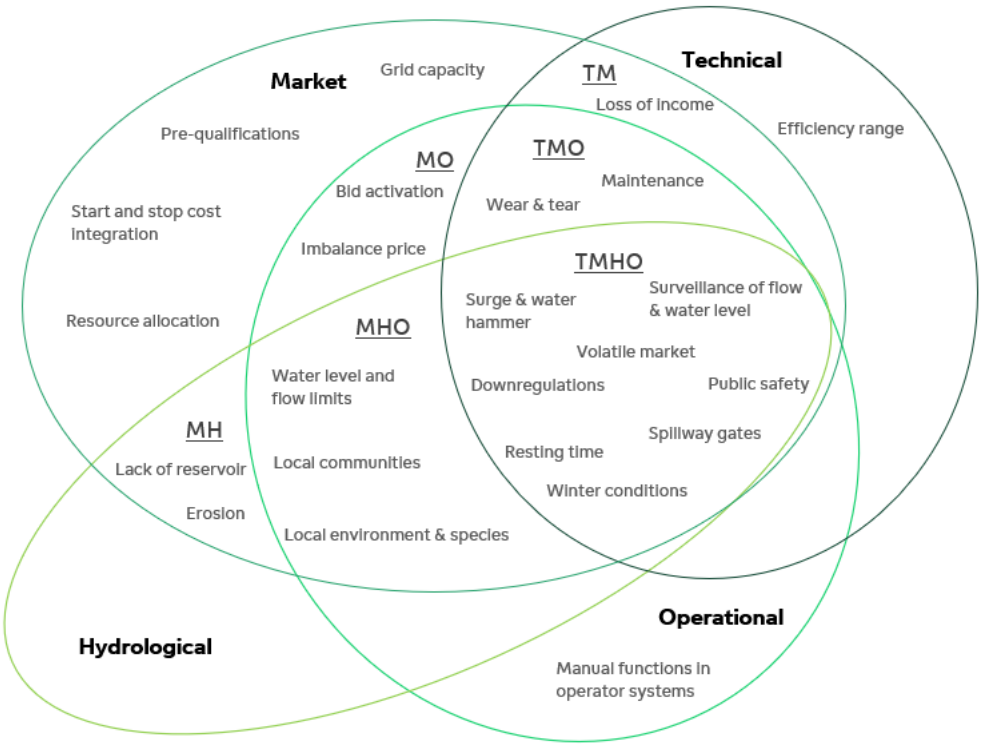

Figure 17. Overview of identified aspects affected by the market change, categorised into four interrelated domains: Technical, Market, Hydrological, and Operational. The diagram illustrates how different aspects overlap across categories, highlighting their interconnected nature. Each label (TM, MH, MO, MHO, TMO and TMHO) denotes a combination of categories in which the aspect belongs.

7.6 Opportunities of the *market change*

The only thing that is certain is that change is constant. Therefore, this type of *market change* offers an excellent opportunity for hydropower producers to learn to be more proactive for future challenges. The implementation of the *market change* has shown the importance of collaboration between departments to exchange knowledge and experience.

Furthermore, the *market change* can introduce opportunities to earn a significant amount of money if a BRP can develop tools that are able to predict or better interpret

the behaviour of the AOF. In addition, if the earnings are higher than the expenses (related to increased degradation of the units), it can be worth the cost of increased wear and tear. If higher prices emerge on the mFRR market it might also create further incentives for pump storage. Another way to adapt the hydropower production for provision of ancillary services is to integrate batteries into hydropower plants. The batteries can then be charged from hydropower operating at a more continuous pattern. When regulation is needed, the output from the batteries can be adjusted instead of changing the operating pattern of the hydropower units.

8. Discussion

In general, the *market change*'s impact on hydropower is strongly connected to the increased use of hydropower assets for short-term regulation as it leads to an intermittent operating pattern. One of the most interesting findings from the cost calculations is not the actual cost of an additional start and stop cycle or ramping event but rather that an intermittent operating pattern leads to shortened rehabilitation intervals. This becomes especially significant for an increasing number of start and stop cycles. As discussed in section 6.4, shortened rehabilitation intervals that cluster together creates pressure on the internal organisation to plan, organise and perform rehabilitations more often. Even if rehabilitation can be postponed with increased maintenance there are still challenges. Maintenance likewise causes an increased pressure to facilitate, for example, personnel, components and at times a temporary shutdown of the hydropower plant. Since rehabilitation is defined as restoring the component it does not consider the possibilities of a complete refurbishment where parts are renewed with an updated design that better fits the flexible operational conditions that is needed for grid stability. Changing units to ones that are better adapted to flexible operation can therefore in the long run decrease the effects of intermittent operating patterns (Tomé Robles et al., 2024).

However, there is also a risk that the external suppliers and contractors face difficulties to meet a growing demand of components if the rehabilitation interval of the unit is drastically reduced due to the *market change*. If such pattern emerges on a national scale among the Swedish hydropower producers, the cumulative effect can lead to bottlenecks in supply chains and delays of rehabilitations. An outcome of bottlenecks and delays is that it leads to less available capacity of hydropower production on the market.

There are several aspects of the *market change* that are not beneficial for hydropower production, assets and organisation. If the response from hydropower producers is to re-allocate the mFRR capacity, it can become an issue for the power grid. This as hydropower stands for around 90% of the pre-qualified mFRR and thereby has a significant impact on the grid stability. In a society that is relying more on electricity to

power industry processes, transports and digitalisation, less grid stability may pose challenges for accomplishing climate targets.

The question is whether it is efficient to wear out critical renewable infrastructure such as hydropower to balance a system with an increasing share of intermittent electricity supply? While the AOF was implemented to eventually align with the European balancing platform MARI and to promote a harmonised market, there is reason to question whether its current design sufficiently accounts for the unique characteristics of Sweden's hydropower dominated system. It may be worth considering whether certain aspects of the AOF could be adapted to better reflect national energy mixes. However, the Swedish TSO, emphasises a technology-neutral approach in its operations and the introduction of the AOF aligns with this principle by automating the selection of balancing resources based on cost-efficiency, regardless of technology type.

However, the *market change* includes lowered capacity and duration requirements for a BSP, from five megawatts during one hour to one megawatt for a quarter of an hour (30 minutes for direct activations) (Svenska kraftnät, 2025e). That gives better conditions for small-scaled BSPs and other energy sources such as batteries but also flexible consumption providers to participate on the mFRR market. A consequence might be an increased market competition for hydropower producers. However, as the mFRR services must be capable to handle the largest dimensioning contingency in the system, hydropower remains a crucial resource to manage larger disturbances in the grid. Therefore, it would be challenging for the grid stability if capacity from hydropower production is withdrawn due to the implications of the *market change.* Additionally, since the *market change* has led to higher imbalance prices, the financial risks are higher. The increased financial risks can particularly affect smaller BRPs as they are more sensitive to high imbalance fees.

An important factor to consider is the limited amount of time that has passed since the *market change*s was implemented. So far, the implications and effects on hydropower is merely indications and may partly reflect the novelty of the system and the limited experience of producers and market participants with the new framework. For example, the operating pattern of hydropower units is highly affected by how the market dynamics evolves as market participants affect each other. This makes it difficult to draw definitive conclusions about its long-term effects, both on the balancing market in general and on hydropower.

8.1 Future studies

Given the discussion, future studies will be valuable once more data is available to assess how the *market change* have actually impacted hydropower. It would be especially interesting to investigate whether balancing capacity has been withdrawn from the mFRR market and what consequences that may have had for grid stability. Further research could also explore how price dynamics on the balancing and power markets have evolved, for example, did the reform lead to greater price volatility? If so,

this may affect the economic viability of technologies like pumped hydropower storage, which rely on price differentials. Additionally, if the price dynamic between the markets would change, it would also be reasonable to evaluate where the capacity should be allocated to maximise the incomes.

Furthermore, ongoing processes such as the National Plan for Modern Environmental Provisions for Hydropower (NAP) may present a chance to investigate the effects of hydropeaking due to an intermittent operation followed by the *market change*. Balancing flexible operation with minimisation of environmental effects is necessary to enable a renewable energy system.

An essential question for the future of Swedish hydropower is whether it will adapt to its emerging role as a real-time flexibility provider. While these *market change*s may initially be challenging, they could also create long-term opportunities for innovation that further improves hydropower. For example, is it economically viable to replace some of the turbines with ones that are better adapted to flexible operation? Could the degradation caused by intermittent operation decrease to such an extent that these types of investments become viable?

Furthermore, in future studies, the marginal and average costs can be calculated with finer granularity by accounting for degradation related to subcomponents. It is also reasonable to calculate income loss during maintenance.

9. Conclusions

It has been found that the *market change* impacts the hydropower system in one way or another. Some aspects of the hydropower system are directly affected whereas others are due to the broader ongoing shift of hydropower, from handling flexibility needs in seasonal and daily consumption patterns to a real-time flexibility resource. Rather than initiating this transition, the *market change* reinforces and accelerates a trend that has emerged over time.

This study identified four categories where the *market change* influences hydropower: technical, market, hydrological and operational. If a hydropower producer continues to operate in order to support the power grid stability in line with the incentives from the *market change*, it would result in more frequent, short-duration activations. This study found several aspects of the hydropower system within the four categories that would be impacted negatively of such operation.

Moreover, it is shown that the increased frequency and unpredictability of activations are accelerating wear on critical components like turbines and spillway gates, leading to higher maintenance needs and reduced asset lifetimes. At the same time, less predictable dispatch and rising imbalance risks can put financial pressure on hydropower producers. These operational demands also reduce the time available for safe water management

which can threaten both the environment and public safety. In short, the *market change* challenges hydropower's ability to provide mFRR balancing services. However, the way that the *market change* affects the categorised aspects are complex and intertwined with many other interactions on the market such as other actors' behaviour, grid and regulatory constraints and ultimately how hydropower producers choose to respond and adapt to the new circumstances. In addition, as the *market change* has been recently implemented, its implications may evolve over time as updates of the *market change* are made.

Furthermore, a more intermittent operating pattern of the hydropower units has shown to impact the capability to provide flexibility. This is due to that an intermittent operating pattern and especially start and stop cycles accelerates the degradation which results in a shortened rehabilitation interval and less time to next rehabilitation. The marginal and average costs derived from the cost model offers valuable insight. Firstly, the marginal cost which increased significantly the closer in time the next rehabilitation was, motivates pricing strategies that reflect the physical condition of the unit. Secondly, if many units experience accelerated wear due to more intermittent operation, units may require rehabilitation within the same time period. Such scenario would lead to clustering effects that ultimately could reduce the overall availability of balancing capacity.

Since the market reform originates from an EU-regulation, Svks implementation has been aligned with that framework. As a result, it may be difficult to modify the rules at a national level unless exceptions are introduced that allow for adaptations to better suit the Swedish, hydropower dominated electricity mix. This shifts the responsibility onto hydropower producers, who must adapt and evolve within the new market conditions.

In conclusion, the conditions for providing mFRR services have become less favourable for hydropower and the intermittent operation of the units can affect hydropower's capability to provide flexibility. However, the *market change* also creates opportunities for innovation and long-term improvement. Can hydropower adapt to their new role under these market conditions or will it lead to withdrawal from balance markets such as mFRR-EAM?

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Appendix A

List of parameters/variables used in the equations, see Section 3 and Section 0.

Parameter	Explanation	Unit
R	Rehabilitation cost	euro
r	Interest rate	-
T_1	Time to first/next rehabilitation	years (calendar)
$t_{operation}$	Nr of operating hours per year	hours
α_{ref}	Total reference/designed operating share per year	-
α_i	Reference operating share per year on low-, part-, normal- and overload	-
β_i	Stress factor for operating time caused by operation on low-, part-, normal- and overload	-
n_{ref}	Designed number of start and stop cycle per year	-
ΔD	Operating time loss per start and stop cycle	hours
Δn	Number of extra start and stop cycles	-
$ramp_{ref}$	Reference number of ramping event per year	-
ΔD_{ramp}	Operating time loss per ramping event	hours
$\Delta ramp$	Number of extra ramping events	-
T_D	Expected operating design lifetime	hours (operating)
T_0	Rehabilitation interval at normal operating pattern	years (calendar)
$T_{\Delta n}$	Rehabilitation interval at intermittent operating pattern with extra start and stop cycle	years (calendar)
$T_{\Delta ramp}$	Rehabilitation interval at intermittent operating pattern with extra ramping events	years (calendar)
mc	Marginal cost	euro/event
ac	Average cost	euro/event

Appendix B

A list of conducted interviews.

ID	Dates 2025	Interview object	Theme and purpose
I.A	27/1	Manager operation Sweden	Interview to understand how the *market change* affects the operation of hydropower assets.
I.B	30/1 27/3	Process manager	Two interviews with process manager to understand the *market change* as well as how it affects the internal market/bidding processes. One interview before and one after the implementation in March.
I.C	3/2	Manager asset optimisation and Manager intraday trading Sweden	Interview to understand what impact the *market change* will have for the spot and intraday markets.
I.D	13/2	Senior intraday trader	Field observation. Understand the intraday market and what implications the *market change* will have.
I.E	18/2	Senior portfolio manager	Discuss hydropower assets and how the operating pattern affects the units.
I.F	19/2	Operation Engineer	Field observation. Understand the operation of hydropower assets and what implications the *market change* will have.
I.G	21/2	Spot trader and Balance settlement specialist	Understand the pre-qualification process of hydropower units for ancillary services and in particular mFRR as well as how it will be affected by the *market change*.
I.H	27/2	Hydropower expert (turbine)	Understand how turbines are affected by the *market change* and an intermittent operating pattern. Besides the interviews, questions have been answered by email.

I.I	5/3	Hydropower expert (generator)	Understand how generators are affected by the *market change* and an intermittent operating pattern.
I.J	11/3	Two intraday traders	Understand how the intraday market and mFRR-EAM was affected after the first weeks with the *market change*.
I.K	11/3 28/3	Operation engineer	Two interviews to further understand the operation of hydropower assets (for example in relation to water permits and operational aspects) and how it will be and got affected by the *market change.* One interview before and one after the implementation in March.
I.L	13/3	Spot trader	Discuss average and marginal cost of a more intermittent operation. Understand the basics of pricing at the spot market.
I.M	21/3	Vice president asset development	Understand the cost of degradation in terms of investments.
I.N	25/3	Manager analysis platforms	Understand investments and how the risk of failure is considered.
I.O	25/3	Asset dispatch	Understand how hydropower assets are affected by the *market change.* Furthermore, how Fortum has acted upon the implementation of the changes.
I.P	26/3	Author of article on cost calculations	Discuss the article and equations regarding the cost calculations. External contact.
I.Q	11/4	Dam safety risk manager	Understand how spillway gates and dams are affected by short-term regulation and the *market change* as well as related risks.
I.R	15/4	Manager environmental policy	Understand environmental and social effects of short-term regulation as well as discussion of water permits.
I.S	22/4	Water regulation specialist	Understand water management as well as hydrologic and social impacts due to short-term regulation.