Contents lists available at ScienceDirect

Renewable and Sustainable Energy Reviews

journal homepage: http://www.elsevier.com/locate/rser
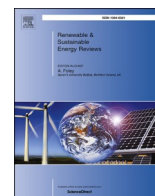
Review of wind generation within adequacy calculations and capacity markets for different power systems

Lennart Söder [a,*], Egill Tómasson [a], Ana Estanqueiro [b], Damian Flynn [c], Bri-Mathias Hodge [d], Juha Kiviluoma [e], Magnus Korpås [f], Emmanuel Neau [g], António Couto [b], Danny Pudjianto [h], Goran Strbac [h], Daniel Burke [i], Tomás Gómez [j], Kaushik Das [k], Nicolaos A. Cutululis [k], Dirk Van Hertem [l], Hanspeter Höschle [m], Julia Matevosyan [n], Serafin von Roon [o], Enrico Maria Carlini [p], Mauro Caprabianca [p], Laurens de Vries [q]

[a] KTH – Royal Institute of Technology, Stockholm, Sweden
[b] Laboratório Nacional de Energia e Geologia, Portugal
[c] University College Dublin, Ireland
[d] NREL / University of Colorado Golden/Boulder, United States
[e] VTT, Technical Research Centre of Finland, Finland
[f] NTNU, Norway
[g] EDF, France
[h] Imperial College London, United Kingdom
[i] PLEXOS/Energy-Exemplar Europe, London, UK
[j] Universidad Pontificia Comillas, Spain
[k] Wind Energy, Technical University of Denmark (DTU), Denmark
[l] ESAT-Electa, KU Leuven & EnergyVille, Belgium
[m] VITO & EnergyVille, Belgium
[n] Electric Reliability Council of Texas (ERCOT) Taylor, Texas, USA
[o] FfE Munich, Germany
[p] Terna Rete Italia, Italy
[q] TU Delft, Netherlands

ARTICLE INFO

ABSTRACT

The integration of renewable energy sources, including wind power, in the adequacy assessment of electricity generation capacity becomes increasingly important as renewable energy generation increases in volume and replaces conventional power plants. The contribution of wind power to cover the electricity demand is less certain than conventional power sources; therefore, the capacity value of wind power is smaller than that of conventional plants.

This article presents an overview of the adequacy challenge, how wind power is handled in the regulation of capacity adequacy, and how wind power is treated in a selection of jurisdictions. The jurisdictions included in the overview are Sweden, Great Britain, France, Ireland, United States (PJM and ERCOT), Finland, Portugal, Spain, Norway, Denmark, Belgium, Germany, Italy and the Netherlands.

1. Introduction

The world's total annual electricity consumption in 2018 was around

---

Nomenclature				
			MERM	Market Equilibrium Reserve Margin
			NERC	North American Electric Reliability Corporation
CAE	long-term power purchase agreements (Portugal)		NOIP	Need Of Import Probability
CCGT	Combined Cycle Gas Turbines		ORDC	Operations Reserve Demand Curve
CDR	Capacity, Demand and Reserves		RES	Renewable Energy Sources
CHP	Combined Heat and Power		RES-E	Renewable Energy Sources for Electricity
CM	Capacity Market		RKOM	Seasonal and weekly options market for regulating power (Norway)
CMEC	Maintenance costs for contractual balance (Portugal)			
CONE	Cost of New Entry		RM	Reserve Margin
CPM	Capacity Payment Mechanism		RMP	Reliability Pricing Model
DSO	Distribution System Operator		RoR	Run-of-River
EENS	Expected Energy Not Served		SARA	Seasonal Assessments of Resource Adequacy
EFC|	Equivalent Firm Capacity		SERVM	Strategic Energy Risk Valuation Model
EUE	Expected Unserved Energy		SO	System Operator
LOLD	Loss of Load Duration		SPAWCC	Seasonal Peak Average Wind Capacity Contribution
LOLE	Loss of Load Expectation		TSO	Transmission System Operator
LOLF	Loss of Load Frequency		VoLL	Value of Lost Load
LOLP	Loss of Load Probability			

26615 TWh [1] of which around 4.8% were served by wind power [2]. However, the share of wind power has increased significantly in the last few years, averaging a 20% increase between successive years [2]. The countries studied here are amongst the frontrunners in wind integration, serving on average 14.6% [2] of demand by wind power in 2018.

In addition to a trend of a significantly increased volume of wind generation, as well as solar power, there is an increasing discussion about ensuring generation capacity adequacy. The main reasons for this discussion are related to the reduction in conventional generation capacity (missing money problem and ageing generation assets) and ambiguity regarding the responsibility for adequacy determination, in particular for systems with liberalized markets. The reduction in conventional generation capacity has a number of causes that can vary by country including: declining investment costs of wind and solar power, policy decisions to phase out certain technologies, and the "missing money problem" [3]. Wind power does, in this context, certainly contribute to system adequacy through its capacity credit [4,5], which then reduces the need for other types of capacity, while achieving the desired level of reliability. In order to maintain high reliability, some jurisdictions have introduced different types of capacity markets [6] including strategic reserves, when energy-only markets were considered an ineffective approach to spur sufficient generation capacity adequacy.

The aim of this article is to provide an overview of how wind power is handled in this context across different systems. Implementations are showcased in fifteen different jurisdictions: Sweden, Great Britain (GB), France, Ireland, the United States (PJM and ERCOT), Finland, Portugal, Spain, Norway, Denmark, Belgium, Germany, Italy, and the Netherlands. The overview examines adequacy goals, capacity markets, how wind power capacity credit is estimated in different systems, if this capacity credit has any impact on the capacity market, and if wind power obtains any payments from the capacity market.

The rest of the article is organized as follows. Section 2 covers the challenges in regulation of capacity adequacy. Section 3 presents the capacity adequacy systems implemented in different countries. Section 4 summarizes the results and section 5 provides conclusions and discussions.

2. Challenges in regulation of capacity adequacy

2.1. Adequacy assessment

An adequacy assessment can be performed by a system operator (SO) or any other organization. It can be performed for different time horizons (week-ahead, seasonal, mid-term, years-ahead), scenarios (for example normal conditions, or rare extreme weather conditions, different forecasts of load growth, political agendas etc)), approaches (hourly, stochastic, probabilistic), using different metrics and criteria.

There are several reliability standards used around the world, which often differ both in the metric used and the parametric value for that metric. A common approach is to estimate the Loss of Load Probability (LOLP) or the Loss of Load Expectation (LOLE). These metrics represent the probability of an outage and the expected number of outage hours per year, respectively (e.g., LOLP = 0.05% and LOLE = 3 h/year). One can use probabilistic simulation such as Monte Carlo simulation to obtain an estimate of the LOLP and LOLE. In the United States (US) it is more common to adopt a slightly different definition such as "one day in 10 years", which corresponds to a LOLP for the peak hour for all days of each year being equal to 0.1 [7]. Energy-related reliability metrics include the Expected Energy Not Served (EENS), which captures the severity of the outages in terms of the energy that is shed. Examples of time-dependent reliability metrics are the Loss of Load Frequency (LOLF) and the Loss of Load Duration (LOLD) which capture the expected frequency and duration of outage events [8]. A more complete survey of reliability metrics can be found in Ref. [9].

These reliability metrics are often used as a basis when defining regional reliability standards. An example of this is the Northwest Power and Conservation Council (NWPCC) in the US which has an annual LOLP target of 5% (i.e. 1 year in 20 with reliability problems). Australia applies an ex-ante planning standard of a maximum expected unserved energy of 0.002% annually. In Denmark, the reliability requirements are expressed in terms of the maximum amount of domestic customer outage minutes (50 min for a network outage and generation inadequacy combined). In Europe, a reliability standard of LOLE expressed in hours/year is commonplace with GB, France and Belgium (3 h/year), the Netherlands (4 h/year) and Ireland (8 h/year), all using this metric [9].

The origins of the reliability standards in many systems are not completely clear. A formal cost-benefit analysis has been applied to derive a few of the reliability standards based on observations of the decreasing marginal value of adding more capacity beyond a certain level of reliability. Such a cost-benefit analysis depends on the Value of Lost Load (VoLL), which is a conceptually important parameter that represents the customer damage from an outage event with a direct monetary value. It is, however, hard to estimate in practice since the VoLL is likely to vary from customer to customer, and it is highly dependent on the timing, the frequency and duration of an outage. GB represents one example of formally expressing a methodological trade-off between the Cost of New Entry (CONE) and customer damage

caused by a capacity shortage [10]. Ireland has a similarly defined relationship between the LOLE, VoLL and CONE in its reliability standards [9]. Interestingly, Ireland considered the benefits of improving its LOLE standard from 8 h/year to a more binding reliability standard of 3 h/year, to match the neighbouring power systems. However, this proposal was rejected by the national energy regulator on the perceived grounds of being uneconomic [11].

The implementation of the different reliability standards by the local practitioners in question often varies with subjective input assumptions, modelling methods, choice of sensitivity analyses, *etc.* [9]. An example of this phenomenon relates to how the LOLE is defined regarding imports and exports. For example, assume that the LOLE is estimated to be 3 h/year. Does this then mean: i) in this system, some consumers will be involuntarily curtailed during 3 h/year, or ii) the expected number of hours per year with adequacy risk (e.g. lack of reserve) is 3? In the US/NERC (North American Electric Reliability Corporation) and France, the LOLP metric estimates the "adequacy for the generation resources and available interconnections only within the bidding area/country". This means that when estimating the LOLP in these systems, a "loss of load event" is defined as: "an event where the system requires import (if available) from outside the area/country in question to serve the demand".

Other sources of descrepancies between jurisdictions are which units are included in the adequacy evaluation, whether the demand is considered to be price sensitive and whether the reserves are included. In some cases, a loss of load event is defined as: "an event where the system needs to use reserve plants (if available)". In some systems, some consumers are affected by the day-ahead price, which can be high in a situation that is close to a shortage. In the future, consumers will have a higher potential to be price-elastic due to new devices that can provide flexibility. The share of electric vehicles will be higher and their demand may be considered as either fixed or flexible. The same applies to electric heating and air conditioning, amongst a range of different loads. The question is then whether the consumers will react to electricity price signals or if they will follow other/own objectives?

Based on variations in the implementation of the different reliability standards, it is clearly essential to link the method, and the data used to estimate the adequacy of a power system to the interpretation of the results for that estimation. One should, however, keep in mind that the reliability standards in place in many regions are seen as a worst-case lower bound rather than a legally binding target. The actual reliability of these systems is thus not necessarily characterized by their reliability standard alone, and the situation is often far more comfortable than the standard would suggest [9].

2.2. Capacity value of wind power

A generator's contribution to the generation capacity adequacy of a power system is more accurately captured by its capacity value than by its installed capacity through considering factors such as forced or planned outages, seasonal ratings and temporally limited primary energy supply. The latter is especially crucial for variable and uncertain renewable energy sources that behave quite differently from other sources. Their installed capacity gives limited information about their contribution to generation adequacy. Approaches to calculate the capacity value have been around since the 1960s when Garver generalized the loss of load probability mathematics and introduced a graphical method for estimating the effective load-carrying capability of a new generating unit [12]. The paper describes the effective capability of a new unit as "the load increase that the system may carry with the designated reliability". More specifically, this definition regards the capacity value of a new generator as the maximum amount that the load in the system, including this generator, can be increased by while keeping the reliability of the system at the same level as before this generator was included.

Wind power has a certain level of capacity value since it can generate

in a situation when there otherwise would have been a capacity deficit, i. e. wind power contributes to increased generation adequacy. In Ref. [13], the IEEE Power and Energy Society Task Force on the Capacity Value of Wind Power describes a preferred method for calculation of the capacity value of wind power. Relevant issues surrounding the method are discussed in addition to a description of approximate methods and their limitations. If wind power is included in a capacity adequacy evaluation mechanism, then it must be assigned a specific capacity value, which then depends not only on the definition, but also on the terminology used for adequacy.

2.3. Capacity remuneration mechanisms

Bublitz et al. [14] and Cigré [15] provide good overviews of several different capacity remuneration mechanisms. They specifically differentiate between six different types:

1. Tender for new capacity. Financial support is granted to capacity providers in order to ensure the required additional capacity. Different variations are possible, e.g., financing the construction of new capacity or long-term power purchase agreements.

2. Strategic reserve. A certain volume of capacity is contracted and held in reserve outside the energy-only market, being different from, and in addition to, operating reserves. The reserve capacity is only deployed if specific conditions are met, e.g., a shortage of supply in the spot market or a price settlement above a certain electricity price.

3. Targeted capacity payment. A central body sets a fixed price paid only to eligible generation capacity, e.g., selected technology types or newly built capacity.

4. Central buyer. The total volume of required capacity is set by a central body and procured through a central bidding process so that the market determines the price. Two common variants of the central buyer mechanism include the forward capacity market and reliability options.

5. De-centralized obligation. An obligation is placed on load-serving entities to individually secure the generation capacity needed to meet their consumers' demand. In contrast to the central buyer model, there is no central bidding process. Instead, individual contracts between load-serving entities and capacity providers are negotiated.

6. Market-wide capacity payment. Based on estimates of the level of capacity payments needed to bring forward the required capacity, a capacity price is determined centrally, which is then paid to all capacity providers in the market.

3. Wind generation in adequacy calculations and capacity markets in different jurisdictions

Wind power has varying availability, but can still possess a capacity value, although often lower (as a percentage of installed capacity) compared to conventional power plants. A range of capacity value estimation approaches have been considered in different power systems. In this section, fifteen systems across Europe and the United States are considered, following the structure outlined below:

B: Background of adequacy goals and targets
C: Capacity market set-up
W: Wind power impact on an adequacy assessment
M: Method to calculate the capacity credit of wind power
S: Summary and conclusion for how wind power is handled in capacity calculations and markets

3.1. Sweden

B: In Sweden, a strategic reserve was considered necessary and is implemented since 2002 when the system operator was allowed to purchase up to 2000 MW of peak capacity [16]. The system has changed slightly during the years and now also demand bids are accepted to the

strategic reserve [17]. There is currently (2019) no specific target concerning adequacy in Sweden. But the TSO sends an "adequacy report" to the Government for the coming winter every year.

C: The strategic reserve is organized by the TSO Svenska Kraftnät. In July each year, there is a tender for the coming winter. In this tender the TSO 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" includes the obligation that the capacity should be activated whenever the SO asks. For the winter 2018–2019, the TSO has contracted 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 [17]. The set-up with yearly tenders depending on need means that this is mainly a system for already existing assets, not for new units. However, also in the current system, there is a possibility to guarantee finance for a longer period, not only the coming winter.

W: Wind power contributed to 12% of Swedish energy supply in 2017 but is expected to double by the year 2022. By the same time, the oldest nuclear power plants will be closed, which has increased adequacy concerns. The current set-up is that the size of the strategic reserve is not coupled to the amount of wind power or nuclear power, but more to the legislation around it. However, the SO sends in an adequacy report to the government, and there the amount of different power plants is essential.

M: When the SO 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 [18]. The other types of power plants are handled in another way, i.e., the available capacity is set to a mean availability during the winter, e.g. 90%. This means that the SO 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, a power balance is estimated. Reserve plants are not included in the estimation.

S: The set-up means that more wind power will lead to an increased amount of available power, but this is not considered when SO decides on needs of a strategic reserve. So wind power, like all other production or demand resources which are paid within the "strategic reserve system", does not get any payment although they, in reality, contribute to the adequacy.

3.2. Great Britain

B: Great Britain (GB) national reliability standard is 3 h LOLE per year. National Grid Electricity System Operator has responsibility for administering the Capacity Market (CM), doing the analysis to derive the CM target requirement [19], as well as monitoring out-turn reliability in each Winter Outlook [20]. The UK Government's Secretary of State for Energy makes the final decision on all matters related to adequacy targets and the CM procurement.

C: The GB CM is in existence [21] since winter 2017/18 onwards when it replaced an earlier form of strategic reserve. It has annual, centrally-cleared, T-4 and T-1 auctions for delivery in 4-year and 1-year time horizons. The majority of the capacity is usually contracted four years ahead. The performance requirement for contracts is to be online and delivered 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 and most other forms of supply receive 1-year contracts.

W: 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 around 60 GW. 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 [22].

Wind power is recently eligible for the CM, though as most of the existing wind farms receive a subsidy and only capacity that receives no other form of support is allowed to participate, then the amounts of CM contracted wind is low to date. The overall Equivalent Firm Capacity (EFC) of the existing wind fleet (as well as the contribution of other CM-non-eligible sources) is subtracted from the total firm capacity required to meet 3-h LOLE, and this residual quantity is then that which is auctioned off in CM.

M: The wind EFC is the amount of perfectly reliable, infinite duration supply that can replace wind yet maintain the same reliability level [23, 24] - with the distinction between total EFC of the entire wind fleet, and incremental/marginal EFCs of additional wind units. In the recent 2017/18 Winter Outlook, the total wind EFC was calculated as ~17%. In a recent consultation by the ESO, the incremental/marginal EFC of wind was calculated around 8–14% depending on CM target year and onshore/offshore wind locations [23]. There is also a distinction now made between the risk metrics used for the EFC assessment – a recent decision was made to use expected energy userved (EEU) as the risk metric upon which to base the EFC of CM participant wind, whereas the overall national reliability standard is still in LOLE terms.

Both "time-collapsed" convolution [25] and "time-sequential" Monte Carlo models have been used to assess the generation adequacy of the GB system. The wind power stochastic variation has been represented using historical wind speeds from NASA MERRA atmospheric reanalysis data [26]. This provides, for each wind farm a position and hub height, hourly wind speed recorded in the past. This is converted to power using system averaged wind turbine power curves (separate ones for onshore and offshore) to get the total wind output. That is 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 LOLE/wind EFC. Presently, 13 years of historical data are used to represent stochastic variations of weather.

S: The CM framework and modelling methods continue to evolve, with a detailed policy review carried out every 5 years [23,27]. The majority of GB wind capacity has been developed with support from a subsidy and is thus ineligible for the CM, though it is foreseen that the recent CM adaptations to allow the participation of unsubsidized wind may change this in the near future.

3.3. 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 102 GW, with extreme volatility (20 GW 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 the 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-based approach) while encouraging adequate investment in generation and demand response capacities (supply-based approach), at a time when energy markets' ability to stimulate such investments was being questioned in much of Europe [28].

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 [29] for a capacity market (in addition to energy market), which have been debated and approved in 2015. This capacity market had just started for a first delivery year in 2017.

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

C: All of these productions can participate in 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 100 kW, for a specific year of delivery [30].

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. This so-called "normative" method is based on historical data (5 years for wind and solar, 10 for RoR), with specific parameters 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 = 3 h). 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 the 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.

W: Wind power in France accounted for 27.8 TWh corresponding to 5.8% of the power production during 2018 [31]. There is 15.1 GW of wind power capacity and the energy production increased with 15.3% compared to 2017.

M: Starting 4 years ahead of the delivery year, the capacity market aims at providing an economic 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".

The obligation is, for suppliers, to acquire enough guarantees according to their clients' consumption during Peak Periods (called PP1 for obligations). Guarantee acquisitions are 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 traded (in the capacity market).

Peak days PP1 & PP2 are during the winter period and announced by RTE in day-ahead. PP1 are 10–15 days/year, only on timeframe [7 h–15 h] + [18 h–20 h], and determined according criterion based on the level of consumption. PP2 are more numerous (10–25 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 = 3 h (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 participates in this mechanism and about 2.3 GW have been certified for 2018 (up to 2.5% of 92.6 GW of total certified capacity level for this delivery year) [32].

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.

3.4. Ireland

B: 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 [33]), and concerns about the exit of some existing market participants (partly associated with the introduction of new electricity market arrangements in October 2018), increased attention has been placed on system adequacy for the future Irish system.

Against this background, the capacity market arrangements incorporate locational capacity constraints in particular areas, e.g., larger Dublin region and N. Ireland. 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 [34]. 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 h per year, based on historical demand patterns and capacity de-rating.

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 were replaced by a capacity market (CM), in order to improve efficiency and achieve cost savings. Consequently, only capacity providers that have been successful in a 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.

W: 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 70% RES-E target was recently announced for

Ireland by 2030.

Under the pre-October 2018 capacity payment mechanism, based on plant availability, wind farms received approximately 7% of their revenues from capacity payments. However, within the new capacity market, only 187 MW of wind capacity was successful in the initial auction (100% of all capacity offered), with the vast majority of wind farm owners not submitting bids. For the second one-year auction (2019/20) the successful figure rose to 252 MW (100% of all capacity offered). A 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 - a market feature that does not suit variable and uncertain wind generation.

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 [35]. 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 neighbouring 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.

S: The new (capacity) market arrangements went live in October 2018, and two T-1 auctions have now taken place, with the second auction resulting in a slightly reduced clearing price, but a slightly increased total cost. The first T-4 auction is due to take place in 2019 for the 2022/23 capacity year. It may be expected that the auction and operational rules will gradually evolve over the next few years with increased experience, perhaps leading to increased participation from wind farms, acknowledging that legal challenges were seen for some of the outcomes of the initial capacity market auction.

3.5. United States

Since the United States has a number of different reliability areas, and many different RTO/ISO regions, as well as many vertically integrated utilities, a complete review of all of the different capacity adequacy calculations in place is beyond the scope of the current work. To highlight some interesting cases of special relevance to wind power we have focused on the PJM and ERCOT regions below. PJM is comparable to many of the European countries reviewed previously because it is a single area within an interconnection, while ERCOT is its own interconnection.

3.5.1. PJM

B: PJM is the transmission system and market operator for all or part of 13 states 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 8100 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) which ensures long-term grid reliability by procuring sufficient supply resources to meet forecasted future energy demands. This supply is procured with the intention of having sufficient planning reserve margin above the system peak demand. Capacity pricing is split into six different delivery areas to reflect transmission constraints within the system.

C: PJM's capacity market is known as the Reliability Pricing Model,

and a Base Residual Auction is conducted three years before the delivery year to procure resource commitments for capacity in each of the 27 Locational Deliverability Areas [36]. In addition, three Incremental Auctions for a delivery year are subsequently conducted to ensure adequate resources are available as the delivery year approaches. PJM recently transitioned to a capacity performance procedure whereby all resources with a commitment for a delivery year are subject to a Non-Performance Assessment, with potential charges to generators not adequately performing during emergency conditions.

W: 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, 1417 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.

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 p.m. through 6:00 p.m., 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 5-min data from the PJM state estimator without constraints, and linearly interpolated over the period with constraints [37].

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

3.5.2. ERCOT

B: ERCOT is the independent transmission system operator serving 90% of the electric load in the state of Texas, United States (US). The ERCOT system is summer peaking due to air conditioning load. The all-time peak demand occurred in July 2018 and was 73.3 GW [38]. ERCOT system is not synchronously interconnected with any of the neighbouring power systems. Five HVDC ties to the rest of the US and Mexico have total capacity of only around 1.2 GW. ERCOT therefore cannot rely on the neighbouring systems for reserves. Installed wind power capacity is 22 GW with almost 15 GW of additional planned wind projects with signed interconnection agreements currently in the interconnection queue as of March 2019 [39].

ERCOT is the only energy-only market in the US; that is, there is no capacity market.

Unlike other power systems in North America, ERCOT does not have a resource adequacy reliability standard or reserve margin requirement. The current minimum target reserve margin established by the ERCOT Board of Directors is 13.75% of peak electricity demand. In accordance with requirements set forth by North American Electric Reliability Corporation (NERC), ERCOT performs a biennial Probabilistic Risk Assessment and reports to NERC various probabilistic reliability metrics such as Expected Unserved Energy (MWh), Loss of Load Hours (hours/year), and Expected Unserved Energy as a percentage of Net Energy for Load with two- and four-year look-ahead periods.

Additionally, a study carried out in 2018 for ERCOT determined market equilibrium reserve margin (MERM) of 10.25%. The MERM describes the reserve margin that the market can be expected to support in equilibrium, as investment in new supply resources responds to expected market conditions. The study used Strategic Energy Risk Valuation Model (SERVM), which reflected ERCOT's wholesale market design and projected system conditions for 2022. The model probabilistically simulated the economic and reliability implications of a range of possible reserve margins under a range of weather and other conditions.

Table 1

US-Texas wind capacity contributions.

Wind Regions	Winter	Spring	Summer	Fall
Coastal	43%	68%	58%	39%
Non-Coastal	20%	30%	15%	37%

the report. Both reports calculate Reserve Margin (RM)[1] for the forecasted peak demand hour in the evaluated season for the SARA or summer and winter peaks for the next 5 years for the CDR. The SARA, in addition to a base case, also evaluates scenarios based on different forced and maintenance outage assumptions as well as an extreme low wind output scenario. These assessments do not account for total
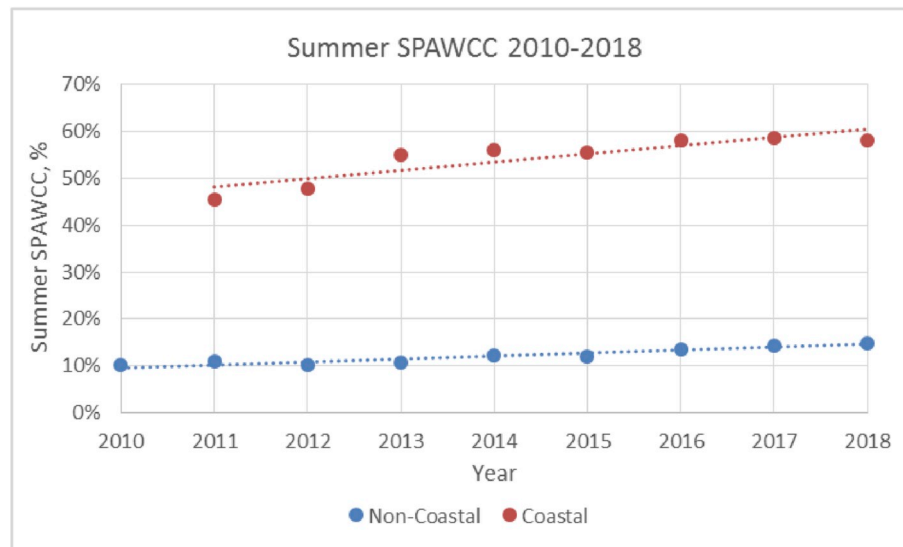

Fig. 1. US-Texas: Evolution of capacity contribution over time.

At a MERM of 10.25% the system could be expected to experience 0.5 loss of load events per year. This is higher than the 0.1 events per year LOLE standard used by most electric systems in North America for planning purposes [40].

C: As stated above, ERCOT does not have capacity market and relies on energy and Ancillary Services (AS) markets to provide incentives for new generation capacity. Energy and Ancillary Services are co-optimized in the day ahead, however real time market currently is energy-only. This construct does not consider opportunity cost of reserves in real-time. In June 2014 an improved scarcity pricing was implemented to support longer-term resource adequacy through proper price signals in the energy-only market [41].The approach determines a real-time online and offline reserve price adders based on the available reserves in real time and the Operations Reserve Demand Curve (ORDC). ORDC is based on analysis of the probability of reserves falling below the minimum contingency level multiplied by the difference between Value of Lost Load (VoLL) and System Lambda (shadow price of the power balance constraint).

The price, calculated as Locational Marginal Prices (LMPs) plus the online reserve adder, approximates the pricing outcome of real-time energy and Ancillary Service co-optimization since the adder captures the value of the opportunity cost of reserves based on the defined ORDC [42].

Currently, ERCOT is also working towards implementation of real-time energy and Ancillary Services co-optimization.

W: Wind power contributed 18.6% of ERCOT's energy supply in 2018 [38]. There is no specific strategic reserve coupled with the amount of wind power. ERCOT closely monitors generation capacity Reserve Margin (RM) and publishes a number of resource adequacy assessment reports through the year. These include quarterly Seasonal Assessments of Resource Adequacy (SARA) for the upcoming season and biannual Capacity, Demand and Reserves (CDR) report with a 5-year look-ahead period. Both reports include the existing generation capacity and future projects that fulfil certain planning criteria and exclude any capacity unavailable to ERCOT during the time horizon covered by

installed capacity of wind and solar generation but rather use seasonal peak average capacity contribution of wind and solar for the season under evaluation.

M: Seasonal Peak Average Wind Capacity Contribution (SPAWCC) in percent of installed capacity is an estimate of the percentage of wind capacity that can be expected to be available during the peak hours of a season. SPAWCC is updated after each season end. For a particular season, for the 20 peak load hours of the season, the capacity factor of wind generation is calculated based on the historical unconstrained[2] power production of operational wind power plants during those hours. The final SPAWCC percentage is a simple average of the past 10 years' values [43]. Currently, capacity contributions are calculated separately for two wind regions: Coastal and Non-Coastal. Coastal wind is positively correlated with load and therefore it has a higher capacity contribution. Table 1 shows SPAWCC percentages based on the most recent assessments for each season [44]:

These SPAWCC percentages are applied to the operational and planned wind capacity when calculating RM in both aforementioned capacity adequacy assessment reports. Fig. 1 shows the evolution of SPAWCCs since this assessment started in 2014. The increase in SPAWCC over time can be attributed to overall wind turbine technology improvements as well as wind projects being built in more resource-rich regions (e.g., the Texas Panhandle) once ERCOT's grid extended to those regions as a result of a large transmission network expansion project that went in service at the end of 2013.

Currently ERCOT is considering separating the Panhandle region from the Non-Coastal region. This region has considerably better wind conditions compared to the rest of Non-Coastal region and contains the

---

[1] Reserve Margin is calculated as Available Generation Capacity minus Forecasted Peak Demand.

[2] Unconstrained power production means the available wind power production prior to any curtailments that might have taken place during the evaluation period. All wind power plants telemeter to ERCOT both actual power production and unconstrained power production based on wind conditions at the time.

largest number of future planned projects. Additionally using capacity weighted average instead of simple average would give less weight to earlier years with less installed wind capacity. These two changes are expected to add to the evaluated RM (for example RM would increase by 1.17% if this method was applied in the CDR assessment for summer 2020).

S: Wind power in ERCOT contributes to overall generation capacity adequacy. The capacity contribution from wind generation is based on historic performance over 20 peak load hours in each season. ERCOT is continuously working on improving the assessment methodology of SPAWCC. ERCOT is an energy-only market so there is no mechanism for capacity remuneration.

3.6. 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.

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.

W: The share of wind power in 2018 was 7% of electricity consumption. It is poised to increase to around 10% in the next two years due to accepted bids from a government auction and due to market-based wind power. Since 2012 also wind power has been considered to contribute to the capacity adequacy in the estimation of the LOLE [45].

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 [46]. 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 for hydro power and combined heat and power as they only indicate what level of generation was economically viable in a given situation and this is heavily influenced by the prices in neighbouring markets among other things. For wind power, the problem is that new wind turbines have a much higher capacity factor than old ones and consequently historical record is of poor quality. 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.

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 not participate in the strategic reserve, because it would not fulfill the reserve requirements, but it would also not be profitable to move wind power plants from normal market operation to strategic reserve even when they become old.

3.7. Portugal

B: The first steps for the integration of wind power energy within the Portuguese electrical power system started in the early 1990s 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. These schemes represented the commitment of the Portuguese government to reduce the national power system dependency from fossil fuels and were always aligned with the Kyoto and European targets (e.g., in 2003 the expected renewable penetration into the electricity demand for 2010 was already 39%).

C: Until recently, the remuneration for the capacity was defined through the CAE and CMEC bilateral contracts. In 2017, a competitive auction mechanism was established by the government with the objective to only remunerate the necessary services (their availability) within pre-defined safety limits and, unlike before, not the whole contracted capacity. Thus, taking into account the operational requirements annually identified by the TSO, and after consultation of the national regulators a ministerial order determines the total capacity which competitors must bid for, also defining a cap price per MW. All power plants with a nominal capacity equal or higher than 10 MW can bid in the auction. It should be noted the technical capabilities of the bidders to provide the system services must be demonstrated, thus the auction naturally excludes variable renewable sources from providing services to the system. In 2017, that "bidding capacity" was set at 1766 MW. In 2018, the yearly auction was postponed once the TSO did not identify any relevant risks that could jeopardize the security of the system. If needed, the TSO should use the interconnections to Spain or the existing interruptibility contracts with large consumers, to maintain the supply/demand balance. Since that postponing, the capacity auction mechanism has been suspended being subject to EC assessment due to governmental concerns regarding the compatibility of this mechanism with the guidelines on state aid for the energy sector.

W: Portugal was one of the countries experiencing a strong wind power deployment that leads to an actual installed capacity of 5.2 GW as well as one of the highest annual share of wind generation in the final consumption (24%). Instantaneously, the demand met by wind energy already achieved 110% [47]. For 2030, the national targets for wind power capacity are between 8.8 and 9.2 GW, which includes repowering, overcapacity and new wind parks (onshore and offshore).

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) greater than 1 with 95% (one occurrence in 20 years) and 99% (one occurrence in 100 years) exceeding probability whereas loss of load expectation (LOLE) is used to assess the security aspects [48]. The LSI also contemplates a contribution from 10% of the net transfer capacity. Based on a sequential Monte Carlo reliability modelling tool (RESERVAS model [49]), 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) [48].

S: Operationally, to ensure the safety of the system, upward and downward reserves requirements were defined taking into account the average wind power forecast error – 20% [50]. The deterministic value of these reserves corresponds to 10% of the forecasted wind generation.

3.8. Spain

B: The System Operator, Red Electrica de España (REE), is responsible for the calculations of system adequacy in the Spanish electricity system. There is no formal obligation to submit periodic adequacy assessments to the regulator. The adequacy target used by REE is based on a deterministic criterion, under which the sum of the total firm generation capacity should be higher than the expected peak demand plus a 10% security margin. The adequacy calculations are made for peak demand in summer and winter. The firm capacity assigned to each generation technology is calculated depending on its availability to supply the peak load by applying a derating factor to the installed capacity. For conventional generators this factor is based on historical availability records, while for wind and solar is based on power productions with a probability to be exceeded. For instance, for nuclear power this factor is 0.97, for CCGTs is 0.96, while for solar photovoltaic is 0.14 and for wind 0.07 [51].

C: After the liberalization of the Spanish electricity sector in 1998, and due to the low levels of interconnection between the Iberian Peninsula and the rest of Europe, the Electricity Act introduced the possibility of allocating capacity payments to those generation facilities required to ensure system adequacy. In practice, capacity payments were implemented under two different remuneration schemes, on top of other generation market revenues. The first is an investment incentive for thermal installations, mainly new CCGTs and refurbishment of coal plants that were needed to cope with high demand growth rates between 1998 and 2008. These payments were set administratively in €/MW·year and allocated to plants that started operations between 1998 and 2016 during the first 10 years of operation. 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 of the year. These availability payments are set administratively by the regulator in €/MW·year for each technology by assuming different availability factors: Coal 0.912, CCGT 0.913, and pumping and storage hydro 0.237 [52]. In June 2018 availability payments were suspended.

W: In mainland Spain, wind installed capacity increased significantly in the last two decades, up to 23.5 GW in 2019, 23% of the generation mix, supported by feed-in premiums and the availability of good onshore wind locations. In the last years, wind production supplied, on average, 18% of the electricity consumption in Spain (in 2013, this figure reached 21%) [53]. Wind is also considered as a technology that contributes to system adequacy in a small proportion. As it has been commented, the capacity credit used by REE in adequacy assessments for wind is around 0.07.

M: This capacity credit is calculated as the power that can be injected by wind in peak demand periods with a probability to be exceeded by 95%. In past studies, wind capacity credits have been close to 7%, with minor oscillations between winter and summer.

S: In Spain capacity credits calculated by the System Operator in system adequacy assessments are not related to the capacity payments allocated to some generation facilities. In particular, wind installations are not rewarded under these capacity payments because wind and other renewable were supported by feed-in tariffs and premiums ensuring a rate of return to the investment. For 2030 scenarios, it is expected that wind and solar power capacity will continue growing steadily to reach penetration values that would exceed 60%. Under these circumstances, system adequacy becomes critical. Current discussions on the reforms to

be introduced in the electricity market to achieve this renewable target point out the need for a new design of the capacity remuneration mechanism, more aligned with the new EU Regulation on the internal market for electricity and based on competitive auctions, where all generation and demand technologies will be able to offer their contributions to achieve the adequacy target [54].

3.9. 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. Availability of power is in general very high; for 2017 it was 99.88%, while the average since 1998 is 99.83% [55]. Most of the outages were due to problems in the distribution grids.

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. In RKOM, consumers and producers are paid to participate in the regulating market, to ensure sufficient reserves. In addition to this, there are reduced grid tariffs for interruptible loads, so they can reduce their power output on request from the SO in constrained situations.

W: Wind generation in Norway was 4 TWh in 2018, which was about 3% of the consumption. However, wind is growing rapidly in Norway; there were 2 GW under construction by the end of 2018, and another 3 GW given permission. With these planned plants in operation, wind will cover about 16% of Norwegian consumption [56].

The energy security in Norway relies on sufficient stored hydropower during the winter, when there is low inflow to the reservoirs as most lake surfaces are layered with ice. It was early shown that wind power has a positive effect on this situation, since the wind speed in Norway is highest during winter on average [57]. The hydropower producers can thus reduce the water spent during winter in the presence of wind power, and increase the energy supply security.

Other Norwegian studies have shown that wind power can increase the capacity margin and reduce the loss of load expectations in regions limited grid capacity [57]. The capacity credit of wind power in such areas was found to be significantly improved if wind power plants are spread over a large area.

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 [58]. 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 [59].

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. Finally, wind power has a positive effect on the energy supply security during winter when reservoir hydro has reduced availability.

3.10. Denmark

B: The Danish power system is split into two non-synchronous areas: Western Denmark (DK1) which is part of the Continental Europe (CE) synchronous area and Eastern Denmark (DK2) which is part of the Nordic synchronous area. 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. The total outage duration in Denmark was for 25 min in 2017, of which 92 s resulted from incidents in the transmission grid [60]. Danish TSO Energinet has set the ambition to continue this level in future. However, major challenge in maintaining high security of supply in future will arise from phasing out of conventional thermal power stations.

C: Currently, there is no capacity market in Denmark. It has been analyzed that a strategic reserve might 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 [61].

W: Denmark has the largest share of wind power in the world. In 2017, 44.7% of the power consumption in Denmark was met by wind power, with a cumulative wind power installed capacity of 5.475 GW. Increasing share of wind power and solar power in Danish power system has not affected the level of security of supply until now. With the increase in total installed production capacity, challenges for the security of supply due to variability and fluctuations of renewable power are augmenting. To meet these challenges, Denmark has significant exchange capacity (expected to grow further in future) in relation to the size of consumption.

M: Energinet is responsible for the security of supply in Danish power system. Balance between production and consumption in Denmark is maintained through trading in electricity markets, manual and automatic reserves. 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 Forsyningssikker-hedsindeks (FSI) model is used for analyzing expected future 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. The stochasticity is modelled as the probabilities of breakdown or maintenance. Planned outages are considered as deterministic. The model operates on hourly basis therefore intra-hour fluctuations are not taken into account. FSI model tends to overestimate the risk of power shortages [60]. In future, Better Investment Decision (BID) model will be used which also considers compulsory heat productions for CHP, flexible energy consumption and modelling of power situation market throughout Europe, therefore incorporating other nation's impact on Danish generation adequacy. 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 [60].

Results of generation adequacy analysis up to 2030 show that DK2 faces higher risk of power shortage than DK1 [62]. DK1 has larger capacity of interconnectors with neighbouring 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 to 2030 (LOLE = 0.6–25 affected hours per year) [60].

S: Denmark aims to continue maintaining a high level of security of supply through regulation and balancing reserve market. Reserve estimation is based on dimensional fault, but wind power forecast uncertainty is also considered [63]. 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 [60].

3.11. Belgium

B: Belgium has recently seen several important changes affecting adequacy: a planned nuclear phase-out, strong increase in wind and solar power capacity and an increased interconnectivity to neighbouring markets. In 2005, the decision was made to phase out nuclear power plants when they reach a lifetime of 40 years, resulting a planned phase out of the 7 nuclear reactors between 2015 and 2025. At that point, a reservation was made to delay the phase-out in case adequacy could not be guaranteed. This uncertainty contributed to a lack of investments in alternative sources, and made a prolongation by 10 years of the oldest plants necessary. The current schedule is to decommission all 7 power plants (+/- 6 GW) between 2022 and 2025, again with a reservation that adequacy must be guaranteed. At the same time renewables, mainly solar and wind, have increased significantly, with resp. 3.6 and 7.7% of the energy production in 2017 [64]. The third evolution is the continued development of the Internal Energy Market and interconnection capacity which has resulted in an increased coupling and a strong convergence in electricity prices with neighbouring countries France and the Netherlands. The above led to few investments in conventional power plants. In the winter of 2014/15 and 2018/19, even schedules for involuntary load shedding after unscheduled unavailability of multiple nuclear power plants were put in place [65].

The criteria for the targeted level of system adequacy are described by federal law in terms of LOLE. They are set to a yearly LOLE 3 h/year and 20 h for the LOLE95, i.e., once in 20 years [66].

C: To reduce the risk of an electricity supply shortage during winter, Belgian authority has decided that strategic reserves are contracted for the first time in 2014/15. The main objective was to contract retired and mothballed conventional generation capacity, complemented with demand response, to ensure the availability of sufficient capacity to meet peak demand levels. An active participation from wind power was not foreseen.

The contracted strategic reserves are activated by Elia, the Belgian TSO, responding to either economic or technical triggers. The economic trigger is linked to insufficient supply to meet the demand in the day-ahead market. The technical trigger is linked to the risk of structural shortage within the control zone.

Each year an assessment for the need of strategic reserves is conducted by the TSO. The analysis determines the required volume of capacity to reach the reliability criteria put forward by the law, i.e., LOLE of 3 h/year, under different scenarios and sensitivities [67].

W: In 2018, wind power capacity had a share of about 11%. The increase of installed wind power is expected to continue at the same speed or even increase. For onshore wind, Elia assumes an increase of 230 MW/year totalling to 3 GW by 2021. For offshore wind, cautious scenarios even include a doubling of capacity from 1 GW to 2.2 GW in 2021, with plans to go up to 4 GW by 2024 [68].

In 2018, the total generation of wind was 6.27 TWh corresponding to a share of 8.9% of the total energy generated [69]. Assuming the nuclear phase-out and the expected increase, the impact of wind power for system adequacy will become extensive.

M: The assessment of the need for strategic reserves is done yearly by Elia using a probabilistic analysis resulting in an adequacy report [70]. Historical wind speeds from the past 34 years are considered. An hourly dispatch model for multiple scenarios is then used to calculate the volume needed to reach the LOLE target [70]. Hence, an increased contribution of wind power to system adequacy would implicitly result in the reduction of the needed volume.

S: So far, wind power cannot take an active part in the strategic reserves to cover winter peaks. The contribution of wind is accounted for during the assessment of system adequacy in the form of different scenarios and sensitivities. As a consequence, wind power is not remunerated for its contribution to system adequacy in any form, even de-rated.

However, the capacity mechanism in Belgium is currently under review. The current draft version aligns with the concepts of Reliability Options and would allow wind to participate and valorize its contribution. Contributions to system adequacy in Belgium will remain of high value as investments to compensate the nuclear phase-out remain scarce. The continued expansion of interconnections with neighbouring countries make it necessary to evaluate the way system adequacy is organized, from purely national point of view, or at a regional or even EU level.

3.12. Germany

B: There are no explicit adequacy goals in Germany as the response of the German government shows [71]. This official response was given to a request concerning the adequacy goals of electricity. Nevertheless security of supply in Germany has ranked among the highest in the world, and the system average interruption duration index was 15.17 min or in other words, the availability of power was 99.997% of the time in 2017 [72].

C: In Germany the capacity market can be distinguished between a capacity reserve, a standby reserve and a grid reserve. The capacity reserve should ensure that the demand of the wholesale electricity market can always be met. The implementation of the capacity reserve is on hold, because of concerns of the European Commission. The standby reserve is limited to old lignite power plants. The main goal of implementing this reserve was to reduce CO_2 emissions by shutting down lignite power plants. Power plants will be decommissioned after four years in the standby reserve. The grid reserve ensures the security of supply in the southern part of Germany until the planned grid extension of the transmission network is fulfilled.

W: Wind power contributed to 16% of German energy supply in 2017 [73]. This share is still growing. Furthermore, by law, all nuclear power plant will be phased out until 2022 and an agreement to shut down all lignite and hard coal power plants until 2038 has been negotiated.

M: Every year, the TSOs calculate the adequacy by comparing the maximum load of the previous year with the calculated capacity credit of all kinds of generation. The capacity credit of wind power is calculated as the minimum value of the previous years and constantly reached 1% in the past [74]. In addition, the Federal Network Agency (BNetzA) publishes a report for the grid reserve capacity for the next two winter periods [75]. For this report a system analysis including grid constraints is performed by the TSO and reviewed by the BNetzA. The results are used as a basis for contracting the grid reserve capacity. This is done by suppressing planned shut downs of generation capacity. For the winter 2018/2019 the grid reserve capacity was 6.6 GW. In the winter 2017/2018 the contracted 10.4 GW were employed on 105 days. Additionally the TSOs calculated the need to build up 2 GW in the Southern part of Germany in the next years.

S: The contribution of wind power has been considered in the capacity adequacy calculation with a factor of 1%. The capacity factor of wind power in Germany has been a constant value over the last years. The main capacity challenges in Germany occur on in the regions from North-East to South-West with limited grid capacity. Herefore the TSOs use different analysis methods (market simulations and grid analysis) for the network development plan and the calculation of the grid reserve capacity.

3.13. Italy

B: Italian electric yearly consumption significantly decreased after 2008 as a consequence of the world-wide economic crisis and, partially, of the increased energy efficiency of domestic and industrial devices (reaching 321 TWh in 2017). In parallel an increased amount of electric cooling systems and/or heat pumps have been installed, increasing the sensitivity of the electrical load to the weather conditions (e.g. temperatures). As a result, during July 2015 the historical peak load (~60 GW) has been registered due to a long-lasting heat wave.

The generation fleet is currently composed by thermal power plants (~62 GW in 2017), hydro power plants (~22 GW), wind (~10 GW) and solar (~20 GW). Starting from 2012, around 15 GW of thermal power plants have been decommissioned due to a missing money problem, caused by the simultaneous demand drop, the significant uptake in wind and solar installed capacity, the effect of permission rights and environmental standards that all contributed to reducing the profitability of the most obsolete plants, less competitive and high emissions plants.

Terna, the Italian Transmission System Operator (TSO), regularly carries out adequacy assessments targeted to different time horizons, both at the national level and at European level (the latter, in the framework of Entso-E MAF, Seasonal Outlook and SMA report). LOLE and EENS are the most relevant indicators monitored in probabilistic assessments, while adequacy margin (computed as the difference between the expected values of available capacity and demand) is considered when a deterministic approach is applied (mainly in the short-term timeframes).

C: Italian NRA's Decision 379/03 introduced a temporary targeted capacity payment mechanism: power plants admitted to the ancillary service and balancing markets receive a fixed premium (€/MWh) for each unit of capacity (MW) made available during the critical hours identified ex-ante by Terna. As well, a new capacity remuneration mechanism has been defined in recent years and will hopefully entry into force by the end of 2019. The new capacity market [76] is a Central-buyer market-wide mechanism, where reliability options [77] are traded, in multi-area multi-round descending clock auctions, four years ahead of the delivery period.

All kinds of resources, including demand response, existing and new capacities, domestic and foreign, are allowed to participate in the auctions, whereby reliably available capacity is computed according to proper derating factors.

Capacity demand curves (one for each market area of the Italian power system) are simultaneously determined by Terna using iterative multi-area reliability simulations. In particular, the LOLE indicator is apprised via Monte Carlo simulations for each delivery year, assuming a starting generation fleet (mainly based on the current set and on the RES penetration forecast scenarios). In a second step, peak generators are progressively installed/decommissioned to meet three different LOLE target levels instructed by the Italian Ministry of Economic Development. The premium for each break-even point is then defined by the Italian National Regulatory Authority (ARERA).

W: Wind contribution to the yearly electric supply is of about 5% (~18 TWh in 2017). Anyhow its infeed is really variable: average value in 2017 has been around 2000 MW with a standard deviation of about 1500 MW (relative standard deviation of about 75%), ranging from a minimum infeed of nearly 0 MW to a maximum of more than 6500 MW. For this reason, when a deterministic approach is adopted to assess the Italian resources adequacy, the 10th percentile of historical time series is typically considered and vice versa. Proper probability distribution of the wind load factor for each relevant area of the Italian system (derived from historical wind speed data) is considered when probabilistic assessments are carried out (e.g. for capacity market demand curves).

M: Terna is currently considering to compute the amount of capacity credits for each wind power plant as the product between its installed capacity and the wind rating factor. This latter term is calculated as follow:

1. In each generation scenario, resulting from capacity demand curve simulations, all the wind installed capacity is decommissioned.
2. LOLE is re-assessed in the new scenarios (by definition, the new value is generally higher than the correspondent scenario target).
3. Standard thermal peak power plants are then put in operation progressively till the LOLE value falls below the relevant target value.
4. For each scenario, the ratio between the additional thermal capacity, installed to meet the target LOLE, and the decommissioned wind capacity is accounted.
5. The average value between the three ratios is assumed as the relevant rating factor for wind.

Current estimations provide values in the range of 15–20%.

S: Wind installed capacity significantly increased in recent years and this trend is expected to endure, thanks to the National and European Climate and Energy Policies. While a significant contribution in terms of energy supply (and CO_2 emissions reduction) is expected, the stable contribution of its infeed will remain quite non-reliable (at least, until the forthcoming 6 GW deployment of additional storage systems needed to cope with planned 30% share of energy from renewable sources in gross final consumption of energy in 2030). Wind power plants are expected to be accounted for in the upcoming new Italian capacity market with a probabilistically computed rating factor.

3.14. The Netherlands

B: The Netherlands has a rapidly increasing share of wind and solar energy. While the current share of renewable energy is small, by 2030 the volume of installed wind generation capacity should be close to peak electricity demand. In 2017, the share of wind energy in the Netherlands was 9.6 TWh, which was 8.0% of electricity consumption. The volume of generated wind energy was 15% higher than in 2016 [78]. The Netherlands has a highly reliable power system. On average, a Dutch customer experiences 32.12 min/year of interrupted power service, but this is entirely due to network service disruptions [79]. The LOLE standard is 4 h per year, but the country has not needed to curtail load due to a shortage of the supply of electricity at any time since the liberalization of its electricity market. The LOLE is calculated with a European dispatch model, together with neighbouring countries in the Pentalateral Forum, which considers the contribution of cross-border trade to the security of supply. Solar and wind energy are included by running the model for 34 weather years. The estimated LOLE was 0.00 for 2014 and 2015 and is currently at 0.01 min/year. It is expected to increase to 2.50 by the middle of the coming decade, but many factors cause this number to be uncertain [79].

C: The Netherlands does not have a capacity (remuneration) mechanism. In 2004, the Electricity Act was changed to provide the TSO with the juridical means to implement a strategic reserve, but this was not implemented [80].

W: The volume of wind energy in the Netherlands is expected to increase rapidly, mainly due to the tendering of large offshore wind parks. The current total wind generation capacity (on and offshore) in the Netherlands is 4.2 GW. By 2022, this is expected to increase to 7.2 GW, growing further to 10.0 GW in 2025 and 18.3 GW in 2033. This compares to a peak demand of 18.5 GW in 2018, which is expected to stay more or less flat over the next 15 years [79].

M: TenneT does not publish data on the contribution of wind energy to firm demand. For the Netherlands in isolation, this contribution probably is small or zero, as windless periods occur during winter consumption peaks, but when imports are considered there may be a positive contribution.

Table 2
Comparison concerning reliability targets and capacity markets.

Area	Reliability Target	Capacity market	Capacity market horizon
Sweden	High reliability with reasonable cost	Strategic reserve	Tender for one year at the time
Great Britain	3 h LOLE/year	Centralized, with required capacity auctioned off in a transparent manner with 'pay as clear' auctions	Two auctions - 4 years and 1 year ahead of the delivery year
France	LOLE = 3 h	Decentralized Capacity market (obligation on suppliers)	Regular auctions, beginning 4 years ahead the delivery year.
Ireland	LOLE = 8 h	Two-part auction with unconstrained (pay as clear) and constrained (pay as bid) mechanisms	Two auctions - 4 years and 1 year ahead of the delivery year
US-PJM	One day, on average, every 10 years	Capacity Market	One Base Residual Auction and three Incremental Auctions per delivery year.
US-ERCOT	13.75% target reliability margin	None	N/A
Finland	High reliability with reasonable cost	Strategic reserve	Tender every three years
Portugal	LOLE = 5 h	Strategic reserve[a]	Long term (CAE/CMECs)/annual (auction)
Spain	Firm capacity = 110% of peak load	Targeted capacity payment	Investment incentive: first 10 years of operation; Availability incentive: annual payment
Norway	"Goal of secure power supply"	Seasonal and weekly reserve options "RKOM"	N/A
Denmark	"Keep a high reliability"	Time limited Strategic reserve in future is possible for Eastern Denmark network	N/A
Belgium	LOLE 3 h/year and 20 h for a once in 20 year	Strategic reserve	Tender for one year at the time with updated reserves volumes based adequacy assessment executed by the TSO
Germany	No reliability target	Capacity reserve, standby reserve, grid reserve	No market, regulated by theFederal Network Agency
Italy	LOLE defined by the Italian Ministry of Economic Development	Central-buyer market-wide mechanism, where reliability options are traded	Delivery period: 1 year for the main auctions, then monthly products can be traded in a secondary market.
Netherlands	LOLE = 4 h	None	N.A.

[a] In Portugal is in a transition phase and still exist earlier long-term capacity payments mechanisms.

S: In summary, the Netherlands has relied on the energy-only market design and has not experienced power shortages to the extent that load has had to be curtailed. The plan to phase out 4 GW of coal plant and the increased reliance on wind and solar power may be reasons for reconsidering the market design.

Table 3

Comparison of results from the 15 different systems.

Area	Method for wind power capacity credit.	Has wind power an impact on the capacity market?	Is wind power paid for the capacity credit
Sweden	Probability of 90% of being exceeded = 9% of installed capacity	No: Wind power capacity credit is not considered concerning size of strategic reserve	No
Great Britain	Equivalent Firm Capacity based on Expected Unserved Energy as the statistical risk metric CM participant wind is paid marginal EFC, overall wind fleet is represented by total EFC	Yes – but as it is mostly ineligible for the CM due to most of the wind projects receiving subsidy, it mainly reduces the amount of capacity that needs to be procured from other supply sources via it's total EFC	CM participant wind is paid as per the marginal EFC. Remainder of the non-CM-participant wind gets subsidies from government schemes, which may include an element of the capacity value indirectly
France	Equivalence to perfect mean to respect LOLE = 3 h	Direct participation in capacity market (1 wind guarantee = 1 thermal guarantee = …)	Yes (but reduces other remuneration from energy market - ie. "Contract for Difference")
Ireland	ELCC relative to LOLE target, within a least worst regrets approach	Yes, participation is permitted but voluntary, with low contribution at present	Yes, subject to voluntary participation, but non-performance strike price penalties
US-PJM	Three year average of capacity factor at peak load hours.	Yes	Yes
US-ERCOT	Ten year average of capacity factor at peak load hours in each season	N/A	No
Finland	Wind power included in the LOLE calculations as time series.	Can decrease the need for the strategic reserve.	No
Portugal	Combination of i) of 95% and 99% exceeding probability and ii) Wind power included in the LOLE calculations as time series.	Yes	No
Spain	Probability of 95% of being exceeded	No. Capacity payments are independent on wind firm capacity	No
Norway	Combination of power market and grid simulations	Indirectly (WP may impact the request for reserve options)	No
Denmark	Wind power included in the EUE, LOLE calculations as time series.	No	No
Belgium	Scenario based probabilistic assessment (Monte Carlo with hourly dispatch on 30 scenario years)	Indirectly (Adequacy assessment to determine volume of strategic reserves)	No
Germany	1% capacity credit	Indirect: due to the regional focus of installed wind power in the northern part, a grid	No

Table 3 (*continued*)

Area	Method for wind power capacity credit.	Has wind power an impact on the capacity market?	Is wind power paid for the capacity credit
Italy	Equivalent Firm Capacity based on LOLE taken as statistical risk metric	reserve is needed for the southern part Direct participation to capacity market	Yes, if selected in the capacity auction
Netherlands	N.A.	N.A.	N.A.

4. Summary

In the investigated systems, wind power is taken into account when calculating the capacity credit. However, whether there is a payment for this or not depends on the market design, which differs between jurisdictions. Table 2 presents a summary from the different studied jurisdictions concerning reliability targets and capacity markets.

Table 3 shows that the jurisdictions in all studied zones consider the capacity credit of wind power as part of their adequacy calculations, although adopting a range of different models. It also shows the possibility for wind power to be paid for it's capacity credit. It can be noted that a lack of "adequacy" in the calculation methods is mostly not defined as LOLP (Loss of Load Probability), but more accurately as "Need of Import Probability" (NOIP), since all studied zones, except for ERCOT, are interconnected to other areas, and most methods do not consider the possibility of import. All studied zones, except for ERCOT and the Netherlands, have some form of capacity market. In all of those jurisdictions, except for Spain and Denmark, wind power has an impact on the capacity market. However, only in France, Ireland and PJM can wind power receive capacity payments.

5. Conclusions and discussions

The conclusion is that wind power will obtain a greater and greater impact on the real adequacy level as this source increases its share. It is also important to note that real adequacy, i.e. considering the risk of involuntary load disruption, includes the possibility of import to the studied area, and with larger volumes of wind power, more transmission between areas will become increasingly beneficial. Today, the value of this import is often not considered in neither the adequacy calculations, nor the payment structures.

In markets with a "strategic reserve" there is no payment to wind power, although wind power should have an impact on the size of the strategic reserve if it is set to obtain a certain adequacy level. However, none of the power plants outside this market receives any compensation from it, even if they should have an impact on the size of it. So wind power is here treated in the same way as the other non-participating power plants.

It is recommended that with larger shares of wind power, the current electricity market structures and power system operation should adapt to reflect reality. This then includes that wind power true capacity value in both studied and neighbouring areas as well as real import possibilities should be considered in adequacy analysis. Concerning payments in capacity markets, it is fair that wind power should be paid in relation to its contribution to adequacy in the same way as other power plants.

Declaration of competing interest

According to https://www.elsevier.com/wps/find/journaldescription.cws_home/600126?generatepdf=true: "Declaration of interest all authors must disclose any financial and personal relationships with other people or organizations that could inappropriately influence (bias) their work. Examples of potential competing interests include employment, consultancies, stock ownership, honoraria, paid expert testimony,

patent applications/registrations, and grants or other funding. Authors must disclose any interests in two places: 1. A summary declaration of interest statement in the title page file (if double-blind) or the manuscript file (if single-blind). If there are no interests to declare then please state this: 'Declarations of interest: none'. This summary statement will be ultimately published if the article is accepted. 2. Detailed disclosures as part of a separate Declaration of Interest form, which forms part of the journal's official records. It is important for potential interests to be declared in both places and that the information matches." Concerning this paper submission: "Declarations of interest: none".

Acknowledgements

References

[1] BP. BP statistical review [Online]. Available: https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2019-full-report.pdf. [Accessed 18 June 2019].

[2] BP wind power statistics 2018 [Online]. Available: https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/xlsx/energy-economics/statistical-review/bp-stats-review-2019-all-data.xlsx. [Accessed 18 June 2019].

[3] Hogan M. Follow the missing money: ensuring reliability at least cost to consumers in the transition to a low-carbon power system. Electr J 2017;30(1):55–61.

[4] Holttinen H, et al. Design and operation of power systems with large amounts of wind power; Final summary report. IEA; 2015. IEA WIND Task 25, Phase three, 2012-2014.

[5] Tómasson E, Söder L. Multi-area generation adequacy and capacity credit in power system analysis. In: 2017 IEEE innovative smart grid technologies - asia (ISGT-Asia); 2017.

[6] Baldick R, Helman U, Hobbs B, O'Neill RP. Design of efficient generation markets. Proc IEEE 2005;93(11):1998–2012.

[7] North American Electric Reliability Corporation. Standard BAL-502-RF-03 [Online]. Available: https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-502-RF-03.pdf; 2017.

[8] Heylen E, Deconinck G, Van Hertem D. Review and classification of reliability indicators for power systems with a high share of renewable energy sources. Renew Sustain Energy Rev 2018;97:554–68.

[9] Burke D. National grid security of supply international survey [Online]. Available: https://nwcouncil.app.box.com/s/ssstzoyl5yioa9awmmbmol7by4upxccm. [Accessed 28 August 2018].

[10] Department of Energy & Climate Change. Annex C: reliability standard methodology [Online]. Available: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/223653/emr_consultation_annex_c.pdf. [Accessed 16 August 2019].

[11] SEM Committee. Capacity remuneration mechanism detailed design. 2015.

[12] Garver LL. Effective load carrying capability of generating units. IEEE Trans Power Apparatus Syst 1966;(8):910–9.

[13] Keane A, et al. Capacity value of wind power. IEEE Trans Power Syst 2011;26(2):564–72.

[14] Bublitz A, et al. A survey on electricity market design: insights from theory and real-world implementations of capacity remuneration mechanisms. Energy Econ 2019;80:1059–78. https://doi.org/10.1016/j.eneco.2019.01.030.

[15] Cigre: Study Committee. C5, "technical brochures: capacity mechanisms: needs, solutions and state of affairs," [Online]. Available: https://e-cigre.org/publication/647-capacity-mechanisms-needs-solutions-and-state-of-affairs. [Accessed 22 May 2019].

[16] Söder L. Analysis of pricing and volumes in selective capacity markets. IEEE Trans Power Syst 2010;25(3):1415–22.

[17] Svenska Kraftnät. The Swedish strategic reserve (in Swedish) [Online]. Available: https://www.svk.se/aktorsportalen/elmarknad/reserver/effektreserv/. [Accessed 5 September 2018].

[18] Svenska Kraftnät. "Power balance on the Swedish power market, report 2018 (in Swedish)," 28 06 2018 [Online]. Available: https://www.svk.se/siteassets/om-oss/rapporter/2018/kraftbalansen-pa-den-svenska-elmarknaden-rapport-2018.pdf. [Accessed 5 September 2018].

[19] National Grid ESO. The GB electricity capacity report [Online]. Available: https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/189/Electricity%20Capacity%20Report%202018_Final.pdf. [Accessed 28 August 2018].

[20] National Grid ESO. The GB winter outlook report [Online]. Available: https://www.nationalgrideso.com/insights/winter-review-and-consultation. [Accessed 16 August 2019].

[21] The GB EMR Delivery Body. The GB capacity market [Online]. Available: https://www.emrdeliverybody.com/cm/home.aspx. [Accessed 28 August 2018].

[22] National grid ESO future energy scenarios [Online]. Available: http://fes.nationalgrid.com/. [Accessed 28 August 2018].

[23] Burke D, Lloyd G, Rimmer D, York S. National grid ESO EMR delivery body consultation - de-rating factor [Online]. Available: https://www.emrdeliverybody.com/Prequalification/EMR%20DB%20Consultation%20-%20De-Rating%20Factor%20Methodology%20for%20Renewables%20Participation%20in%20the%20CM.pdf. [Accessed 16 August 2019].

[24] Shakoor AA, Strbac G, Allan R. Quantifying risk of interruptions and evaluating generation system adequacy with wind generation. In: 2006 international conference on probabilistic methods applied to power systems. New York: IEEE; 2006.

[25] Ofgem. Electricity capacity assessment report [Online]. Available: https://www.ofgem.gov.uk/ofgem-publications/75232/electricity-capacity-assessment-report-2013-pdf. [Accessed 18 August 2018].

[26] NASA MERRA data system [Online]. Available: https://gmao.gsfc.nasa.gov/reanalysis/MERRA/. [Accessed 28 August 2018].

[27] Burke D. National grid ESO security of supply - international review of standards and implementation [Online]. Available: http://sites.ieee.org/pes-rrpasc/working-groups/wg-on-lole-best-practices/. [Accessed 16 August 2019].

[28] Veyrenc Thomas. "The French capacity market: lessons learnt and way forward, Conference on security of supply," RTE, 21 05 2015 [Online]. Available: https://energie-fr-de.eu/fr/manifestations/lecteur/conference-sur-la-securite-dapprovisionnement-en-electricite-regards-croises-france-allemagne-120.html. [Accessed 4 September 2018].

[29] RTE. French Capacity Market - report accompanying the draft rules. 09 04 2014 [Online]. Available: https://www.rte-france.com/sites/default/files/2014_04_09_french_capacity_market.pdf. [Accessed 4 September 2018].

[30] RTE. "French Capacity Market - certification process," 02 04 2015 [Online]. Available: https://clients.rte-france.com/htm/an/mediatheque/telecharge/2015_04_02_PPT_mecapa_en.pdf. [Accessed 4 September 2018].

[31] RTE, SER, Enedis, ORE, ADEeF. Panorama OF renewable power IN France IN 2018 [Online]. Available: https://www.rte-france.com/sites/default/files/angpanoramat4-2018hd.pdf. [Accessed 18 June 2019].

[32] RTE. Dedicated WEB-site for capacity mechanism [Online]. Available: http://clients.rte-france.com/lang/an/visiteurs/vie/meca_capa/meca_capa.jsp. [Accessed 4 September 2018].

[33] EirGrid. Tomorrow's energy scenarios 2017: locations consultation. March 2018.

[34] CRU. Regulatory approach to maintaining local security of supply in electricity, CRU17346. December 2017.

[35] EirGrid, SEMO, SONI. I-SEM Capacity Market: methodology for the calculation of the capacity requirement and de-rating factors, SEM-16-082a. December 2016.

[36] PJM. PJM manual 18. 25 July 2019 [Online]. Available: https://pjm.com/-/media/documents/manuals/m18.ashx?la=en.

[37] PJM System Planning Dept. PJM manual 21: rules and procedures for determination of generating capability, revision: 12. 2017 [Online]. Available: https://www.pjm.com/-/media/documents/manuals/m21.ashx. [Accessed 4 September 2018].

[38] ERCOT. ERCOT quick facts. January 2019 [Online]. Available: http://www.ercot.com/content/wcm/lists/172484/ERCOT_Quick_Facts_01.17.19.pdf.

[39] ERCOT. Generator interconnection status report. March 2019 [Online]. Available: http://www.ercot.com/gridinfo/resource.

[40] Brattle Group. Estimation of the market equilibrium and economically optimal reserve margins for the ERCOT region, 2018 update prepared for ERCOT by the brattle group. 2018.

[41] Hogan W. Electricity scarcity pricing through operating reserves:an ERCOT window of opportunity. 2012 [Online]. Available: https://sites.hks.harvard.edu/fs/whogan/Hogan_ORDC_110112r.pdf.

[42] ERCOT. Methodology for implementing ORDC to calculate real-time reserve price adder. August 2019 [Online]. Available: http://www.ercot.com/mktrules/obd/obdlist.

[43] ERCOT. ERCOT nodal protocols [Online]. Available: http://www.ercot.com/mktrules/nprotocols; August 2019.

[44] ERCOT. CDR peak capacity contribution reports [Online]. Available: http://www.ercot.com/gridinfo/resource.

[45] Kiviluoma J, Kekkonen V. The need for capacity reserves for the years 2013–2017, VTT tutkimusraportti VTT-R-06032-14. VTT; 2012 (in Finnish).

[46] Pöyry Management Consulting. Study on the amount of peak load capacity for 2017-2020. Pöyry, 09 2016. [Online]. Available: https://www.energiavirasto.fi/documents/10191/0/Summary_Amount+of+peak+load+capacity+2017-2022_v100.pdf/07f0a3a2-b8cc-4954-91dc-4c14360ed62e. [Accessed 4 September 2018].

[47] IEA Wind TCP. "IEA wind 2017 annual report," 09 2017 [Online]. Available: https://community.ieawind.org/publications/ar. [Accessed 8 April 2019].

[48] DGEG. Relatório de Monitorização da Segurança de Abastecimento do Sistema Elétrico Nacional 2017 – 2030. DGEG technical report (in Portuguese), [Online]. Available: https://www.voltimum.pt/sites/www.voltimum.pt/files/pdflibrary/relatorio_de_monitorizacao_de_seguranca_de_abastecimento_do_sistema_eletrico_nacional_2017-2031_-_janeiro_de_2017.pdf. [Accessed 4 April 2019].

[49] Matos MA, Lopes JAP, Rosa M, Ferreira R, Leite da Silva A, Sales W, Resende L, Manso L, Cabral P, Ferreira M, Martins N, Artaiz C, Soto F, López R. Probabilistic evaluation of reserve requirements of generating systems with renewable power sources: the Portuguese and Spanish cases. Int J Electr Power Energy Syst 2009;31(9):562–9.

[50] ERSE. ERSE technical report (in Portuguese). 04 2014. [Online]. Available: http://www.erse.pt/pt/electricidade/regulamentos/operacaodasredes/Documents/MPGGS%20SE%20consolidado_Abril2014_vs%20PExterno.pdf. [Accessed 4 September 2018].

[51] Gerres T, Chaves J, Martín FRM, Cossent R, Sánchez A, Gómez T. Rethinking the electricity market design: remuneration mechanisms to reach high RES shares. Results from a Spanish case study. Energy Policy June 2019;129:1320–30.

[52] CNMC. Report on surveillance of the Peninsula electricity generation market. Year 2015 (in Spanish). 2016 [Online]. Available: https://www.cnmc.es/expedientes/isde02516. [Accessed 10 April 2019].

[53] REE Red Eléctrica de España. Data from website [Online]. Available: http://www.ree.es/en/statistical-data-of-spanish-electrical-system/statistical-series/national-statistical-series. [Accessed 4 April 2019].

[54] CEETE. Analysis and proposals for decarbonization (in Spanish). Commission of Experts on Energy Transition Scenarios; 2018 [Online]. Available: http://www6.mityc.es/aplicaciones/transicionenergetica/informe_cexpertos_20180402_veditado.pdf. [Accessed 4 April 2019].

[55] Norwegian Water and Energy Directorate. Power outage statistics 2017 [In Norwegian],"NVE Report 64:2018. Oslo, Norway: Norwegian Water and Energy Directorate; 2018 [Online]. Available: http://publikasjoner.nve.no/rapport/2018/rapport2018_64.pdf. [Accessed 17 June 2019].

[56] Norwegian Water and Energy Directorate. New power generation: permissions and construction. NVE Status Report 4. Quarter. Oslo Norway: Norwegian Water and Energy Directorate; 2018 [Online]. Available: https://www.nve.no/media/7696/ny_kraft_tillatelser_og_utbygging_4kv_2018.pdf. [Accessed 17 June 2019].

[57] Tande JG, Korpås M. Impact of offshore wind power on system Adequacy in a regional hydro-based power system with weak interconnections. Energy Procedia 2012;24:131–42.

[58] Statnett. Grid development plan 2017 (in Norwegian). 2017 [Online]. Available: http://www.statnett.no/Global/Dokumenter/NUP%202017-endelig/Nettutviklingsplan%202017.pdf. [Accessed 4 September 2018].

[59] Statnett. Power system in Finnmark, analysis and need of measures after 2020 (in Norwegian). 2016 [Online]. Available: https://www.statnett.no/globalassets/for-aktorer-i-kraftsystemet/planer-og-analyser/kraftsystemet-i-finnmark.pdf. [Accessed 4 September 2018].

[60] Energinet. Security of electricity supply report. 2018 [Online]. Available: https://en.energinet.dk/About-our-reports/Reports/Security-of-electricity-supply-report-2018. [Accessed 10 June 2019].

[61] Energinet. Market model 2.0 final report. 2015 [Online]. Available: https://en.energinet.dk/About-our-reports/Reports/Market-Model-2-0. [Accessed 10 June 2019].

[62] Danish Energy Agency. Security of electricity supply in Denmark. 2015 [Online]. Available: https://ens.dk/sites/ens.dk/files/Globalcooperation/security_of_electricity_supply_in_denmark.pdf. [Accessed 10 June 2019].

[63] Energinet. Ancillary services to be delivered in Denmark tender conditions. 2017 [Online]. Available: https://en.energinet.dk/-/media/Energinet/El-RGD/Dokumenter/Ancillary-services-to-be-delivered-in-Denmark.pdf. [Accessed 10 June 2019].

[64] FEBEG. Statistics on electricity in Belgium [Online]. Available: https://www.febeg.be/statistieken-elektriciteit. [Accessed 12 April 2019].

[65] Heylen E, Van Hertem D, Belmans R. Fact check: the Belgian energy provision of electricity in the winter of 2018-2019. 8 10 2018 [Online]. Available: https://www.energyville.be/en/press/fact-check-belgian-energy-provision-electricity-winter-2018-2019. [Accessed 12 April 2019].

[66] Belgian Federal Law. Wet betreffende de organisatie van de elektriciteitsmarkt. 2014. Brussels, Belgium.

[67] Höschle H, De Vos K. Implementation of a strategic reserve in Belgium: product design and market results. In: CIGRE paris session; 2016. Paris.

[68] Belgian offshore platform. Offshore wind energy in the Belgian part of the North Sea: up to 4,000 MW by 2024. 19 3 2019 [Online]. Available: http://www.belgianoffshoreplatform.be/en/news/offshore-wind-energy-in-the-belgian-part-of-the-north-sea-up-to-4000-mw-by-2024/. [Accessed 12 April 2019].

[69] ENTSO-E. ENTSO-E transparency platform - actual generation per production type [Online]. Available: https://transparency.entsoe.eu. [Accessed 12 April 2019].

[70] Elia. The need for a Strategic Reserve for winter 2019-20. 2018. Brussels.

[71] Response of the Federal Government of Germany to a request of the party FDP. "Electricity reliability" (in German) [Online]. Available: https://www.bmwi.de/Redaktion/DE/Parlamentarische-Anfragen/2018/19-5721.pdf?_blob=publicationFile&v=4. [Accessed 13 June 2019].

[72] Federal Network Agency (BNetzA). "Indicators for system interruption (in German)," federal network agency (BNetzA) [Online]. Available: https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Versorgungssicherheit/Versorgungsunterbrechungen/Auswertung_Strom/Versorgungsunterbrech_Strom_node.html. [Accessed 13 June 2019].

[73] Federal Enviromental Agency (UBA). Figures of renewable energies (in German) [Online]. Available: https://www.umweltbundesamt.de/sites/default/files/medien/376/publikationen/180315_uba_hg_eeinzahlen_2018_bf.pdf. [Accessed 13 June 2019].

[74] German Transmission System Operators. Report on the system balance 2016-2020 (in German) [Online]. Available: https://www.netztransparenz.de/portals/1/Content/Ver%C3%B6ffentlichungen/Bericht_zur_Leistungsbilanz_2017.pdf. [Accessed 13 June 2019].

[75] Federal Network Agency (BNetzA). Determination of needs of grid reserve capacity for the winters 1018/2019 and 2020/2021 [Online]. Available: https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/Versorgungssicherheit/Berichte_Fallanalysen/Feststellung_Reservekraftwerksbedarf_2018.pdf?_blob=publicationFile&v=3. [Accessed 13 June 2019].

[76] SpA Terna. "Regulation of the remuneration system for the availability of electricity capacity (in Italian)," Terna SpA [Online]. Available: http://download.terna.it/terna/0000/1036/29.PDF. [Accessed 18 June 2019].

[77] Perez-Arriaga I. The method of reliability options. In: Regulation of the power sector. Springer; 2013. p. 617–9.

[78] Statistics Netherlands, [Online]. Available: www.cbs.nl. [Accessed 11 6 2019].

[79] TenneT TSO. Monitoring leveringszekerheid 2018 (2017-2033). 2018. Arnhem.

[80] Dutch Electricity Act. Dutch electricity Act 1998. 1998. Art. 16.2.d.