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Wind Generation in Adequacy Calculations and Capacity Markets in Different Power System Control Zones

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Abstract—Generation capacity adequacy is a major issue in most power systems, but there are many approaches which can be assessed. Power system planners often define target values for the capacity adequacy, which may be achieved through capacity markets/auctions, capacity reserves, or capacity purchases. Wind power contributes to the generation capacity adequacy of the power system since there is a possibility that wind power will generate in high load situations and thereby decreases the risk of generation capacity deficit compared to the system without this source. The contribution is probabilistic—as it is with any other source, since nothing is 100% reliable - but the capacity value of wind power is significantly smaller compared to the capacity value of conventional fossil-fueled plants.

In this article, an overview of the fundamental challenges in the regulation of capacity adequacy as well as how wind power is treated in some selected existing jurisdictions is presented. The jurisdictions that are included are Sweden, Great Britain, France, Ireland, United States (PJM), Finland, Portugal, Spain Norway and Denmark.

Index Terms—Wind power, integration, power system, capacity credit, adequacy, capacity markets

I INTRODUCTION

The world’s total electric consumption is currently, 2017, around 25550 TWh per year [1] of which around 4.4 % [2]. However the share of wind power has increased significantly in latest years, +20% increase between successive years [2].

In addition to the trend of significantly increasing amounts of wind power, and also solar power, there is also an increasing discussion about adequacy, especially since many systems are liberalized where an earlier adequacy responsibility for the vertical integrated power company is not any longer so clearly defined. Wind power does, in this context, certainly contribute to the adequacy with its capacity credit [3] [4], which then decrease the need of other types of capacity in order to reach a requested reliability.

In order to keep a high reliability, different systems have introduced different types of capacity markets [5] including strategic reserves and other types, when an energy only market is not considered efficient in order to obtain a rational adequacy.

The aim of this article is to provide an overview on how wind power in handled in this context in ten different power systems: Sweden, Great Britain, France, Ireland, US (PJM), Finland, Portugal, Spain, Norway and Denmark. The overview includes how wind power capacity credit is estimated in different systems, if this capacity credit has any impact on the capacity market, and also if wind power obtains any payments from the capacity market. In Section II the different systems are presented. Section III summarizes the different results and provides an analysis and comparison of different results. References are found in Section IV.

II WIND GENERATION IN ADEQUACY CALCULATIONS AND CAPACITY MARKETS IN DIFFERENT SYSTEMS.

Wind power has a varying availability but still a capacity credit although often lower (in percentage of installed capacity) in relation to thermal power plants. And this is in different ways estimated and considered in different systems. In this section we will go through this for eleven different systems.

The general set-up for all descriptions are:

B: Background of wind power and adequacy challenge in studied area

M: Method for how to calculate the capacity credit of wind power in the studied system

C: Capacity market set-up in the studied system

S: Summary and conclusion for how wind power is handled in capacity calculations and markets

A. Sweden

B: In Sweden there was, before the deregulation, which started in early 1990:th, a system with reliability targets for
each producer. This was, at that time, possible, since the producers could move the reserve plant costs to the consumers, since the consumers could not choose another supplier. But after the deregulation several rarely used plants were closed and a strategic reserve system was implemented from 2002 where the system operator was allowed to purchase up to 2000 MW of peak capacity [6]. The system has changed slightly during the years and now especially demand bids are promoted as strategic reserve [7]. Wind power contributed to 12% of Swedish energy supply in 2017.

M: When the TSO decides how much strategic reserve that is needed, then the “available capacity” has to be estimated. For wind power this level is estimated from “the national wind power production that is exceeded during 90% of a winter. This level has then been set to 9% of installed capacity [8]. This means that the TSO uses a deterministic model where the probabilistic nature of each source is handled per source. For possible import, specific estimations for each connection results in a certain MW potential import. Concerning demand, only the estimated demand that could occur one time in 10 years is used. In this way it is estimated how much extra capacity that is needed

C: In July each year there is a tender for the coming winter. In this tender the SO asks for bids for reserve power (maximum 2000 MW), which then can receive a fixed payment, per MW, for the coming winter (November-15 to March-15). A “bid” then includes that when the SO asks, then the capacity should be activated. For the winter 2018-2019, the TSO has contract with 562 MW of production and 205 MW of demand bids, i.e. a total of 767 MW. A specific rule is that the resource can have an unavailability of 5%. If the unavailability is larger, then the payment decreases [7]. The set-up with yearly tenders depending on need means that this is mainly a system for already existing assets, not for new units.

S: The set-up means that more wind power will lead to an increased amount of available power so the SO needs less strategic reserve. But the only ones who are paid in this system are the ones who participate in the strategic reserve. So wind power, as all other production or demand resources, does not get any payment although they in reality contribute to the adequacy.

B. Great Britain

B – Wind power capacity has been growing steadily in Great Britain over the last two decades. It now represents circa 20.7 GW (split between ~ 8.7 GW onshore, 12 GW offshore), which helps in part to serve an average winter peak demand level of ~ 60GW. This has been driven by various government subsidy schemes, with potential for up to another ~ 7 GW of wind capacity expansion anticipated over the next 5 years in long-term planning scenarios [9].

There is a Capacity Market (CM) in existence in GB [10], since winter 2017/18 onwards, which replaced an earlier form of strategic reserve. Annual CM auctions target the national reliability standard of 3 hours LOLE per year. National Grid, the System Operator has responsibility for running the CM, as well as the monitoring of system reliability in each Winter Outlook [11] - including conducting relevant technical analysis to derive the amount of capacity to be auctioned [12]. The UK Government’s Secretary of State for energy makes the final decision on matters related to the CM, which is also overseen by Ofgem, the Regulator, as well as a Panel of Technical Experts (a peer review group to scrutinize analysis methods). The majority of GB wind capacity has been developed with support from subsidy, and is thus ineligible for the CM. The cost of wind development is dropping however, and it is foreseen the CM may need to be adapted to allow unsubsidized wind to participate.

This growth in wind capacity is not happening in isolation of other market change – there have also been increases in external HVDC interconnection to other European countries, demand response and battery storage too, leading to advances in the modelling, with time sequential Monte Carlo simulation becoming more common [13], as well as pan-European modelling to account for statistical dependency with other interconnected regions. Part of the evolution of this analysis also required increased stakeholder engagement with surveying of the modelling applied internationally [14].

M: In the GB capacity adequacy calculations, wind is represented by means of Equivalent Firm Capacity (EFC). This is the amount of perfectly reliable, infinite duration supply that can replace wind yet maintain the same reliability level [15] - with distinction between total EFC of the entire wind fleet, and incremental/marginal EFCs of additional wind units. It is known that as the amount of wind capacity on the GB system increases, then it’s marginal contribution to supply may reduce. In the recent 2017/18 Winter Outlook, the wind EFC was calculated as ~ 17%.

Both “time-collapsed” convolution and “time sequential” Monte Carlo models have been used to assess reliability of the GB system. In both, the wind power stochastic variation has been represented using historical wind speeds estimated using NASA MERRA atmospheric reanalysis data [16]. This provides, for each GPS location and hub height of each wind farm, an hourly wind speed estimated for that historic period. This is converted to power using system averaged wind turbine power curves (separate ones for onshore and offshore wind to reflect different turbine sizes/designs) to get the total wind output. This historical time series is then fed through risk assessment models, in coincidence with the historical demand time series (care is taken to capture statistical dependency between demand and wind power) to derive the wind EFC. Presently, 13 years of historical data are used to represent stochastic variations of weather.

C: The CM has annual T-4 and T-1 auctions for future delivery in 4 years or 1 year. The majority of capacity is usually contracted 4 years in advance, with small amounts held back for the T-1 auction to allow for changes in the intervening period. The CM structure is centralized, whereby the System Operator derives the total auction capacity via LOLE study (taking account of planning uncertainty via a mini-max-regret decision analysis). This is auctioned off to bidders in a transparent, centrally-cleared auction. The performance requirement for contracted is to be online and deliver to the market in periods of shortage as they may happen anytime over the winter. New-build supply is allowed the option of a 15-year contract at the clearing price of the first year’s auction, refurbished plants can receive 3-year contracts - other forms of supply (including demand response and interconnection) receive 1-year contracts.

As mentioned earlier, wind power is presently ineligible for the CM - only capacity that receives no other form of direct support is allowed to participate. The overall EFC of
the existing wind fleet as well as the contribution of other ineligible sources is subtracted from the total firm capacity required to meet 3-hours LOLE, and this residual quantity is that which is auctioned off. If in future, unsubsidized wind participates in the auction, then it would be treated like any other form of eligible capacity in this respect.

S: The CM framework and modeling methods continue to evolve, with a detailed policy review carried out each 5 years. There are ongoing discussions on e.g. (i) use of combined technologies such as wind and storage (or demand-side) : initial studies suggest that combined capacity contribution may be higher than the sum of individual contributions and (ii) the use of other risk indices such as frequency, duration, magnitude, and cost of interruptions [17]. In order to create a level of playing field across different technologies, future policy could consider a whole-system approach in developing new market arrangements.

C. France

B: French electric consumption has increased regularly for several years (up to 10% during last decade). But for the same period, peak loads during winter periods has increased drastically during cold waves (+33% in 10 years), reaching a peak in February 2012 at 102GW, with an extreme volatility (20GW between 2012 and 2014). The reason is the demand composition, with a high share of electric heating (and so, an important sensitivity to the temperature), leading to more important consumption during winter.

RTE, the French Transmission System Operator (TSO), has carried out future analysis (generation adequacy outlook and assessment of the resilience of the system) to conclude in 2010 that the stress on the system balancing will be more and more frequent in a near future, with a potential and important risk on security of supply.

The French capacity mechanism was designed to address this issue by modifying consumption behaviour during peak period (demand-base approach) while encouraging adequate investment in generation and demand response capacities (supply-base approach), at a time when energy markets’ ability to stimulate such investments was being questioned in much of Europe [18].

Based on conclusions from a parliamentary commission and a law (NOME law) in 2010, which commended investment in new capacity and development of demand response, RTE proposed in 2014 a set of first rules [19] for a capacity market (in addition to energy market), which have been debated and approved in 2015. This capacity market has just started for a first delivery year in 2017.

Regarding production, electric mix (installed capacities) is composed mainly of nuclear (63GW), renewables energies (first hydraulic with 47GW, then wind and solar), and thermal (gas and coal). Variable Renewable Energy Sources (RES) have reached respectively 13GW and 7 GW for wind and photovoltaic in 2017, with an RES increase of more than 2.5GW/year (wind + PV).

C: All of these productions can participate to the capacity market, including variable RES. RTE, responsible for the certification process, provides certificates according to the contribution of capacities to reduce risks of supply. One capacity certificate (or guarantee) is equal to 100kW, for a specific year of delivery [20].

For controllable technologies, capacity guarantee depends on power available measured during reference periods, taking into account technical constraints (such as energy limitation or dynamic constraints).

But this “generic process” is not suitable for variables RES, depending on non-controllable primary energy (weather hazards). Wind or solar or Run-of-River (RoR) capacities owners are able to seek certification with a second method. These so called “normative” method is based on historical data (5 years for wind and solar, 10 for RoR), with specific parameter for each technology (depending on technology contribution to reducing the shortfall risk).

Contribution for a capacity (to reducing the shortfall risk during peak period) is based on equivalence with a perfect source to ensure the same level of risk in a system sizing to respect security criteria (LOLE = 3h). This determines capacity credit for the technology considered (capacity credit normalized then by technology installed capacity).

Capacity guarantees for variable RES depends then on:

- Capacity installed,
- Availability (for the capacity) during reference period,
- Contribution Coefficient (CC) for the technology (set to 0.7 for wind, 0.25 for solar and 0.85 for RoR, dependent upon capacity credit per technology and availability during reference period).

All capacity certificates are considered to be equivalent (technology neutral: 1 wind certificate = 1 thermal certificate = 1 demand response certificate) and operators can value them in the capacity market.

M: Beginning 4 years ahead delivery year, the capacity market aims at providing an economical signal, complementary to the energy market.

Suppliers and capacity operators (producers and demand-response operators) have their own obligations regarding capacities: a capacity obligation for suppliers, along with a certificate market. The French capacity market is then said to be “decentralized”.

Obligation is, for suppliers, to acquire enough guarantees according to their clients’ consumption during Peak Periods (called PP1 for obligations). Guarantee acquisitions is done directly with capacity operators or through capacity market. Capacity operators must seek certification from TSO (or DSO, depending on capacity connections) according to capacity availability during Peak Period (called PP2 for certifications). Guarantee obtained are then trade (in capacity market…).

Peak days PP1 & PP2 are during winter period and announced by RTE in day-ahead. PP1 are 10 to 15 days/year, only on timeframe [7h-15h] + [18h-20h], and determined according criterion based on the level of consumption. PP2 are more numerous (10 to 25 days/year), and determined according to level of consumption and also stress on system balancing.

Methodologies for obligation and certificates definitions take into account, for a specific delivery year, a security criterion of LOLE = 3h (for France interconnected with neighbouring countries). Different parameters and data (such as volumes of guarantees per year…) are available on RTE’s websites.

After delivery year, once obligations have been computed and effective availability of capacities controlled, imbalances are calculated (for both suppliers and capacity operators) and valued according to a reference price (price of market or administrative price, depending on if security of supply is at risk or not). The price of settlement of
imbalances is an incentive for stakeholders to respect their obligations and to favour the market.

Trading of capacity certificates is organised by EPEX Spot. RTE is responsible for certification process and registry management. French regulator (CRE) monitors capacity market and publishes information.

S: Capacity market in France has been running for a short period. Wind power participate to this mechanism and about 2.3GW have been certified for 2018 (up to 2.5% of 92.6GW of total certified capacity level for this delivery year) [21].

Modifications of RES’ support mechanisms (wind, solar…) and their direct integration into markets are parts of an in-depth markets design reform to facilitate and make energy transition successful.

D. Ireland

B: Wind generation across Ireland and N. Ireland represents an installed capacity of 4.5 GW, and supplied 26% of demand in 2017. Wind is targeted to provide 37% of energy against a 40% renewable target for 2020, and a 55% RES-E target has recently been announced for Ireland by 2030. Against a background of a significant increase in forecast demand, mainly driven by new data centers (which may cover 30-40% of the demand in the coming years [22]), and concerns about the exit of some existing market participants, partly associated with the introduction of new electricity market arrangements in October 2018. The capacity market arrangements incorporate location capacity constraints to limit such issues in particular areas, e.g. larger Dublin region. It is noted that larger generators are required to provide 3 years notice of closure, while, in the longer term, capacity auctions will take place 4 years ahead of time, whereby system stability, transmission constraints and other issues may be (somewhat) addressed given sufficient notice [23]. For all units, including wind generation, the capacity offered is the de-rated capacity, recognizing availability due to outages and energy limits. The capacity auction is intended to achieve a system-wide LOLE of 8 hours per year, based on historical demand patterns and capacity de-rating.

M: A range of forecast demand scenarios are considered for the capacity market year, assuming differing demand growth projections and distributions across the year. In general, multi-scenario adequacy analysis identifies a de-rating factor curve for each technology type as a function of unit size [24]. Assuming a number (currently 5) of randomly selected capacity adequate portfolios, a marginal de-rating factor is determined for each technology by quantifying the system adequacy benefit when introducing in turn an additional unit of a specific technology class for each portfolio. (Due to the correlated nature of the output from neighboring wind farms, all wind capacity is represented as a single technology class.) Subsequently, the de-rating factors are averaged across all portfolios within a scenario, and finally a least-worst regrets approach (based on VoLL, Net-CONE and LOLE standards) is applied to select the scenario upon which the de-rating factors are defined. Participants to the market auction are permitted to adjust their technology de-rating factor by a specified amount (currently zero), while variable production units, e.g. wind, can be aggregated into a single capacity market unit.

C: Prior to 2018, as part of the Single Electricity Market (SEM) across Ireland and N. Ireland, capacity providers were paid based on their availability to provide electricity when required, through a capacity payment mechanism (CPM). The capacity price varied by trading period, being inversely proportional to the capacity margin, such that total capacity payments reflected the cost of a "best new entrant" plant.

However, with the introduction of I-SEM (Integrated SEM) in October 2018, as part of harmonizing electricity markets across Europe, the existing arrangements have been replaced by a capacity market (CM), in order to improve efficiency. Consequently, only capacity providers that have been successful in the capacity auction can receive capacity payments (a per MW per year rate based on the capacity sold at auction). Capacity payment income is sourced from suppliers, subject to a maximum strike price which is updated monthly. The first auction took place in December 2017, and covers the period October 2018 to September 2019. In the longer term it is intended that (T-4) capacity auctions will take place 4 years before the year under auction, supported by (T-1) auctions in the year before implementation, as appropriate.

S: Under the existing capacity payment mechanism, wind farms received approximately 7% of their revenues from capacity payments. However, within the new capacity market only 200 MW wind capacity was successful in the initial auction, with the vast majority of wind farm owners did not submit bids. Particular concern is associated with the maximum strike price concept, which implies that financial penalties are applied when capacity is not available during (high price) periods. It is noted that the new market arrangements will first go live in October 2018, so it may be expected that the auction and operational rules will gradually evolve over the next few years with increased live experience, which may lead to more wind farms offering bids to the capacity market.

E. United States (PJM)

B: PJM is the transmission system and market operator for all or part of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia in the United States. PJM has a relatively low share of wind power, with wind producing approximately 2.6% of the total demand in 2017. This is from an installed capacity of wind of over 8,100 MW in 2017 out of a total generation capacity of over 178 GW. PJM operates a capacity market known as the Reliability Pricing Model (RPM) to ensure long-term grid reliability by procuring enough supply resources to meet forecasted future energy demands. This supply is procured with the intent of having sufficient planning reserve margin above system peak demand. Capacity pricing is split into six different delivery areas to reflect transmission constraints within the system.

M: The calculation of the capacity value for a wind plant in PJM utilizes the summer hourly capacity factors for each plant during the period June 1st through August 31st for the peak hours of 3:00 PM through 6:00 PM, for the previous three summers. The mean of the three single year capacity factors is called the Capacity Factor and when multiplied by the current net maximum capacity of the plant provides the capacity value for the plant. If the data for the time period in
question includes times when the wind plant was curtailed by the system operator constraints then this production data is replaced by five-minute data from the PJM state estimator without constraints, and linearly interpolated over the period with constraints [25].

C: Wind power producers can choose to bid for annual capacity or separate bids for Summer and Winter capacity. In the most recent capacity auction, results released in May 2018 for the period June 1, 2021 to May 31, 2022, 1,417 MW of wind power capacity cleared in the market from a total of 163,627 MW of total resources procured. The clearing price for the main (RTO) delivery area increased significantly to $140 per MW/day in the most recent auctions due to planned nuclear and coal plant retirements.

S: Wind power actively participates in the PJM capacity market, though it currently has a relatively small influence due to its relatively small penetration rate in the balancing area and the relatively low wind plant capacity factors during the summer load peaks.

F. Finland

B: Finland uses a form of strategic reserve. Energy Authority of Finland has the responsibility to maintain a good level of reliability during demand peaks and electricity import failure events. While doing so, the Energy Authority should also consider the available capacity and costs of procuring strategic reserves. This leaves the officials with considerable discretion as what amounts to a ‘good’ level of reliability. In practice, the Energy Authority regularly procures studies that assess the need for the strategic reserve. These studies then calculate the LOLE for different levels of strategic reserve.

Finland does not have sufficient power generation capacity to meet its peak load. The approach has been to consider also possible imports during the peak loads with the associated uncertainty. Since 2012 also wind power has been considered to contribute to the capacity adequacy [26]. The share of wind power in 2017 was 5.8% of electricity consumption.

M: The method of considering capacity value of wind power in the evaluation for strategic reserve is up to the evaluation method that is used. Energy Authority selects the consultant and the method through procurement. In 2012 and 2014 the method was a LOLE calculation with capacity outage probability that considered multiple years of correlated demand and wind power time series. Since then, a Monte Carlo based dispatch has been used [27]. The initialization of probability distributions for the sampling has been based on historical data with some consideration towards correlations and potential availability. In principle, both methods can produce reasonable results. However, the potential availability of hydro power, combined heat and power as well as wind power is a challenging task. Using historical values is not sufficient as they only indicate what level of generation was economically viable in a given situation and this is heavily influenced by imports. For wind power, the problem is that new wind turbines have a much higher capacity factor than old ones. Furthermore, public data concerning power plant capacities and their availability is not very reliable. Consequently, the results can be strongly impacted by the modelling assumptions taken.

C: The Energy Authority organizes an auction for capacity that will be moved into the strategic reserve. This capacity cannot be used in normal market operation - it receives a compensation based on the promised capacity during peak loads as well as on actual utilization. Both power plants and demand response can participate in the auction with similar rules. Energy Authority reviews the bids and uses discretion to decide how much capacity will be procured based on the bids and the capacity adequacy evaluation.

S: The contribution of wind power has been considered in the capacity adequacy calculation with adequate probabilistic methods. The capacity factor of wind power in Finland has been rapidly increasing and this is likely to increase the capacity contribution as well - this should be considered in future analysis. Wind power does participate in the strategic reserve, because it does not make sense to move wind power plants from normal market operation to strategic reserve even when they become old.

G. Portugal

B: Portugal was one of the countries with an impressive increase in wind power deployment (5.2 GW) as well as in the annual share of wind generation in the final consumption (24%), only surpassed by Denmark. Instantaneously, the demand met by wind energy already achieved 110% [28]. Thus, the large-scale integration of stochastic renewable energy allied with a strengthening of the interconnection capacities between Portugal and Spain has added more challenges to maintain the balance between power supply and demand [29].

The first steps for the integration of wind power energy within the Portuguese electrical power system started in the early 1990th with the deregulation of electrical power system. To guarantee the energy supply security, long-term power purchase agreements (CAEs) were established. In these long term-contracts (no less than 15 years), the producers linked to the public energy service have pledged to supply all the energy produced in their respective power generation centers to the national power system. In 2007, with the first steps to implement the Iberian Electricity Market (MIBEL), most of the CAEs were replaced by a mechanism entitled maintenance costs for contractual balance (CMECs). Additionally, a target capacity payment scheme was designed. Under this scheme, pre-determined fees are fixed by the regulator and paid to capacity providers. The power plants receiving capacity payments participate only in the energy market.

M: In Portugal, the level of reserve requirements for security of supply standards comprises two equally binding parts related to adequacy and security aspects. In specific, adequacy is computed through the probabilistic Load Supply Index (LSI) with 95% and 99% exceeding probability whereas loss of load expectation (LOLE) is used to assess the security aspects. Based on the RESERVAS model [30] the TSO verify the suitability of the available operational reserve levels to cope with unexpected variations in wind power, power consumption and available power resulting from unavailability. According to recent studies from the TSO, the LOLE indicator should be equal to or less than 5 (h/year) [29].
C: Until recently, the remuneration for the capacity was defined through the CAE and CMEC bilateral contracts, and the value ratified annually by the regulator. Starting in 2017, a competitive auction mechanism was established by the government which remunerates only the availability of services to be delivered within pre-defined safety limits (and not the whole existing capacity). Thus, taking into account the operational requirements identified annually by the TSO, the regulator determines the total capacity which competitors should bid for and defines a maximum price per MW. All power plants with a nominal capacity equal or higher than 10 MW can bid in the auction. In 2017, that “bidding capacity” was set at 1,766 MW. In 2018, the yearly auction was postponed since the TSO did not identify any relevant risks that could jeopardize the security and guarantee of supply. If needed, the TSO should use the interconnections to Spain or the contracts of interruptibility with large consumers, to maintain the supply/demand balance.”

S: Operationally, to ensure the safety of the system, upward and downward reserves requirements were defined taking into account the average forecast error - 20% [31]. The value of these reserves corresponds to 10% of the forecasted wind generation. Within the ANEMO.plus project, a probabilistic operating reserve tool was developed and tested in Portugal. Results show that the deterministic reserve requirement is a reliable approach although; it can lead to operational conditions with a higher risk for the power system with high penetration of wind power [32].

H. Spain

B: In mainland Spain, wind installed capacity increased significantly in the last two decades, up to 22.9 GW in 2017 [33] 23% of the generation mix, supported by feed-in premiums and the availability of good onshore wind locations. In 2017, wind production supplied 19% of the electricity consumption in Spain (in 2013, this figure reached 22%). On the other hand, after the liberalization in 1998, and due to the low levels of interconnection between the Iberian Peninsula and the rest of Europe, the Electricity market revenues. The first is an investment incentive for thermal plants, mainly new CCGTs and refurbishment of coal plants that were needed to cope with high demand growth rates between 1998 and 2008. The second is an availability incentive for thermal plants, CCGT and coal, and pumping and storage hydro that are available and generating in the critical periods previously defined by the System Operator. Both type of incentives were set administratively by the regulator in €/MW for each technology. Wind installations are not rewarded under these capacity payments because wind and other renewable investment were supported by feed-in tariffs and premiums.

S: In Spain capacity credits used by the System Operator in system adequacy assessments are not related to current capacity payments for some generation facilities. For 2030 and 2050 scenarios, it is expected that wind and solar power capacity will continue growing steadily to reach penetration values that would exceed 50%. Under these circumstances, system adequacy becomes critical. Current discussions on the reforms to be introduced in the electricity market to achieve this objective point out the need for a new design of the capacity remuneration mechanism, more aligned with the recommendations given by the EU and based on competitive auctions where all generation and demand technologies will be able to offer their reliability [34].

I. Norway

B: The power supply in Norway is highly dominated by reservoir hydropower, which makes the system energy constrained (due to the seasonal and yearly variations in hydro inflow) rather than capacity constrained. The capacity margin has therefore traditionally been high, with limited need for specific capacity markets. The adequacy challenges in Norway occur mainly on regional level. Constraints in the transmission grid can give insufficient capacity margin in certain areas of the country that experience a large load increase. Development of wind power can increase the capacity margin and reduce the loss of load expectations in such areas [35].

M: Statnett is responsible for the supply security in Norway and uses today the “N-1” criterion as basis for assessing the need for grid reinforcements. At the same time, they are gradually increasing their use of different probabilistic models [36]. In a recent study of the supply situation in Northern Norway, Statnett used a combination of power market analysis, detailed grid simulations and outage analyses to calculate the impact of wind power on the Energy Not Supplied and Loss of Load Expectation in the region [37].

C: The system adequacy in Norway relies on a well-functioning spot market, different market products for reserves, abundance of reservoir hydropower and efficient arrangements for power exchange within the Nordic region and through cable interconnectors in the North Sea. In addition to this, Norway has a seasonal and weekly options market for regulating power (The “RKOM” market), where consumers and producers are paid to participate in the regulating market, to ensure sufficient reserves. Also, there are reduced grid tariffs for interruptible loads.

S: The main capacity challenges in Norway occur on in specific regions with limited grid capacity. Wind power can reduce the need for grid reinforcements in such areas, and the TSO uses different analysis methods (market simulations, grid analysis, LOLE calculations) to quantify the impact of wind power on the supply situation. On national level, there is an options market for ensuring sufficient reserves in the regulating market. Wind power has an indirect influence on this options market as wind variations and uncertainty influences the need for regulating power in the system.
J. Denmark

B: Denmark has the largest share of wind power in the world. In 2017, 43.4% of the consumption in Denmark was met by wind power. In 2017, Denmark had cumulative wind power capacity of 5475 MW.

Denmark has an atypical power system network in the way that Western Denmark (DK1) control area is synchronously connected to Continental Europe (CE) and Eastern Denmark (DK2) is connected to Nordic power system. These two areas are asynchronously connected through HVDC. This complexity makes it difficult and challenging to operate the network especially since the share of renewables is very high in Danish power system.

Historically, security of supply in Denmark has ranked among the highest in Europe, and the availability of power was 99.995% of the time in 2017 [38]. Danish TSO Energinet has set ambition to continue this level in future. However, major challenge in maintaining high security of supply in future will arise from phasing out of traditional thermal power stations.

M: Balance between production and consumption in Denmark is maintained through trading in electricity market. Electricity is traded in the day-ahead spot market based on wind forecast. Imbalance due to forecast error and contingencies are balanced through manual reserves within the operating hour through regulation power market.

Energinet is responsible for calculation of system adequacy. A stochastic tool called Forsynings sikkerhedsindeks (FSI) model is used for analyzing generation adequacy in Denmark. The model uses historical time series for electricity consumption and fluctuating electricity generation (wind and solar power). Electricity generation from thermal power stations and imports via interconnectors are stochastic. Planned outages are considered as deterministic. In future, Better Investment Decision (BID) model will be used which also considers compulsory heat productions for CHP and modelling of power situation throughout Europe. Generation adequacy is quantified in terms of Expected Unserved Energy (EUE) and Loss Of Load Expectation (LOLE). Sensitivity studies of the input are performed for reducing uncertainty of the results [38].

Results of generation adequacy analysis up to 2030 show that DK2 faces higher risk of power shortage than DK1 [39]. DK1 has larger capacity of interconnectors with neighboring countries as opposed to DK2. All results for DK1 show a risk of less than one weighted minute per year. DK2 is expected to have 11-42 weighted minutes per year from 2025-2030 (LOLE= 0.6-25 affected hours per year) [38].

C: It has been analyzed that a strategic reserve would be the best way of addressing the expected needs in future for DK2 as compared to capacity market. This reasoning is further justified since 2 neighbors of Denmark – Germany and Sweden also have strategic reserve. Denmark has many CHP generating both heat and power. Therefore, the possibility is analyzed to have a special type of strategic reserve allowing a CHP plant to continue to operate in the heating market, while also taking part in a strategic reserve. Cost analysis showed that the payments from consumers to generators in a capacity market could amount to approx. EUR 100 million per year – and more than three times as much if foreign capacity is to receive Danish capacity payments. However, strategic reserve in DK2 might result in payments of up to EUR 8 million from consumers to generators [40].

S: Denmark aims to continue high level of security of supply through regulation and balancing reserve market. Reserve estimation is based on dimensional fault as well as wind power forecast uncertainty is considered [41]. Generation adequacy is estimated using wind power as time series therefore indirectly wind power capacity credit is taken into consideration. Denmark has been adding interconnectors and will keep on doing so in future as well, reducing the risk of inadequacy.

III SUMMARY AND CONCLUSIONS

As shown above wind power has an estimated capacity credit in many power systems. However, if there is a payment for this or not depends on the market design which differs. Table 1 shows a summary of the result from the different systems.

Table 1 shows that all studied countries consider the capacity credit of wind power in their adequacy calculations although with different models. It can be noted that lack of “adequacy” in the calculation methods is mostly not defined as LOLP (Loss of Load Probability), but more “Need of Import Probability” NOIP, since all studied areas are interconnected to other areas, and most methods do not consider possibility of import. All countries have some kind of capacity market. In all countries except for Spain and Denmark, wind power has an impact on the capacity market. Only in France, Ireland and PJM can wind power receive capacity payments, but this is logical since the other systems have strategic reserves where most units do not get any payment.

<table>
<thead>
<tr>
<th>Area</th>
<th>Method for wind power capacity credit.</th>
<th>Capacity market</th>
<th>Wind power has impact on capacity market</th>
<th>Is wind power paid for the capacity credit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sweden</td>
<td>Probability of 90% of being exceeded = 9% of installed capacity</td>
<td>Strategic reserve</td>
<td>Yes: decreases need of strategic reserve</td>
<td>No</td>
</tr>
<tr>
<td>Great Britain</td>
<td>Equivalent Firm Capacity based on LOLE as the statistical risk metric</td>
<td>Centralized, with required capacity auctioned off in a transparent manner with 'pay as clear' auctions</td>
<td>Yes – but as it is presently ineligible for the market, it mainly reduces the amount of capacity that needs to be procured from other supply sources</td>
<td>Not directly in the capacity market at present, but wind does receive other subsidies from government schemes, which may include an element of the capacity value indirectly</td>
</tr>
<tr>
<td>France</td>
<td>Equivalence to perfect mean to respect LOLE = 3h</td>
<td>Decentralized Capacity market (obligation on suppliers)</td>
<td>Direct participation in capacity market (1 wind guarantee = 1 thermal guarantee = …)</td>
<td>Yes (but reduces other remuneration from energy market - ie. “Contract for Difference”)</td>
</tr>
<tr>
<td>Ireland</td>
<td>ELCC relative to LOLE</td>
<td>Two-part auction with</td>
<td>Yes, participation is</td>
<td>Yes, subject to voluntary</td>
</tr>
</tbody>
</table>
Table 1 Comparison on results from the ten different systems.

<table>
<thead>
<tr>
<th></th>
<th>target, within a least worst regrets approach</th>
<th>unconstrained (pay as clear) and constrained (pay as bid) mechanisms</th>
<th>permitted but voluntary, with low contribution at present</th>
<th>participation, but non-performance strike price penalties</th>
</tr>
</thead>
<tbody>
<tr>
<td>PJM</td>
<td>Three year average of capacity factor at peak load hours.</td>
<td>Capacity Market</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Finland</td>
<td>Wind power included in the LOLE calculations as time series.</td>
<td>Strategic reserve</td>
<td>Can decrease the need for the strategic reserve.</td>
<td>No</td>
</tr>
<tr>
<td>Portugal</td>
<td>Specific</td>
<td>Capacity Payment</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Spain</td>
<td>Probability of 95% of being exceeded</td>
<td>Capacity payments</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Norway</td>
<td>Combination of and grid simulations</td>
<td>Seasonal and weekly reserve options “4KOM”</td>
<td>Indirectly (WP may impact the request for reserve options)</td>
<td>No</td>
</tr>
<tr>
<td>Denmark</td>
<td>Wind power included in the EUE, LOLE calculations as time series.</td>
<td>Time limited Strategic reserve in future is possible for Eastern Denmark network</td>
<td>No</td>
<td>No</td>
</tr>
</tbody>
</table>

IV References


