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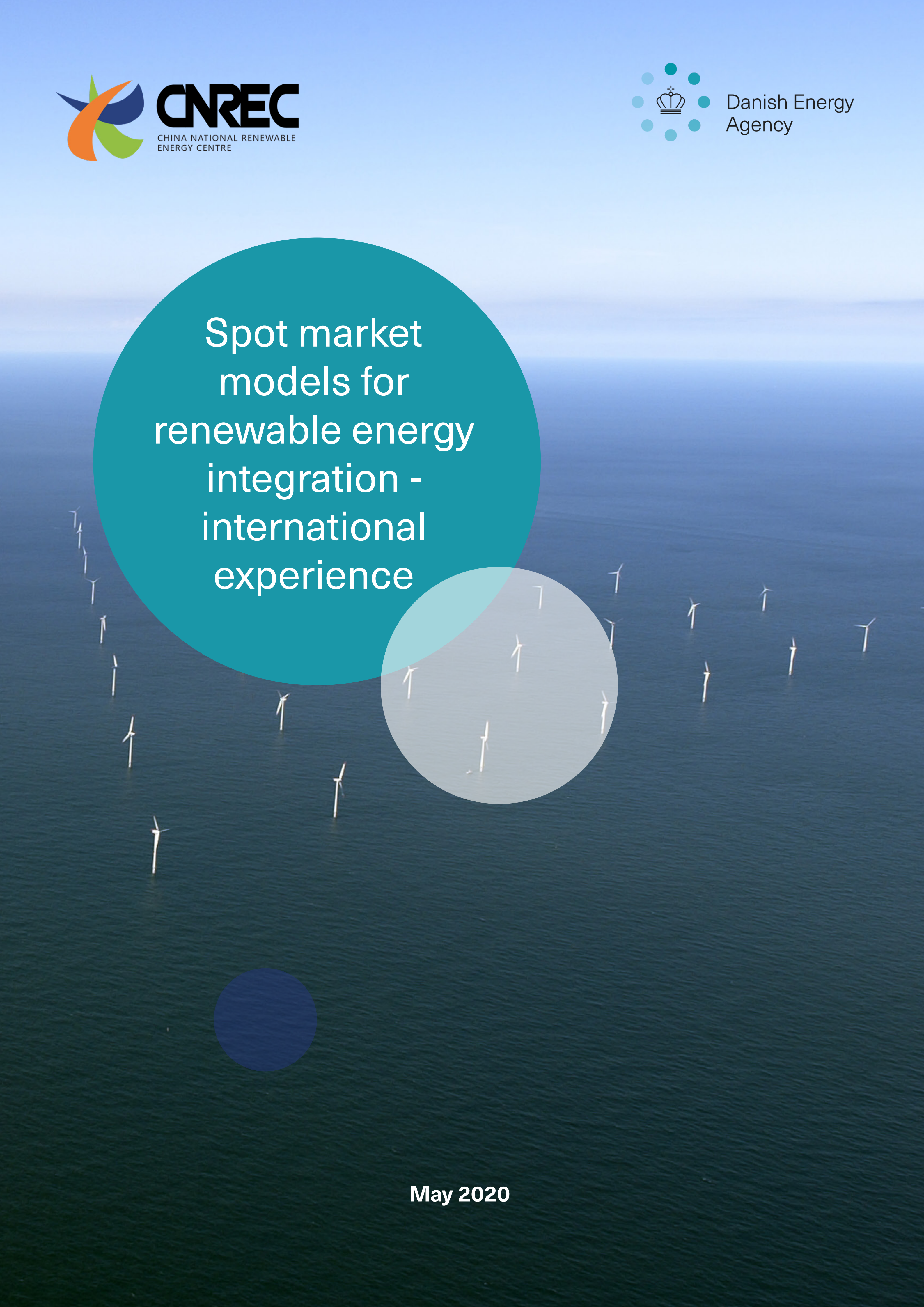

Spot market models for renewable energy integration - international experience

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CONTENTS

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1 Introduction

Nowadays, power systems are experiencing significant changes in design and operation. The introduction of variable renewable energy (VRE) sources is driving power systems toward a decentralised structure. The share of VRE varies substantially from country to country, as shown in Figure 1-1. In order to integrate VRE in a flexible and cost-effective manner, it is important to thoroughly analyse and choose between different market mechanisms and subsidy schemes. By defining incentives of VRE operators, market mechanisms and subsidy schemes determine how VRE sources interact with the overall energy system.

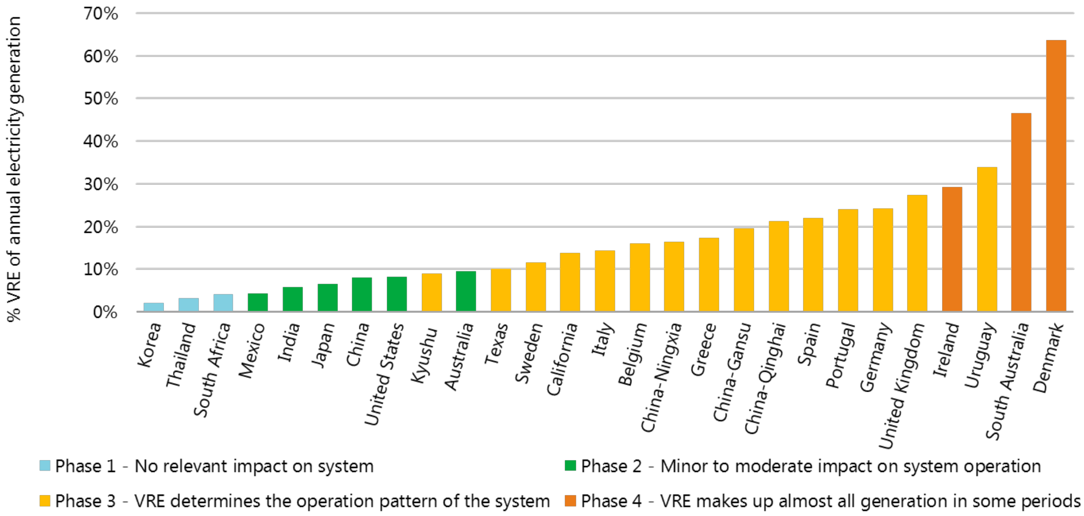

Figure 1-1 | VRE generation share for different countries (Source: https://www.iea.org/publications/reports/StatusofPowerSystemTransformation2019/).

2 Overview of the main features of spot market models implemented in Europe and USA

The adoption of electricity spot markets can facilitate cost-effective dispatch of VRE-based production. Depending on the country in exam, electricity spot markets may be developed differently. The main features in spot market design comprise level of market centralization, pricing, bidding structure, balancing mechanisms and imbalance settlement. Table 2-1 introduces such features for the European and USA spot markets (i.e., Texas and California), in relation to the VRE integration.

Market	Market type	Pricing	Bidding structure	Main energy sources
Single Day-Ahead Market Coupling (EU)	Decentralized	Zonal	Two-sided	Hydro, wind, nuclear, thermal (gas, coal)
ERCOT (USA, Texas)	Centralized	Nodal (zonal until 2010)	Two-sided	Natural gas, wind, coal
CAISO (USA, California)	Centralized	Nodal	Two-sided	Natural gas, wind, solar, hydro

Table 2-1 | Overview of main market features in the EU and USA, in ERCOT/CAISO.

The table shows that Europe approaches a decentralized power market with zonal pricing, whereas the US markets generally consist of centralized markets characterized by nodal pricing.

The following section clarifies strengths and weaknesses of the main market features.

2.1 Centralized and decentralized market

In real-time, electricity markets are coordinated by an operator. However, prior to the delivery time, central coordination can differ between markets. In a centralized market, the wholesale dispatcher determines the least-cost schedule and dispatch, whereas, in a decentralized market, generators can determine their own schedules.

Table 2-2 summarizes features, strengths and weaknesses of centralized and decentralized power markets.

	Description	Strengths	Weaknesses
Centralized market	All generating resources submit bids to the wholesale dispatcher, who determines the least-cost feasible schedule and dispatch.	Better control of grid congestion and losses. Higher efficiency in congestion management.	Slow response to shocks occurring after the DA[1] market has closed. Although market participants need more access to grid information, it may be challenging to make such data available. Clearing results can be complicated to interpret in order to inform generator bidding strategies. Prices are subject to greater fluctuations due to lack of hedging possibilities.
Decentralized market	Generators determine their own schedules, optimizing between self-generating and purchasing in DA and intra-day markets to fulfil their contracts. The market coupling operator provides the result of flow optimization to the TSOs[2] who operate the system and are responsible for providing the cross-border flow.	Market rules are relatively simple. Participants have more decision-making power and better control over hedging unforeseen costs and price spikes.	High technical requirements on market participants. Lack of flexibility when grid is congested. Possible lack of incentives for generators to fully optimize production schedules.

Table 2-2 | Overview of centralized and decentralized power markets.

In the centralized market, clearing results are more complicated to explain, as they are the result of an optimization model which takes local grid congestions into account in an intransparent manner (as market participants do not have access to the intermediate model results). The resulting lack of transparency may therefore cause reduced trust in the results and a sense of perceived injustice.

[1] DA - Day Ahead Market (also referred to as spot market).

[2] TSO – Transmission System Operator.

In the decentralized market, the incentives for generators to adjust their production schedules depend on the available bids/offers on the intraday market and their expectations to the overall system imbalance. If the generator expects its own imbalance to have the opposite operational sign than the total system imbalance, he/she has no incentive to adjust his/her production schedule. If such expectation is correct, this approach reduces the total system imbalance. If this expectation is wrong, it worsens the imbalance.

2.2 Nodal and zonal pricing

Two pricing schemes are mainly approached in relation to electricity markets, i.e., nodal and zonal pricing. Nodal pricing entails local individual pricing for each node, where each node may contain one or more generators and/or consumers. Zonal pricing implies that prices are equalized over a certain zone containing several nodes. Typically, European countries have one or, in a few cases, more zones per country.

Table 2-3 provides a brief description of the nodal and zonal pricing schemes, highlighting strengths and weaknesses of each solution.

	Description	Strengths	Weaknesses
Nodal	Each node adopts a separately calculated electricity price (LMP[3]). The LMP reflects congestion and marginal losses in the price, approaching feasibility in the least-cost dispatch optimization.	Market reflects physical conditions. Combines market and system operation. Therefore, the security-constrained unit commitment is also the economic dispatch. Fully reflects the temporal and spatial value of electricity. Isolates price spikes to congested regions instead of driving up market-wide prices.	Highly reliant on the physical grid topology and requires full transparency for market participants. Calculation is more complicated and difficult to understand. Complexity increases computational time. Often requires complicated hedging contracts for congestion (FTRs[4]). Is exposed to market manipulation since large generators may potentially dominate the market in small nodal zones.
Zonal	All nodes in one zone adopt a uniform electricity price - usually the marginal cost of the overall zone.	Electricity delivered in one zone becomes a standard product that can be traded with other market participants in a secondary market, such as intra-day market.	If there is significant internal transmission congestion (due to ill-defined zones), the zonal system is less efficient. Zones can enable local protectionism, especially when boundaries are legal or historical –

[3] LMP – Locational Marginal Pricing.

[4] FTR – Financial Transmission Rights.

		Intra-day prices are frequently updated. This gives producers the right price signal when making corrections in the dispatch. Easier for market members to perceive pricing as fair, especially for those located in chronically congested regions. Helpful compromise for markets spanning jurisdictions, which may not agree to unified nodal pricing[5].	definitions of zones and how to change zones must be regulated. Regulation must ensure that suboptimal definitions of zones are avoided.

Table 2-3 | Overview of the nodal and zonal pricing schemes.

2.3 One-sided and two-sided bidding

Bids submission can be approached considering two possible set-ups, i.e.k, one-sided or two-sided bidding. Today, the majority of electricity markets adopts two-sided bidding.

Table 2-4 provides an overview of the two possible bidding schemes, listing strengths and weaknesses of each solution.

	Description	Strengths	Weaknesses
One-sided bidding	One-sided bidding implies that only generators can submit bids. Such bids are accepted at whatever price to the level needed to meet demand.	Easier in the initial stage of deregulation, it relies on current demand forecast and procurement methods. Reduces risk of immature DR[6] market not fully responding and creating a reliability risk.	Limits options for demand responsiveness. Requires complicated methods for market intermediaries or BRP[7]s/LSE[8]s to procure alternative generation. Requires DR to participate as generation resource.
Two-sided bidding	Generators and consumers can submit bids and offers in the market. The demand which can be	Fully enables DR options.	Depending on the DR setting, may require online real time meters approved for settling

[5] Approaching a pure nodal pricing, substantial price variations may occur from node to node. This situation can be smoothened by adopting averages of nodal prices in a unified nodal pricing mechanism.

[6] Demand Response.

[7] Balance Responsible Party.

[8] Load Serving Entity.

	fulfilled, based on offer prices, is cleared, while the demand which is not cleared will need to be reduced.	Supports easier 3rd party/power trader involvement. Allows differential bidding (although it is not required).	accounts and interaction between BRP and consumers. Expands system operator reliability considerations (contingencies of demand non-response).

Table 2-4 | Overview of one-sided and two-sided bidding.

By omitting two-sided bidding, demand curve becomes horizontal, increasing the risk of exceptionally high prices and no-equilibrium events (i.e., when demand exceeds maximum supply). With a well-functioning bidding structure, electricity demand can decrease in the event of exceptionally high prices.

2.4 Comparison of market designs

In principle, market design may combine the above features in several manners. Nevertheless, as it can be seen from the European and USA markets presented, two main versions are adopted:

- Decentralized market with zonal pricing and two-sided bidding;
- Centralized market with nodal pricing and two-sided bidding.

Although both systems have proved able to integrate VRE to some extends, Figure 1-1 shows that European countries have been integrating far more VRE than progressive USA states such as California and Texas. However, the power market structure may not be the only reason for this.

2.5 Balancing

In Europe, different TSOs follow various rules for balancing and settlement of imbalance costs. This chapter focuses on the Nordic setup, as it is relatively liberalized and decentralized.

The balancing responsibility imposes a risk on the BRP that will be transferred to the VRE operator. The risk emerges as the imbalance cost is unknown to all parties and may depend on other parties' imbalances and regulating bids. Therefore, if the balancing regime is imposed on the VRE generators, this increases the level of risk of the business case of the VRE investment. However, imposing balancing responsibility also provides an incentive to develop forecasting tools and consider scarcity of supply when dispatching the expected generation volumes. BRPs compete to offer VRE operators the lowest imbalance costs. By imposing the balancing regime on the VRE generators, the quality of forecasting is improved.

If a consumer, generator or a portfolio of such cannot comply with the scheduled volumes, it occurs an imbalance and the responsible faces balancing costs.

In the **decentralized market with zonal pricing**, BRPs can handle their imbalances by trading in the intraday market with other parties located in the same bidding zone (or from other bidding zones, if interconnection capacity is available). As an example, it is possible to consider a wind turbines portfolio that faces smaller generation than the amount scheduled the day before. To handle that, the wind turbines portfolio may purchase the generation from another portfolio (e.g., gas engines) to substitute the missing volumes and reach balance. Alternatively, the wind turbines portfolio might wait and let the TSO order regulating power. In this manner, the wind turbines portfolio will have to pay the balancing cost to the TSO (which corresponds to the price paid by the TSO for activating the regulating power[9]). The regulating power is ordered by the TSO and is provisioned through a centralized mechanism. However, the way BRPs interact with the balancing market/regulating power market is very decentralized, since BRPs can decide whether to neutralize expected imbalances themselves in the intraday market or let the TSO settle the actual imbalances using regulating power.

From a VRE producers perspective, it means that the VRE owner and the BRP should agree on a contract reflecting the preferred risk profile of the VRE owner to develop a balancing strategy accordingly. If the VRE owner is very risk adverse, the BRP should reduce almost all of the foreseen imbalances via the intraday market. If not, the intraday market should only be use for imbalance reduction, in case that VRE owner and BRP find the intraday prices attractive, compared to the expected balancing costs. In general, balancing is not a very high cost burden compared to the total revenues from electricity markets and subsidy schemes. However, it is highly relevant (especially for owners of large off shore wind turbine park) to develop a strategy to cope with expected imbalances. As an example, it can be mentioned that the event of a storm often means either production at 100% capacity or null (when the storm is strong enough to shut down the park). Since VRE owners do not know the outcome when dispatching, the imbalances can be substantial if they make the wrong bet. Therefore a strategy should be in place, in a way that operators and BRP staff have guidelines on how to deal with the situation.

It is important to note that it is not always possible to reduce imbalances on the intraday markets at attractive prices. For example, available connectivity to neighboring bidding zones has a huge influence on how many bids and offers are available on the intraday exchange. It is important to note that the trading occuring at the DA market has also an impact of the intraday market. In fact, if prices are very high in the intraday market, it is likely that many generators have sold their production at the DA spot market, limiting the flexibility traded in the intraday market.

Moreover, BRPs can also decide whether to make their flexibility available in the intraday market and/or as regulating power. Wind turbines typically offer down-regulation when the down-regulation price is below zero (i.e., wind turbines are paid to cut off their production). The price needs to be below zero in order to be attractive for the wind turbines to provide down-regulation, as their variable production cost is close to zero.

In a **centralized market with nodal pricing**, balancing is centrally controlled by the system operator. The system operator must first ensure that the DA schedule has sufficient resources available to balance in real-time; afterwards, it dispatches least-cost resources in real-time based on market bids to maintain reliability. The cost for reserving necessary balancing capacity in the DA market is reflected in the DA energy prices paid by each market participant. Real-time balancing are allocated

[9] In some countries outside the Nordic region, the BRPs not only pay the cost of activating regulating power but also a fee to provide them an incentive to handle imbalances in the intraday market.

to LSEs based on divergences from their DA schedules or their overall contribution to energy demand in that hour (depending on the service dispatched and which USA market they are in).[i]

In USA centralized markets, generation does not pay for imbalance costs and is responsible for penalties for diverging from dispatch signals outside of a certain range. For VRE owners, such penalty ranges are more lenient, allowing for both greater divergence from dispatch in real-time and updates to their schedules much closer to the closure of real-time markets. Demand pays for imbalance costs based on its divergence from their DA schedule. Therefore the increasing balancing cost due to higher VRE penetration is borne by all demand units (i.e., consumers) in the market, regardless of their exposure to VRE in their long-term contracts. However, such costs remain relatively small in most of the regions and have not been an issue to date.[10]

Theoretically, this cost-shifting should not be a problem in the long run, as: 1) market prices will increasingly reflect the lower value of energy during high penetration hours and increased value of dispatchable generation during VRE scarce hours, and 2) real-time and ancillary service market prices will increasingly rise to compensate dispatchable resources available to respond to imbalances. LSEs holding bilateral contracts with dispatchable resources should be shielded from high real-time price spikes, while LSEs holding bilateral contracts with VRE should supplement them with other bilateral contracts or risk to remain exposed to real-time balancing prices. One challenge the USA is facing is that many long-term PPAs signed before the VRE revolution do not have provisions to consider the increasingly volatile nature of wholesale power prices. This condition causes that some of the generation is more shielded or exposed to volatility, leading to some cost shifting due to VRE balancing. Debates over how to handle the effects of cost shifting under these existing bilateral contracts in market environments ranges from: a) no changes, since contracts are meant to hedge risks for both parties, and adjusting them would imply bailing them out at the expense of customers, b) allowing contracts to be resigned, since many were signed under some form of utility regulation, c) placing some balancing obligation onto VREs by having them manage dispatch divergences prior to real-time markets,[11] and d) redesigning electricity markets to better reflect the need for dispatchable generation on an energy market that is not designed for zero marginal cost energy.

In some regions, cross-regional voluntary balancing markets have been created to help LSEs manage balancing at least cost, inviting operators from neighboring markets (and non-market regions) to participate to find the cheapest resources that can balance the grid over a wider geographic region. This has significantly improved VRE integration and reduced the flexibility costs for integrating VRE for each region. Specifically, it allows any momentary imbalances to be absorbed by other regions, having a excess VRE in one region integrated in another. See CAISO's Western Energy Imbalance Market for more details.[ii]

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[10] Potential cost-shifting within centralized markets are also managed through RPS obligations evenly spreading this obligation across all actors, but in the USA usually only works within a single state since RPS's are state-set obligations.

[11] This is often considered alongside the creation of intraday markets (not a feature in most centralized markets) to allow for VRE to manage divergences further out (and at lower cost) than waiting until real-time.

3 European experience in mitigating risk related to spot market development

In order to understand risk factors that VRE producers are facing, it is important to recognise the investment and cash flow specifics of VRE projects, and the impact that market design can have on these specifics.

VRE producers are mainly characterized with high CAPEX- and low OPEX- dominated cost structure. Therefore, in order to accommodate important shares of VRE, focus should be on how to ensure market mechanisms that facilitate CAPEX recovery. Furthermore, an efficient allocation of risks, such as subsidy/pricing and grid connection risk, is critical to ensure that VRE investments become bankable.

The main political and regulatory risk factors faced by VRE investors and producers are illustrated in Figure 3-1.

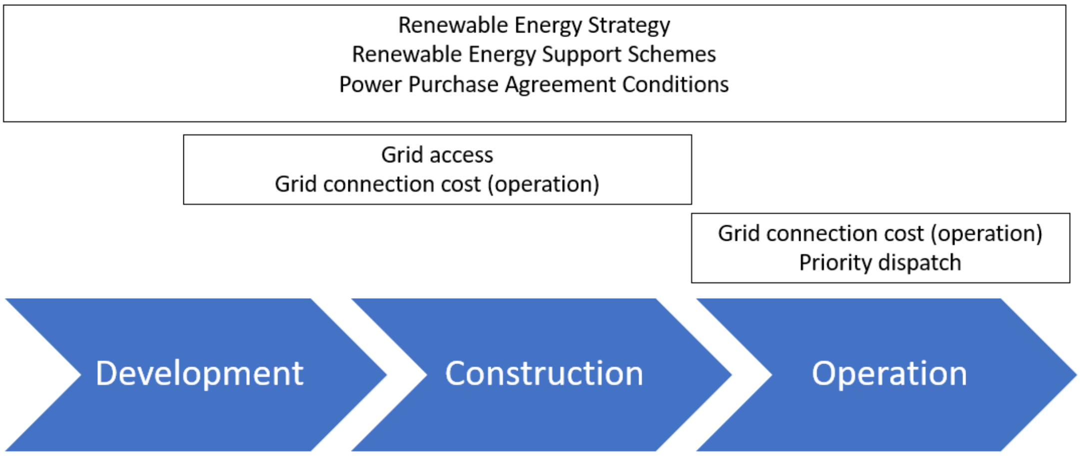

Figure 3-1 | Policy related risks for VRE investors during the project cycle (Source: COWI).

In this chapter, focus will be on policy, market (regulatory) and grid-related risks.

3.1 Policy design

VRE support schemes aim to increase VRE generation in order to mitigate climate change. However, when designing such schemes, it is important to acknowledge trade-offs between providing the right incentives and reducing the risks of VRE operators. During the policy design process, technologies matureness and competence building in industry should be taken into account.

The support schemes and regulation should, when possible, provide incentives to:

- Not generate electricity at negative prices;
- Develop efficient prognosis and control systems;

› Install VRE production where the need for power production is most urgent.

However, this should be achieved in a way that only limited risk is induced on the investors, as additional risk requires additional subsidies.

Depending on the subsidy scheme approached, policy risks that VRE producers may face include:

› Uncertain production due to wind potential uncertainties;

› Uncertain number of hours with negative prices and withdrawal of subsidy in these hours;

› Uncertain balancing costs (if subsidy schemes impose balancing costs on VRE operators);

› Uncertain market prices on power (if revenues in subsidy schemes are dependent on market prices).

3.1.1 Feed-In-tariffs

Feed-In-Tariffs (FIT) consist of a very simple subsidy scheme, in which VRE producers are payed a fixed price for the production. In this setting, the uncertain production volume is the only risk. The TSO dispatches the generation and encounters the imbalance costs and the possible generation cost in hours with negative prices.

In order to provide appropriate incentives to VRE producers, FIT can also include:

› Withdrawal of subsidy in hours with negative prices. In order not to impose eccessive risk on VRE producers, there may be a limit on the number of hours that the subsidy can be withdrawn.

› Obligations for VRE producers to dispatch the expected generation and carry the imbalance costs. Sometimes, a fixed part of the subsidy is aimed to cover the imbalance costs. However, as the imbalance costs are variable, and the subsidy is fixed, there is still an incentive to minimize imbalance costs.

The simple form of the FIT subsidy scheme does not require a spot market and therefore, FIT can be utilised in both liberalized and non-liberalized markets.

3.1.2 Contract for Differences

Contract for Differences (CfD) is another tool to provide VRE producers with a fixed price for their production. However, this model is more market-based compared to the FIT, as VRE producers dispatch the expected volume of production and receive the market price for this. Afterwards, the CfD contract is settled so that the total revenue from production equals a fixed amount per kWh. Usually, the uncertain balancing costs are imposed on the VRE producers. This condition increases the risk but also provides an incentive to develop reliable forecasting and control systems (or buy such a service from a sub-supplier). The CfD contract must be supplemented by an obligation to sell production with a price limitation of zero at the spot market exchange if production at negative prices should be avoided.

FIT and CfD schemes do not imply an incentive to place VRE production where electricity prices are high, since revenue is unaffected by market prices. High market prices are a symptom of low production capacity compared to demand and therefore, VRE production should be incentivized to locate in high bidding zone.

3.1.3 Feed-In-Premiums

Feed-In-Premiums (FIP) is paid 'on top' of the spot market price, and does not provide a fixed price per kWh. As such, VRE producers face market price risks (i.e., price fluctuations). However, the subsidy on top of the market price is fixed, reducing the risk. As FIP is paid independently on the market spot price, there is an incentive to produce electricity when the negative market value is less than the premium. Therefore, the FIP subsidy scheme must include a cancellation of the subsidy when prices are negative, which will give the generators an incentive to use a price limitation of zero at the spot market exchange.

3.1.4 Comparison of FIT, CfD and FIP

FIT, CfD and FIP are usually applied to a specific number of full load hours[12]. Beyond that, VRE producers can sell their production without subsidy on liberalized market conditions, if a market is established. This also means that, if VRE producers are starting out on a simple FIT for some years (e.g., 5 or 10), a liberalized market can be prepared in the meantime. When VRE producers are no longer dependent on FIT support, they can become part of the liberalized market. This approach has three main advantages:

- VRE producer's policy risks are reduced, due to the fixed price per kWh in the first years. In terms of NPV[13] of investment, the first years are most important.

- After quitting the support scheme, VRE producers can join the liberalized market and therefore improve volume, liquidity and competence building.

- When sufficient "out of support scheme[14] VRE producers" have entered the liberalized market, the market actors will have gained experience in managing VRE. Moreover, the market may be ready for moving support scheme to CfD and FIP in support of further VRE capacity expansion. The market can be considered ready when enough well-functioning and competing BRPs will offer their services to VRE operators.

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[12] "Full load hours" is a notion expressing the number of hours which multiplied with the installed capacity will give the production for one year.

[13] NPV – Net Present Value.

[14] I.e. they have reached the maximum number of full load hours with FIT.

3.1.5 Power Purchase Agreements

Power Purchase Agreements (PPAs) have become widespread due to the decreasing VRE prices and increased climate awareness and willingness to pay for VRE generation. After the adoption of support schemes has kick-started VRE capacity expansion, PPAs can be adopted to provide predictable revenue for new VRE plants for a certain period. PPAs consists of bilateral agreements between VRE owner/developer and a consumer. PPA can ensure the VRE developer a fixed price for electricity generation for a period. Moreover, consumers are ensured a fixed price for the the consumption which is covered by VRE production. PPAs can be an important tool to make VRE projects bankable. Consumers can claim that they are supporting the development of VRE projects, making it bankable.

In order for PPAs to drive a substantial expansion of VRE production, CAPEX and OPEX of such projects must be at competitive levels and/or consumers have to pay a premium for claiming PPAs use as part of their CSR strategy. As such, there are examples of new VRE capacity financed 100% from PPAs. Moreover, it is now possible for consumers to make PPA agreements with BRPs who offer to balance their consumption with different sources of VRE to mitigate the simultaneity issue.[15] Specifically, the "simultaneity issue" refers to the misfit between consumption profile of, e.g., a factory, and a single source of VRE, such as a wind park. However, by combining several VRE sources, it is possible to match the consumption profile.

3.1.6 Status in the use of support schemes

Nowadays, all the described incentive schemes are in use throughout Europe. FIT are approached to ignite the technological development of new types of VRE. Afterwards, there is movement towards FIT with balance responsibility, FIP and CfD, when the volume of VRE generation increases and the need for high quality forecasting merges. For some years, the need for subsidies decreased to, for example, offshore wind parks. Moreover, some tenders won by consortiums offering to establish wind parks without receiving any subsidy (the so-called zero bids).

The design of different markets is particularly relevant for VRE producers that rely on subsidy schemes linking to the market. By utilising FIT, FIP, CfD and/or PPAs, VRE generators can participate in the electricity market through their BRPs. That is the case for DA market, intraday market and balancing markets.

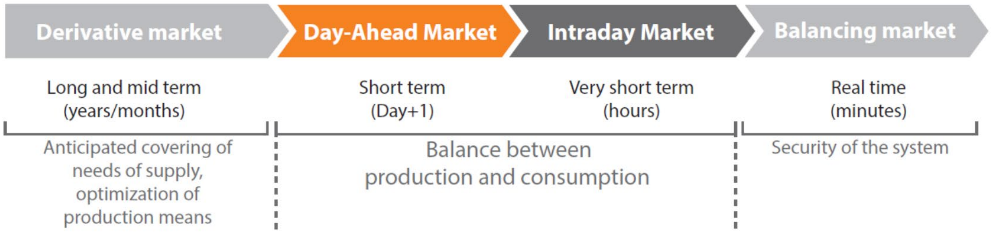

Figure 3-2 | Overview of market mechanisms and their respective roles (Source: EPEX SPOT).

[15] https://www.energidanmark.com/market-info/news/news/news-2019/09/energi-danmark-handles-the-balance-in-a-ground-breaking-ppa-agreement-between-chr-hansen-and-better-energy/.

Long-term financial markets are very important for VRE producers (whose cost mainly refers to the time of investment) to hedge long-term price risk and ensure sufficient revenues to cover their costs.

DA market assures that the power demanded is produced at the lowest possible cost with due consideration to the interconnector transmission capacities between bidding zones. Moreover, the result (i.e., volumes of MWh) of the DA market provides generation and consumption schedules. The prices are marginal, meaning that the same price is paid to all consumers and received by all generators. VRE are often characterized by low bidding prices; therefore, the market ensures that fossil fuel-based generation is activated only if more cost-effective solutions such as VRE cannot meet the demand.

After the closure of the DA market, which results in the scheduled production and consumption for each hour of the day before delivery, several markets allow adjusting the planned schedule and trade flexibility. The intraday market is particularly important for VRE producers, as they do not know their precise production more than a few hours in advance, and therefore need the possibility to trade and reduce their imbalance (i.e., difference between scheduled and actual production). The intraday market relies on bilateral trades that are matched and settled pay-as-bid.

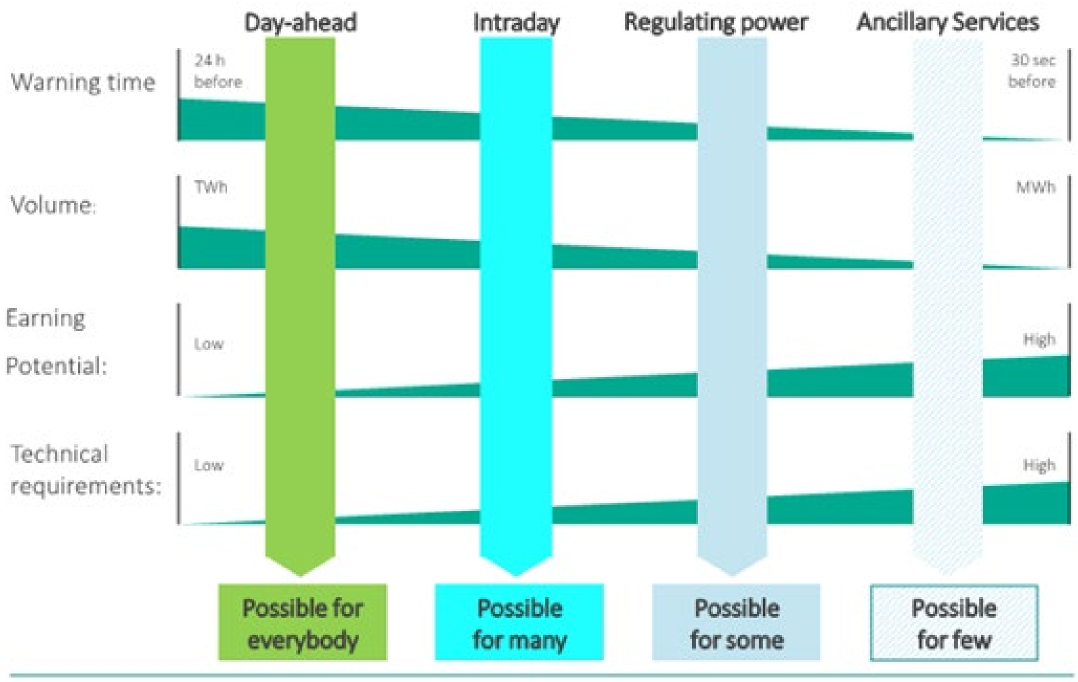

Figure 3-3 | Overview of market mechanisms (Source: Energinet, the Danish TSO).

In Figure 3-2, an overview of the different markets is provided, including DA, intraday, regulating and ancillary services markets. The figure shows that, the quicker market participants can react to price signals and activations, the more earning potential they have. Short-term flexibility is very expensive and should be limited by improved forecasting and intraday trading. In other words, for market participants, improving flexibility and ability to react quickly gives access to new and more rewarding flexibility markets. This stands not only for dispatchable generation but to some extent also for VRE producers.

Although wind turbines can participate in most of the markets, for the sometimes-rewarding regulating power market, wind turbines are only able to deliver down-regulation. Moreover, wind turbines do not participate in ancillary services markets and, to any substantial degree, solar power does not sell flexibility. Nevertheless, different markets serve VRE producers to reduce imbalances through trade.

3.1.7 Market transparency

Market transparency, meaning publicly available information of volumes and prices, is necessary to achieve fair competition, providing the same information to all market participants. Price information is important to support investment decisions for both VRE and other investments. If a bidding zone has high prices for a long period of time, it implies that generation capacity is scarce, and security of supply might be challenged. However, high prices and the available information also consist of an incentive to invest in generation capacity and transparency, increasing security of supply.

In Europe, once DA market is cleared, spot prices and volumes are known to all and published by the exchanges and TSOs. As an example, the ENTSO-E transparency platform collects and publishes data from most of Europe in compliance with the European transparency regulation. However, some information on specific bids is considered confidential and cannot be published, as competitors might take advantage of such information. For this reason, the volumes produced and consumed by each BRP generation/consumer portfolio the bids/offers of each BRP in the market are not public knowledge.

The intraday power exchanges publish volumes and hourly prices. Parties entering the deals are not revealed, as this might provide competitors with confidential information relevant for identifying competitors' bidding strategy.

TSOs receive bids on regulating power through BRPs. The list of bids is confidential, in order not to reveal information to competitors. If regulation is needed due to BRP imbalances, when TSOs activate regulating power, the volumes and prices are published within hours, where the regular balancing is settled with marginal pricing.

If imbalances are caused by TSOs (i.e., due to outage on interconnectors), TSOs can order the re-dispatch[16], which is settled with pay-as-bid. Redispatch volumes are published in a few hours. As publishing pay-as-bid prices would reveal individual bids, the Danish pay-as-bid prices are published as average of monthly prices with a 3 months gap, to limit their confidentiality while providing price signals to the market.

The Utility Regulator is an independent public body that controls the data transparency on power exchange and TSOs.

Europe has a high level of market transparency enforced through the European legislation and independent regulatory authorities. Transparency increases trust and reduces risks for market

[16] Nordpoolspot.com uses the term "Special Regulation".

participants. At the same time, transparency is linked to market surveillance and reduces the opportunity for market participants to engage in non-competitive behavior.

3.1.8 Risks and benefits of favorable VRE conditions

When considering support schemes to increase VRE generation, policy makers have to consider the expected rate of return of the investors as well as their perceived risks and the risk of the public body and taxpayers/consumers.

In Europe, several subsidy schemes are approached. Also, how such schemes approach curtailment, balancing responsibility and balancing costs can affect VRE producers in different manners.

In Denmark, household wind turbines are subsidized on a simple FIT without any risk of subsidy withdrawal in case of negative prices and without balancing costs. TSO carries the balancing costs and the production cost at negative spot prices. Such costs are then passed on to the consumers. However, more mature technologies, such as commercial onshore wind turbines production, carry the balancing costs and the risk of subsidy withdrawal. Alternatively, they are obliged to place price limitation bids at zero EUR/kWh.

Overall, if a technology is considered immature, investors should not have to face market and balancing risks on top of technological risks. However, when such technology matures, the subsidy schemes must be adjusted to become more market-based. At that stage, VRE operator needs to cooperate with BRPs.

There have been examples of fixed-per-kWh subsidies for balancing purposes which are not linked to the actual balancing costs. Because of the missing link to the actual balancing costs, VRE producers have an incentive to minimize the balancing cost. In Table 3-2, priority dispatch and balancing responsibility are analysed, including main strengths and weaknesses.

	Strengths	Weaknesses	Notes
Priority dispatch	Reduced risk of VRE investment, as offtake is guaranteed. In the short-term, it reduces overall CO_2 emissions.	Against free market competition. No competencies developed in flexible operation of VRE. Limits the amount of VRE that can be integrated.	If it is possible to leverage VRE for down-regulation, VRE volumes that exceed minimum load can be integrated into the system.
Balancing responsibility	Better competencies and systems for prognosing and controlling will be built.	VRE investment risks will increase since balancing costs are unknown.	If competition between BRPs is well functioning, BRPs will have a strong incentive to minimize balancing costs by constantly improving prognosis and controlling.

Table 3-1 | Overview of priority dispatch and balancing responsibility.

From the table, it emerges that priority dispatch is a quick-fix solution to integrate VRE into the electricity system. However, it does not promote competence building and if e.g., coal CHP plants are not able to regulate down electricity generation, it can lead to environmentally and socioeconomic suboptimal situations.

The market mechanism requires competition between BRPs and generating units in order to be well-functioning. From the Northern European experience, it can be affirmed that, if a well-functioning market is established, VRE integration will be facilitated.

3.1.9 Physical contracts

Most European countries have used bilateral physical contracts between generators and TSOs. When the DA spot market is introduced, the TSO can sell the volume bought from the generator at the spot exchange and that way they can provide volume and liquidity to the spot market. The price for this is that the TSO carries the price risk. In most of Europe, bilateral contracts between TSOs and generators are only used for ancillary services and most TSO try to phase them out.

Currently, bilateral PPAs are mainly between TSO and VRE owners, although the number of PPAs between private companies and VRE owners is increasing. In this last type of PPAs, the volumes are still sold in the spot market and there is a financial agreement (CfD) regulating the sales price into a fixed price. This CfD is based on the physical volume of production differentiating the contract from a typical financial contract.

3.1.10 Market coupling mechanism on DA market

The market coupling between different power exchanges allows bids to cross borders, if there is capacity available on the interconnectors. It implies that the lowest cost of energy production required to satisfy the demand is guaranteed across borders. For a VRE producer, market coupling is an advantage if it connects the generating capacity to a high price area. The opposite is the case for consumers. Therefore, introduction of market coupling is often subject to significant debate. However, connecting markets leads to an overall positive socioeconomic impact.

A similar case is for regulating power and other ancillary services. Although some of the TSOs have fully integrated shared platforms for bidding at activation, others have agreements to exchange ancillary service products without fully integrated platforms.

There are also examples of trade between bidding zones which are not integrated on shared exchanges. As an example, there are two modes of power trade between Russia and Finland: bilateral trade and direct trade. Fingrid (the Finnish TSO) and the Russian parties confirm the bilateral trade volumes for the next commercial day (D+1) on the morning of the previous day (D). The confirmed trade volumes must be bidden onto the DA market and intraday market of the Power Exchange. The volumes of the direct trade are determined by the given bids on the DA market and intraday market of the Power Exchange and the corresponding Russian power markets.

3.1.11 Minimum and maximum cap on prices in day ahead market

Minimum and maximum cap on spot market prices avoid extreme financial implications of spot market prices. For instance, they ensure that a factory owner will not have to pay extreme power prices or temporarily shut down the factory due to extremely high electricity prices. Moreover, producers who are not able to stop their power generation are ensured that they will not have to sell electricity at extreme negative prices.

A large span between minimum and maximum prices provides incentives to invest in flexibility. For instance, owners of wind turbines will have an incentive to invest in control mechanisms curtailing the production from the wind turbines in case of negative prices, if there is a risk of significant negative prices. The lower the minimum price, the stronger the incentive.

Moreover, events of very high spot prices provide incentives to invest in peak generation capacity. In other words, incentives should be leveraged to increase electric capacity of CHP[17] plants as well as support flexible consumption. Examples include well insulated cooling houses, which are able to temporarily turn off the cooling system, and factories that can reduce their consumption to an absolute minimum without interrupting sensitive processes. The higher the maximum price, the stronger the incentive to invest in flexibility or reserve capacity. In this way, a high maximum cap of the prices improves security of supply.

Moreover, minimum and maximum prices apply if the total volumes of generating bids are not enough to meet necessary minimum consumption (bids for consumption without price limitation), or in case that generating bids without price limitations exceed the consumption bids (i.e., no market clearing). Minimum and maximum prices apply instead of the market prices in the case where there is no market price.

The lower the maximum price and higher the minimum price, the less risk is induced on inflexible producers and consumers from participating in the spot market. For instance, in case that a wind turbine is not able to shut down in case of negative prices, no minimum price would impose a risk to the VRE owner. In other words, the minimum price limits the risk.

When deciding the width of the price span between minimum and maximum prices, it is necessary to consider the trade-off between reducing risks of the inflexible generators and consumers and providing incentives to invest in flexibility and reserve capacity.

3.1.12 Price variation in day ahead market

If FIP are used as subsidy scheme or VRE producers are not part of any subsidy scheme, there may be a need for reducing the market price risk by entering into financial agreements with counter parties or consumers. Liquidity of financial markets for forward contracts are best in the short-term, since parties have the best knowledge of what quantities to hedge in the short-term. Therefore, forward

[17] Combined Heat and Power.

markets are normally leveraged to reduce market price risk on an up to 5 years horizon. In such regard, it is in the interest of all parties to establish markets with good liquidity.

If VRE investors are concerned about generally low DA prices, it is possible for them to enter into financial contracts on the forward market or into PPA agreements. It consists of an advantage for both parties if such markets are well-functioning. However, with the appropriate legal and financial preparations, it is possible for both parties to enter into bilateral agreements even though market is not established yet.

On the longer-term, PPAs become more popular than forward contracts in order to reduce the market price risk of VRE investments. As PPA terms are individual and buyers of power have different priorities of how to utilize PPA agreements in their CSR strategies, it is difficult to trade PPAs on an exchange. Nevertheless, brokers may be able to establish some sort of market place for PPA contracts with a kind of liquidity in order to ensure sellers and buyers that they can enter into long-term PPA contracts on market-like conditions. As such, PPAs require willingness of large consumers to commit to long-term contracts in order to claim the use of VRE power.

3.1.13 Intraday market

The intraday market is an hourly market like the DA market. It opens shortly after the hourly DA volumes and prices are published for each bidding zone. The intraday market allows for trade until approximately 1 hour before the delivery starts. Such a market gives generators and consumers the possibility, through their BRPs, to correct the dispatched volumes if they can find a counterparty and agree on a price. For example, if a wind park operator realizes that the actual generation will be lower than the dispatched volume, he/she can find a CHP unit which is willing to increase its generation under remuneration . If both parties agree on a price (i.e., pay-as-bid) for the power generated and conclude the deal, they can correct their dispatched volumes, and the wind park owner reduces the expected imbalance. In case of available transmission capacity to other bidding zones, it is also possible to find counterparties outside own bidding zone. In principle, it is up to the parties to agree on a price. However, the intraday exchange offers a platform for submitting bids and offers, and therefore, average prices for each hour can be established based on the bilateral trades if liquidity is sufficient. However, the market price changes over time when new information on expected wind power production, consumption or breakdown of major units is published. As it is a market with continuous trade, large electricity trading companies have established 24/7 trading floors to take advantage of the opportunities in the intraday markets. Opportunities are both to reduce own imbalance or to sell flexibility.

3.1.14 Balancing market

The Nordic regulating power market is designed using combinations of capacity and activation payments. If a supplier receives a capacity payment, he/she has an obligation to submit a bid for activation and have the promised capacity available. Although TSOs often buy the capacity using auctions or tenders, also, bilateral agreements between TSOs and generators have also been adopted, especially when there is a lack of suppliers (i.e., no competition). In these cases, suppliers must document their costs of supplying the capacity.

TSOs acquire the necessary obligatory reserve capacity and pay the capacity payment for it. Suppliers can submit bids for activation in order to increase the competition in that market.

When actual load or generation deviates from the scheduled volume clearing the spot market, the regulating power is activated and the suppliers receive activation payment. The need for regulating power often emerges suddenly and therefore, enough capacity of regulating power must be available 24/7. Some regulating power suppliers have several units supplying regulating power and therefore, they might have a good real-time understanding of the volumes and prices of the activated regulating power. Moreover, the reasons for activation are often known among suppliers and therefore, they might have a good feeling of how long the activation will last. Suppliers are often aware of the other units supplying regulating power, including general knowledge of their cost structures.

Competition between suppliers of regulating power ensures competitive prices of up-regulation (as low as possible) and down-regulation (as high as possible). If some of the suppliers of regulating power have too much information of competing bids, they might start changing their bids to maximize their own profit while reducing the efficiency of the market and increasing the imbalance costs of VRE and other parties. For such reasons, it is important that policy makers are continuously working on ensuring proper competition between generators and consumers, which will sell their flexibility on the regulating power markets.

3.1.15 Special rules for VRE

Immature VRE technologies often supply the grid with priority dispatch and without participating in spot markets or ancillary services markets. Therefore, they have dispatch priority since they receive the FiT no matter when they supply to grid. More mature technologies on CfD contracts or FIP have access to supplying ancillary services as well. Solar power is most often on simple FIT with priority dispatch and do not supply ancillary services.

In general, priority dispatch and balancing responsibility excemption is phased out in the new European electricity market regulation and will be used only in developing new technologies with insignificant generated volumes.

3.1.16 Payment for forecasting error

In the Danish case, the TSO used to make the forecasting and carry the balancing cost itself for some years, until it made a tender that was won by one of the Danish BRPs. After the tender, the BRP is paid a fixed amount per kWh for preparing prognosis and taking the risk of the balancing costs. In that way, the risk of balancing costs on immature VRE technologies is still not carried by the VRE owner but has been transferred from the TSO to a private company. In the end, the costs of balancing are paid by consumers since TSOs pass on the cost to consumers.

More mature VRE technologies, such as wind turbines, must have an agreement with a BRP or act as BRP themselves (this is only valid for larg VRE owners/operators). Most of VRE owners enter into contracts with BRPs and are paid for the value of their production at the exchange minus the balancing cost. In such regard, some BRPs offer both fixed and variable price for balancing. BRPs make the production profile forecasting themselves using inputs from one or more independent forecast providers. Ideally, the competition between BRPs and the development of better forecasting systems and balancing strategies, using intraday and balancing markets, will drive balancing costs down. Other factors that can reduce balancing costs include easy and cost-efficient access to flexibility selling at the intraday and balancing markets. If a significant amount of flexible units (also across bidding zones) compete for supplying flexibility, the price of forecast errors decreases.

3.2 Grid access

EU member states have not yet adopted a harmonized approach with respect to grid connection access rules and charges. There are some generally applicable network codes, although these leave quite some flexibility to member states.

Regulatory authorities at the individual member states are handling the issue of grid connection access rules and charges, where regulation depends on the balancing of interests between developers, investors, financing parties and TSOs. Further, VRE strategy considerations including the promotion of VRE in the energy mix play a significant role.

3.2.1 Grid connection and charges

In order to ensure non-discriminatory treatment of all applications for grid connection, detailed and common rules about connection should be available to all prospective new generators in due time.

Grid connection and associated costs are generally split between the TSO and generators. Grid connection comprises works necessary to reach from the generating point to the nearest PoC[18] in the grid as well as existing grid reinforcement. The related costs can be allocated in different ways:

- **Deep cost allocation,** which charges generator all costs related to grid connection, including possible reinforcement costs;
- **Shallow cost allocation,** which charges generator only cost related to the works necessary to reach the PoC;
- **Hybrid cost allocation,** which charges generator cost related to reaching PoC and an additional fee for any possible reinforcement calculated on a shared basis;
- **Super shallow cost allocation,** in which TSO carries cost of possible reinforcement and some of the cost related to works necessary to reach PoC.

Below, the different cost allocation scenarios are depicted for the example of an offshore wind farm. However, the cost allocation scenarios apply in general to all sorts of power producing projects connecting to the grid.

[18] PoC – Point of Connection.

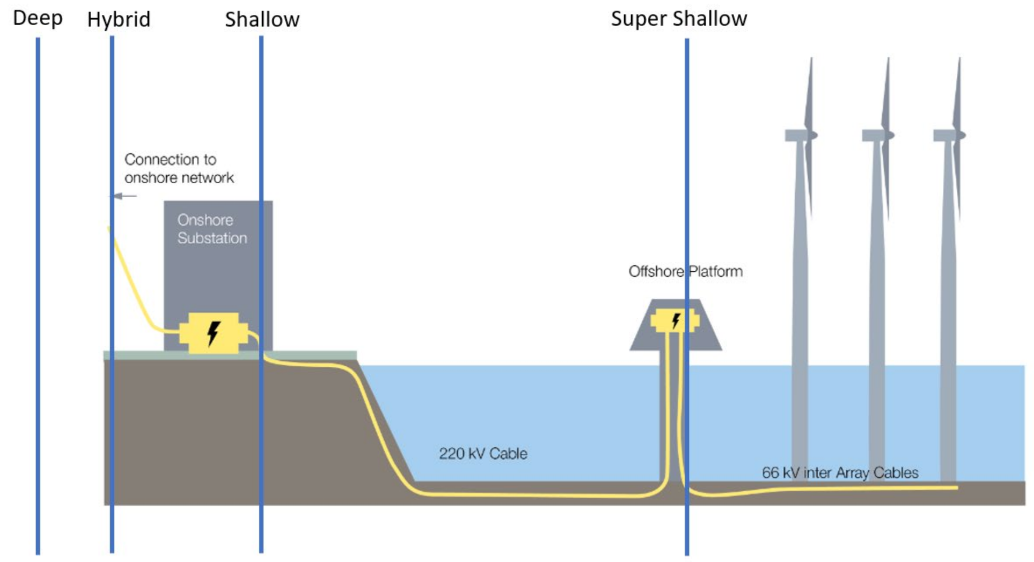

Figure 3-4 | Illustration of grid connection cost allocation strategies for an offshore wind farm (Source: COWI).

Continuing with the example of an offshore wind farm, Denmark has taken the super shallow approach, whereas Germany operates according to the shallows approach. This difference has affected the risk perception on the developer/investor-side, where grid connection risk in Denmark generally is considered lower than in Germany.

3.2.2 Standards and codes

Electrical power grids are regulated by standards and grid codes. Grid codes seek to ensure stable and safe operation of the power grid, defining the main factors that must be considered when connecting any kind of power generation plant to the grid.

Grid codes focus on the technical requirements for power generation plants. Such requirements are, to some extent, based on relevant international standards, although local requirements and considerations might force a significant and unique content into the grid code. Requirements in the grid code must ensure that power generation plants have the technically characteristics, performance and capacity so that organizations/authorities responsible for power system security and safety (e.g., TSO) can obtain stable and efficient operation of the power grid in normal conditions.

A major part of the grid codes specifies performance and capability of the power generation plants during and after faults in the power grid. Some of the most import aspects dealt with in the grid codes in this context are the so-called FRT[19] capabilities. The power generation plant is required to remain connected to the grid, with a disturbance to its power production as small as possible for quite severe faults in the grid. Power generation plants located in very close vicinity to the grid fault can disconnect themselves in order to sustain no damage. However, power generation plants located at medium and remote distances from the fault must not disconnect from the power grid. If the FRT capabilities are insufficient, a single fault in the power grid can lead to the loss of a substantial amount of power generation, leading to an unstable and unrecoverable situation – ultimately, to wide-area black-out.

[19] FRT – Fault Ride Through.

The importance of FRT capabilities is visible in the grid code requirements for testing and proving compliance. Extensive simulations are often mandatory and carried out to verify compliance with the grid codes. In addition, grid codes require that FRT capabilities and performances are verified and documented during commissioning as well as periodically (e.g., every 3 years) to ensure compliance at any time.

Increasing amounts of VRE (i.e., non-synchronous generation) has necessitated amendments and/or changes to grid codes, leading to the distinction between FRT requirements for synchronous and non-synchronous generation plants. FRT requirements for VRE has become important and necessary in order to ensure system stability and security of supply.

3.2.3 Curtailment

Curtailment consists of the reduction in the output of a generator from what it could otherwise produce given available resources, typically on an involuntary basis. Curtailment is typically imposed because of transmission congestion or lack of transmission access. However, it can occur for a variety of other reasons, such as excess generation during low load periods, voltage or interconnection issues.

Curtailment of generation has always been a factor, but it imposes greater risk to VRE generators. For VRE generators with no fuel-cost, high CAPEX and low OPEX, curtailment hits harder on project economics. This condition has spurred that increasingly, contract provisions addressing use of curtailment hours and/or priority dispatch are negotiated and greater explicit sharing of risk between the generator and the off-taker is emerging.

Further, solutions to reduce curtailment are continuously being introduced and investigated, such as interconnection upgrades, improved forecasting, energy storage and better management of reserves and generation.

4 USA experience in mitigating risk related to spot market development

CAISO and ERCOT, like most ISOs in the USA, are centrally dispatched, bid-based markets. They both use nodal-LMPs to settle in DA and real-time markets (two-step clearing). They both allow for generation bids and load offers. Both have high penetrations of VRE, 22% and 18% respectively (2017).

CAISO's territory is dominated by 3 large vertically-integrated utilities, who remain highly regulated despite competitive wholesale. CAISO's centralized market design was set up to optimize economics across the entire region and prevent the major utilities (who serve 75% of CA's customers) from preferentially using their own generation when cheaper resources from other utilities or merchant generators were available. Accordingly, the primary objective for CAISO's energy and ancillary services markets is cost optimization, not long-term price signaling, which is managed by placing resource adequacy requirements on LSEs to ensure sufficient generation is procured in future years. This requirement, adopted to reduce volatility after the 2001 energy crisis, means most plants are governed by long-term (10 years+) financial contracts, which cover their full costs through CfDs alleviating pressure for generators and utilities from aggressively competing in the market.

Given CAISO's market design is primarily focused on cost optimization, all resources are required to bid into CAISO's markets. Exemptions for renewable and CHP self-scheduling being eliminated as more renewables drive greater needs for more flexibility. CAISO also selected to use nodal markets early on to fully endogenize technical constraints in the least-cost dispatch and price setting and manage their many transmission constraints. Given the extensive use of long-term PPAs, challenges with geographic disparities and equity issues from LMPs is largely ameliorated for demand.

Despite having a two-sided market, CA has had to mandate utilities to procure DR[20] as a least-cost alternative to building new plants (their default solution). These mandates usually maxed DR out at about 2% of peak demand. To circumvent these misaligned incentives, CAISO enabled DR to participate through aggregators and are paid as generation resources when dispatched by the market. CAISO pays this DR a resource adequacy payment to reserve its capacity for future years, and this upfront payment has played a large role in bringing more DR online (as of 2018, 7% of peak demand).

ERCOT has fully competitive retail and wholesale generation, and generally holds a market purist perspective in designing their market. ERCOT operates energy and ancillary services markets and relies on scarcity pricing and high market price caps to encourage LSEs to procure sufficient generating resources to avoid/hedge against high prices in future years. There are few regulatory requirements placed on LSEs to prove resource sufficiency, allowing the market, not regulators to set reserve margins. Competitive retailers and generators choose what mix of bilateral contracts, hedges, self-scheduling, and exposure to market prices is acceptable for their business model. Most generators have chosen to bid all of their capacity into the market and sign financial contracts with retailers and power traders to have price certainty. Over the years, generators have found centralized

[20] DR – Demand Response.

dispatch is easier (and typically yields better economic results) than optimizing their own schedules/contracts independently. ERCOT has many market intermediaries and power traders that manage the complexity of selecting between contracting for energy, direct market procurement, and financial hedges on the behalf of retailers and generators (whose core competencies lie elsewhere).

Market intermediaries are a large reason why ERCOT's two-sided market sees more demand bidding activity than other markets, since many power traders are shopping for better prices in the market. Demand response's participation through demand bidding has been limited, since competitive retailers have struggled to sell customers on time of use rates and have minimal incentives to push DR programs to customers. ERCOT is exploring provisions for 3rd party DR aggregators to participate in the market as generators and have started an emergency demand response program to bring more DR capacity online (reaching 3.5% in 2018).

ERCOT originally used zonal pricing but shifted to nodal in 2010. Nodal pricing has increased dispatch efficiency and helped isolate some of the high price spikes in the market caused by zonal pricing. Most of the complexity of managing congestion hedging has been managed by the financial and power trading intermediaries playing in ERCOT, alleviating the concerns for retail and generator capacity building. This switch has also been important to manage Texas's huge growth in renewables in remote regions, where LMPs play an important role in signaling economic curtailment and informing wind investment.

In **both markets**, renewables utilize PPAs to participate, which guarantees that their contracting partner, often an LSE or large user, will pay a set price for all MWhs they produce (the LSE also keeps the associated renewable attributes in this deal). Any difference between the ISO market price and the contract price is paid by/to the LSE, regardless of time of generation. This has encouraged the practice of VRE self-scheduling as a price-taker (CAISO) or submit low-to-negative bids (ERCOT) to maximize integration, thereby also maximizing their production tax credit (a subsidy). This model, while effective at low penetrations, is increasingly creating challenges. Both regions have made substantial market design changes to accommodate the large increase in VRE on their system, including:

CAISO and ERCOT have made substantial market design changes to accommodate the large increase in VRE on their system, including:

1. Incorporating renewables (and all generators) into the market for central dispatch (CAISO)
2. Moving from zonal to nodal pricing (ERCOT)
3. Increasing demand-side participation (CAISO & ERCOT)
4. Moving to 5-minute markets to increase granular and flexible dispatch (ERCOT & CAISO)
5. Mandating advanced inverters for VRE to provide active support to the system (ERCOT & CAISO)
6. Updating forecasting requirements for RE (ERCOT & CAISO)
7. Introducing variable regulation reserve requirements, multi-time frame scheduling, and adding new fast ramping ancillary service products (CAISO)

8 Implementing inertial minimums (ERCOT)

9 Expanding balancing areas (CAISO)

We cover each update in more detail below:

1) In CAISO, as VRE capacity grows, self-scheduling of hydro, solar, wind, nuclear, geothermal, and CHP resulted in less and less dispatchable generation participating in the DA and real-time markets, making it hard to cover marginal energy needs. Starting in 2015, CA started adjusting market rules to encourage more active bidding for all regulatory must-take and self-schedule generators.

2) In ERCOT, wind is concentrated in remote regions, and transmission constraints often appear. This, in part, pressured ERCOT to switch from zonal to nodal pricing in 2011 to reflect the real-time changes to congestion and losses from VRE output in market dispatch.

3) Both markets are two-sided markets, meaning both demand and generation submit bids. Despite this, both markets have seen minimal uptake of demand-side flexibility until they 1) required some use of time-based rates for customers, 2) allowed DR to participate as a generator in the market, 3) paid DR providers some upfront payment (either for service as a demand resource or a generator resource). In ERCOT, DR participates through retailers who theoretically have incentives to minimize their procurement costs during high price hours, but often participation is low because retailers also own generation and benefit from high prices. ERCOT has been exploring how to enable 3rd party aggregators to participate in the market outside of their retailer. ERCOT also runs an emergency DR program where demand is paid a capacity payment to provide mandatory ramp down service in emergency situations. Together, these DR programs represent 3.5% of ERCOT's peak demand. In CAISO, DR both participates through utility programs to minimize their procurement costs, but typically needs utility mandates for DR to be procured. DR now also participates as generators in CAISO markets capturing revenues during critical peak hours or in 5-minute markets. These resources receive a centralized availability payment which has been critical to bring on enough DR to reach 7% of CAISO's peak demand. CA is now also mandating time-of-use pricing for all of its regulated utilities.

4) Both markets have moved to 5-minute time segments for clearing in the real-time market to better select which resources to use for least-cost balancing of VREs. CA has extended 5-minute clearing to ancillary services and has implemented administrative scarcity pricing when there are shortages in ramping capability to further encourage fast response by market players.

5) CAISO and ERCOT have mandated advanced inverter standards for both wind and solar which require some level of responsivity from VREs to provide momentary increases or decreases in output to manage frequency, mitigate contingency events, etc. These are unpaid services. These standards also required mandatory low-voltage and low-frequency ride-through to reduce the chances of VREs tripping off in an underfrequency event and leading to a blackout.

6) VREs are required to submit forecasts and schedules to the ISO in both markets. The distinction is forecasts are only informational and schedules are financially binding. In CAISO, energy forecasts are submitted by all VREs. Scheduling coordinators (usually LSEs or VREs) are required to submit schedules based on these forecasts to the day-ahead market (as a price-taker if physically

scheduled). They can update these schedules as needed until 75 minutes ahead of delivery, without settlement or penalties. In ERCOT, each VRE facility must provide a rolling 168-hour hourly forecast to inform other market participants in day-ahead markets to bid accordingly. They must also install and telemeter site-specific meteorological information every hour to ERCOT for use in their ISO forecast. VRE must submit bids or schedules to the DAM but can adjust or update their schedules up until one hour before the start of the operating hour without paying settlement or penalties.

Both ERCOT and CAISO system operators conduct their own ensemble forecasts (compiling a bunch of different forecasts) to set reserves and confirm reliability-ensured unit commitment. Ensemble forecasting has allowed ERCOT's DA forecast error to drop to 5-7% from a high of 12%, and hour ahead from 7% to 3-5%. Costs for procuring adequate reserves are paid by LSEs, with the logic that these costs would be passed through from generators anyway. ERCOT and CAISO are looking at the impacts of assigning reserve/reliability charges to generators, placing an additional burden on VRE. If any generator diverges from their schedule over a certain margin (10% in ERCOT and 5% in CAISO) they must pay penalties due to their overusing their share of regulating reserves. This is usually paid by the LSE since VRE PPAs don't typically allow pass through of penalties from LSEs. LSEs are increasingly passing some of these costs to VREs in their contracts.

7) CAISO updated its scheduling, reserve definitions, and reserve products to ensure reliability at higher levels of RE. During hours with high amounts of VRE, CAISO was using all of its available regulating reserves to balance disruptions caused by VRE, forcing them to use operational reserves instead, posing a security risk.[21] CAISO implemented a variable reserve margin, which means the percent of regulation reserves required in each hour changes based on the forecasted percent of generation coming from VRE. Overusing regulation reserves in one hour, could prevent it from being available in a subsequent hour when it was previously scheduled (e.g. CAISO ramps up a generator from 90% to 100% of its nameplate capacity in hour 1, preventing it from ramping up further in hour 2 if yet another shortage occurred). CAISO updated its economic dispatch models to consider future ramping and reserve needs when making dispatch decisions in this hour by doing a least cost optimization across the next 3 hours to make sure dispatch decisions made in this hour, do not prevent least-cost resources from being available in future hours. CAISO is also testing a new ramping reserve product, which procures resources that can ramp up quickly and beyond the range of inter-hour ramping covered in automated generation controls (AGC). This product supplements the current regulation reserves, procuring fast responding, fast ramping services to cover more sudden changes in VRE output.

8) ERCOT implemented inertial minimums (in 2019, 100 GWs) as a requirement in the SCED process to ensure during hours with high penetrations of VRE, adequate inertia was available. ERCOT explored

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[21] Regulation reserves in CAISO are resources available to be adjusted in real-time to maintain system frequency and are separate from operational (aka contingency) reserves, which are resources available to recover for an event where generation or load is unexpectedly lost.

creating a market product for this, but instead decided to update scheduling requirements and generator standards to address at least cost.[22]

9) CAISO created the Energy Imbalance Market, (EIM), a voluntary balancing market that utilities in neighboring states can participate in to find the cheapest resources to balance the grid over a wider geographic region. This has improved RE integration significantly and reduced the flexibility costs for integrating renewables, with gross benefits from 2014 to June 2019 reaching 736.2m dollars. EIM dispatches resources on 15- and 5-minute intervals, and as of 2019 includes 13 participating utilities.

[i] Renewable energy offtake contracts with LSEs typically do not pass balancing costs incurred by RE forecast errors back to the generator, but there is no legal reason why this could not be passed on.
[ii] Western Energy Imbalance Market, Quarterly Benefits Report, Q4 2018. CAISO, 2018.
https://www.westerneim.com/Documents/ISO-EIMBenefitsReportQ4-2018.pdf

[22] Inertia is the momentum stored in the rotating generators that allows the system to ride through a sudden loss of generation for a short period of time (e.g. like a bike having enough momentum to roll over a big bump). This leaves enough time for reserves to kick on and cover for the loss.