D3.1 – Performance specifications for a (near) 100% RES system

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Executive Summary

In the last months, the urgency to address climate change has become a priority at a European and global level. The European Union recently increased its sustainability goals towards the aim to become climate neutral by 2050. The target to reduce greenhouse gas emissions by 2030, compared to 1990, was increased to at least 55%. To design the energy policy, the EU considered the energy trilemma which is to increase the sustainability, considering the security of supply and in the least costly manner. The recast of the internal market for electricity recognizes the necessity to put the consumers at the centre of the energy transition and give them tools for their active participation in the market. The power system is evolving quickly, and the regulations must be modified accordingly to enable the energy transition. This deliverable review the technical challenges that have surged from integrating renewable energies and which will increase along their share in the power system increases. Furthermore, the indicators that can serve to compare the performance of different designs are outlined.

In the first part of the report, we review the current performance indicators for power systems in terms of the energy trilemma. We identify that most of these indicators are based on a market where demand is inflexible. In the future, the flexibility of the system will be attributed in great part to the demand side, so new indicators that consider an elastic demand are proposed. The clean energy package strengths that the energy transition must benefit everyone. For this reason, we also analyse affordability and fairness indicators. To evaluate the market designs that we decide to model, it will be important to consider a combination of the proposed indicators.

In the second part of the report, we analyse the technical challenges that have raised due to an increase in the share of renewables in the power system and identify how the design should evolve to enable the generation to be 100% renewable.

In the short term, first and foremost a future market design should enable consumers to actively participate in the market. Electricity prices should be more granular in time and space. Reflecting the network congestions costs should facilitate a more efficient use of the grid. The trade of energy and balancing services between member states should be enhanced. After-market closure, the volatility of renewable energies is expected to increase the need for balancing capacities and ancillary services. The most relevant technical changes have been the reduction of the system inertia, the increase and steepness of ramp rates and the shortage of reactive power, short circuit power and black start capabilities. The positive side is that REs are capable of delivering most of these ancillary services contributing to the stabilization of the grid. A future market should enable more REs to participate in the balancing market and new market-procured ancillary services should be considered.

In the long term, the biggest challenge will be to guarantee a security of supply in extreme situations with scarce natural resources and high demand. A future market design should provide signals for the right technologies to be built, generators and storage should be built at the level and location where they would get the highest market value, considering the grid expansion and contributing to the cost effectiveness of the whole system. Finally, the

future markets should maximize the potential of a fully integrated European system procuring a stronger coordination of DSOs, TSOs, energy suppliers and consumers, considering local, national and EU-wide decarbonisation objectives

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List of Abbreviations

aFRR automatic frequency restoration reserve
AS ancillary services
CAISO California Independent System Operator
CONE cost of new entry
DSO distribution system operator
EIR energy index of reliability
EIU energy index of unreliability
ENTSO-E European Network of Transmission System Operators for Electricity
ERCOT Electric Reliability Council of Texas
ENS energy not supplied
ETS Emission Trade System
EV electrical vehicles
FCR frequency containment reserve
FRT fault ride through
HHI Herfindahl-Hirschman index
IGCC International Grid Control Cooperation
IRRE insufficient ramping resource expectation
LOLP loss of load probability
LOLE loss of load expectation
LOLH loss of load hours
F&D frequency and duration indices
FACTS flexible AC transmission system
FCR frequency containment reserves
mFRR frequency restoration reserves with manual activation
NECP National Energy and Climate Plans
NERC North American Electric Reliability Corporation
NEMO nominated electricity market operators
PEC Power electronic converter
PJM Regional transmission organization (US East Coast)
PPA power purchasing agreement
PSI pivotal supplier indicator
PV photovoltaic
RoCoF rate of change of frequency
RT restoration time
SAIDI system average interruption duration indicator
SAIFI system average interruption frequency indicator
SG synchronous generators
SIDC Single Intraday Coupling
TLP total loss of power
TSO Transmission system operator
UE unserved energy
VIBRES variable inverted-based REs
VRE Variable renewable energy
VOLL average Value of lost load
VSWT Variable speed wind turbines

1 Introduction

1.1 Purpose of this report

In energy policy, three objectives need to be balanced: energy security, sustainability and affordability[1] (the 'energy trilemma'). The objective of TradeRES is to design a sustainable market with near 100% renewable electricity system, taking into consideration the other two objectives. In this report, we describe the performance indicators which can be used as a guide to propose new market designs. Other deliverables of Work Package 3 will describe the market design choices.

In section 1, we summarize the European Union's policy goals for a sustainable power system. In section 2, we summarize the most commonly used performance indicators of a reliable, adequate, fair and climate neutral electricity. After identifying the current indicators, we propose additional indicators for evaluating the performance of future electricity systems.

In section 3 of this report, we analyze the performance of the current market design in the timeframe specified in next subsection. The current technical issues are likely to pose challenges when the share of REs will increase and that should be addressed by the market design. The economic challenges and market design options are outlined in Deliverable D3.5.

Power systems with high shares of renewable energies are characterized by increasing ramp rates and less inertia, which may make it harder to maintain voltage and to provide sufficient black start capacity, among others. In section 3.1, we identify these technical challenges, which occur after the market closure and which will likely become more frequent. We analyze the trends in the market-provided services and the services provided by network operators. In section 3.2, we propose improvement for the economic dispatch of a system with more flexible demand. We review the causes of the network congestions at the distribution level, within a price zone and between price zones and review market measures that should be considered to alleviate these congestions. In the long term, there should be enough investment in renewable and conventional energy to be able to cover the demand in extreme scarcity situations. In section 3.3, we specify the aspects that a future market design should consider to fulfill a long-term adequacy.

1.2 Relevant timeframes for future market design specifications

The challenges with respect to achieving policy goals can be divided into three timeframes. In the long term – the timeframe within which assets can be built and removed – the challenges are to build the right assets and to build enough of them, to reach the right mix of generators, network investments and investments on the consumer side. For the

[1] Article 1, Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on Common Rules for the Internal Market for Electricity and Amending Directive 2012/27/EU (Recast), 2019.

short term – the operational phase – we divide between a phase in which market-based decisions are made and the phase after-market closure. Short-term market decisions have as a goal to use available assets efficiently, which means efficient generation dispatch, which includes the balance between electricity generation, storage and demand response, and efficient use of available network assets, for which network congestion management is the main instrument. After the market closure, the system operators need to maintain the stability of the system and the quality of the power that is delivered and remediate any disturbances. To this end, they contract ancillary services from market parties. The tendering of these services is part of the market design. See Deliverable 3.5 for an analysis of challenges and options with respect to ancillary services.

1.3 EU clean energy policy

By 2050, the EU aims to become climate neutral. This goal is in line with the commitment of the EU to global climate action under the Paris Agreement. And, as part of the European Green Deal, the commission proposed the European Climate Law, which ensures that all EU policies contribute to this goal. The commission proposes an EU-wide trajectory for greenhouse emissions reduction and from September 2023 will assess the consistency of European and national measures with this trajectory. Finally, the Climate Law has the objective of providing predictability for investors and other economic actors and to ensure that the transition is irreversible.

One of the seven pillars to achieve climate neutrality in Europe is to maximize the deployment of renewable energy sources and the use of electricity to decarbonize the energy supply. According to the 2030 climate and energy framework, the key targets for Europe for 2030 are to cut greenhouse gas emissions by at least 40% (from 1990 levels), to achieve a share of renewable energy of at least 32% and at least a 32,5% improvement in energy efficiency. In September 2020, the European Commission raised the environmental ambition of the Green Deal for 2030 increasing the greenhouse gas reduction target to at least 55%, compared to 1990.

The Clean energy for all European package, adopted in May 2019, establish a legal framework to accelerate the clean energy transition in the EU, modernise the economy to benefit of everyone, increase energy security, bring people and countries closer, put consumers at the heart of the energy transition, make Europe a climate action leader and move towards a clean planet for all. In this package it is stated that each country will decide how it contributes to the EU objectives by drafting National Energy and Climate Plans (NECPs) for 2021-2030. (European Commission, 2019a)

The European commission analyzed the European and concluded that the energy mix is expected to change faster than expected. By 2030 the share of electricity produced by renewables is projected to reach 60%. Coal is projected to decrease by 70% compared to 2015. Under planned measures, a range of 33.1% – 33.7% of REs in 2030 at the Union level would surpass the initial target of at least 32% in 2030; nevertheless, the new ambition for 2030 requires at least 38 – 40% of renewable energy in the EU. There are some countries with very high goals: Austria and Sweden declared an objective of 100% renewable electricity by 2030 and 2040, respectively. In contrast, several members remain below their cost-efficient potential. (European Commission, 2020) The commission scenarios still contain 17 to 18% of electricity produced based on fossil fuels by 2050. (Climact, 2020) In regard to energy efficiency, a gap of 2.8% for primary energy consumption and 3.1% for final energy consumption was identified from the NECPs. (European Commission, 2020) In our research we investigate a more ambitious goal, with near to 100% renewable energy scenario and we expect that the market design would also work with a smaller share of VREs.

The European Energy Union aims to provide final customers with safe, secure, sustainable, competitive and affordable energy. In Europe, the internal market design aims to enhance cross border trade, achieve competitive prices, give quality and to contribute to security of supply and sustainability. In 2019, the European Commission presented a recast of the regulation on the Internal Market for Electricity (EU) 2019/943. This recast provides consumers with more tools for active participation in the energy market, introduces measures to improve retail competition and sets out principles to ensure that aggregators can fulfil their role as intermediaries between customers and the wholesale market. Besides active consumers it establishes guidelines for energy communities. This regulation puts the consumers at the centre of the transition and places a strong framework for consumer protection. ("Directive 2019/944 on Common Rules for the Internal Market for Electricity," 2019) A more detailed analysis of this regulation is presented in Deliverable 3.5. To fulfil the goals of the Clean energy for all European package of increasing energy security, the new electricity market design strengthens the cross-border trade and strives for a more flexible market to integrate a greater share of renewables. Among others, it states that electricity can be traded closer to real time, when weather and renewable forecast are more accurate. It also tries to reconcile the security of supply with decarbonisation by putting an emission cap on new capacity mechanisms to restrict subsidies for the most polluting technologies. (European Commission, 2019a)

The Clean energy for all European package also gives more rights for consumers. Among others, it states that energy bills will be made clearer; give the right to consumers to request a smart meter; providers should offer at least one energy comparison tool to allow consumers to find the best deal in the market and should help consumers to better control their costs. It also makes new rules to make it easier for individuals to produce their own energy, store it and sell it. It strengthens that the clean energy transition must benefit everyone - no citizen, no region should be left behind. (European Commission, 2019a)

2. Performance Indicators for a future market design

In this section, the current power system indicators based on the objectives of the European energy policy are outlined. In addition to the conventional indicators for security, sustainability and affordability, we propose new indicators that are relevant for the performance of a future market a high share of renewable energy as well as more elastic demand and energy storage.

2.1 Conventional indicators of security of supply

In a reliable power system, supply meets demand in an adequate and secure manner. Adequacy refers to the existence of enough installed available capacity to be able to cover the estimated demand; secure, in the sense of being able to withstand disturbances such as the loss of generator units of transmission lines. (I. J Pérez-Arriaga, 2001) (Ayyub, 2003)

According to the European Network of Transmission System Operators for electricity (ENTSO-E), reliability is the ability of a system of delivering electricity to customers within accepted standards and in the amount desired. As an economic value, reliability is linked to the impact of the supply interruption on the end user. It is often evaluated with indicators of energy not supplied, load curtailment, interruption costs or interruption frequency. ENTSO-E considers the reliability standard as a trade-off between the cost of new generation capacity and the average Value of lost load (VOLL). The VOLL expresses the marginal cost of unserved energy at a particular location and time, to a type of consumer and of a particular duration. In other words, it expresses the monetary damage from not supplying a unit of energy. In a power system with insufficient demand price elasticity, social welfare is maximized when the long-run marginal cost of a new power plant is equal to the average VOLL. The cost of new plant is quantified as the gross cost of new entry (CONE), the lowest cost of a new entrant peaking plant. (European Commission, 2016) (Heylen, Deconinck, & Hertem, 2020)

The challenge in evaluating the socio-economic surplus and therefore in determining the reliability standard is that it is difficult to determine the value of reliability. Estimates of the VOLL differ strongly from one country to another because of differences in economic activities and dependency on electricity and due to differences in measurement techniques. The EU designated to ENTSO-E the responsibility to deliver a methodology for Resource Adequacy Assessment and a methodology to calculate the VOLL, CONE and reliability standards. ("Regulation (EU) 2019/943 of the European Parliament and of the council on the internal market for electricity," 2019)

Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all time, taking into account scheduled and reasonable expected unscheduled outages of system elements. It is the systems' ability to meet demand in the long term. The methods to calculate the adequacy are categorized as deterministic and probabilistic. Probabilistic methods aim to estimate the probability of meeting the load considering the stochastic variables that determine the adequacy, the generation, demand and availability of lines. (European Commission, 2016)

Billington (1994) explained that to evaluate the adequacy, the impacts and the monetary losses by customers due to electric power supply failures should be considered. Billington and Allan (1992) suggested how to assess the power system reliability with the following indices. The loss of load probability (LOLP) is defined as the likelihood of the load exceeding the available generation. The loss of load expectation (LOLE) is the average number of days or hours that peak load is expected to exceed the available generating capacity. The loss of energy expectation (LOEE) is defined as the expected energy that will not be supplied in scarcity situations. In comparison to the first two, this third index reflects the severity of the issue. Other indices are the loss of load hours (LOLH), the frequency and duration indices (F&D), energy index of reliability (EIR), energy index of unreliability (EIU) and system minutes (SM).

The Scandinavian system uses the unserved energy (UE) metric and applies as a standard that the loss of load may not exceed 0.001%. (Lueken, Apt, & Sowell, 2016) Most US systems use the Loss of load expectation per ten years and apply a standard of 0.1 events per year. An event refers to an outage lasting one or more consecutive hours. This metric can be problematic because it does not consider the duration nor the magnitude of the event. To consider the magnitude of outages, the North American Electric Reliability Corporation (NERC) has recommended System operators to adopt UE standards. These standards consider only the risk of generator outages and exclude the transmission or distribution outages. Lueken et al. (2016) found that the PJM system would only need 13% of reserve margins considering the 0.001% UE standard against 20.5% to fulfil the 0.1 LOLE standard.

The ENTSO-E considers other parameters such as the estimation of energy not supplied (ENS) to final consumers due to incidents in the transmission networks; the total loss of power (TLP) [MW]; and the restoration time (RT) [mins] which is the time from the outage until system frequency returns to its nominal value. (Brancucci Martínez-Anido et al., 2012)

Extreme situations can vastly influence quantity indicators such as TLP, RT and ENS. For example, in Italy in 2003 there was an important blackout which accounted for more than 30% of the ENS in ENTSOE countries. These indicators do not reflect the fact that more interconnected network topologies have experienced four times more fault events than lower interconnected European grids. For this reason, it is important to also consider single fault events. (Brancucci Martínez-Anido et al., 2012)

Heylen et al. (2020) analyzed 129 indicators from system operators and coordinating organizations and identified four main classes of indicators: adequacy, security, socio-economic and reliability indicators. They concluded that adequacy indicators focus on end-consumer adequacy and not enough on adequacy for flexibility providers. Only the ENTSO-E methodology for adequacy assessment considers the curtailment and the full load hours, which are specific for REs. The full load hours represent the utilization rate of the generation park and the REs curtailment refer to the amount of REs that cannot be fed into the grid because of security reasons. (Heylen et al., 2020) Morales-España and Sijm (2020) demonstrated that curtailing renewables can actually bring emission and cost savings. For this reason, it is necessary to evaluate the complete spectrum of a performance system, considering also the CO2 emissions as explained in section 2.4.

Holttinen et al. (2020) argue that the assessment of adequacy needs to evolve to capture the flexibility of the system and not only the amount of peak load power plants. Adequacy will also depend on storage devices, sector coupling, connected transmission areas, distributed connected generation and flexible demand. Deliverable D3.4 analyzes the changes in the electricity markets due to interaction with other energy carriers. An additional aspect to consider is the digitalization level, which can enable more loads to participate in the grid. If there are more smart meters, electric cars and heat pumps can be aggregated and contribute with flexible demand. Similarly, smart grids may allow customers to respond with their demand to market signals.

2.2 Security of supply indicators for systems with more flexibility

With more flexible demand being available in the system, the volume of ENS can be reduced or even eliminated. An electricity system with a high degree of flexibility may never witness power shortages due to energy imbalances. Outages due to technical failures may of course still occur. The level of peak electricity prices may decrease but, as more customers shift their demand, the number of hours with relatively high electricity prices may increase. These prices will be lower than the VOLL in a system without flexibility, but still well above the marginal cost of generation, as they are determined by the marginal willingness to pay of consumers. The question is how to define system adequacy in such a system. Indicators such as the UE, SAIFI (System average interruption frequency indicator) and SAIDI (system average interruption duration indicator) would lose their meaning. For such a system, an indicator for a lack of adequacy, would be to measure the degree to which average electricity prices exceed average cost. If the electricity prices are higher than the system cost, this would mean windfall profits for generators and high prices for consumers. On the contrary, if the market prices are not enough to cover the generators costs, this would worsen the security of supply as the generator companies will tend to invest less and eventually this would cause shortages. The cost recovery indicator is also related to the cost efficiency of the system, so it will be further explained in subsection 2.3

In an efficient market, the electricity price is formed by matching the marginal system cost, i.e. the additional cost to supply the last unit of energy, with the marginal willingness to pay of consumers. See Deliverable 3.5 for a description of price formation in a future market. If demand is sufficiently price-elastic, the VOLL does not need to be used if consumers express their willingness to pay for electricity individually. The willingness to pay indicates the inclination of consumers to pay higher electricity bills to have higher quality. If all consumers are exposed to real time prices, consumers with a limited willingness to pay may prefer to limit their demand instead of paying high prices, contributing to prevent outages. Instead of outages, generation shortages would then lead to voluntary reductions in demand, with the electricity price set by the marginal willingness to pay of consumers. In this case, the traditional reliability indicators may not sufficiently reflect the degree to which a system is not able to cover demand.

Short-term price volatility should not be a significant obstacle to investment, but year-on-year revenue fluctuations, e.g. due to weather differences between years, may increase investment risk significantly. The total output of VRE can vary by more than 10% per year, as a result of which the annual revenues of both VRE and other resources will become less stable than they were in thermal energy systems. This effect is exacerbated by the fact that costly back-up resources will be needed to serve infrequent events with extreme weather. In theory, if investors know the probability and duration of such events, and can estimate the electricity prices that will occur, they can anticipate and build exactly the socially optimal volume of backup capacity. However, due to climate change, the probability distribution of extreme weather events is not known and investors may be averse to providing facilities that are expected to operate less than once per year. This risk is a new risk that comes in addition to regulatory uncertainty, market risks and technology risks. Therefore, it is a question whether scarcity prices during rare, extreme weather events will provide sufficient stimulus for investing in the backup capacity that is needed during these events. Therefore, an indicator for investors risk is the variability of annual returns to the energy supply industry.

$$\sigma_Y^2 = \frac{1}{n}\sum_{i=1}^{n}(Y_i - \bar{\bar{Y}})^2$$

Where $\bar{Y}$ is the mean of annual returns and *n* is the size of the sample (number of years).

$$\bar{Y} = \frac{1}{n}\sum_{i=1}^{n} Y_i$$

To compare between capacity mechanisms Bhagwat et al. (Bhagwat, Richstein, Chappin, Iychettira, & De Vries, 2017) used the supply ratio (MW/MW) which is the ratio of available supply at peak demand to peak demand. The available supply at the peak can be defined as follows:

$$Available\ supply\ at\ peak = \sum_{i=1}^{n}(PAC_i \times C_i)\ .$$

PAC is the peak segment availability factor of the power plant and *C* is the installed capacity of the power plant.

Finally, to capture the interactions between security of supply and markets, the time period (hours) with scarcity can be an indicator. With elastic demand, supply can be considered to be scarce when prices rise above a certain threshold, e.g. when they reach the maximum price in the day-ahead market, or when balancing prices reach a certain level. While there may be enough demand elasticity to avoid service interruptions, supply may still be considered as inadequate if prolonged periods with very high prices occur.

Indicators:

- Supply ratio at peak demand

- Energy not served

- Scarcity time period

- Variability of annual returns to the energy supply industry

2.3 Affordability

The increase in energy sustainability and reliability is correlated to the increase in costs. Electricity markets are designed to provide reliable electricity supply at least cost to consumers. (Cramton, 2017) In other words, the ideal reliability level is obtained at a maximal socioeconomic surplus. The socioeconomic surplus is defined as the sum of consumer surplus, producer surplus, TSO surplus and government surplus. The surplus equals the value of a particular reliability level minus the cost to obtain a particular reliability level. (Heylen et al., 2020)

From an economic point of view, the objective for the power system is to maximize social welfare. According to microeconomic theory, if a number of conditions are met, competitive markets incentivize companies to build optimal volume and mix of generation technology. The goal for market design and regulation is therefore to ensure that these conditions are met as well as possible.

Besides economic efficiency, the question of how to transfer the system costs to the consumers is not trivial. Even if the electricity system can in theory be economically efficient, the costs to consumers may not be efficient, leading to producers' high profits. When designing future markets, a fair distribution of costs among consumers and a guaranteed accessibility of the service and to the satisfaction of basic needs to low-income households should be considered. (Neuteleers, Mulder, & Hindriks, 2017) Heylen et al. (Heylen, Ovaere, Proost, Deconinck, & Van Hertem, 2019) summarized indices to measure the fairness of a power system. They explained that there are two opposing fairness preferences. Equity, which is defined as giving everyone what they need or deserve, and equality which is defined as treating everyone the same.

2.3.1. Cost efficiency and price volatility

Investment costs must be recovered, however sustained above-normal profits are an indicator of a lack of investment, even if the outage rate is not higher than normal. To compare the economic efficiency of different market designs, Bhagwat et al. (2017) used the average cost to consumers (Euro/MWh). This cost should include the variable and fixed costs, the capacity mechanism, the balancing market costs, ancillary services and the cost of subsidies per unit of electricity consumed. An indicator of a well-functioning market design is when average electricity prices are close to the average total costs of the energy supply system, or in other words, when the energy supply industry recovers its cost with an appropriate rate of return. An undesirable opposite situation is that capacity mechanisms provoke windfall profits for generators. In the study mentioned they also used the cost of the capacity mechanism (Euro/MWh) to compare different mechanisms.

Price volatility can be taken considered as a system parameter to estimate price risk for consumers and revenue recovery risk for producers. High price volatility can be problematic for consumers, as was recently witnessed in Texas. Even if the long-term average price of electricity is affordable, short periods with extreme prices may be difficult to handle for consumers. For producers, the risk is the opposite, in that volatility can create uncertainty regarding investment cost recovery. For them, however, the long-term returns matter more than short-term uncertainty, as was described in Section 2.2

Prices are more volatile when demand and supply (including storage) are less elastic. VRE adds volatity, while storage and demand response reduce volatilty. It is therefore uncertain how volatile prices will be in a future electricity market.

Even if average electricity prices are efficient – i.e. they are near the average cost of electricity supply – price volatility can be an issue for producers as well as consumers because of the risk they may create. Both consumers and producers will have problems if prices are below average most of the time but exhibit high spikes occasionally. For consumers who might be exposed to real time pricing – as appears to be necessary for integrating them efficiently into the market – price volatility may create more risk than they can handle, especially if rare periods of unfavourable weather create extremely high price spikes. They may perceive the pricing as more unfair (see section 2.3.3). Nevertheless, a high frequency of peak prices could also imply that many consumers have a very high willingness to pay. It is true that retail companies, energy service companies and aggregators can provide services to mitigate price volatility, they may not be able to do so in full. Producers (providers of electricity generation and storage facilities) face a symmetrical risk, with high volatility creating uncertainty about cost recovery and probably becoming more price averse. Therefore, price volatility will be included as an indicator.

The European Union suggests the following methodology to calculate the volatility of electricity prices: (European Commission, n.d.),

$$X_i = log_{10}P_{dayT} - log_{10}P_{DayT-1}$$

X_i denotes the logarithmical difference of the daily average prices of two consecutive trading days,

$$\overline{X_k} = \frac{\sum_{i=1}^{k} X_i}{k}$$

k denotes the number of trading days observed and X_k denotes the averages of X_i-s over a period of k trading days. The annualised volatility can be calculated as follows,

$$VOL_{(T-k+1,T)} = 100 * \sqrt{N} * \sqrt{\frac{\sum_{i=1}^{k}(X_i - \bar{X})^2}{k}}$$

where N is the number of trading days for a year. For electricity markets it is recommended to eliminate the weekend prices. Lower trading volumes might cause higher daily price variations, so an average monthly 21 trading day period and yearly 252 days period is recommended.

To construct regional and European level volatility indices from the regional sub-indices, the methodology suggests to calculate the weighting factors for each market on each trading day and t, and then aggregate the daily logarithmic differences. From these values then calculate the standard deviation and finally to multiply the results by the annualisation factor and by 100. The weighting coefficient would be

$$Wci = \sum_{T-k+1}^{T} Dci$$

Dci is the daily traded volume of day ahead contracts on a given market on a given trading day. The daily logarithmic differences are aggregated as weighted arithmetical averages,

$$X_{EUi} = \frac{\sum Wci * Xi}{\sum Wci}$$

To evaluate how responsive the demand will be to prices, it would be worth considering the time ahead that customers have to react and the degree to which they will be exposed to electricity prices. Some market designs may pass the direct wholesale prices through more directly than others. Choosing to subsidize VREs and introducing capacity mechanisms would mitigate investors' risk adversity and would drive down wholesale price volatility. On the contrary, an energy-only market would rely on peak pricing for cost recovery and would expose companies and end-consumers to higher price spikes. In a future market, where real time pricing might be implemented, a high frequency of peak prices would imply that some consumers have a very high willingness to pay.

An undesirable opposite situation is that capacity mechanisms provoke windfall profits for generators. In the mentioned study (Bhagwat et al., 2017), the authors also used the cost of the capacity mechanism (Euro/MWh) to compare different mechanisms.

Indicators:

- Degree of cost recovery of generation and storage facilities (average revenues / average total cost of supply)

- Price volatility

2.3.2. Network tariffs

Volumetric network tariffs, which allocate network costs to consumers based on energy consumption, are most common for residential consumers, but can lead to unfair situations in a system with renewable energy. For example, when network tariffs are based on energy consumption, consumers can avoid taxes, levies and network costs by auto-generating solar energy and reducing their own consumption, even though they still rely on the grid for a reliable service. The network costs then might need to recover their costs from a smaller amount of end users who end up paying more. Simshauser (2016) refers to this effect as "grid defection"; it has been observed in Australia, US and Europe. Under flat energy rates, customers who consume less power during peak periods subsidize those who consume relatively more power at same times. He proposes that a peak demand tariff would be more effective, cost reluctant and would have a more equitable pricing. Pereira et al. (Pereira, Marques, & Fuinhas, 2019) also identified that subsidies of PV installations for large consumers have reduced their energy bill, but these savings are not shared with the rest of the consumers. They suggest that policymakers should raise awareness of the advantages of real-time tariffs to enable consumers to benefit from reduced prices.

Neuteleers et al. (2017) investigated the fairness of dynamic grid tariffs. From a bottom-up approach, they analyzed the concepts of needs and desert (the link between undertaking a valuable activity and a received benefit) to find how these affect people's perception. From a top-down approach they considered how to distribute common costs, caused by equal treatment, based on the ability to pay, based on costs and based on benefits. They identified some enhancers of fairness perception. A tariff increase is more accepted if there are increasing underlying costs for the product. Predictable dynamic tariffs also increase acceptability because consumers are given the opportunity to adapt their behavior in advance, in the same way that recurrent peak pricing is more acceptable that if this happens in exceptional occasions. Tariffs were especially acceptable if the revenues were used for something related to peak pricing. Nevertheless, changing into another tariff scheme is not so straightforward. The net-metered volumetric charges have been prevailing due to a lack of smart metering and customers customs. (Neuteleers et al., 2017).

Schittekatte & Meeus (2018) considered that fairness also encompasses distributional issues, transparency and graduality. As distributional issues, they remark that tariffs should be affordable and non-discriminatory, although this can be contradictory. On one hand, real time pricing can cause some poor households to curtail their basic demand, on the other hand, it is deemed as fair to charge the same amount for the same service independent of the use or consumer. The authors also pointed out the fairness debates about the cost allocation between active and passive consumers and between type of users (residential / larger consumers/ commercial businesses) connected to different voltage levels.

Finally, prosumers in the grid complicate the cost allocation between consumption and production connected to the same voltage level. Perez-Arriaga et al. (Ignacio J. Pérez-Arriaga, Jenkins, & Batlle, 2017) recommend that electricity rates should be technology agnostic and based only on the injections and withdrawals of electric power at a given time, voltage level and location in the grid, rather than on the specific devices behind the meter. They also suggest that prices should be symmetrical. This means that electricity injection at a given time and place should be compensated at the same rate that is charged for withdrawal.

The rationality of fairness in network tariffs also applies to electricity prices. In a future system it will be necessary for customers to adapt their energy consumption to electricity prices, which will be explained in the deliverable 3.5. For this reason, it will be important to evaluate how fair the costs are passed to the customers through fairness indicators.

2.3.3. Electricity prices and fairness

The mentioned reliability indicators evaluate the system as a whole, but don't reveal the distribution of not delivered energy across customers. The VOLL, which can be calculated with the interruption energy and the value to customers, does not express equity. As poor households typically have a lower VOLL than rich households. To measure the fairness of the system reliability, Heylen et al. (2019) propose to consider the relative reliability level.

$$relative\ reliability\ level = \frac{reliability\ indicator}{base\ variable} = \frac{r_j}{b_j}$$

where Table 1 summarize some possible reliability indicators and its base variables.

Table 1 Reliabiliy indicators, their associated base variables and its fairness types (reproduced with permission with permission from (Heylen et al., 2019))

Reliability indicator *r*	**Unit of *r***	**Base variable *b***	**Unit of *r/b***	**Equality/ Equity**
Energy not supplied[a]	MWh	Energy demand[b]	%	Equality
Load curtailment	MW	Power demand[b]	%	Equality
Total interruption duration	Min	# consumers per group	Min/cons	Equality
Interruption cost	€	Energy demand[b]	€/MWh	Equity
Total cost born by consumer[c]	€	Energy demand[b]	€/MWh	Equity
RES energy curtailment	MWh	Scheduled energy output	%	Equality
RES energy curtailment	MWh	Capacity factor	MWh	Equality

a) If the evaluation is ex-ante, then the expected energy not served (EENS) of the energy not served is used (ENS)

b) Effective electricity request including the load and the curtailed load.

c) Interruption cost added with the payments made to fund a compensation scheme reduced with received compensations

Heylen et al. (Heylen et al., 2019) also propose a fairness ratio, where the indicator and the base variable are normalized using the total sum of their values.

$$fairness\ ratio\ \rho_j = normalized\ relative\ reliability\ level = \frac{\frac{r_j}{\sum_j r_{j'}}}{\frac{b_j}{\sum_j b_{j'}}}$$

The fairness ratio ρ of consumer type j express the share of its unreliability r_j in the total unreliability, relative to its share in the total base variable. A fair distribution of reliability would be one where all the consumers would have the same relative reliability level. As it is difficult to calculate the inequality per customers (as there is no information on demand and exact energy not served), the fairness index can be calculated to measure the inequality between nodes or consumer groups. Another used power sustainability fairness indicator is the standard deviation of the individuals from a reference point that can be the fair relative reliability level ($\rho_j = 1$). To assess the total unfairness in the power system, the authors propose using the most used index that measures inequality in economic context, the Gini index. It combines individual fairness ratios and enables a graphical presentation based on Lorenz curves and because its value is between zero and one, it is easy to compare different fairness ratios.

Such as reliability levels, the highest fairness levels come along with remarkably high costs. For this reason, the authors propose a way to reduce the level of unfairness, which is to price consumers contracts according to the reliability level or by offering interruptible load contracts for small consumers. The design of future markets will have to balance between the trade-off of cost reflective and fairness in electricity pricing. (Heylen et al., 2019)

The fairness indicator will depend on the chosen pricing scheme. For capacity subscription mechanism, where users declare its reliability level, a suitable indicator would be the ratio of the total interruption duration to the energy demand (consumer groups by desired reliability level). In an energy only market, the ratio of the total cost borne by consumer group to the energy demand can reveal unfairness in the system.

Indicator: fairness ratio

2.3.4. Competitiveness

From the microeconomic theory, the way to maximize social welfare is when markets are competitive. The degree of competitiveness of a market is an indicator of its economic efficiency. A perfect competition exists when many small firms produce a homogeneous service and none of the firms can influence the market. The simplest and most widely used parameter to measure market concentration is the m-firm concentration ratio. It is defined as the aggregate of the m largest companies, normally calculated for the four most prominent companies. Other common metrics used to evaluate the competitiveness of a market are the number of companies representing at least 95% of the market share and the concentration-based measure, so called the Herfindahl-Hirschman index (HHI). It is the sum of the squared market share per firm. In power systems acceptable values are 1000-1800. Higher values indicate a concentrated power. (Borenstein, Bushnell, & Knittel, 1999)

Due to inelastic demand that characterizes energy markets one supplier is able to raise the market price if its capacity is indispensable to meet demand. The pivotal supplier indicator (PSI) is used to measure if a firm is pivotal or not. It is defined as the ratio of the company's residual supply divided by the total demand. Additional to this parameter the number of hours that a company is pivotal can complement the competitiveness report. (Perekhodtsev, Lave, & Blumsack, 2002)

Finally, the Lerner index measures the difference between prices in perfect competition and prices assuming that agents manipulate market outcomes to maximize their profit. This index is more difficult to compute ex-ante and is more useful to evaluate markets in operation (Ignacio J Pérez-Arriaga, 2013).

$$L_I = \frac{p_{real\ market} - p_{perfect\ market}}{p_{real\ market}}$$

2.4 Climate neutrality

The EU emissions trading system (ETS) is the EU's main instrument for achieving climate neutrality. It covers around 40% of the EU's greenhouse gas emissions and the commission is considering expanding its scope. For phase 4, the annual reduction in allowances will be 2.2% as of 2021. The major issue with this mechanism has been its overlapping goal with VREs subsidies and the limited adaptability of the ETS in the first three phases. National climate protection measures such as coal phase outs and economic development were not considered. VREs targets have decreased the carbon emissions. In order for the carbon pricing signal to be effective, more ambitious VREs targets should be more coordinated with the tightening of ETS.

More than a percentage of VREs, its efficient dispatch will contribute to carbon emission avoidance. A common indicator is the total amount of CO_2 emissions (tons). Although we will focus our research on scenarios with 100% renewable energies, we will include CO_2 emissions as an indicator for scenarios that are not fully CO_2 neutral. As the increase in sustainability is related to an increase in costs, we can also evaluate the system cost per avoided ton of CO_2 in different scenarios.

Indicator: Total CO_2 emissions [tons].

Table 2 summarizes the most relevant new indicators to evaluate the adequacy of a high-RES system with flexible demand.

Table 2 Selected TradeRES Indicators for future market designs.

Indicator	Advantages	Disadvantages
Security of supply ***Variance of annual returns to the energy supply industry***	- Indicate the risk aversion of companies to invest	- Doesn't give any hint about investment waves of gaming that can cause this variance
Adequacy $\mathit{supply\ ratio\ at\ peak\ demand} = \frac{\mathit{available\ supply\ at\ peak}}{\mathit{peak\ demand}}$	- Evaluates effectiveness of capacity mechanisms	- Doesn't consider that the peak demand changes according to prices - requires that peak is determined
Adequacy ***Scarcity time period***	- Gives an overview about the level of stress in the system	- There are multiple measures, each with shortcomings.
Affordability $\mathit{cost\ recovery} = \frac{\mathit{total\ market\ revenues}}{\mathit{total\ cost\ of\ the\ system}}$	- Simple interpretation - Can hint if the generators have windfall profits or if they aren't able to cover their costs. - Considers that demand might flatten - A well-functioning market design is that where the total revenues are close to the total cost of the system.	- In a transition phase the ratio can indicate wrongly that the system is imbalanced. - All costs, including integration costs, should be considered as well as all market revenues. Some costs can be difficult to determine.
Affordability **Price volatility of electricity prices**	- Simple - Includes total supply and demand flexibility - Reveals price stability for consumers and generators	- Ignores that demand might shift to avoid high prices but at a high inconvenience cost. - Is not a cost-efficiency indicator
Fairness **Fairness ratio**	- Easy to compare (scale invariant)	- Doesn't consider the WTP of consumers
Climate neutrality ***total CO2 emissions***	- Simple	- Although fossil fuels emissions are easy to calculate, the total emissions might be ignored.

3. Performance Specifications for a future market design

3.1 System services

As the share of distributed renewable energies in the power system increases, technical challenges arise for the reliability of the system. More variable generation in the market may increase the demand for and cost of ancillary services. In this section, the technical challenges that have been most apparent since the introduction of VREs are outlined. Deliverable 3.3. outlines concrete options in which these new technologies can alleviate the surging technical problems, participating in ancillary services markets.

ENTSO-E defines ancillary services as the functions provided to DSOs and TSOs to keep the operation of the grid within acceptable limits for security of supply and delivered mainly by third parties or by the TSOs and the DSOs themselves. When these services are contracted from market parties, the TSO or DSO who contracts the services coordinates them and is responsible for the end result. When the services are remunerated, the costs are included in the network system tariffs. Network operators can obtain these services by making their provision compulsory or they can contract them in markets, through bilateral contracts or through tenders. Not all ancillary services are remunerated, especially at the DSO level. (Oureilidis et al., 2020)

In Europe, the main ancillary services are frequency control (primary or frequency containment reserves (FCR)), secondary or frequency restoration reserves with automatic activation (aFRR), tertiary or frequency restoration reserves with manual activation (mFRR)), voltage control (primary, secondary, tertiary), reactive power supply, and black start capabilities. Generally, the TSO is the operator and sole purchaser in the ancillary services market, while sellers are prequalified generators and in some cases demand response and storage facilities. Nevertheless, DSOs play an increasing role in providing some services such as voltage regulation. The procurement can be compulsory provision, bilateral contracts, tendering and spot markets. (Oureilidis et al., 2020)

Voltage support is not remunerated in all countries of the EU. If they are, the settlement procedures are similar to the frequency reserves. Voltage control providers can be synchronous generators (SGs), wind farms, PV systems, HVDC links, assisted by static VAR compensators (SVCs), flexible AC transmission system (FACTS), etc. Black start is seldom clearly defined, provided and remunerated. In some countries, providing black start support is mandatory for conventional plants, while in others, black start is procured through bilateral contracts. All European countries provide black start at the transmission level but only in a few countries it is provisioned in the transmission and distribution grid. (Oureilidis et al., 2020)

3.1.1. System services contracted from market parties

The frequency stability of a power system can be described as its ability to maintain an operating frequency close to its nominal value when an imbalance occurs. Reduced system inertia leads to faster frequency dynamics which challenges the control of system frequency, it is related to a faster rate of charge of frequency (RoCoF) and larger frequency deviations. In the last years in several countries in Europe and US, the demand for frequency reserves has increased nearly up to 10% of the additional VRES capacity. (Meegahapola et al., 2020) This is not the case in Germany, where the balancing power demand has decreased. This can be attributed to better forecasting techniques of VREs, an increase of intraday trading, improved intra-day liquidity, cooperation of the balancing market of the four German TSOs and more international coordination through platforms, such as the International Grid Control Cooperation (IGCC). In the past years, there has been an increase in projects and platforms that enable the cross-border exchange of balancing energy and imbalance netting and these have resulted in reduced activation of balancing energy and overall reduced costs. (Schittekatte, Reif, & Meeus, 2020)(Hirth & Ziegenhagen, 2015)

Different solutions can contribute to stabilize the disturbances related to frequency. In this sense, PV wind turbines can use batteries, supercapacitors and flywheels to supply additional active and reactive power in an imbalance situation. Furthermore, PV can be operated below their optimal generation point to supply active power if it is necessary, this is also known as de-loading technique. Wind plants can also be operated at de-loading level to be able to contribute to frequency stabilization through pitch angle control and over speed control, although this would be subject to a loss of energy revenue. Variable speed wind turbines (VSWTs) can increase the output power for a few seconds supplying additional power to the grid, reducing the generator speed and releasing the kinetic energy of the rotating blades. (Fernández-Guillamón, Gómez-Lázaro, Muljadi, & Molina-garcía, 2019) However, using rotational energy from wind turbines can hinder the frequency restoration if reacceleration is required after some seconds. There are also opportunities from the demand side. A Danish project has developed algorithms for electric vehicles to provide fast frequency response (FFR) and synthetic inertia during transients. (Hartmann, 2019)

Poplavskaya and de Vries (2019) compared the Austrian, German and Dutch balancing market and concluded that so far, the participation of REs has been hindered due to market requirements such as the minimum bid size and low bidding frequency.

3.1.1.1. Inertia

Inertia is a characteristic of synchronous generators that prevent fast frequency variations in the first few cycles after a power imbalance. (Oureilidis et al., 2020) The main types of synchronous generators are thermal generators, i.e. generators that operate on natural gas), coal or nuclear power. As renewable generators are coupled to the grid with electronic converters, the inertia of the system reduces because the share of coupled rotating mass (synchronous generators) decreases. (Tielens & Hertem, 2016) Fernandez et al. (2019) considered the annual average electricity generation to calculate an average equivalent inertia constant provided by conventional power plants. They found that from 1996 to 2016, in the EU the equivalent inertia constant was reduced by nearly 20%, which is in line with the 20% increase of VRE in the system.

So-called synthetic, emulated or virtual inertia is a frequency control strategy for VREs, specifically wind turbines. PV cannot inherently provide inertial response based on its own primary source, but only through energy storage technologies, e.g., with a fast storage system based on supercapacitors. Variable speed wind turbines (VSWT) have rotational inertia constants comparable to those of conventional generators. However, this inertia is hidden to the system due to the converter. Considering this hidden inertia, the equivalent inertia reduction is only of 10%.

The level of inertia in the system can become an important constraint for adding renewables to the system. Nowadays the system operator of the Republic of Ireland, EirGrid, already considers non-synchronous generation and inertia as an operational system constraint. (Meegahapola et al., 2020) It is the first system operator in Europe to design new ancillary services related to non-synchronous variable generation. (Mehigan, Al, & Deane, 2020) It has investigated the implementation of a minimum available kinetic energy constraint in the unit commitment dispatch calculations which ensures a maximum rate of change of frequency (RoCoF) value.

Mehigan et al. (2020) simulated decarbonised scenarios for Europe in 2030 and concluded that the low inertia consequences were depending on size, generation mix and interchange with neighboring synchronous areas. The share of hydro and nuclear energy in a system can help a system with high penetration of renewables to stay below the RoCoF limits.

In the past, inertia was a characteristic of many of the power plants that were built by market parties. In the future, the provision of inertia by electricity market parties is not a given and the system operator may therefore need to contract it. Additionally, the load is increasingly having power electronic interfaces, such as electric vehicles, variable speed drives and light-emitting diodes which adds negative damping to the power system.

3.1.1.2. Ramp rates

System adequacy is not only a matter of quantity, but also of having sufficient resources that are sufficiently flexible. An extensive solar penetration has led to the famous duck curve, reported first by the grid operator in California (CAISO) in 2013. The problem arises during sunset when the solar generation drops to zero and there is a peak on the demand side. Then there is a need to rapidly ramp up conventional generators to stabilize the system. Large RES ramp downs can also cause price spikes in case these happen during reserve scarcity, as seen in US ERCOT and PJM markets. (Oureilidis et al., 2020) According to the calculation of the Network Development Plan 2025, published by the ENTSO-E, within just ten years there will be a fivefold increase in the number of hours with a rapid change in feed-in of more than 5 GW. From 2015 to 2025 the number of events with a change of 30 GW or more will increase from 15 to 190. (Bundesnetzagentur, 2017) The need for more flexible generation, where power plants can ramp up and down quickly, and plants that be turned down and quickly restarted will continue increasing. Active power ramp rate control, provided by RES, has also been proposed as a new AS. However, this issue might be solved more efficiently with more granular timed markets and closer to real-time closures.

To measure if a system has enough ramping capabilities, the indicator 'insufficient ramping resource expectation' (IRRE) is commonly used. This indicator reveals the expected percentage of incidents in a time period when a power system cannot cope with the predicted and unpredicted net load. The downward flexibility of each unit and system flexibility time series are considered to calculate the IRRE (Lannoye, Flynn, & O'Malley, 2012). Nevertheless, this indicator doesn't consider the demand side response (DSR) flexibility and the controllability of VRE output. For this reason, to estimate the operational flexibility with the consortium models, an operational simulation could determine where there is sufficient ramping capacity in the system.

3.1.1.3. Voltage stability

Voltage stability is the ability of power networks to recover steady-state acceptable voltage levels after being subjected to a fault or a disturbance. This recovery can be affected by renewable energies due to a shortage of reactive power reserve and low short circuit capacity in the network.

Following a disturbance, synchronous generators naturally inject short circuit power to the grid. Power electronic converter (PEC) connected devices don't contribute naturally to the short circuit power and therefore impede the protection systems to function properly. The stability of the power grid under high penetration levels of PEC interfaced sources is also influenced by its fault ride through (FRT) capability which determines its ability to remain connected during network faults to return quicker to normal operation.

Reactive power is normally supplied by SGs near to where it is needed as it cannot be transmitted over long distances. As RES are integrated in remote locations, the power is transmitted over long distances and the system requires additional reactive power reserves to maintain voltage levels within the stipulated limits. Similarly, the VREs with convertor power electronic interfaces have a lower capability to absorb reactive power. This can become problematic as the fluctuations in reactive power demand are increasing. Nevertheless, PEC-interfaced REs can produce reactive power. This should also be coordinated to avoid instability when the wind generators operate at maximum reactive power.

3.1.1.4. Black start

Black start is the ancillary service provided by generating units that, after a general or partial system shutdown, can inject energy into the system without any external electrical supply, and can set and control the voltage of the grid. After energizing the network, these units facilitate the start-up of other generators. To control the voltage, these units also provide and consume reactive power. (Oureilidis et al., 2020) There have been some demonstration projects that research the capabilities of battery storage systems to participate in black starting the system. (Brown et al., 2018) In order to provide black start support, variable inverted-based REs (VIBRES) would need to provide large in rush currents, capacitive currents and maintain voltages in acceptable limits. (Hodge et al., 2020) The challenge is for VIBRES inverters to create the voltage waveform and maintain a constant frequency. There have been scarce trials with full black start from VIBRES and integrated storage. (Holttinen et al., 2020)

Since REs haven't been able to participate in ancillary services markets, there is no incentive to offer their services, though they have potential for it. There are many challenges for REs to participate in ancillary services markets. As new services will be explored, the coordination between TSOs and DSOs will be important for these to be functional. Currently, this coordination is quite poor and not apt for a bottom-up provision of ancillary services. Furthermore, a proper ICT infrastructure would need to be installed to provide the data for monitoring and controlling the ancillary services.

The market design of ancillary markets is complex due to the characteristics of the products and the many market design variables. Poplavskaya and De Vries (2019) identify more than 20 design variables for balancing markets alone. Billimoria et al. (Billimoria, Mancarella, & Poudineh, 2020) describe that ancillary services can be seen as a basket of goods, more than public goods, with different economic characteristics in time and space. Some products, such as the provision of inertia and fault level, are inseparable. The procurement of services should also consider the trade-offs between services, otherwise the value of DSR and other flexible services can be overestimated. (Strbac et al., 2020) Badesa et al (Badesa, Teng, & Strbac, 2020) propose a pricing methodology for the procurement of inertia and frequency regulation services which would allow providers of frequency services to submit the parameters of the services and operators to make the optimal tradeoff between them. Deliverable 3.3 will expand on this subject and will identify the most suitable ancillary services markets where RES can participate to be part of the solution.

To conclude, VREs affect power quality and will continue to do so as their share increases. Nevertheless, VREs also have the capability to contribute to the stabilization of the grid. For this to be possible, new ancillary services need to be considered and the current market, including the balancing market, should be modified to allow more renewable energies to offer more flexibility.

3.2 Short term system performance specifications

3.2.1. Economic dispatch

As described in the last section, there is great flexibility potential from integrating renewables resources as well as consumers participation in the economic dispatch of resources. The goal of it is to maximize the availability of resources and to minimize system cost. This requires an efficient combination of generation, storage and demand response at all system levels, and therefore efficient integration of retail consumers/prosumers in the wholesale market.

If distributed RES, which are behind the meter, would be available for operators to curtail them, the flexibility of the system can be largely increased. Enabling final consumers to benefit from the market, lowering its consumption when electricity prices are high, is a measure that can add flexibility and help the system to be more stable and less expensive. A study by Strbac et al. (2019) illustrated how decentralized markets with more flexible demand resulted in more competitive electricity markets, where the market power of major electricity companies can be reduced. This market competitiveness can be enhanced by P2P energy trading and local markets.

The European regulation on the internal market for electricity (“Regulation (EU) 2019/943 of the European Parliament and of the council on the internal market for electricity,” 2019) recognized that a proper market design will reflect the time dependent value of renewable energies. To be able to provide transparent price signals to consumers, there is aready a European roadmap for the deployment of smart meters in households. A considerable number of NECPs refer to smart meter deployment with a measurable target. However, few set clear timelines. (European Commission, 2020) The question remains in which degree will consumers will be able and willing to adjust their demand according to electricity prices.

3.2.2. Network congestion

Congestion refers to a situation when the demand or generation at a certain point in the network, exceeds its transfer capabilities. There are three levels of congestion:

- In the distribution network
- Within a price zone
- Between price zones / cross-border congestion

Since the liberalization of electricity markets, the number of congestions has increased steadily. This is mainly because power plants are built taking into consideration only the plants' cost and not the proximity to consumers of the grid costs. Renewable generators are placed where the natural resources are more available and thermal generation are preferably built near the shore, where cooling water is available, and the transport costs are low. Furthermore, there has been an increase in imports and exports due to the more integrated European electricity markets.

3.2.2.1. Network congestion in the distribution network

Traditionally, the role of the distribution network was to transport energy from the transmission lines to consumers. This is changing gradually as now there is a need to integrate distributed generation and to facilitate consumers' demand response.

Photovoltaic and wind generators, except large wind parks, are mainly connected to the distribution grid. When these are producing at full capacity and the load is low, congestion can be provoked. At times when the amount of locally generated power exceeds the local load, it can be that the power begins to flow towards the substation. This is known as reverse power flow. As the reverse flow increases, the impact on the voltage profile gets stronger. In the extreme scenario, where thermal limits of the network are reached, the distributed generators have to be interrupted. In the distribution network, congestion may also be caused by wholesale market conditions such as balancing prices, so coordination with the TSO is necessary.

In the near future, the increase of electrical vehicles (EV) and heat pumps is likely to raise the congestion in distribution level. If all consumers intend to charge their electrical vehicles between 5 and 7 pm, or when prices are the lowest, this is also likely to cause congestion. However, these technologies also have the potential to add flexibility to the grid if adequate remuneration schemes are introduced, but also if proper information and communication technology (ICT) infrastructure and control algorithms are in place to provide intelligent congestion management. Verzijlberg et al. (Verzijlbergh & Vries, 2014) simulated a system where the share of REs and EVs are large enough to influence the electricity prices. They concluded that integrating the network constraint on EV charging has a low cost associated with it, in comparison to investing in additional network capacity. They showed among others, that an iterative grid capacity allocation was a successful algorithm to converge into an optimal tariff.

An option to avoid the complexity of overlapping tariffs and electricity prices is for network operators to capture congestion costs and automatically control flexible loads. Furthermore, aggregator concepts will also change the value chain of the system. Perez-Arriaga et al. (Ignacio J. Pérez-Arriaga et al., 2017) confirm that automation and aggregation reduce the burden of responding to time varying rates and the cost of computation, communication and control technologies. The aggregators' role in future market designs will be analyzed in deliverable 3.2.

3.2.2.2. Network congestion within a price zone

The development of the European renewable electricity generation portfolio depends on the geographical availability of resources. In the south of Europe, more onshore wind and solar energy is being built, whereas more offshore wind is being built in the north. In Germany, most wind energy is produced in the north, while the highest electricity demand is in the south. The construction of power lines from north to south has been delayed due to public opposition. The phase-out of nuclear energy and the integration of European electricity markets have contributed to the loading of the transmission lines and the need for internal reinforcements. The German TSOs have to redispatch flexible generators in the system to facilitate the market results while maintaining grid stability. Redispatching may involve curtailing wind energy in the north and ramping up gas plant in the south. The volume of curtailed energy from all renewable sources more than tripled between 2014 and 2015 in Germany. In 2015, the total volume of energy curtailed was 4.7 TWh, with around 11% due to congestion relief in the distribution network. (Bundesnetzagentur, 2017) In 2018, redispatching and feed in management measures (including the grid reserve) caused costs of EUR 1.5 billion, and around 4% of electricity generation was affected by redispatch measures. (Hirth, Schlecht, Maurer, & Tersteegen, 2019) The rate of grid expansion is increasing. The commissioning of the Thuringian Electricity Bridge, with its 5 GW transmission capacity, has helped significantly to release pressure on the transmission grids. There have also been improvements to the efficiency of existing networks regarding the weather-dependent monitoring of overhead lines. Nevertheless, the nuclear phase out will increase the need of reserve capacity. (Federal Ministry for Economic Affairs and Energy, 2019)

Germany will retain its cost-based redispatch after the analysis that a market-based redispatch can be susceptible to strategic behavior, which could actually worsen the network congestion. Nevertheless, the regulations have been modified to allow renewables and CHP plants bigger than 100 kW to participate in congestion management. The next step will be to enable network operators to manage flexible loads, such as electrical vehicles, to support the network. An option is to separate the network connection capacity of flexible consumption devices and postponing consumption if necessary. (Federal Ministry for Economic Affairs and Energy, 2019)

3.2.2.3. Network congestion between price zones (Cross border transmissions)

The increase in RES may affect energy trade between countries. So-called loop flows occur when there are unscheduled power flows in bidding zone B from scheduled flows within zone A. These can decrease the available network capacity and increase the grid management costs of zone B. (Peng & Poudineh, 2019) According to the recent European Electricity Market regulation, 70% of physical transport capacity must be available for electricity trading. In the future, it will no longer be permitted to accommodate loop flows and internal flows in cross border trading capacity, which would lead to regular cross congestion from more cross border and intra-zonal exchanges. However, this regulation also makes it mandatory for TSOs to make their redispatch potential available to each other, which can alleviate congestion. (Hirth et al., 2019)

In the report Completing the map Power system needs in 2030 and 2040, ENTSO-E published that following investments in cross border emissions would be cost efficient: the already planned 25 GW by 2025, additional 50 GW by 2030 and 43 GW by 2040. Building this network reinforcements would save until 5% of the annual REs energy generation or 110 TWh/year by 2040. Allowing the integration of more renewable energies, this network capacity leads to a reduction of 55 MTons of European CO_2 emissions by 2040 in contrast with a scenario where no grid investment is made.[2] Similarly, the generation costs would decrease by €10 billion per year. Outweighing the cost of building the grid, which would be 45 billion Euros for 2040. In the case that no investment is made, the bidding zones could have an average marginal cost difference of 35 Euros/MWh. (ENTSOE, 2020) One of the short-term benefits of cross border integration is the attractiveness of including the huge storage capabilities of Norway and the Iberian Peninsula (70 and 25 TWh) and the possibility to exploit the different asynchronous natural resources across the continent. (Newbery, Pollitt, Ritz, & Strielkowski, 2018)

Parallel to the grid expansion a future market design can alleviate congestions by enabling markets to reflect the physical constraints and by enabling the integration of cross border capacity.

To minimize the costs generators, demand side response should be activated considering the transmission costs and constraints. Reflecting the total costs should incentivize companies to build power plants where they are needed and where they would be most cost-efficient for the system. Perez Arriaga et al. (Ignacio J. Pérez-Arriaga et al., 2017) recommend to progressively improve the granularity of price signals with respect to time location. They explain that the ideal price signal would be to extend the locational marginal prices to the distribution network to capture the time and location varying value of electrcicity at every connection point to the system, including prices for active and reactive power.

A future market design should enable consumers to benefit from participating actively in the market. Electricity prices should have a more granular spatial and temporal resolution. Reflecting network congestion costs, a future market design should facilitate a more efficient use of the grid and optimal allocation of REs flexibility. It should also facilitate the trade of energy and balancing services between regions and member states.

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[2] Because the CO2 price increase would change the merit order in the 2025 starting grid, the level of needed grid capacity would also increase along with the reduced CO2 MTons in case the network is built optimally.

3.3 Long-term system performance specifications

3.3.1. Resource mix

As more renewable energy sources are participating in the markets, they have reduced electricity prices and have made generation more difficult to predict. This has caused complementary technologies to have low margins and short activation times. Demand for generation has not only been characterized by steeper ramps, but also by periods where generation is supplied at higher level are becoming shorter. (Milligan et al. 2011).

One of the biggest challenges for the energy transition will be to guarantee a security of supply when generation is 100% renewable, consisting for a large part of intermittent resources. As the volume of RES in the system continues to increase, the reliability of the grid will be vulnerable at moments when there is limited wind and solar radiation and temperatures are low. These extreme situations are referred to as “kalte Dunkelflaute” in German and they will determine the need for controllable generation capacity (including storage). Such extreme weather situations may increase the severity of scarcity and the levels of price extremes, which would also be reflected in the electricity bills. This price volatility could also result in a high variance of returns for investors who may become risk averse and reduce investment in more capacity, which could threaten security of supply. A proper future market design provides incentives for sufficient investment in controllable generation capacity and long-term storage to meet demand, including the demand for power conversion to other energy carriers, even at extreme situations. Exactly how much capacity should be provided depends on the socially acceptable ENS per year.

To achieve a zero-carbon emissions system without firm low-carbon generation, the mentioned need for long-term energy storage could be provided by hydrogen, in addition to thermal storage, sector coupling and demand response. Hydrogen can be produced at times that there is oversupply of REs and can be stored for long time horizons with minor losses, although the conversion from electricity to hydrogen and back is costly and is characterized by significant energy losses. (Strbac et al., 2020)

System flexibilities technologies and services will be the key enablers and the most cost-effective solution for a high penetration of REs. Strbac et al. (Strbac et al., 2019) modelled the UK electricity system, adding 10 GW of new energy storage and maximum DSR uptake and demonstrated that flexibility solutions can bring gross savings between 3.8£ and 8£ billion/year, not including the cost of DSR and storage. The savings include the lower REs curtailment, reduced network reinforcement, reduced investment in low-carbon generation, improved utilization of installed technologies and reduced investment in conventional generators. They also calculated that in contrast to a transmission – or distribution centered approach, a whole-system-based network management approach may result in 30 to 100% savings in investment and operation costs of the system. In the traditional DSO-centered or TSO-centered approach, the network investments are delayed and the potential of the other transmission level are ignored.

3.3.2. Optimal combination of market and network investments

A higher level of decentralization comes along with higher coordination requirements. A major challenge will be to transition from focusing on local and national objectives to an international, whole-system cost approach. Strbac et al. (Strbac et al., 2019) calculated that if investments would be made at the most efficient locations across Europe, it wouldn't be necessary to build 150 GW of REs capacity to produce the same energy compared to a system with a state-centric approach. This is equivalent to €150 billion savings by 2030. Additionally, an EU-wide capacity market and shared balancing market would result in €75 billion and €50 billion respectively.

A zero-emission energy system cannot be possible if the transmission capacity is not built accordingly. Beside flexible generation and flexible demand side resources, flexible transmission has become more relevant. The investment in network infrastructure should be planned along with generation resources. A more interconnected system would reduce the uncertainty and variability of renewable energy generation. Hence the curtailment of RES, the need for storage and the balancing resources would be reduced.

The ENTSO-E calculated 5% of annual RES curtailments, 55 MTons of CO_2 emissions and 10 billion Euros per year of savings, if the network would be reinforced efficiently by 2040 (ENTSOE, 2020). Schlachtberger et al. (Schlachtberger, Brown, Schramm, & Greiner, 2017) also modeled the European electricity system with a reduction of carbon emission of 95% compared to 1990 levels (on the year 2030) and concluded that restricting transmission drives total costs up by a third. A limited grid capacity would not be able to balance the variations of wind in space, needing then more hydrogen storage to balance the variations. In that case, a system with more solar generation and battery storage would be more economic. This reflects the need for a parallel extension of the transmission network along the clean generation capacity. The 2030 vision of the ENTSO-E is a market design that fosters "One system" with strong integration between different market models within the European union. A more integrated market can cause more network congestions, e.g. as more hydro energy is imported from Norway to southern countries more congestions will be caused in Germany. Therefore, it will also be important to enable the markets to reflect the physical constraints (transmission capabilities).

The roll-out of smart metering, complemented by smart end-use appliances, will provide unique opportunities for a radically different demand management approach in which non-essential loads could be switched off at times of network stress, while maintaining the essential supply. This will result in a very significant enhancement of reliability of energy supply delivered by the existing networks because many more consumers will have their essential demand supplied during network congestion events. Furthermore, this will provide the opportunity for customer choice-driven network design, which is the core objective of the market-based system design. In a scenario with flexible consumers, the breakeven VOLL level tends to be very high justifying the deferral network reinforcement. In such a scenario it will be critical to move away from the historical VOLL concept and N-1 security standards and recognize that VOLL will very much depend on the type of load that is disconnected. (Strbac et al., 2019) Besides demand side management, flexible non-network technologies (distributed generators and energy storage) should also be considered at the same level as network assets for the reinforcement of electricity grids. Additionally to the new network standards, suitable commercial frameworks can enhance the integration of new resources based on their risk profiles. (Strbac et al., 2020)

A future market design should allow generator companies to recover their investment costs so that the type of generators needed are built and where they bring the highest value to the system. It should incentivize companies to build the type of generation and storage in places where they are most valuable and where they would cause the smallest cost to the system. Furthermore, it should facilitate a stronger coordination of DSOs, TSOs, energy suppliers, consumers and EU-wide decarbonization objectives when planning the generator and network expansion.

4. Conclusion

A future power system composed of near 100% renewable energies will present challenges with respect to reliability and affordability. To specify how the future market should perform, this report outlines indicators that can be used to evaluate its performance according to the three pillars of energy policy. In this report, we reviewed the current performance indicators and concluded that these need to be augmented for future markets because currently they apply to a power system with limited demand price-elasticity. The EU proposed the future electricity market design to be consumer-centered and to enable more demand side response. In a scenario with a large degree of flexibility from demand response and storage, additional indicators for security of supply that we identified are the supply ratio at peak demand, energy not served, the annual duration of scarcity periods and the variability of annual returns to the electricity supply industry. To benchmark affordability in different market designs, we propose price volatility and the degree of cost recovery of generation and storage facilities as indicators. In addition, we recommend using a fairness ratio as an indicator to assess the degree to which the energy transition benefits everyone and a market power indicator to identify the possibility of strategic behaviour.

Reviewing the research on the technical challenges that have arisen from the introduction of REs in the European power system, we identify the specifications that need to be covered with future market designs. In the after-market closure timeframe, we expect that the uncertain nature of variable renewables will cause the ancillary services to become more relevant and valuable to the system. Renewables increased the need for frequency reserve, inertia, active ramp rates and voltage stability control. The positive side is that REs are technically able to contribute to these services. A future market design should consider these technologies as part of the solution, enabling them to participate more in short term balancing markets and in new ancillary markets.

Future markets should also become more time granular to facilitate more VRE and consumers participation in all markets. Passing real-time electricity prices and network costs on to customers is a cost-effective solution to incentivize demand side response, but, as the recent experience in Texas shows, consumers also need protection against prolonged periods of high prices. More electrical vehicles and heat pumps along with more solar generators at the distribution level may cause distribution network congestion. Automation and aggregation will be a key component to making optimal use of available flexibility in the system.

As markets are becoming more integrated, more imports and exports are expected to increase the need for grid expansion. The market should also give signals for companies to build the type of flexible generators at the most valuable locations. To fulfil the adequacy of a future power system, a major challenge will be to transition from a local and national to a whole-system-cost approach. More trade of energy and balancing services have proven to bring major cost savings. Similarly, coordination between the TSOs, DSOs has also proven to be more cost effective in investment and operation costs of the system.

In the long term, a major challenge will be to secure supply in rare periods of days or weeks when there is limited wind and sun and low temperatures trigger high demand. The recent crisis in Texas demonstrates that such situations are not hypothetical and can be severely disruptive. In these situations, the installed capacity, including all flexibility sources, may not be sufficient to meet demand. One central question that will be addressed in the TradeRES is if there is enough exploitable flexibility in the system, or if a capacity mechanism will be needed to guarantee a security of supply.

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