CEER

Council of European Energy Regulators

Fostering energy markets, empowering **consumers**.

Long-Term Generation Investment Signals in a Market with High Shares of Renewables

A CEER report

Future Policy Work Stream of Electricity Working Group

Ref: C21-FP-49-03
5 May 2021

Council of European Energy Regulators asbl
Cours Saint-Michel 30a, Box F – 1040 Brussels, Belgium
Arrondissement judiciaire de Bruxelles – RPM 0861.035.445

INFORMATION PAGE

Abstract

This paper shares some considerations on whether the market framework currently in place in Europe is fit for the steady development of renewable energy, and if it will carry the necessary long-term generation investment signals.

In particular this paper will:

(1) Investigate the decision maker's problem and consequences of risk aversion.
(2) Propose several options for the current market model to evolve in order to solve the challenges brought, amongst others, by high RES penetration and high carbon prices.

Target audience

National Regulatory Authorities (NRAs), European Commission, energy suppliers, traders, gas/electricity customers, gas/electricity industry, consumer representative groups, network operators, Member States, academics and other interested parties.

Keywords

Renewables; Renewable Energy Sources (RES), generation investment signals; adequacy, capacity mechanisms, Electricity Regulation, flexibility, security of supply.

If you have any queries relating to this paper, please contact:
CEER Secretariat
Tel. +32 (0)2 788 73 30
Email: brussels@ceer.eu

Related documents

CEER Documents

- CEER White Paper on Long-Term Storage, February 2021, Ref: C21-FP-48-03.
- CEER Paper on DSO Procedures of Procurement of Flexibility, July 2020, Ref: C19-DS-55-05.
- CEER Paper on Unsupported RES, May 2020, Ref: C19-RES-64a.
- CEER Treatment of Interconnectors and Neighbouring Resources in Capacity Remuneration Mechanisms, June 2016, Ref: C15-ESS-06-03.

External Documents

- European Commission (2019). Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity. https://eur-lex.europa.eu/legal-content/EN/TXT/?toc=OJ%3AL%3A2019%3A158%3ATOC&uri=uriserv%3AOJ.L_.2019.158.01.0054.01.ENG
- European Commission (2018). Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32018L2001&from=EN
- European Commission (2019). Communication on the European Green Deal, COM/2019/640 final. https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1576150542719&uri=COM%3A2019%3A640%3AFIN
- Joskow, P. (2019). Challenges for Wholesale Electricity Markets with Intermittent Renewable Generation at Scale: The U.S. Experience. Oxford Review of Economic Policy, Volume 35, Number 2, 2019, pp. 291–331.
- Kulakov, S, Ziel, F. (2019). The Impact of Renewable Energy Forecasts on Intraday Electricity Prices. Economics of Energy and Environmental Policy, 10(1) 2021.
- PJM (2018). Fourth Review of PJM's Variable Resource Requirement Curve,
- Cramton, P. (2017). Electricity market design. Oxford Review of Economic Policy, Volume 33, Issue 4, Winter 2017, Pages 589–612, https://doi.org/10.1093/oxrep/grx041
- De Maere d'Aertrycke G., Ehrenmann A., Smeers Y., (2016). "*Stochastic investment equilibrium in incomplete electricity market: modelling of remedy proposals to missing money"*
- De Maere d'Aertryckea, G, Ehrenmanna, A and Smeers, Y (2017). Investment with incomplete markets for risk: The need for long-term contracts. *Energy Policy*, 2017, vol. 105, issue C, 571-583.
- European Commission (2017). Regulation (EU) 2017/2195 establishing a guideline on electricity balancing. https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2017.312.01.0006.01.ENG&toc=OJ:L:2017:312:TOC#d1e259-6-1
- Petitet, M. (2017). Long-term dynamics of investment decisions in electricity markets with variable renewables development and adequacy objectives. Economics and Finance. Université Paris sciences et lettres.
- European Commission (2016). Communication from the Commission on Clean Energy For All Europeans. https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1582103368596&uri=CELEX:52016DC0860

- Rintamaki, T. (2016). Does Renewable Energy Generation Decrease the Volatility of Electricity Prices? An Analysis of Denmark and Germany. Energy Economics Volume 62, February 2017, Pages 270-282.
- Green, R, Léautier, T-O (2015). "Do costs fall faster than revenues? Dynamics of renewables entry into electricity markets," TSE Working Papers 15-591, Toulouse School of Economics (TSE).
- Phan, S, Roques, F. (2015). Is the depressive effect of renewables on power prices contagious? A cross border econometric analysis. EPRG Working Paper 1517.
- Aïd, R. (2014). A Review of Optimal Investment Rules in Electricity Generation
- European Commission (2014). Guidelines on State aid for environmental protection and energy 2014-2020. http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52014XC0628%2801%29
- Clò, S, Cataldi, A & Zoppoli, P. (2014). The merit-order effect in the Italian power market: The impact of solar and wind generation on national wholesale electricity prices. Government of the Italian Republic (Italy), Ministry of Economy and Finance, Department of the Treasury Working Paper No. 9
- Böckers, V, Giessing, L, Rösch, J. (2013). The Green Game Changer: An Empirical Assessment of The Effects of Wind and Solar Power on the Merit Order. DICE Discussion Papers 104, University of Düsseldorf, Düsseldorf Institute for Competition Economics (DICE).
- Meunier (2013). Risk aversion and technology mix in an electricity market. Energy Economics, 40, 866-874.
- Aïd, R. (2012). A Review of Optimal Investment Rules in Electricity Generation. Springer New York
- Ketterer, J.C. (2012). The Impact of Wind Power Generation on the Electricity Price in Germany. Renewable Energy Volume 94, August 2016, Pages 474-487.
- Green, R, Vasilakos, N. (2010). Market behaviour with large amounts of intermittent generation. Energy Policy, v. 38, iss. 7, p. 3211-3220.
- Finon, D, Defeuilley, C, Marty, F. (2009). Signaux-prix et équilibre de long-terme. Reconsidérer l'organisation des marchés électriques.
- Joskow, P. (2008), 'Capacity Payments in Imperfectly Competitive Electricity Markets', Utilities Policy, 16, 159–70.
- Eydeland, A., Wolyniec, K., (2003). Energy and Power Risk Management: new Developments in Modelling, Pricing and Hedging. Wiley Finance, John Wiley and Son.
- Oren, S, Shmuel, S. (2003). Ensuring Generation Adequacy in Competitive Electricity Markets, University of California, Berkeley.
- Artzner, P., Delbaen, F., Eber, J. M., & Heath, D. (1999). Coherent measures of risk. Mathematical finance, 9(3), 203-228.
- Trigeorgis, L. (1993). Real options and interactions with financial flexibility. Financial management, 202-224.
- Trigeorgis, L. (1996). Real options: Managerial flexibility and strategy in resource allocation. MIT press.
- Myers, S. C. (1977). Determinants of corporate borrowing. Journal of financial economics, 5(2), 147-175.
- Arrow, K. J., & Fisher, A. C. (1974). Environmental preservation, uncertainty, and irreversibility. In Classic papers in natural resource economics (pp. 76-84). Palgrave Macmillan, London.
- Henry, C. (1974). Investment decisions under uncertainty: the" irreversibility effect". The American Economic Review, 64(6), 1006-1012.

- Litzenberger, R. H., & Rao, C. U. (1971). Estimates of the marginal rate of time preference and average risk aversion of investors in electric utility shares: 1960-66. The Bell Journal of Economics and Management Science, 265-277.
- Turvey, R. (1968). Peak-load pricing. Journal of Political Economy, 76(1), 101-113.
- Drèze, J. H. (1964). Some postwar contributions of French economists to theory and public policy: With special emphasis on problems of resource allocation. The American Economic Review, 54(4), 2-64.
- Sharpe, W. F. (1964). Capital asset prices: A theory of market equilibrium under conditions of risk. The journal of finance, 19(3), 425-442.
- Boiteux, M. (1960). Peak-load pricing. The Journal of Business, 33(2), 157-179.
- Boiteux, M. (1956). Sur la gestion des monopoles publics astreints à l'équilibre budgétaire. Econometrica, Journal of the Econometric Society, 22-40.
- Morgenstern, O., & Von Neumann, J. (1953). Theory of games and economic behavior. Princeton university press.
- Boiteux, M. (1951). La tarification au coût marginal et les demandes aléatoires. Cahiers du Séminaire d'économétrie, 56-69.
- Boiteux, M. (1949). La Tarification des demandes en pointe: application de la théorie de la vente au coût marginal. Revue Générale de l'Électricité.

Table of contents

List of figures

List of tables

EXECUTIVE SUMMARY

Background

Based on current experiences, it has been shown, in theory[1], that market penetration of resource-dependant generation capacities with low marginal cost of production (e.g. wind and photovoltaics (PV)) tends to decrease the average price of electricity during windy and sunny periods and increase the price during dark and windless times. As a result, the need for flexibility will substantially change.

Objectives and contents of the document

In this context, questions have been raised about the ability of the current markets to adapt to the changing circumstances and to continue to send adequate long-term signals to remunerate necessary and reliable capacity providing flexibility and security of supply.

Following current renewable energy sources (RES) policy and the European Green Deal[2] road map, it is the regulators' responsibilities to ensure that the rule-setting allows the markets to work properly and encourage efficient long-term investments for the energy transition.

Therefore, this paper will:

(1) Investigate the decision maker's problem and consequences of risk aversion; and
(2) Propose several options for the current market model to evolve in order to solve the challenges brought, amongst others, by RES penetration and high carbon prices.

Brief summary of the conclusions

While it is clear, both from a theoretical and practical point of view, that RES penetration tends to lower the average energy price in the short term and increases market volatility, the concrete effect on investments is more difficult to determine. It has been demonstrated that the difficulties linked with the penetration of RES is not the problem per se but just a reflection of market failures.

It is therefore, essential that Member States and regulators give priority to eliminating as many market failures as possible, as required by Regulation 2019/943[3]. These actions must be clear, transparent, credible and predictable in order to help attract investment and to avoid increasing uncertainty.

[1] The impact of the integration of RES on electricity prices has been widely discussed by academics. Various statistical models were used to investigate the correlation of the market price and volatility regarding the percentage of RES installed in the system. In general, the results are in concert with the expectations: the average base load price is decreasing, all other things being equal, and intraday and intra week volatility price is increasing. For now, wind has a greater impact due to its wider penetration. See Annex 1.

[2] European Commission, A European Green Deal.

[3] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity.

1 Introduction

As more renewables are integrated onto the system, the price signals and volatility of the market are being affected. This brings about challenges, not only for areas such as market design, but also in continuing to provide adequate long-term investment signals to remunerate the necessary capacity providing both flexibility and security of supply.

The aim of this paper is to explore this challenge, and outline some of the issues which contribute to it. The paper first highlights the theoretical effects on prices and volatility of renewables penetration, and then goes onto examine investment theory and solutions for an efficient energy transition in the long-term. This includes exploring the history of the transition from a vertically integrated energy system to a liberalised market, and the challenges this brought for stakeholders in terms of investment decisions.

The paper exposes some of the current market failures in Europe and indicates that the source of concerns in terms of investment in Europe is certainly more related to these failures than to the penetration of RES, even if the latter seems to amplify the distortions.

The issue of adequate bidding zones and the improvement of locational price signals is intentionally not mentioned in this paper, even if it could be related to RES penetration.

Finally, this paper explores the options to evolve the current market model and how they could solve the challenges brought by RES penetration and high carbon prices. This includes an assessment of not only the action, and its impacts and ease of implementation, but also the potential distortive impact on the market.

2 Transition from a vertically integrated system to a liberalised market increased the complexity for stakeholders – an intended development

Whilst the recent penetration of RES highlighted the issue of long-term investment, investing in electricity generation has always been a challenge, even before the liberalisation of the market during the 1990s.

In order to gain state support, or at least a weak price control, monopolistic actors have always claimed that investments in production assets are characterised by many hurdles:

- The non-storability of electricity compels production to be adjusted on a real-time basis to consumption;
- The high level of uncertainty involved in both production (outages) and consumption (demand has a short-term weather dependency and a mid-term economic growth[4] dependency);
- The necessity to anticipate demand on a long-term basis to be able to satisfy the demand at all times, due to the long time it took to build gigawatt-scale power plants;
- Electricity producers must choose amongst a wide range of very different technologies, with uncertainty in cost of construction; and
- Some capacities are capital-intensive and have long payback periods.

In order to tackle these challenges in the previously vertically integrated electric utility monopolies subject to some kind of (weak) regulation, including government ownership and support, models of investment and tariffication were developed (Boiteux (1949, 1960, 1951, 1956); Dreze (1964); Turvey (1968)).[5]

These former models were built on simplifying assumptions, leaving little room for, for example, demand response. Electricity demand was supposed to be non-price-dependent, exogenous from the perspective of the monopolistic system operator, to vary widely from hour to hour, to be inelastic in the short run, and controlled by consumers and not the system operator – except under exceptional shortage conditions when non-price rationing would have been applied by the system operator. Limitations to storage was also considered.

Based on these assumptions, an optimal generation fleet could be determined by the central planner. The consistency between prices and investment cost was assured by a specific tariffication, maximising the use of the available resources[6]. The aforementioned claims were designed to create a willingness of regulators to accept the “specific tariffication”.

Nevertheless, the old central planner models were continuously abandoned. As described by Joskow (2019), it is commonly thought that regulated monopolies have poor incentives to

- Control operating and construction costs;
- Maintain generator availability at optimal levels;
- Retire generators when the expected present value of their costs exceeds the expected present value of continuing operations;
- Overinvest in new generating capacity;
- Fail to aggressively seek out innovations; and
- Other inefficiencies.

[4] The development of energy efficiency has also become an issue in mid-term demand forecasting.
[5] Challenges for Wholesale Electricity Markets with Intermittent Renewable Generation at Scale: The U.S. Experience, Paul L. Joskow, 2019.
[6] *La Tarification des demandes en pointe : application de la théorie de la vente au coût marginal*, Boiteux, 1949.

The liberalised model should, in theory, perform better than the regulated monopoly.

A liberalised market implies the decentralisation of the decisions. Should the competitive market mechanisms have been well designed and market power absent, competing generators would have strong incentives to control construction and operating costs, to maintain availability, to seek out innovations, to invest to enter the market, and to exit the market to cut expected losses.

Furthermore, spot prices for energy and ancillary services are widely transparent in the organised wholesale markets. These prices constitute the main signals to investment and exit decisions. If these price signals are correctly transferred to consumers that better match variations in marginal cost through variable retail pricing, more efficient consumption behaviour will be induced.

However, electricity market liberalisation has added competitive pressure to this already complex situation. Power producers are now competing for production and retail market shares. Like in most other markets, competition also implies uncertainties as producers have to foresee competitor behaviours as well as future policies.

Penetration of subsidised RES is a vibrant example of these new risks. In many cases, fossil and nuclear production is also subject to explicit or implicit subsidies (e.g. direct payments, combined heat and power (CHP)-support, self-supply privileges). Stakeholders have also to deal with supported generation schemes and anticipate political decisions that can alter their outcome. This fact needs to be kept in mind when designing new support for conventional generation. The more policy-designed mechanisms that are in place, the bigger the uncertainties.

3 Decentralised market puts stress on price signals

In Europe, decentralised energy-only electricity markets have been adopted based on the original California design. To explain the functioning of this market, see below a brief summary of the description by S. Oren, 2003[7].

Simplifying, in day-ahead markets, generators bid energy prices for a specific point or period in time and, in the absence of constraints, all bids below the market-clearing price in each hour get dispatched and paid the market-clearing price, this is the so-called energy only market (EOM). This clearing takes place on different market platforms. As the offer is dedicated to specific points or periods in time, they may contain not only energy offers but also power offers.

In day-ahead markets, the primary income source for recovery of capacity cost is the difference between the market-clearing price and the generators' marginal costs. In competitive electricity markets additional sources of revenue are available: long-term markets and intraday markets. The former allows, in general, for directly power-related revenues; the latter allows for mark-ups. When ancillary services are procured separately by the system operator, generators can earn additional revenue by selling ancillary services through ancillary service markets.

Economic theory indicates that in a long-term equilibrium of pure day-ahead EOMs, the optimal capacity stock is such that scarcity payments to the marginal generators when demand exceeds supply will exactly cover the capacity cost of these generators and will provide the correct incentives for demand-side mitigation of the impending shortage (i.e. the scarcity rent will induce sufficient demand response so that available supply can meet the remaining load).

Furthermore, in an equilibrium of pure day-ahead EOMs, the optimal generation mix (where generators are characterised by their fixed and variable costs) will be such that the operating profit of each generator type will exactly cover their capacity costs. This optimal equilibrium mix is achieved through the exit of plants that do not cover their cost and the entry of plants whose cost structure will yield them operating profits that exceed their capacity costs. A shortage of capacity will increase scarcity rents, producing profits in excess of what is needed to cover the amortised capacity cost. Such profits will attract generation expansion. On the other hand, excess generation capacity will eliminate scarcity rents, driving prices to marginal cost. When this occurs, generators on the margin will not be able to cover their investment cost. Unless such generators receive extra revenues through some form of extra payments, policy-driven capacity payments, ancillary services revenues, heat generation, etc., this will result in early retirement or mothballing of plants which will reduce capacity and drive prices back to their long-term equilibrium level.

The aforementioned effects of long-term, intra-day and ancillary service markets safeguard even more profit for generators and thus help to refinance the capacity costs. However, there are capacities installed that earn their capacity costs outside the EOM (e.g. back-up capacities and emergency generators) and that enter the market in case of high scarcity rents. These extra capacities limit the revenues in scarcity situations.

Alternatively, there are also back-up capacities in place which may only produce electricity once it is apparent that demand will not be covered, and not merely when prices are high (e.g. the strategic reserve in Germany). Hence, price peaks will not be capped through market intervention.

---

[7] Ensuring Generation Adequacy in Competitive Electricity Markets, Oren, Shmuel S., University of California, Berkeley, 2003.

Thus, “standard" decentralised market theory **assigns long-term and short-term prices a central role**[8] in temporal coordination by linking short- and long-term decisions. Price expectations confer the required information with regard to equipment choices and innovation. Technologies are assumed to emerge spontaneously from a basket of technologies at predictable dates with known learning effects in line with the expected evolution of the relative prices of factors of production. Technical adaptions to changing market conditions are stimulated by the same price signals, such as additional flexibility of coal power plants, reduced minimum load, steeper ramping, decreased starting cost, optimised fuel storage planning, automation of operation, price related maintenance, etc.

The decentralised market model relies on the assumption of a market with perfect competition and perfect information. Under this assumption, the market is assumed to perfectly reproduce the optimal prices ensuring the short-run-long-run linkage. In fact, the actual market is not a perfect one. There are, for instance, several imperfections stemming from political interventions (RES and CHP support, carbon-pricing, capacity payments, taxes, levies, and so on). It is necessary to safeguard that the effects of political intervention are smaller than the underpinning effects of long-term, intraday and ancillary service market revenues.

The operation of the hourly markets on which the whole system is based (without being limited to it) should ensure a socially optimal level of investment and allocation between technologies to follow the development of hourly demand.

Hourly price signals alone would make it possible to achieve an optimal fleet structure in a given market, minimising long-term costs by covering hourly requirements and ensuring reliability of supply. Hourly price levels aligned with the variable costs of the last power plant called by the market or the Value of Lost Load (VoLL) are deemed to be able to cover on an annual average basis all the fixed costs of the various technologies, on the basis of these assumptions of perfect information and perfect competition, including an appropriate return on capital.

The probable anticipation of the surplus of infra-marginal capacities on the hourly markets would enable operators to trigger the appropriate investments to guarantee both the adequacy of capacity and the optimum mix of equipment. Additional market options like long-term, intraday and ancillary service markets provide more incentives to invest.

In the event of a change in the sector's institutional and economic environment (e.g. market integration shock, fuel price shock, internalisation of the cost of carbon, cross-border competition, increase/decrease of consumption, etc.), the investor may decide to invest in other technologies and other sizes of plants after having identified the scarcity rents resulting from these shocks, which move away from the equilibrium state based on an optimal fleet (the optimal fleet being formed by the addition of the fleets of all competing producers).

[8] *Signaux-prix et équilibre de long-terme. Reconsidérer l’organisation des marchés électriques*, Dominique Finon Christophe Defeuilley Frédéric Marty, 2009.

4 The decision maker's problem and risk aversion due to price volatility

In this chapter we would like to briefly expose the complexity of the problem of making investment decisions in electricity generation. This question also has been widely tackled in the literature[9].

As discussed previously, the standard theory is built on the fact that if the discounted expected future benefits for a new capacity exceed the present costs, then investors will construct it. This rule is known as the net present value (NPV) rule. The rule is not specific for electricity but for all kinds of industrial investment decisions. In electricity markets, durations of up to 30 years are common.

However, as highlighted by Finon and Marty 2009[10], the volatility of short-term prices due to RES penetration, political interventions (such as carbon-pricing, coal phase out and nuclear phase in or out), when not considered sufficiently firm by stakeholders, and the lack of clarity of long-term trends all contribute to the blurring of income expectations.

Volatile short-term prices are not necessarily indicative of the state of long-term fundamentals and capacity scarcity on base and semi-base equipment.

Producers invest without any guarantee that the prices will be in line with their long-term marginal development costs. However, it should be noted that, if renewable capacity is assumed to be small enough that baseload technology is present at the equilibrium, then the long-term revenues of conventional plants are broadly not affected by RES penetration[11].

In a highly capital-intensive[12] sector, such as electricity, decisions are taken on investments that are totally or partially irreversible. The expenses incurred are sunk to the extent that the investor will not be able to recover all the costs if they chose to withdraw when market conditions become unfavourable (affecting the expected future income for any new buyer). In view of the high fixed costs and technical constraints (particularly high in the case of most means of production), they will not be able to complete the construction of the facility and then decide not to use it without this leading to heavy losses.

This can lead to risk-averse behaviour of investors, who, because they have to make decisions in a probabilistically uncertain environment, cannot rely on the current price to calculate their expectations of future gains. The use of financial instruments to hedge risk will not fully restore the intertemporal price relationship, as there is currently no liquidity for products longer than three years[13] even if long-term bilateral contracts exist. At the same time, if investments are more costly due to higher risks, the reliability standard (LoLE = CoNE/VoLL) will be relaxed due to this increase of risks.

An important instrument to base investment decisions on is an analysis of fundamentals: one or two decades into the future expectations can be made for fuel and carbon prices, electricity consumption, RES penetration and so on. These "capital-intensive" projects often call upon

[9] See A Review of Optimal Investment Rules in Electricity Generation, René Aïd, 2012.
[10] *Signaux-prix et équilibre de long-terme. Reconsidérer l'organisation des marchés électriques*, Finon et al., 2009.
[11] Dynamics of renewables entry into electricity markets, Richard J. Green, Thomas-Olivier Léautiery, 2015.
[12] Nevertheless, options like demand response and emergency generators may constitute a cheap alternative to units providing peak load capacity.
[13] It should be noted that longer products exist in the Nordic area.

bank financing or project financing structures, and lenders require guarantees and visibility on revenues and therefore, volumes and prices.
In practice, the risks taken on by an investor in adding capacity have multiple forms (Petitet, 2017)[14]:

Volume-risk
Risk related to the quantity of electricity generated and sold on the market, which strongly depends on the electricity demand of consumers. To a lesser extent, the volume-risk also depends on the availability of the generation units. This source of volume-risk can be partially hedged by taking technical measures to reduce forced and unplanned outages. Due to RES, the volume of electricity generated within a year is also significantly sensitive to weather conditions.

Price-risk
Risk related to the revenue from the electricity sold on the market, which depends on electricity prices and fuel and carbon prices ("spreads"). Generally, the furthest horizon on electricity futures markets is three years, while the horizon for investments lasts at least ten years. Technological changes may also significantly affect price-risks.

Risk in costs
Risk related to investment cost (steel cost, financing cost etc.), or to a lesser extent, Operations and Maintenance (O&M) cost, which may significantly impact the NPV of a generating power plant. Depending on the technologies, fuel cost and CO_2 emissions can also add risks to the project (for example for coal or CCGT). However, companies can limit this risk by improving their expertise.

Technical risks
Risks related to construction time, availability factor or load factor can be substantial sources of risk if not correctly managed. Environmental restrictions (e.g. mercury limits) are capable of strongly influencing revenues. Policy and regulatory risks may also be significant. Compared to volume and price risks, a power company can hedge against technical risks through continuous improvements of its knowledge and expertise.

There seems to be an overall agreement on the existence of risk aversion on the supplier side in the case of private investments in the electricity sector (Aïd, 2012[15]). It is, however, very challenging to estimate the risk aversion level. Such estimation can be carried out either by econometric analysis on markets' or firms' data, or by laboratory experiments, but generally, both methods are time- and context-specific[16].

However, the lack of empirical estimation of the level of risk aversion in the electricity sector does not impede the proposing of electricity models that take into account risk aversion. In practice, approaches detailed below have been used to model the electricity sector (Aïd, 2012 and de Maere d'Aertrycke, 2016):

[14] Long-term dynamics of investment decisions in electricity markets with variable renewables development and adequacy objectives, Marie Petitet, 2017.
[15] Ibid.
[16] T. Litzenberger and Rao (1971) propose an empirical estimation of risk aversion in the electricity sector. Referring to the 1960's and based on a sample of eighty-seven electric utilities, they show that investors are risk averse and estimate their marginal required return.

The von Neumann-Morgenstern utility functions that appeared in economics in 1953 (van Neuman Morgenstern, 1953), and risk functions (Artzner et al., 1999) developed more recently in finance are two methods that associate a deterministic equivalent to risky payoffs. The latter is directly related to risk criteria used in risk management practice[17].

The CVaR (Conditional Value at Risk) has become the most widely used coherent risk function. The investment criterion is then restated as follows: one invests in new equipment as long as the CVaR of its gross margin computed for the different demand scenarios is greater than or equal to its capacity cost.

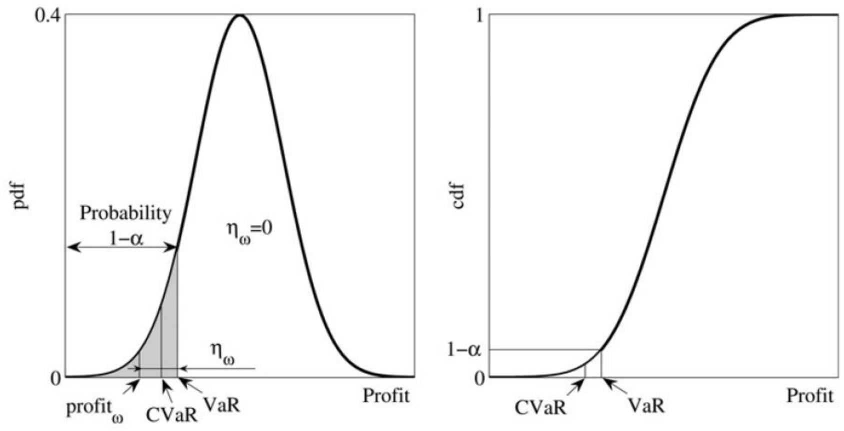

Figure 1 – Illustration of Conditional Value at Risk

The Capital Asset Pricing Model (CAPM) was first developed by Sharpe (1964) and is mainly used for long-term investment. It states that the expected return r_i for the financial asset i satisfies at the equilibrium:

$$r_i = r_f + \beta_i(r_m - r_f)$$

where r_f is the expected return from a risk-free financial asset, r_m is the expected return from the market portfolio and

$$\beta_i = \frac{cov(\mathbf{r}_i, \mathbf{r}_m)}{\sigma_m^2}$$

is the variance of the return of the market portfolio. Bold letters are used here to designate random variables. The CAPM states that an investor is expecting an excess return over the risk-free rate that is proportional to the market risk premium. The more the financial asset return r_i is correlated with the market returns r_m, the higher the expected return. The investor is only expecting to be rewarded for the systematic risk of the project, i.e. the risk that cannot be cancelled out by a well-diversified portfolio. The simplicity of the CAPM makes it a preferred tool by corporate finance divisions despite it being known that it has a limited ability to predict expected returns.

[17] Investment with incomplete markets for risk: The need for long-term contracts, Gauthier de Maere d'Aertryckea, Andreas Ehrenmanna, Yves Smeers, 2017.

Real options[18]: The NPV rule states that an investment is to be made as soon as its present value exceeds its costs. The real options rule challenges this point. It states that if the decision maker can wait and if the investment is irreversible, then the investment should not be undertaken according to the NPV rule, rather, it should be evaluated according to a rule that values this option to wait.

If there is an opportunity to wait, then the decision maker should use this freedom as a control variable to increase the firm's value to its maximum. After Arrow and Fisher (1974) and Henry (1974a, b) highlighted real options in the real economy, the major conceptualisation of real option theory is proposed by Myers (1977), which criticises common valuation and states that "a significant part of many firms' market values is accounted for by assets not yet in place, i.e., by the present value of future growth opportunities".

In the same vein, Trigeorgis (1993, 1996) argues that traditional NPV does not account for flexibility in a project's management and thus, he supports the use of real options. Despite its presence in economic and corporate textbooks, real options remain scarcely used in practice (Aïd, 2014).

Another way to take this risk aversion into account is via a so-called hurdle rate, which increases the return an investor wants to get on its investment.

A high level of risk aversion, which increases the cost of equity, tends to make the system converge at a poor long-term equilibrium. Moreover, it would trigger non-optimal technology development (Meunier, 2013) and lead to socially inefficient investment choices: lack of investment in peak capacities; and a preference for technical sectors that are not very capital intensive for basic equipment but which may prove more costly in the long term.

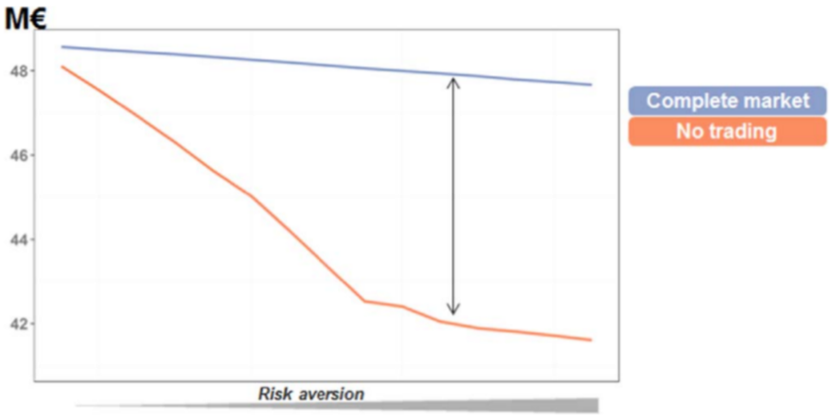

Figure 2 – Welfare as a function of risk-aversion in the "complete" and "no risk trading" cases (existence or not of trading products) *Source: G. de Maere d'Aertrycke et al., 2016.*

In the end, with a common level of risk aversion, the simple play of the market would give an inefficient orientation (dimensioning, composition) to power generation facilities.

Moreover, it is important to remember that not only producers are reluctant to take risks, but also consumers. As the price of electricity is no longer regulated, consumers may be exposed

[18] Long-term dynamics of investment decisions in electricity markets with variable renewables development and adequacy objectives, Marie Petitet, 2016.

to price spikes. Symmetrically to generators, some consumers appreciate price visibility and are willing to pay more than the expected value of electricity in order to avoid potentially high prices. This effect is an important means to overcome the risk aversion of producers: they can partly shift their risk to hedging instruments using consumers.

Therefore, the problem of the decision maker actually has two aspects – buyers and sellers – both of whom are risk averse for opposite reasons (coping with soaring prices, or not reaping sufficient benefits from lower prices). Simplifying the problem, the fact that suppliers are inclined to be paid less to reduce uncertainty, and the consumer to pay more for the same reason, should lead to an equilibrium where the price of hedging products represents the expected value of energy without any risk premium. This is verified by Eydeland[19] (2003).

Forward products are not the only solution to mitigate risk by pooling the aversions of suppliers and consumers. A vertically-integrated structure or a long-term agreement also reduces risk and, consequently, the cost of equity capital. Option markets could also be explored to help overcome an excessive level of risk aversion.

In practice, under-deployment of generators has not been yet noted in competitive European markets. On the contrary, overinvestment can still be observed. Risk aversion is more an issue of future than current investments.

National regulators have to tackle the issue of risk aversion and facilitate public policies and market designs that can provide a better long-term visibility.

[19] Eydeland, A., Wolyniec, K., 2003. Energy and Power Risk Management: new Developments in Modelling, Pricing and Hedging. Wiley Finance, John Wiley and Son.

5 Market failure and regulatory distortions are amplified by RES penetration

Aside from risk aversion, regulatory distortions and market failures could also be exacerbated by RES penetration and notably by the drop of the base load price.

Indeed, in order to support an efficient long-run equilibrium, prices must rise above the short-run operating cost of the highest marginal operating cost plant in the system when total available generating capacity is a binding constraint on balancing supply and demand. Prices must rise high enough under these contingencies for decentralised investors to expect that the present discounted value of future prices will be high enough to cover the capital costs as well as the operating costs of an investment in generating capacity.

In the standard model, prices must be high enough to be expected to cover the capital costs of a "peaker power plant", the least capital-intensive generating technology in the standard model. This in turn produces enough revenue to cover the capital costs of an optimal portfolio of infra-marginal generators as well (Joskow, 2008).

If prices in wholesale markets cannot rise much above the short-run marginal operating cost of the highest operating cost generator at the top of the bid-based dispatch curve (e.g. by imposing price caps), these prices cannot support a long-run equilibrium with an optimal configuration of generators (Boiteux (1949 and 1956), Dreze (1964), Joskow (2008)).

This means that the problem of missing money[20] could arise as a result of regulatory imperfections, i.e. price limitations and the lack of safeguards that would prevent anticipatory intervention by the grid operator to ensure system stability in periods of capacity stress. These imperfections will likely become more and more important as supported renewable generation with zero marginal operating costs becomes a large(r) portion of generation.

Developing "publicly driven" supported RES in a context where revenues from peak capacities are already insufficient, can only accelerate the closure of these capacities, which will see their revenues decrease unalterably. Moreover, the rise in prices expected from the exit of peak capacities could be altered by the fact that the development of supported RES is widely independent of prices and that their volume will increase with little consideration of the signal sent by the market (at the cost of increased taxes). It is, therefore, important to reduce support levels, to apply Feed-in-Premiums (FiP) rather than Feed-in-Tariff (FiT) and to achieve deployment of unsupported RES.

Abolition of these distortions is the pre-condition for an efficient long-term price signal. It would be notably pointless to establish a long-term framework that is not able to provide sustainable prices for investment cost covering. In that sense, the new regulation on the internal market of electricity (Regulation 2019/943[21]) aims to go to the source of the problem. Pursuant to Article 20, Member States with identified resource adequacy concerns have to consider removing any regulatory distortions and market failures, in particular, price caps.

[20] The "missing money problem" refers to the idea that prices for energy in competitive wholesale electricity markets may not adequately reflect the value of investment in the resources needed for reliable electric service.

[21] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity.

Analysis of these distortions and market failures should be the sticking point for all future policies and market designs. However, if some market failures[22] cannot be mitigated easily, for example due to market power, remedial actions could be implemented by the Member States, i.e. a capacity mechanism (CM).

According to the Regulation 2019/943, the capacity mechanism is a "last resort" solution if (1) adequacy concerns are identified by the European Adequacy Assessment and (2) if suppression of the identified market failure does not resolve the(se) problem(s).

These mechanisms, although moving away from the energy-only model, are intended to bring a solution to the problem of having insufficient long-term price signals.

The capacity mechanisms seek to guarantee a sufficient level of installation (ensuring an adequate level of capacity) and aim to encourage maximum availability of existing equipment by offering additional income (this is the short-term dimension). Nevertheless, the capacity mechanisms, which have to remain temporary, have limitations and effort should be also put to their design in order to avoid inefficiencies which have been well identified since their beginning in the United States (US).

Generally, it should be pointed out that the design of CMs is complex and may be subject to repeated adjustments, even when CMs are in place for many years (see the several reviews of PJM's Variable Resource Requirement Curve[23] or the functioning rules of the Belgian Strategic Reserve[24]). Depending on the design of CMs, they add a second price signal to generators which, particularly in scarcity situations can make it unclear for generators which signal they should follow.

Because capacity mechanisms are policy driven by nature, they can eventually create new distortions and further blur expectations. In addition, the authority that designs and operates the capacity mechanism (e.g. the Transmission System Operator (TSO)) may also be risk averse in some way. There could be an overestimation of capacity needs, which would not be beneficial to the community.

It should also be noted, with regard to CMs, that although they might increase total social welfare, they often induce a significant redistribution of income between providers and consumers.

[22] As already mentioned, the prerequisites for an effective price formation are a perfect competitive environment and full transparency to avoid asymmetry of information, including full transparency on network models and market algorithms.

[23] PJM, Fourth Review of PJM's Variable Resource Requirement Curve, 2018.

[24] Elia, The Strategic Reserve, 2018.

6 Evolution of the current market model in order to solve the challenges brought by RES penetration

Challenges with the existing electricity market design were identified where the impact of increased RES on the market could limit "optimal" long-term investments[25]. These include:

- Impacts on price levels via the "merit order effect", where the low marginal prices of RES on the system are causing average wholesale market prices to decrease. This could exacerbate the "missing money problem", and limit investment even further for risk-neutral stakeholders.
- More renewables on the system can result in higher volatility levels in production, which then results in a higher volatility of price levels. This can impact the risk premium of investments, depending upon the risk profile of buyers and sellers for forward products. It can also have an impact (although not always) on the economic viability of investments, especially for those who are more risk averse and at the top of the merit order, i.e. thermal power plants, in the energy sector.

It is clear that the impact increased RES has on long-term investment signals is complex, as it concerns a number of aspects of electricity market design and in particular, adequacy[26]. Member States and regulators have a role in ensuring that future policy helps to address these challenges, in order to enable continued investment in the energy sector to enable the effective decarbonisation of the sector as well as maintaining operational security and efficient prices for consumers. Policies must enable the investor to recover the cost of the investment and be able to take into account the generally capital-intensive dimension of building new electricity generation and encourage risk mitigation. It should be noted that not all investments are capital intensive such as refurbishment, demand response and emergency generators. These low-capital investments mostly have a short lead time to development and are very complementary with RES penetration, given their suitability to provide (super) peak capacity.

There are a number of actions that can be taken by Member States that contribute to these objectives and alleviate some of the challenges; these are listed in the table below including their potential effects, complexity and potential distortive impact on the market. Most of these are addressed via the European Union's Clean Energy for All Europeans package (CEP)[27].

The CEP looks to establish an EU electricity market, adapted to the new realities of the market – being more flexible, more market-oriented and better placed to integrate a greater share of renewables.

Deliberately, actions linked to improving locational price signals are not mentioned in this paper, although they could also be part of the answer to the problems related to (higher) RES penetration.

[25] Capacity decommissioning may also reflect overcapacity or unfitting technologies which need to exit the market. The question of optimal investment is therefore a delicate one and cannot be reduced to the support of all capacities.
[26] See Oxford Review of Economic Policy, Volume 33, Number 4, 2017, pp. 589–612, Peter Cramton.
[27] European Commission, Clean energy for all European's package. European Commission, Electricity market design.

Actions	Potential effects related to increased RES on long-term investment signals	Complexity of action	Potential distortive impact
I. Removing wholesale market price caps affecting price formation	Increase economic viability	Low	This should have low to no distortive impact as most Member States should have already removed wholesale market price caps affecting price formation.
II. Increasing interconnection	Decrease price volatility	Medium – as it requires investment in high CAPEX infrastructure	Low to no distortive impact as increased interconnection is allowing for the flow of energy more freely from places where supply is high to places with high demand.
III. Enabling demand-side measures	Decrease price volatility	Medium – as it depends on the measures being introduced	Medium to low distortive impacts would be expected, depending on how the measures are implemented.
IV. Enabling energy storage	Decrease price volatility	Low	Potentially high distortive impacts would be expected; however, these can be carefully managed by taking a well-considered approach to enabling storage.
V. Ensuring cost-efficient and market-based procurement of balancing and ancillary services;	Increase economic viability	Low when done nationally, however would be medium for cross-border balancing and ancillary services	If implemented well, would expect low distortive impacts. Cost-efficient and market-based procurement of balancing and ancillary services should be beneficial to the market by giving them the right signals to react to ensure security of supply.
VI. Scarcity pricing	Increase economic viability	Medium – especially for cross-border	Scarcity pricing should have low distortive impacts in the market in which it is implemented as it is ensuring that energy reflects its real-time value. It can have small indirect effects in neighbouring markets.
VII. Capacity mechanism	Increase economic viability	High	Potentially high distortive, depending on implementation of similar mechanism in the neighbouring markets, unless cleared during the procedure foreseen based on the Regulation 2019/943.
VIII. Enhancing forward market liquidity and products	Decrease price volatility	Low	There should be zero distortive impact.

Actions	Potential effects related to increased RES on long-term investment signals	Complexity of action	Potential distortive impact
IX. Promoting Power Purchase Agreements (PPAs)	Decrease price volatility	Low	The distortive impacts would depend on how PPAs are designed. Market power is an issue which can arise with numerous very long-term contracts.
X. Regulatory predictability	Decrease price volatility	Medium	Increased regulatory predictability should not cause any distortive impacts.

Table 1 – Actions to alleviate the long-term investment challenges which arise from of increased RES and high carbon prices

The following sections explore these actions in more detail.

6.1 Removing wholesale market price caps affecting price formation

Undistorted prices provide accurate market signals for dispatched generation, and provide the clear market signals required for investors. With more RES, there is a need to have more precise price signals to ensure that the market reacts accordingly. Increased variable RES (VRES), and therefore, intermittency of generation, also needs to be accompanied by developments in emerging technologies such as storage, demand-side response and peak generation – all of which require investment. Ensuring the wholesale market has wholly reflective pricing ensures market participants to get the signals they need to identify when to invest in these future technologies, increasing the economic viability.

Wholesale price caps are put in place to protect end consumers from high levels of price volatility in the market. However, the increased volatility does not always correlate to higher prices for end consumers. In fact, if the correct hedging tools are available (and physical assets), then there should not be any increased risk to system security or prices for end consumers. Effective forward products and/or hedging tools are integral in limiting the impacts of the increased volatility of short-term prices due to increased RES (this will be discussed more in item *VIII. Enhancing forward market liquidity and products* in section 6.8).

Wholesale price caps are not the only form of limitations to play a part in the market and to react to price signals. Pricing rules in network charges or levies and preferential treatment can discourage generation and demand from participation. In case of CHP, the requirement for meeting the criteria of "high-efficiency cogeneration" implies specific operational constraints, which are different from the price signal. All these circumstances have the effect of indirect price caps.

6.2 Increasing interconnection

Increasing interconnection across Europe can help to reduce overall price volatility, as well as ensure that European consumers are able to benefit from cheaper energy generated by RES. Interconnectors are high-voltage cables which connect the electricity transmission systems of two markets. The direction of the energy flow over the interconnector is dependent on the price differentials between these two connected markets; therefore, if there is an abundance of low-cost RES in one market, the connected market can import this cheaper energy. More interconnections being built means that markets are more able to benefit from the trade of excessive generation; however, there comes a natural point at which the level of interconnection causes prices to converge between the connected markets. This is what can help to reduce the overall price volatility in those markets, whilst also enabling the efficient use of excess RES generation. In less-integrated markets across Europe, the power is less efficiently utilised as it is not able to flow from lower-cost areas to more expensive ones. This, therefore, results in a more fragmented market, which can see more increases in marginal prices and as a result, higher costs for consumers. When identifying potential interconnector projects careful assessment must be done as to whether the project brings about an overall net benefit. This can be done through assessing potential projects against how they impact socio-economic welfare, security of supply, as well as integration of RES and CO_2 mitigation – this is shown in ENTSO-E's 2018 Ten-Year Network Development Plan (TYNDP)[28].

6.3 Enabling demand-side measures

Increased (V)RES brings with it the need for increased flexibility, a challenge which can be managed via demand response. Demand-side response has the ability to "time-shift demand" and reduce price volatility by calling upon flexible customers to turn-up or turn-down consumption to help manage the peak time(s) of demand.

Due to the intermittency of renewables, it is challenging to match supply and demand on a day-to-day basis. When wind and solar are the generating assets, intraday markets gain in importance. Demand-side management can help with these challenges, enabling the most efficient utilisation of VRES, for example, in helping meet residual demand versus flexible generation assets. In order to be able to absorb and make best use of excess RES in the system, which is integral in helping meet targets like the European Union's aim to be carbon-neutral by 2050, there is a need to have short-term intraday price signals relevant for (industrial) demand.

Demand response is where energy users (customers) are provided with a financial incentive to either turn-up or turn-down energy consumption to support the system at a time of high or low demand. This helps to balance supply and demand in the market without requiring additional generation. One of the key benefits of demand response is that it generally requires no large initial investment and capital outlay[29], as it makes use of assets which already exist, are underutilised, and have a very short lead time. Demand response could also be used for providing services such as frequency response, when there is a sudden drop in the system frequency due to the loss of a generator, and this phenomenon is increasing due to the limited inertia capability of RES such as wind. Frequency response from demand response could greatly reduce system operability costs, wind curtailment and help to reduce carbon emissions.

6.4 Enabling energy storage

Increased RES, especially VRES, brings with it the need for increased flexibility, a challenge which, like demand-side measures, can also be managed via energy storage. This technology has the ability to "time-shift demand" and reduce price volatility by keeping excess generation for when it is needed.

[28] Section 3.3, How are the projects assessed?, ENTSO-E's 2018 TYNDP.

[29] It should be noted that the capital investment for demand response is reliant upon policy choices such as smart meters and therefore, can be uncertain.

Due to the intermittency of renewables, it is challenging to match supply and demand on a day-to-day basis. Storage can help with these challenges, enabling the most efficient utilisation of VRES, for example, in helping meet residual demand versus flexible generation assets. In order to be able to absorb and make best use of excess RES in the system, which is integral to helping to meet targets like the European Union's aim to be carbon-neutral by 2050, the markets might develop a need for a combination of both short-term daily storage as well as large volumes of long-duration storage[30]. Stored generation can also be utilised for the production of, for example, hydrogen for use in heating or the transport network[31].

In order to actually build the storage required, investment signals are integral in driving this technology forward. If you consider storage such as large-scale batteries, these still have a high proportion of their costs[32] related to the initial CAPEX (Capital expenditure) and other fixed costs. However, this is not always the case for all batteries; for example, the spare capacity in electric car batteries can be used for delivering power services (e.g. ancillary services) at low CAPEX.

Therefore, there should be consideration as to whether some form of policy intervention to encourage the development of electricity storage, and provide some protection to investors, might be beneficial in the short term. It should be noted that such support measures may result in high risks of market distortion, therefore any intervention must be well considered.

Batteries are still deemed to be high-risk investments due to a number of factors, including forecasting volatility, monetising volatility and technological uncertainty. One of the biggest challenges facing batteries today is implicit in the technology itself: batteries still degrade each time they complete a charge and discharge cycle. There are ways, however, to help improve the investment signals for batteries, these include ensuring there are offtake arrangements in place and investors having a diverse portfolio.

6.5 Ensuring cost-efficient and market-based procurement of balancing and ancillary services

The procurement of balancing energy and ancillary services through markets or tenders, as opposed to bilateral contracts, encourages more competition and as a result, lower costs to balance the system. Balancing services tend to refer to two different things:

i. Balancing capacity, which is the volume of reserve capacity that a balancing service provider (BSP) has agreed to provide for balancing purposes; and
ii. Balancing energy, which is the energy activated by the system operators to perform balancing and is provided by a BSP.

Ancillary services refer to the tools necessary for the operation of a transmission or distribution system, including balancing and non-frequency ancillary services, but not including congestion management. Therefore, these include the balancing services listed above and others such as black start capability, frequency response, fast reserve, reactive power and others.

[30] For more info, also see the CEER White Paper on Long-Term Storage, February 2021, Ref: C21-FP-48-03.

[31] For more on hydrogen, please see: ACER-CEER Paper on "When and How to Regulate Hydrogen Networks?" part of the "European Green Deal" Regulatory White Paper series.

[32] It should be noted that projects for reusing used batteries are under development, which could significantly change the storage business model.

In the EU, through the implementation of market codes such as the Commission Regulation (EU) 2017/2195 electricity balancing guideline[33] (EBGL) as part of the internal energy market, TSOs are developing and implementing harmonised pan-European balancing markets such as the Trans European Replacement Reserves Exchange (TERRE). TERRE is the European implementation project for exchanging replacement reserves (RR), and aims to build the RR balancing market using an auction design of "pay as clear"[34] in order to determine the assets that will provide the service. This design is key in helping to provide clear investment signals and increase economic viability. This means that participants are incentivised to bid at their marginal cost; smaller players find it easier to participate; there is more efficient dispatch; and there is a clear reference price which acts as an incentive on balancing service providers. RES tends to have very low to zero marginal costs, therefore, if participating in balancing or ancillary markets they are likely to be activated through pay as clear.

6.6 Scarcity pricing

The main instrument of scarcity pricing is to set an administrative short-term price in order to present an additional investment signal, and thereby increase the economic viability of investments which are administratively considered necessary. Scarcity pricing can be complementary, or not, to other mechanisms.[35]

To maintain a politically defined equilibrium between generation and demand there is a need to have ancillary services available, including fast reacting reserves, to compensate for a sudden generation loss or load change. Reserves are essential in maintaining the reliability of an electricity system.

In the past, when the majority of generation on the system was thermal, the "all-inclusive" price of electricity was based on the intersection of the supply and demand curves. The provision of reserves was built in based on energy infeed commitments.

In situations of scarcity, before resorting to curtailment, it may be tempting for the administration to reduce the amount of reserves necessary for the reliability of the system. However, this could have the unintended consequence of making the system evolve less reliably, as the amount of reserves that can be deployed in real time is a good indicator of the conditions of reliability (and thus adequacy) of a system.

With the paradigm of an energy-only market, and for systems with a large contribution of units with low variable cost and which usually do not provide reserves, a price signal based on the intersection of the offer price curve and the demand cannot constitute an "all-inclusive" (namely energy and reserves) price for energy anymore.

Therefore, in order to alter the price, the energy price should be determined by the intersection of the offer curve and of the demand curve augmented by the necessary volume of reserves. Operating Reserve Demand Curves ("ORDC") introduce price elasticity to the artificial price signal. With an ORDC mechanism, the demand curve for reserve (price versus volume) is determined on the basis of the (implicit) political valuation of demand for reliability through the Value of Loss of Load and the Loss of Load Probability[36].

---

[33] Regulation (EU) 2017/2195 establishing a guideline on electricity balancing.

[34] A pay as clear auction means that participants are automatically awarded the price of the most expensive offer accepted.

[35] In particular, scarcity pricing can be implemented in coordination with a capacity mechanism.

[36] This mechanism makes it possible to reflect consumer value for reliability without the use of scarcity bidding, which can be considered as a market power abuse.

6.7 Capacity mechanism

A capacity mechanism (CM) can be a way to ensure security of electricity supply by providing a payment to sources available during system stress, in addition to their revenues from electricity, to ensure that they deliver at times of system stress. This mechanism can increase the economic viability of investment needed to build assets replacing older power stations, as well as provide back-up generation for the more intermittent RES.

These mechanisms also allow a better articulation of investments and reduce the risks for the stakeholders.

However, capacity mechanisms are difficult to design and operate. Mistakes in the design might lead to a reduced security of supply because actors might react to misleading signals. It is considered that capacity mechanisms may act in some cases as a support payment for fossil fuel plants, which is contrary to Europe's overarching decarbonisation strategy. This risk will become significantly less likely with the implementation of CM emissions limits set out in Article 22 of Regulation 943/2019.'

The capacity mechanism can be market-wide, which means that all capacity contributing to the security of supply can participate. It is the case in France, Italy, Ireland and Great Britain. The Polish capacity mechanism is slightly different as only defined categories of sources may take part in it; RES being excluded.

A different approach might also be seen in Germany for example. Despite a comprehensive capacity market, Germany introduced a strategic reserve, which is kept outside of the energy markets. Assets are neither allowed to participate in the market, nor may they return to the EOM after leaving the reserve. Thus, it will increase the economic viability of the capacity remaining in the EOM. The strategic reserve only serves as back-up for the EOM and is meant to tackle unforeseen events where market-based supply will not entirely cover demand. Costs are borne by grid fees and by penalties related to caused imbalances in the system. However, the actual total impact is more difficult to estimate because of the changes that the strategic reserve brings to the energy market.

6.8 Enhancing forward market liquidity and products

Forward markets offer market participants hedging opportunities against unpredictable short-term prices in order to provide an element of stability in their cash flows as they decrease price volatility. Forward markets can provide different benefits depending on the market participant. Established players will use forward markets as the most important tool to manage risk; new generation will use these markets to lock-in long-term prices to match their fixed exposure to investment costs (up to 15 years ahead); and new entrant supply will be looking to lock-in prices to match their contracts to supply their customers (around two years ahead).

All hedging instruments allow participants to lock-in energy prices at a reasonable cost, or at least have some provisions, which allow for more price certainty depending on future market conditions. Electricity forwards, futures, swaps, contracts for difference, electricity price area differentials, spreads and electricity options are the most common financial and physical instruments used in the electricity sector in order to hedge underlying energy price risk. Markets themselves have become very creative in developing more and more of these hedging instruments and methodologies since the start of competitive markets.

Forward markets are essential for investment signals, as they provide the most reliable information to market participants. Future markets allow generators to earn capacity-related revenues – which is especially important for the willingness to invest in capacity. On the basis of financial hedging, the suppliers hedge their ability to supply. Thus, physical-financial hedging and future security of supply are two sides of the same coin.

In order to ensure that forward markets are liquid and therefore, able to provide good hedging opportunities, some regulators have brought in measures to help. An example of these kinds of measures is a "market making obligation" where the "big" energy market participants are required to respond to offers of trade.

6.9 Promoting PPAs

A power purchase agreement (PPA) is a contract between an energy buyer and an energy seller, created by market participants to best frame the market conditions of VRES. The PPA itself defines all the commercial and contractual terms for the sale of energy between the two parties. They tend to be signed for long-term periods of between five and 20 years, and although they can apply to any new generation asset, they bring most benefit to renewable forms of generation. The promotion of PPAs is a valuable tool to increase revenue certainty and security, especially to RES with the continued phasing out of government-led subsidies across Europe. In the energy market, due to the increased volatility of energy prices, as it is challenging to have any form of security for long-term investments in new RES projects without subsidies, PPAs provide security that the project will bring return on the capital investment – helping to reduce cash flow uncertainty. The main feature of PPAs is an agreement to sell an amount of energy from the producer to the buyer at a fixed price. This ensures a secure stream of revenue for the producer, but also a fixed price of energy for the buyer for a certain amount.

A physical PPA means that the customer receives the physical delivery of (or title to) the energy through the grid. A financial PPA, (also referred to as a virtual PPA and synthetic PPA) allows the buyer to purchase renewable energy virtually – in other words, there is no need to own the title to physical energy. This enables the buyers, for example corporate companies, to receive renewable attributes without owning the asset.

At present, there is fragmentation across Europe as to the rules surrounding PPAs. The UK and the Netherlands allow financial PPAs, whilst in France and Germany onsite[37] PPAs are permitted but physical PPAs are restricted. It is important that future PPAs find a good balance between ensuring the competitiveness and cost effectiveness of projects in order to ensure they do not allow opportunities for exploitation, as well as maintain competition in the marketplace and security of supply. PPAs must also be considered alongside Renewable Energy Guarantees of Origin (REGOs) as an integral tool in ensuring that the claimed green credentials of electricity actually reflect what is supplied.

The CEP introduces the requirement for all Member States to "assess the regulatory and administrative barriers to long-term renewables PPAs, and to remove unjustified barriers and facilitate the uptake of such agreements".[38] This is an important step in helping to increase the market share of renewables in the energy mix whilst maintaining longer-term investment certainty.

[37] An onsite PPA is where a company will partner with a generator to produce renewable electricity on the company's land to power the company's operations.

[38] Article 15(8) of the Directive (EU) 2018/2001 of the European parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources.

6.10 Regulatory predictability

Regulatory predictability is frequently defined as a key feature for attracting investment in any sector. Therefore, as the energy sector transforms to a low-carbon energy system with increased RES, regulatory predictability and clear long-term investment signals are integral. It is clear that, as the energy system transforms, regulatory and wider government policy also need to change and transform. Changes in regulatory policy can bring about uncertainty and therefore increased risk, something investors are keen to reduce. Therefore, it is essential that changes in policy or direction must be clear, transparent, credible, and predictable. It is clear from the list of other actions above that regulatory policy can come in many forms, from providing regulatory models to support infrastructure investment to intervening in markets to increase liquidity. This suite of actions must be complementary across the different areas in order to effectively increase the economic viability of investments; conflicting policies can hinder investment whilst complementary ones can incentivise it.

Policies, such as the European Green Deal and the CEP, provide clear direction, commitment and signals on longer term energy policy – helping to provide the stability needed in order to support long-term investment. The European Green Deal provides an action plan to “boost the efficient use of resources by moving to a clean, circular economy” and “restore biodiversity and cut pollution”[39]. The plan also outlines the necessary investment needed to achieve these goals, as well as the financing tools available. The CEP is an update of the EU’s energy policy framework to facilitate the transition away from fossil fuels towards cleaner energy and to deliver on the EU’s commitments related to the Paris Agreement to reduce greenhouse gas emissions. This package includes a defined direction of travel in regulatory policy in the EU, providing a clear outline of the future of the energy sector and regulatory policy. A number of the actions outlined above are in line with the regulatory policy of the CEP, which looks to ensure that regulators are able to set rules to enable the markets to work properly and encourage long term investment for renewable and – as long as necessary – conventional generation capacities.

[39] European Commission, A European Green Deal.

7 Conclusion

While it is clear, both from a theoretical and practical point of view, that RES penetration tends to lower the average energy price in the short term and increase market volatility, the concrete effect on investments is more difficult to determine.

Indeed, the long-term investment challenges in the context of the energy transition seem to primarily be linked to exacerbated market distortions rather than only to the arrival of medium or low variable costs, even if these new means of production intensify the problem. Moreover, it would seem some conclusions drawn on increased RES can be extrapolated to all low variable-cost capacities, in particular, the short-term increase in missing money for higher variable cost capacities.

It is therefore, essential that Member States and regulators give priority to eliminating as many market failures as possible, as required by Regulation 2019/943. These actions must be clear, transparent, credible and predictable in order to help attract investment and to avoid increasing uncertainty.

Nevertheless, it also seems possible for the regulator and the Member State to go further in promoting the efficiency of the system in order to ensure, in addition to the respect of long-term adequacy (LoLE = CoNE / VoLL), the establishment of a system architecture that maximises benefits to the community (by decreasing investment costs (CoNE), LoLE will also decrease). This paper explored a number of actions which aim in particular to reduce uncertainty in this market. However, it is important to be aware whilst implementing these solutions of the impacts they can have, which can lead to second-order distortions and significant income redistribution.

Annex 1 – Literature review

The impact of the integration of RES on electricity prices has been widely discussed by academics. Various statistical models were used to investigate the correlation of the market price and volatility in terms of the percentage of RES installed in the system.

In general, the results are in concert with the expectations: the average base load price is decreasing, all other things being equal, and intraday and intra-week volatility price is increasing. For now, wind has a greater impact due to its wider penetration. Please find below a list which is a non-exhaustive review of academic papers dealing with the impact of RES on the market price.

Study	Country investigated	Period investigated	Results
The Green Game Changer: An Empirical Assessment of The Effects of Wind and Solar Power on the Merit Order, Böckers et al., 2013	Spain	2008 - 2012	Wind has a negative impact on price. The results for PV are ambiguous; solar power may have a positive effect on wholesale prices.
Is the depressive effect of renewables on power prices contagious? A cross border econometric analysis, *Sébastien Phan, Fabien Roques, 2015*	Germany & France	2012 - 2014	Renewables depress power prices on average and increase volatility not only domestically but also across borders.
The merit-order effect in the Italian power market: The impact of solar and wind generation on national wholesale electricity prices, Clò Stefano et al., 2014	Italy	2005 - 2013	Over the period 2005 - 2013 an increase of 1 GWh in the hourly average of daily production from solar and wind sources has, on average, reduced wholesale electricity prices by respectively €2.3/MWh and €4.2/MWh and has amplified their volatility.
The Impact of Renewable Energy Forecasts on Intraday Electricity Prices, Sergei Kulakov & Florian Ziel, 2019	Germany & Austria	2016 - 2017	A rising amount of wind or solar power capacities in fact increases the volatility of intraday prices.
Market behaviour with large amounts of intermittent generation, Green, R.; Vasilakos, N., 2010	UK	2020	The development of wind generation increases short-term volatility of prices and leads to significant year-to-year variation in generation's profit.

The Impact of Wind Power Generation on the Electricity Price in Germany *Janina C. Ketterer, 2012*	Germany	2006 - 2012	The results show that variable wind power reduces the price level but increases its volatility. With a low and volatile wholesale price, the profitability of electricity plants, conventional or renewable, is more uncertain.
Does Renewable Energy Generation Decrease the Volatility of Electricity Prices? An Analysis of Denmark and Germany, Tuomas Rintamaki, 2016	Germany & Denmark	2010 - 2014	In Denmark, wind power decreases the daily volatility of prices by flattening the hourly price profile, but in Germany, it increases the volatility because it has a stronger impact on off-peak prices. The weekly volatility of prices increases in both areas due to the intermittency of RES.
Challenges for Wholesale Electricity Markets with Intermittent Renewable Generation at Scale: The U.S. Experience, Paul Joskow, 2019	California (USA)	2010 - 2018	Price volatility has increased and is expected to continue to increase as more intermittent generation is added to the system. Indeed, as intermittent generation has expanded, the number of hours with zero or negative energy prices has grown, especially during mid-day hours on weekends and other low-demand days.

Annex 2 – List of abbreviations

Term	Definition
BRPs	Balancing Responsible Parties
BSPs	Balancing Service Providers
CAPM	Capital Asset Pricing Model
CCGT	Combined Cycle Gas Turbines
CEER	Council of European Energy Regulators
CEP	Clean Energy Package
CfD	Contracts for difference
CHP	Combined Heat and Power
CoNE	Cost of New Entrant
CMs	Capacity mechanisms
CVaR	Conditional Value at Risk
DA	Day-ahead
DSOs	Distribution System Operators
EE	Energy efficiency
EOM	Energy Only Market
EU	European Union
EU ETS	EU Emission Trading Scheme
FiP	Feed-in-Premiums
FiT	Feed-in-Tariffs
ID	Intraday
IEM	Internal Energy Market
kWh	Kilowatt hour(s)
LoLE	Loss of Load Expectation
LTTRs	Long-term Transmission Rights
MS	Member State(s)
MWh	Megawatt hour(s)
NPV	Net present value
NRA	National Regulatory Authority
O&M	Operations and Maintenance
OTC	Over-the-counter
PPAs	Power Purchase Agreements
PV	Photovoltaics
RES	Renewable Energy Sources
TSOs	Transmission System Operators
VoLL	Value of Lost Load
VRES	Variable Renewable Energy Sources

Annex 3 – About CEER

The Council of European Energy Regulators (CEER) is the voice of Europe's national energy regulators. CEER's members and observers comprise 39 national energy regulatory authorities (NRAs) from across Europe.

CEER is legally established as a not-for-profit association under Belgian law, with a small Secretariat based in Brussels to assist the organisation.

CEER supports its NRA members/observers in their responsibilities, sharing experience and developing regulatory capacity and best practices. It does so by facilitating expert working group meetings, hosting workshops and events, supporting the development and publication of regulatory papers, and through an in-house Training Academy. Through CEER, European NRAs cooperate and develop common position papers, advice and forward-thinking recommendations to improve the electricity and gas markets for the benefit of consumers and businesses.

In terms of policy, CEER actively promotes an investment friendly, harmonised regulatory environment and the consistent application of existing EU legislation. A key objective of CEER is to facilitate the creation of a single, competitive, efficient and sustainable Internal Energy Market in Europe that works in the consumer interest.

Specifically, CEER deals with a range of energy regulatory issues including wholesale and retail markets; consumer issues; distribution networks; smart grids; flexibility; sustainability; and international cooperation.

CEER wishes to thank in particular the following regulatory experts for their work in preparing this report: Sven Kaiser, Holly MacDonald, Alain Marien and Michel Strek.

More information is available at http://www.ceer.eu.