Secondary reserves and how to procure them

A comparative report on balancing capacity procurement in Denmark and Vietnam considering options for the future of balancing capacity procurement in Vietnam

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Danish Energy Agency

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Executive Summary

This report, jointly produced by the Danish Transmission System Operator (TSO), Energinet, and the Vietnamese National Market and System Operator (NSMO) - as part of the Danish Energy Partnership Program (DEPP3) between Denmark and Vietnam - compares use and procurement of balancing capacity in Vietnam and Denmark. It outlines key differences to inform discussions on future ancillary services procurement in Vietnam, focusing on secondary reserves. The paper evaluates sequential capacity and day-ahead wholesale markets versus co-optimised capacity and day-ahead markets, assessing their strengths and weaknesses.

Danish Energy Agency

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Abbreviations

AGC	Automatic Generation Control
aFRR	automatic Frequency Restoration Reserves
AS	Ancillary Service
BESS	Battery Energy Storage Systems
BRP	Balancing Responsible Party
CM	Capacity Market
CZC	Cross-Zonal Capacity
DA	Day-ahead
DCS	Distributed Control Systems
DEPP	Danish Energy Partnership Program
EAM	Energy Activation Market
EAV	Electricity Authority of Vietnam
EMS	Energy Management System
EVN	Vietnam Electricity
FCR	Frequency Containment Reserve
FCR-D	Frequency Containment Reserve for Disturbances
FCR-N	Frequency Containment Reserve for Normal operation
FiT	Feed-in Tariff
HVDC	High-Voltage Direct Current
IPP	Independent Power Producer
mFRR	manual Frequency Restoration Reserves
MoIT	Ministry of Industry and Trade
NEMO	Nominated Electricity Market Operator

NSMO	National System and Market Operator
PICASSO	Platform for the International Coordination of Automated frequence restoration and Stable System Operation (the common energy activation market for aFRR in the European Union)
PPA	Power Purchase Agreement
PV	Photovoltaic
R&D	Research and Development
SO	System Operator
TSO	Transmission System Operator
UFLS	Under-Frequency Load Shedding

Introduction

This report compares the Vietnamese and Danish (Nordic) electricity systems, focusing on ancillary services amid rising renewable energy from solar and wind. It highlights Nordic experiences, especially Denmark's methods of reserve procurement. Practices by Energinet, Denmark's Transmission System Operator (TSO), in the shared Nordic markets are presented to inform and support Vietnam's National System and Market Operator (NSMO) in establishing its secondary reserve market. The document first reviews the electricity market systems in Denmark and Vietnam, highlighting Denmark's proactive and Vietnam's central/reactive approaches to balancing services. It then discusses insights from the ongoing Vietnam–Denmark System Operator (SO) Partnership Program, as part of the Danish Energy Partnership Program (DEPP3) between Denmark and Vietnam, comparing co-optimised and sequential market setups for balancing capacity procurement. The aim is to guide Vietnam's ancillary service (AS) market development, informed by the Danish/Nordic experience and European market development currently researching co-optimisation.

Finally, the report concludes by highlighting opportunities for Vietnam to develop its market structure and discusses why co-optimised procurement of day-ahead (DA) and balancing capacity may offer fewer implementation challenges in Vietnam compared to the Danish/European context.

Comparative Description of Danish/Nordic and Vietnamese Systems

This report is motivated by the system operator (SO) cooperation between Denmark and Vietnam. Despite significant differences, both systems share geographical similarities, including the Nordic and Vietnamese extensive north-south spans and concentrated hydroelectric resources important for wholesale electricity and balancing services.

Vietnam's power system ranks among the largest and most rapidly expanding in Southeast Asia. By 2025, total installed generation capacity is projected to exceed 80,000 MW, supported by a transmission network that interconnects the Northern, Central, and Southern regions via a national 500 kV backbone. The generation mix continues to rely primarily on conventional sources—hydropower, coal-fired, and gas-fired plants—which serve as the foundation for system reliability. However, between 2019 and 2023, the system experienced a surge in renewable energy deployment, particularly solar and wind, driven by government feed-in tariff (FiT) schemes. By the end of 2023, variable renewable energy accounted for approximately 25–30% of total installed capacity, placing Vietnam among the regional leaders in renewable integration.

Vietnam's electricity market is currently in a pre-wholesale phase and retains a de facto single-buyer model. Vietnam Electricity (EVN) is responsible for around 95% of spot market purchases, while the remaining 5% is procured by its distribution subsidiaries, which operate with separate financial accounts but remain under EVN ownership. As such, market competition remains limited. The ancillary service (AS) market is also underdeveloped: most generators providing AS do so through bilateral contracts with EVN rather than transacting with an independent system operator, as is standard practice in more liberalized power systems.

Denmark, although small, is divided into two bidding zones, DK1 and DK2, belonging to separate synchronous areas. A part of the European wholesale market coupling as well as cross-border reserve markets, Denmark is highly integrated with its neighbors, particularly the Nordic system.

The Nordic system in total comprises 12 market zones across Denmark, Sweden, Norway, and Finland. West Denmark, DK1, is synchronized with the European continent, while the other 11 zones including East Denmark, DK2, form the Nordic synchronous area. Connections include subsea cables and high-voltage direct current (HVDC) technology linking the Nordic synchronous area to West Denmark, continental Europe, and the Baltic region. With Denmark being split between two synchronous areas this also affects the need and product types of ancillary services. Since the Nordic system in particular shares certain similarities with the Vietnamese system, the focus will therefore be on the ancillary services deployed in DK2 and the Nordic region, which varies from the standard products in DK1 and continental Europe. There are 5 types of ancillary services procured in DK2. The different products each serve a different role in the balancing of the grid as they have different characteristics such as volume, activation time etc.

Denmark, as well as the European and Nordic region, relies on a sequential market structure to procure energy and reserves. The wholesale market is a common European Day-ahead (DA) market for each hour – which went to 15-minute granularity in October 2025. Here energy volumes are submitted to a power exchange and an algorithm (Euphemia) optimizes the resource scheduling, cross-zonal flows and thereby the spot market prices for all bidding zones in Europe.

The Nordic sequential market setup from a Danish perspective is visualized in Figure 1.The introduction of the electricity markets around year 2000 was also accompanied by a privatization of production assets, ending the time of a more central dispatch in favor of decentralized production and ultimately leaving the balancing responsibility with the generators and supply companies (called balancing responsible parties (BRPs)). With the increasing share of intermittent solar and wind power and need for closer to real time optimization and new balancing products, the complexity is increasing. Regulatory requirements to further investigate potential developments has furthermore initiated a dialogue in Europe on potential benefits from a co-optimised approach, currently investigated in a research and development (R&D)-project performed jointly by the Nominated Electricity Market Operators (NEMOs) and TSOs.

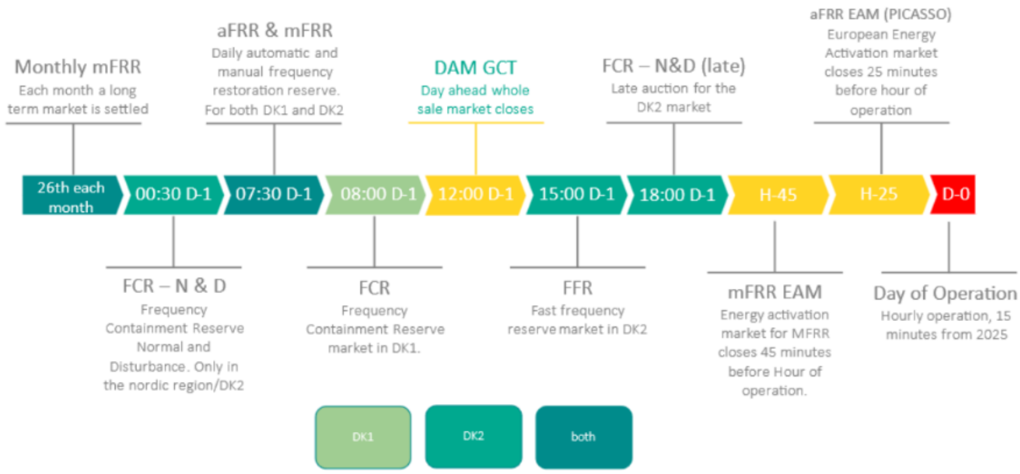


Figure 1: Capacity reserve markets gate closure times

In the Nordic region there are three types of ancillary services that can be described as primary reserve - more on these can be found in the Appendix - while secondary reserve (Automatic Frequency Restoration Reserve (aFRR)) and tertiary reserve (Manual Frequency Restoration Reserve (mFRR)) puts the total to 5.

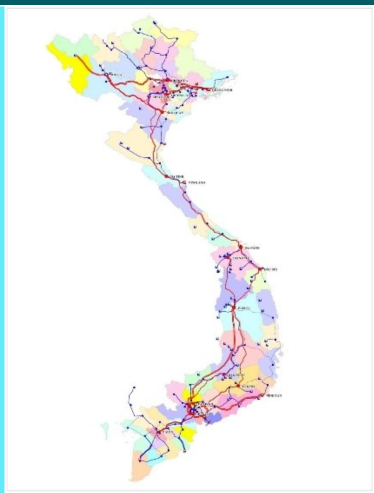
In contrast, Vietnam currently operates as a single bidding zone without markets for ancillary services and is increasingly experiencing that the geographical distribution of resources for reserves is becoming challenging as grid congestion increases.

This is an important challenge to mitigate, not only from a security of supply standpoint but also to reap gains from enhancing economic efficiency, as low-cost renewable generation otherwise faces greater risks of forced curtailment if balancing operations and reserve procurement are not optimised based on both asset characteristics and geography.

With rising renewable penetration and grid congestion, both the Nordic and Vietnamese systems face similar challenges. This report outlines how reserve markets and procurement methods for secondary reserves might alleviate these issues. Insights from recent developments in the Danish/Nordic markets and the rationale behind their design choices may offer valuable guidance for shaping Vietnam's future electricity market.

Table 1 provides a descriptive comparison of key features in the Nordic/Danish and Vietnamese electricity systems. This is followed by an overview of current practices regarding ancillary services within each system.

Table 1: A descriptive comparison of the Danish/Nordic and Vietnamese systems

	Danish/Nordic system	Vietnamese system
		
Area	Nordic: 1.216.741 km^2 Denmark: 43.093 km^2	331.230 km^2
Length	1.850 km (Scandinavian Peninsula)	1.650 km

Inhabitants	Nordic: 27.8 million Denmark: 5.9 million	98.9 million
Km's of cable	Nordic: 48,000 km Denmark: 4,200 km	25,236 km of transmission lines[1]
Annual power consumption	Nordic: ≈380 TWh Denmark: ≈ 36 TWh	Vietnam: ≈310 TWh
RES-share[2]	2025: 70% 2030: 90% 2050: 98%	2025: 45% 2030: 47% 2050: 67-72%
Bidding zones	Nordic: 11 (incl. East Denmark) Denmark: 2	1
Market integration	Secondary Reserve: aFRR • Energy activation: PICASSO • Capacity market (CM): Nordic aFRR CM	Vietnam currently operates a wholesale electricity market; however, an ancillary services market has yet to be developed. Secondary reserve: Automatic Generation Control (AGC)

Secondary Reserve in Denmark

The secondary reserve in Denmark (Europe) is called automatic Frequency Restoration Reserves (aFRR). It is a medium fast reserve and must have all power delivered within 5 minutes of activation.

1 Vietnam - Power Generation, Transmission, and Distribution

2 Viet Nam Energy Outlook Report, 2024

It serves three main purposes:

- Releases activated frequency containment reserves (FCR-D and FCR-N[3]).
- Corrects minor imbalances that are too small for manual regulation (mFRR) activation.
- Restores the agreed balance on the interconnectors to neighbouring bidding zones.

Activation of aFRR does not occur directly as a response to the frequency deviations at individual generating units. Instead, activation is triggered by an automatic regulation signal sent by the system operator (Energinet) to the BRPs.

Energy activation typically occurs via the European activation market, PICASSO[4], which can utilize both local and cross-border bids. Additionally, strictly local activations outside the PICASSO platform may also take place when cross-border transmission constraints limit the total allowable exchange of aFRR. Denmark and Finland are currently the only Nordic countries participating in the PICASSO-platform.

aFRR capacity is procured hourly through daily auctions in the Nordic aFRR Capacity Market (CM). The reserve capacity (of aFRR and mFRR) that is procured through the daily auctions is obligated to participate in the respective Energy Activation Markets (EAM), except for the primary reserves, since these reserves are responding directly to the frequency deviations. The primary reserves payment is, depending on the specific product, settled based on the imbalance price or the mFRR-price of the system at time of activation.

Since the inception of the aFRR product the procurement methodology has seen several changes for DK2. At first it was procured on a monthly basis, as a symmetric product, with combined capacity and energy activation payment. In December 2022, a combined Nordic market was introduced, still with combined capacity and energy activation, but now as an asymmetric product procured daily. On the 2nd of October 2024 the European Energy activation market PICASSO was introduced in DK1 and DK2. This splits the procurement into separate capacity and energy activation for both areas. These changes have had short-term impacts on the price volatility in the CM but have been found to return to somewhat more stable prices after some time. This tendency stems from the market actors adapting to the new formats, and this trend is often seen when making such market changes.

[3] FCR-D is frequency containment reserve for disturbances, while FCR-N is frequency containment reserve for normal operation

[4] PICASSO: platform for the International Coordination of Automated frequence restoration and Stable System Operation (the common energy activation market for aFRR in the European Union)

The price development of the aFRR capacity market for DK2 can be seen in Figure 2 below.

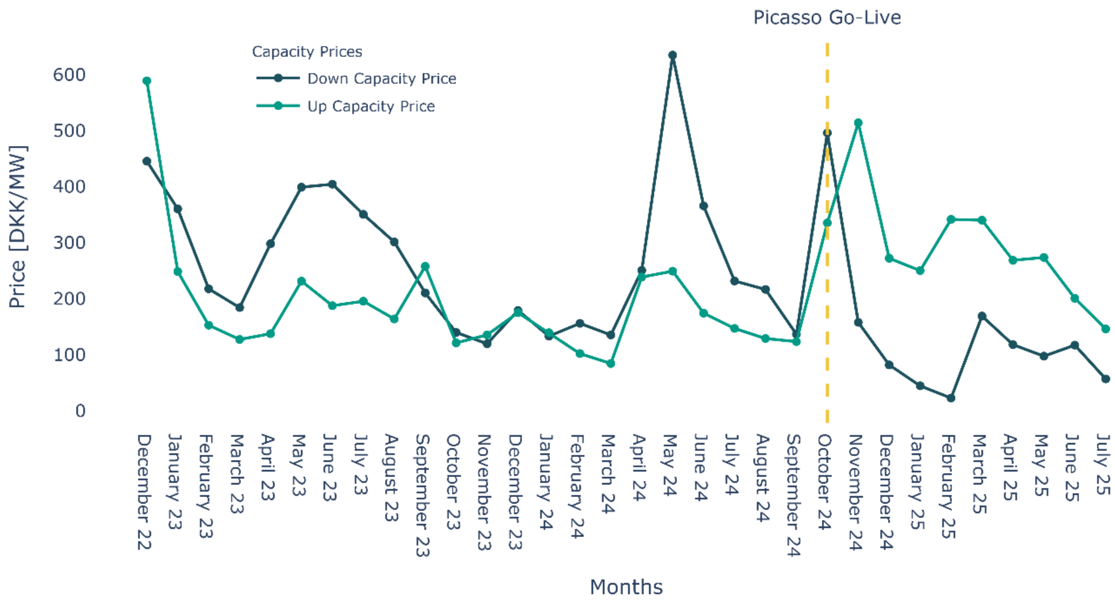


Figure 2: aFRR price development in DK2 from December 2022[5]

For secondary (aFRR) and tertiary reserves (mFRR), energy payments are settled through the EAM. Participants receiving capacity payments in the reserve market are required to submit corresponding bids into the EAM, matching their reserved capacity. Additionally, voluntary bids from assets not contracted through the reserve market may also participate by offering available flexibility.

The EAM for secondary reserves is settled through the PICASSO platform, the pan-European aFRR EAM facilitating settlements across participating bidding zones. Currently, within the Nordic region, only Denmark's DK2 bidding zone and Finland participate in PICASSO, while DK1 in the continental synchronous area also participates. Other Nordic TSOs (Sweden and Norway) plan to join PICASSO around 2027–2028. Due to certain limitations, including restrictions on aFRR exchanges across HVDC cables, there are situations where the Danish national price diverges from the PICASSO platform price, even when physical cross-border capacity remains available.

The volumes and prices for the daily auctions for capacity and energy activation can be found on Energi Data Service.

[5] Data collected from: Energi Data Service: aFRR, Automatic Frequency Restoration Reserves, Capacity Market

Tertiary Reserves

Tertiary reserves, also known as manual Frequency Restoration Reserves (mFRR), are activated to balance the power system during significant, unplanned fluctuations in production or consumption, such as power plant outages or sudden changes in renewable generation. These reserves must reach full activation within 12.5 minutes after receiving a signal from Energinet's control center, ensuring system stability for extended periods.

Like aFRR, the tertiary reserve mFRR has separate capacity and energy activation markets (EAM). Energinet activates mFRR from the common Nordic mFRR energy activation market for both upward and downward regulation. Both production and consumption units can provide these manual reserves.

The capacity procurement takes place in the Nordic mFRR CM, which operates in connection with the aFRR CM. The dimensioning of mFRR reserve procurement, i.e. how much to procure, uses a dynamic model that considers factors such as the largest reference unit or the 99th percentile of historical imbalances, whichever is greater. In West Denmark (DK1), the reference unit is either the cable Skagerrak 4 (Norway) or the cable COBRA (Netherlands), both at 700 MW. Energinet has announced that the DK1 reference unit will increase to 1,000 MW by 2030. In East Denmark (DK2), the reference units are the cable KONTEK (Germany) or the Great Belt connection, each with 600 MW capacity.

Current Status of the Ancillary Services Market in Vietnam

Under the existing regulatory framework, Vietnam recognizes five main categories of ancillary services (AS) for the power system: (i) Secondary frequency control (automatic generation control (AGC)), (ii) Fast start-up reserves, (iii) Voltage regulation, (iv) Must-run reserves to ensure system security, and (v) Black start capability.

These services are essential for maintaining system frequency and voltage stability, as well as restoring the system after major disturbances. It is important to note that primary frequency control is mandatory for all generating units equipped with governors in Vietnam, but it is not treated as a market-based AS. Instead, it is considered a general technical requirement. Therefore, the ancillary services framework in Vietnam primarily focuses on secondary frequency control (AGC), fast start reserves, must-run reserves, voltage support, and black start services.

Currently, Vietnam's AS market does not operate under a fully competitive framework like its wholesale electricity markets. Instead, AS procurement is primarily based on dispatch planning and contractual arrangements between the system operator and generating units. Each year, the National Power System and Market Operator (NSMO) estimates the required quantities for each type of AS and submits the plan to the Electricity Authority of Vietnam (EAV) for approval. This approved plan then serves as the basis for service procurement and dispatch in the following year.

AS prices are regulated by the Ministry of Industry and Trade (MoIT) using a cost-plus pricing methodology. Specifically, Circular No. 11/2025/TT-BCT, issued in early 2025, outlines the procedures for determining and approving AS tariffs. In summary, Vietnam applies a regulated, cost-based pricing model for AS, rather than a competitive bidding mechanism as adopted in more liberalized electricity markets. Prices are determined administratively and approved by regulatory authorities rather than being set through market-based clearing.

Most large-scale power plants (≥30 MW) in Vietnam are required to have the capability to provide certain types of AS. For primary frequency control, all generating units must be equipped with governors configured with appropriate deadbands and must respond automatically when system frequency deviates from the nominal 50 Hz. Technical regulations mandate that each unit must deliver its full primary frequency response capacity within 15 seconds and sustain it for at least 15 seconds.

For secondary frequency control, only a limited number of units have been integrated with AGC to participate in automatic dispatch. According to the current standards, a unit providing secondary frequency regulation must begin responding within 20 seconds of receiving the AGC signal, reach the committed output level within 10 minutes, and maintain it for at least 15 minutes. However, in practice, AGC deployment remains limited: many plants have AGC functionality built into their Distributed Control Systems (DCS) but are not yet connected to the NSMO.

For other AS categories: Fast-start reserves are typically provided by gas turbines or diesel generators, which must be capable of reaching rated output within 25 minutes and sustaining it for 8 hours. Must-run reserves are mainly provided by coal- or oil-fired units operating at technical minimum load, ready to ramp up within 1 hour when needed. Voltage regulation services are supplied by generators with MVAr control capability as per dispatch instructions. Black start capability is handled by selected large hydropower plants with the ability to self-start and energize portions of the grid following a blackout.

The specific participation rate for each type of AS remains limited. It is understood that most EVN-owned power plants and several large independent power producers (IPPs) have signed contracts to provide one or more AS to EVN. Participation from renewable energy sources is still very limited: wind and solar farms have not yet contributed meaningfully to frequency or voltage support, primarily due to the absence of incentive mechanisms and existing technical constraints (see Challenges section below).

Since 2024, Vietnam has undergone a significant institutional reform in power system operations. The National Load Dispatch Center was separated from EVN and restructured as the National Power System and Market Operator (NSMO)— a fully state-owned but legally and functionally independent company. This separation was intended to enhance transparency and neutrality in power system dispatch and market operations, especially given that EVN is also the dominant generation asset owner. NSMO is responsible for operating the national transmission grid, preparing AS procurement plans, and running day-to-day electricity market operations. Meanwhile, the EAV, under the Ministry of Industry and Trade (MOIT), serves as the national regulatory agency. EAV is tasked with issuing technical and market regulations, supervising implementation, and approving key aspects of AS management—including service volumes and pricing. In summary, NSMO acts as the system operator and AS procurer in the electricity market, while EAV functions as the regulatory body ensuring that AS are deployed in compliance with national rules and that stakeholder interests are balanced.

Currently, according to regulations on the operation of the transmission power system in Vietnam, frequency control is a process in the power system aimed at maintaining stable system operation. It includes primary frequency control, secondary frequency control, and tertiary frequency control, defined as follows:

- Primary frequency control is the immediate frequency regulation process in the power system, automatically performed by numerous generating units equipped with governor systems.
- Secondary frequency control is the subsequent control process following primary frequency control, carried out through the AGC system to restore frequency within the permissible long-term operating range.
- Tertiary frequency control is the next stage of frequency regulation following secondary frequency control, implemented through dispatch commands to stabilize system frequency according to current regulations while ensuring the economic distribution of generation output among power plants.

The nominal frequency of Vietnam's national power system is 50 Hz. Under normal operating conditions, frequency is permitted to fluctuate within a range of ± 0.2 Hz from the nominal frequency. In contingency operations, the frequency range extends from 49.5 to 51 Hz for single disturbances and from 47.5 to 52 Hz for multiple contingencies, severe incidents, or emergency situations.

In Vietnam, primary frequency control is mandatory for all generating units participating in the national power system. In actual grid operation, NSMO evaluates system security based on the principles of ensuring primary frequency reserves to prevent load shedding in the event of the largest generating unit failure and secondary frequency reserves to restore frequency to the allowable range.

The evaluation of the system security is measured by two standards which calculates the frequency reserve requirements:

1. Standard 1: Calculation of primary and secondary frequency reserves based on the Procedure for Defining and Operating Ancillary Services, excluding the impact of renewable energy fluctuations.
2. Standard 2: Calculation of frequency reserves considering the impact of renewable energy output reductions.

For example, frequency reserve requirements for July 2023, under both peak and off-peak conditions, showed that primary frequency reserves remained between 150 MW and 175 MW across both standards for the same renewable energy output levels. However, secondary frequency reserve calculations differed significantly:

- Under Standard 1, the secondary reserve was fixed at 700 MW.
- Under Standard 2, it ranged from 750 MW to 1700 MW.

This discrepancy arises because Standard 1 does not account for renewable energy variations, using a traditional calculation approach. In contrast, Standard 2 considers the fluctuating nature of renewable energy sources, which are highly dependent on weather conditions, leading to variable and unstable generation output.

Since October 2018, the AGC application for secondary frequency control has been successfully tested and officially deployed by A0, the National Load Dispatch Center. Currently, approximately 120 conventional power plants (accounting for about 75%) have successfully connected to the AGC system, enabling remote active power control of generating units and ensuring readiness for secondary frequency regulation. From a technical perspective, the AGC system is capable of performing secondary frequency regulation with diverse power sources. However, in actual operation, A0 dispatchers primarily use a limited number of large multi-purpose hydroelectric plants for frequency regulation in local control mode (without AGC connection at A0) to minimize system operating costs and due to incomplete SCADA communication reliability from power plants.

Another limitation in secondary frequency control in Vietnam is that power reserves are currently expressed as a single quantity rather than being divided into upward and downward reserves.

Separating these into distinct categories would enhance system safety and stability. For instance, on holidays, the demand for downward secondary frequency reserves is greater than upward reserves due to reduced load demand and high renewable energy generation.

Furthermore, Vietnam has not yet established an AS market. The NSMO assigns certain hydroelectric plants to participate in frequency regulation. However, selecting lower-cost hydro plants may not always be optimal, as it may require activating more expensive power sources for energy supply while low-cost sources are allocated for frequency regulation.

Given the goal of achieving carbon neutrality by 2050, which includes expanding renewable energy sources and phasing out coal-fired power by the 2040s, Vietnam must accelerate the development of an AS market. This process should incorporate lessons from advanced power markets while adapting to Vietnam's unique operational conditions.

Therefore, in the context of Vietnam's electricity market gradually evolving and modernizing, a deeper investigation into the design and operation of secondary frequency control is necessary. This report aims to assess the current situation, identify design and operational limitations, benchmark with advanced global models, and propose a suitable co-optimization model of energy and frequency reserves tailored to the technical characteristics and development roadmap of Vietnam's electricity market during its energy transition phase.

Technical and Market Challenges in Deploying New Ancillary Services in Vietnam

Vietnam is rapidly transitioning to a power system with a high share of renewable energy, leading to growing demand for new forms of flexible system support such as Fast Frequency Response (FFR) and virtual inertia. However, the deployment of these services faces several challenges:

System inertia decline and growing FFR need: The increasing installed capacity of solar and wind power (accounting for approximately 27% of total capacity by the end of 2023) has led to a reduction in system inertia in Vietnam, particularly during midday hours and periods of high wind generation. Renewable energy sources using inverters do not contribute rotational inertia as synchronous generators do. Monitoring data from NSMO during the 2021 Lunar New Year week showed a sharp decline in system inertia at midday when solar output peaked, resulting in greater frequency fluctuations and a heightened risk of triggering under-frequency load shedding (UFLS).

When large generation losses occur, the faster rate of frequency decline under low-inertia conditions may cause frequency to reach the emergency thresholds of 49 Hz or 51 Hz before primary frequency control can respond. To address this issue, FFR is considered essential, as it can inject power almost instantaneously (within ~1 second) to stabilize frequency before primary control becomes effective. The current challenge is that Vietnam lacks both technical standards and market mechanisms for FFR.

In reality, most wind and solar power plants in Vietnam are not equipped with FFR or virtual inertia functionality, and therefore do not contribute to frequency regulation during major disturbances. Implementing these features would require inverter upgrades and additional investment costs, yet no incentive or penalty mechanisms currently exist to compel renewable project developers to comply. This creates a significant market barrier: renewable energy sources have little motivation to participate in AS because they receive no compensation for providing FFR or virtual inertia.

Primary and secondary frequency control services: From a technical standpoint, maintaining sufficient primary FRR is a significant challenge, especially as many renewable energy sources do not contribute rotational inertia. Vietnam's power system has had to increase its available primary frequency reserves to compensate for this loss of inertia. Studies by NSMO indicate that lower system inertia can be tolerated if the volume of primary frequency reserves is increased proportionally. However, maintaining higher reserves often requires conventional generators to operate at no-load or part-load levels, which results in increased fuel consumption and operational costs. For secondary frequency control (AGC), the primary challenge lies in the control and communication infrastructure. To enable broad AGC deployment, all power plants larger than 30 MW must have stable SCADA/Energy Management System (EMS) connections, high-resolution signal exchange, and precise unit control capabilities. In practice, some generating units still respond slowly or inaccurately to AGC commands due to limitations in legacy control systems, making it difficult to maintain frequency at the desired setpoint. Additionally, the market mechanism for secondary frequency regulation in Vietnam remains underdeveloped. Improving this mechanism is essential to encourage broader participation in secondary frequency regulation—including from flexible resources such as battery energy storage systems (BESS).

Integration of Renewable Energy into Ancillary Services: renewable energy sources in Vietnam rarely participate in the provision of AS such as frequency or voltage regulation, primarily due to technological limitations and the absence of regulatory requirements. Older-generation wind turbines typically operate in "maximum power output" mode without maintaining upward reserve capacity, making it difficult for them to provide upward frequency response. Some turbines are technically capable of downward regulation (i.e., reducing output when frequency is high), but Vietnam does not yet mandate this functionality.

Solar photovoltaic (PV) is even less capable of frequency regulation due to its dependence on solar irradiance. For solar plants to provide frequency support, they would need to operate below their available power output to maintain headroom for regulation, which reduces energy yield unless financially compensated.

On the voltage control side, the capability of renewable energy sources to provide local voltage support—via synchronous condensers or inverter-based reactive power control—is also underutilized. Many renewable energy plants are grid-connected through step-up transformers and static compensation devices that could contribute to voltage stability, but there are currently no mandatory requirements or incentive mechanisms for this.

The core market challenge is the lack of integration of AS obligations into power purchase agreements (PPAs) or operating licenses for renewable plants. Without such provisions—along with adequate compensation – renewable energy developers have no motivation to participate in AS. If this gap persists, the responsibility for maintaining system stability will increasingly fall on conventional generators, which are being forced to operate more flexibly and at higher cost as the share of renewables grows.

In summary, Vietnam faces the urgent task of upgrading its existing AS and introducing new ones to accommodate a power system with high shares of renewable energy. Key challenges include the absence of mandatory technical standards for FFR and virtual inertia, limited control infrastructure for large-scale AGC deployment, and a lack of market mechanisms to mobilize participation from emerging resources such as renewables, battery energy storage systems, and responsive loads. Addressing these issues will require comprehensive legal and regulatory reforms (including updates to technical circulars and electricity market rules), investment in advanced control technologies, and lessons learned from international best practices in AS market design.

With this paper's main focus on secondary reserves, Table 2 summarizes and compares the Nordic and Vietnamese approaches to secondary reserves.

Table 2: Secondary reserves Vietnam vs. aFRR Nordic (Denmark)

	Nordic (Denmark)	Vietnam
Balancing philosophy	Pro-active Forecasts inform scheduling of mFRR, and remaining imbalances are handled by faster products, primarily (measured on the used energy) aFRR.	Realtime balancing The AGC system continuously calculates setpoints for power plants in secondary frequency control. Calculations are based on deviations from the nominal system frequency.
Product name	aFRR	Secondary reserve

Characteristics	aFRR activates automatically after 30 seconds Full Activation Time: 5 min.	Start within 20 seconds of AGC signal Achieve full activation within 10 minutes Sustain for at least 15 minutes
Capacity procurement	Total Nordic System: 325 MW up-regulation 375 MW down-regulation (values continuously assessed)	716 MW in both directions
Energy activation	PICASSO (Common European Energy Activation Market)	No energy activation market for ancillary services (AS) Activated by AGC signal
Market mechanism & payment	Highly market-based. Denmark participates in the integrated European/Nordic AS market. Services such as FCR, aFRR, and mFRR are procured via regular auctions (daily/hourly). Prices are determined by the market. Denmark purchases AS through both national and regional platforms to ensure transparency and competition.	No competitive market for AS. AS are procured through contracts between NSMO/EVN and generators. Prices are regulated by the government using a cost-based methodology. Payments include fixed capacity payments and variable energy-based payments (e.g., for reserve capacity or upward dispatch).
Supply sources & participation	Diverse and flexible supply. AS in Denmark are provided by thermal plants, wind power, hydropower (via Nordic interconnection), energy storage systems, and industrial demand. With ~50% of electricity from wind, Denmark uses technologies enabling wind turbines to provide ancillary	Mainly conventional generators owned by EVN or large IPPs. All generating units over 30 MW are required to provide primary frequency response. Many hydro and thermal units also participate in secondary frequency control (AGC). Renewable energy sources

	services. Strong grid interconnections with Norway, Sweden, and Germany enable Denmark to "import reserves".	rarely participate in AS (e.g., do not provide frequency regulation).

Co-optimisation vs. Sequential Market

Having outlined the differences in characteristics, use and procurement of ancillary services (AS) in both the Nordic and Vietnamese power systems, this section examines theoretical foundations of reserve procurement methods relevant to the Vietnamese context. Specifically, the analysis focuses on two procurement options:

1. **Sequential market-based procurement**, similar to the existing Nordic approach, where reserve procurement predominantly, but not exclusively, precedes the day-ahead (DA) market.
2. **Co-optimised procurement**, where reserve procurement is directly integrated into the DA market optimisation.

The two procurement options are visualized in Figure 3.

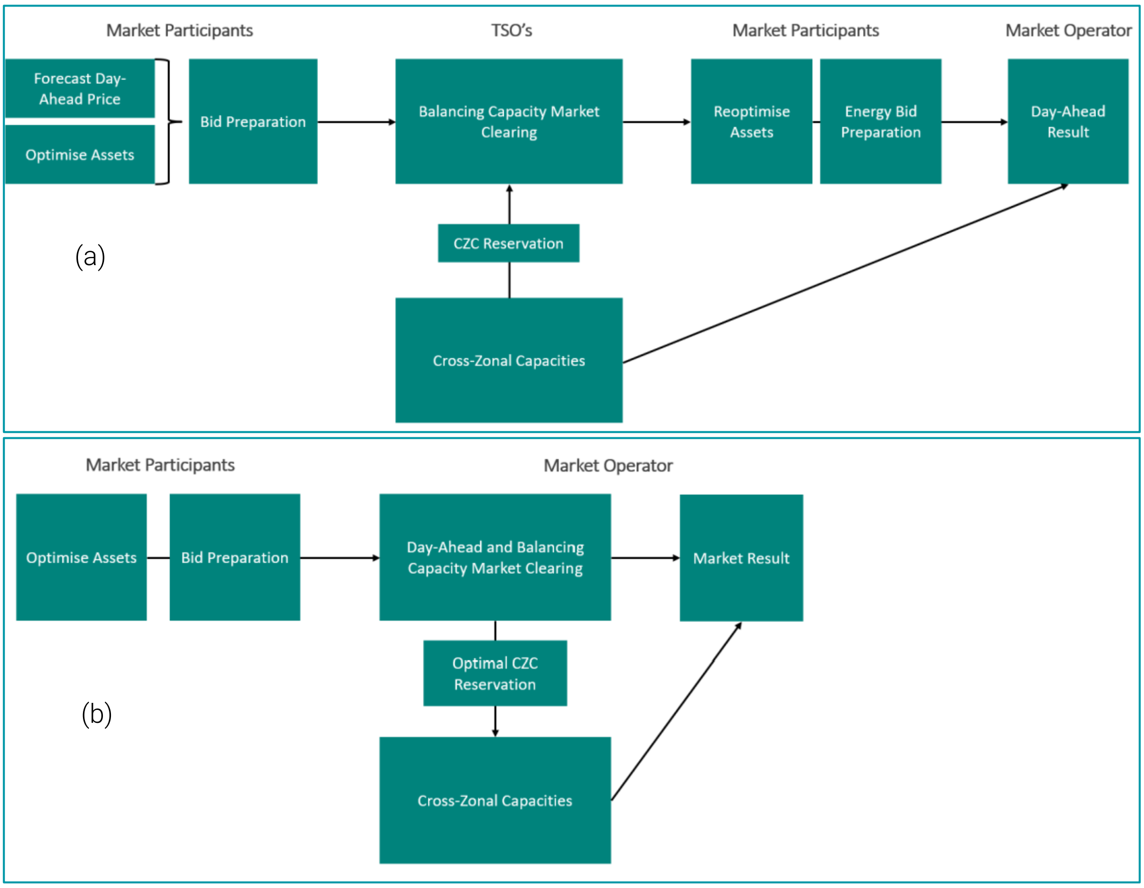


Figure 3: Sequential market-based process (a) and Co-optimised process (b) as considered in a European context[6]

[6] Figure is adaption of original kindly made available by Gerard Doorman, professor emeritus at the Department of Electrical Energy at the Norwegian University of Science and Technology

Co-optimisation, in the context of balancing capacity, refers to the simultaneous optimisation of wholesale electricity markets (day-ahead market) and reserve allocation. Specifically, in joint clearing of the day-ahead energy market and balancing capacity market across bidding zones, co-optimisation efficiently allocates cross-zonal capacity (CZC) between energy dispatch and secondary reserve procurement while respecting physical grid constraints. This implicit efficient allocation of CZC can be a great benefit as it allows for a direct economic trade-off between energy and reserve requirements, which becomes even more crucial with higher volatility due to intermittent renewable energy.

A primary advantage of co-optimisation is its ability to minimize total system costs by jointly considering energy and reserve requirements, in contrast to sequential or separate optimisation approaches.

In sequential clearing of electricity markets, where energy and reserves are optimized separately, it becomes necessary to accurately forecast CZC for reserves. This is because the CZC allocation for reserves occurs within the clearing of the balancing capacity market, i.e. before the DA energy market is cleared.

Table 3 summarizes and compares the different aspects of sequential optimization and co-optimization.

Table 3: Comparison of different aspects of sequential vs. co-optimization

Aspect	Sequential optimisation	Co-optimisation
Definition	Separate optimization of energy and reserve capacity	Joint optimization of energy and reserve capacity
Process	Energy market and reserves are cleared separately and in sequence. Nordic aFRR capacity market (CM) is cleared in the morning D-1.	Energy and reserve capacity allocation are calculated simultaneously

Flexibility	Low flexibility; reserves are fixed before DA market and commitment is firm	High flexibility; reserves are adjusted based on energy dispatch
Efficiency	Potential inefficiencies due to separate optimizations	Higher efficiency by minimizing total costs
Cost implications	Theoretically higher costs due to potential misallocation of CZC	Lower costs through optimal capacity allocation. Critical, that assets are able to accurately reflect their costs in their bids, otherwise welfare gains compared to sequential setup will erode.
Example usage	Nordic aFRR and mFRR CM	United States (US) market designs where energy and reserves are co-optimised. Though the US design, for other reasons, is not comparable to the version under R&D in Europe.

Discussion

The joint report by NSMO and Energinet evaluates two ancillary service (AS) market designs: sequential and co-optimized. Drawing on Energinet's experience in Denmark, the analysis highlights each market's strengths and challenges in terms of efficiency, reliability, transparency, complexity, and implementation.

Operational Efficiency

In a sequential market, the AS are procured separately from the energy market, typically following a step-by-step sequence. While this structure simplifies the procurement process and clearly distinguishes between market stages, it often results in suboptimal resource allocation. Specifically, resources might not be utilized in the most economically efficient manner due to the lack of integrated consideration of energy and reserves, potentially increasing overall system costs. An accurate cross-zonal capacity (CZC) forecast ensures that sufficient capacity is available for reserve activation without compromising cross-zonal energy flows. If the forecast is inaccurate, it may either result in the underutilization of available transmission capacity or the inability to activate reserves when needed, thereby impacting grid stability and increasing system operating costs. On the other hand, reservations that are too large and underutilized naturally take away capacity from the wholesale power market thereby hurting efficiency. Therefore, reliable CZC forecasting is essential to the efficiency of sequential market designs. This highlights a major strength of the co-optimised approach, i.e. that CZC are allocated to energy and balancing capacity, not based on forecasts of the values, but based on co-optimisation. By doing so, co-optimisation ensures the optimal allocation of resources across both services, significantly enhancing operational efficiency. However, this approach introduces increased complexity in market operations, requiring sophisticated computational infrastructure and advanced optimisation algorithms to realize these benefits.

Market Transparency and Complexity

The sequential clearing approach typically benefits from high transparency, as each step in the market-clearing process is distinct, clearly documented, and easy for market participants to understand. This straightforward methodology allows participants to make informed decisions and reduces potential confusion or market entry barriers. Additionally, due to its simplicity, the sequential approach facilitates easier communication and demonstration of potential profits to generation units. Consequently, market operators can more effectively attract new participants, broadening market participation. This increased participation fosters competitive dynamics, enabling the market to self-regulate more efficiently and thus reducing the risks associated with market manipulation. On the other hand, co-optimization integrates energy and AS procurement into a single process, theoretically enhancing economic efficiency but at the same time at risk of considerably increasing the complexity of the market structure. While this sophisticated method accurately reflects the true costs and constraints associated with resources, it may challenge transparency in the price formation. Stakeholders, especially new entrants, may find the integrated optimization procedure complex. Especially so, if bidding formats to a large degree necessitate bid linking to reflect the underlying costs of the assets, this could potentially hinder market participation or lead to reduced market confidence if not effectively communicated.

Implementation Requirements

Implementing a sequential clearing mechanism typically requires relatively simpler digital infrastructure and operational procedures compared to co-optimized setups, making it attractive for markets at earlier stages of development. However, "simpler" does not imply uncomplicated—sequential clearing still involves substantial technical, regulatory, and operational preparations. If market participants lack prior experience with reserve markets, significant efforts in capacity-building, regulatory design, and operational readiness will be necessary, regardless of the chosen procurement approach.

Nonetheless, sequential clearing generally demands fewer initial investments in advanced computational technologies and optimization software, enabling easier deployment with existing technical and human resources. On the other hand, co-optimization demands substantial upfront investments in sophisticated computational infrastructure, specialized software, and highly skilled personnel to manage complex algorithms and data processes, though differences in costs between co-optimised and sequential markets are not easily assessed up-front. While these initial challenges are substantial, co-optimization offers notable long-term advantages, including improved economic efficiency and optimal resource utilization. As energy systems evolve to incorporate more variable renewable energy sources, reserve markets may critically enhance the ability of system operators to ensure efficient resource allocation.

Table 4 summarizes the pros and cons of the two approaches.

Table 4: Pros and cons of the two approaches

Criteria	Sequential market setup	Co-optimization market setup
Operational efficiency	Lower – Separate procurement leads to inefficient resource allocation.	Higher – Simultaneous clearing optimizes total system costs.
Market transparency and complexity	High transparency, simpler, encourages broader participation.	Lower transparency, complex market results, potential barriers to entry.
Implementation requirements	Simpler – Lower infrastructure and computational demands; easier to implement initially.	More complex – Requires advanced infrastructure and clear regulations to ensure participants understand the system.

Co-optimization therefore emerges as the more forward-looking and robust foundation for Vietnam's long-term market development. While sequential clearing offers clarity and simpler initial implementation, its dependence on accurate CZC forecasts and its inherent separation of energy and reserve procurement limit long-term efficiency. Co-optimisation, despite higher initial complexity and infrastructure requirements (assumed, but the actual difference would have to be assessed), directly integrates resource allocation across services, ensuring economically efficient outcomes and more efficiently supporting a future power system with growing shares of variable renewables. Given Vietnam's evolving system needs and the ambition to strengthen both efficiency and reliability, co-optimisation should be treated as the working assumption for future AS market design for secondary reserve procurement.

Concluding Remarks

This report has examined the theoretical foundations and practical implications of two distinct methods for secondary reserve procurement: the sequential market-based approach currently applied in the Nordic system and a co-optimised approach integrating reserve procurement with the day-ahead (DA) energy market.

Drawing on theoretical understanding and comparative experience, it is clear that a co-optimised procurement setup stands out as a prominent and relevant solution for Vietnam. This model offers the advantage of minimizing total system costs by simultaneously addressing both energy and reserve requirements, while also efficiently managing cross-zonal transmission constraints. Such features are particularly crucial as Vietnam pursues ambitious renewable energy targets and faces increasing grid congestion. Furthermore, since the ancillary service (AS) market is not yet established, it can be easier for market participants to adapt to the co-optimised setup, since they do not have prior experience with a sequential setup, which works differently.

Vietnam presents a unique context as a relatively isolated power system with limited interconnections to neighbouring countries. This independence simplifies some aspects of co-optimisation, as interconnector constraints are less of a concern, though the potential use of zones within Vietnam should be considered. Key advantages of adopting a co-optimised approach include:

- Efficient joint allocation of energy and reserve capacity.
- Reduced total reserve procurement, enhancing economic efficiency.
- Increased system flexibility to accommodate variable renewable energy.

However, these benefits come with trade-offs:

- Increased market complexity compared to the sequential model.
- Higher computational and IT infrastructure demands.
- Greater burden on regulatory oversight and market transparency.

Importantly, while a co-optimised approach appears promising, it is not without risks. Future research and implementation efforts in Vietnam must address key challenges such as:

- Algorithmic tractability and fallback mechanisms.
- Market participant adaptability and preparedness.

- Selection of appropriate bidding formats.
- Implementation timelines and cost.

Given these considerations, the co-optimised market design emerges as a strong candidate for Vietnam's future secondary reserve procurement framework. Still, any transition should be approached cautiously and with thorough evaluation to ensure long-term success in both economic and operational terms.

Vietnam and Denmark exhibit clear differences in the development of AS. Vietnam is still in the early stages of building its AS market, relying heavily on cost-based regulation and conventional generation sources, while also facing mounting challenges due to the rapid increase in renewable energy penetration. In contrast, Denmark—thanks to early market reforms and advanced technology adoption—has established a highly flexible and market-oriented AS ecosystem that mobilizes a wide range of resources, including generation, storage, and demand response, to support system balancing.

Denmark's experience underscores the importance of a competitive AS market, which helps optimize system costs and incentivize technological innovation. It also highlights the need to introduce mandatory technical standards for renewable energy sources, such as frequency support capabilities. These lessons are highly valuable for Vietnam as it works to modernize its power and AS market, with the aim of operating a stable and efficient power system under high renewable energy conditions in the near future.

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Appendix

Primary Reserves in the Nordic Synchronous Area

In the Nordic region there are three types of ancillary services that can be described as primary reserve. These are:

- Fast Frequency Reserve (FFR) - FFR is a very fast responding reserve with a response time of 0.7-1.3 seconds, which is used to ensure the dynamic frequency stability in scenarios with low inertia in the Nordic power system. The need for FFR is reciprocal to the inertia in the system, which means that the need is primarily during the summer. FFR is procured dynamically each hour through a daily auction, whenever there is a need.

- Frequency Containment Reserve Disturbance (FCR-D) - In the event of major operational disruptions, FCR-D is a fast reserve that helps regulate the frequency during significant drops caused by outages of large production units or power lines. FCR-D is an automatic upregulation or downregulation reserve provided by production or consumption units that responds directly to the system frequency by monitoring the frequency. It is automatically activated at frequency dips below 49.9 Hz or overfrequency above 50.1 Hz and remains active until balance is restored or until FCR-N or manual reserves take over. FCR-D requires 86% of the power to be delivered within 7.5 seconds. The total amount of FCR-D needed in the Nordic system is equal to the largest possible fault in the synchronous area (N-1). Each country's share is calculated based on the sum of its own production and consumption divided by the total production and consumption of the synchronous area over one year. The share is updated weekly based on information about planned in-/outages of relevant units in the network. This reserve is procured in a joint Swedish-Danish market in collaboration with Svenska Kraftnät. The total need in Sweden and DK2 is procured through daily auctions.

- Frequency Containment Reserve Normal (FCR-N) - FCR-N ensures that the balance between production and consumption is continuously maintained. FCR-N fine-tunes the frequency in DK2 through automatic activation due to frequency deviations within the normal operating range of 49.9-50.1 Hz. FCR-N power output must be maintained continuously throughout the agreement period as it is used to stabilize the frequency close to 50 Hz over longer periods. FCR-N must deliver approximately 60% of the sold capacity within 60 seconds and the remaining amount within 180 seconds. Additionally, FCR-N must be capable of symmetric operation, meaning both upregulation and downregulation. The Nordic system operating guidelines has set the need for FCR-N in the entire Nordic synchronous area to 600 MW. The allocation of FCR-N procurement among the Nordic countries is based on annual consumption and production from the previous year and is updated annually in March. In DK2, Energinet must secure about 18 MW (2025). Energinet procures this amount in a joint Swedish-Danish market through daily auctions, with part of the need being procured early on the day before the operational day (D-1 early) and the remaining part later on the day before the operational day (D-1 late).