CEPS SPECIAL REPORT
Thinking ahead for Europe

The EU power sector needs long-term price signals

Fabio Genoese, Eleanor Drabik and Christian Egenhofer

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Abstract

By 2030, half of the EU's electricity demand will be covered by renewables and will need to be accompanied by flexible conventional back-up resources. Due to the high upfront costs inherent to renewables and the progressively lower running times associated with back-up capacity, the cost of capital will have a proportionately greater impact on total costs than today. This report examines how electricity markets can be designed to provide long-term price signals, thereby reducing the cost of capital for these technologies and allowing for a more efficient transition. It finds that current market arrangements are unable to provide long-term price signals. To address this issue, we argue that a system for long-term contracts with a regulated counterparty could be implemented. A centralised system where capacity or energy or a combination of both is contracted, could be introduced for conventional and renewable capacity, based on a regional adequacy assessment and with a competitive bidding system in place to ensure cost-effectiveness. Member states face a number of legislative barriers while implementing these types of systems, however, which could be reduced by merging legislation and setting EU framework rules for the design of these contractual agreements.

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Executive Summary

The European Commission has announced a legislative proposal to implement the Third Energy Package in full and to make the electricity market fit for a low-carbon future. One of the biggest challenges will be to ensure that the market gives adequate price signals for commercial investment in generation capacity and for maintaining sufficient capacity online to guarantee security of supply. Additional capacity will be required both for renewables and to replace carbon-intensive generation with more flexible, less carbon-intensive forms. In 2030, half of the EU's electricity demand will be met by renewables, and in 2050 the power sector will have to be completely carbon-free.

The transition to low-carbon electricity implies an increasing share of generation capacity with high upfront costs. This is different from the technology choices envisaged by the Third Package. In low-carbon technology investments, costs mainly occur in the planning and construction phase; there is limited scope to reduce costs once a wind turbine or solar panel has been deployed. High upfront costs imply that the cost of capital has a proportionally greater impact on total costs when compared to today's technologies. Consequently, both uncertainty and risk will play a greater role in investment decisions than is the case today. This has been widely recognised for renewables, for example by the International Energy Agency;[1] but it applies to flexible back-up resources in a similar way, because of their progressively lower running time (load factor).

Insufficient long-term price signals will be reflected in the cost of capital for an investment, ultimately resulting in higher costs for consumers. This can lead to inappropriate investment or divestment signals, i.e. too-late investment or short-sighted capacity retirement choices, for example in gas, which might turn out to be inefficient in the long run. In the case of renewables, where policy targets exist, great uncertainty about future cash flows means paying more to achieve the same result.

This report examines whether markets can be designed to provide long-term price signals and thereby reduce the cost of capital for renewables and flexible conventional resources alike. In the current market framework, long-term arrangements can in principle originate from bilateral contracts or forward markets, i.e. a central marketplace for trading electricity ahead of delivery.

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[1] See IEA (2016).

Most bilateral contracts tend to be short- to medium-term with a forward period of five years or less. A similar observation can be made for forward markets: The volume of commercial transactions ('liquidity') tends to decrease with increasing forward periods. Data from the German forward market – which is the most liquid market in the EU – confirms that liquidity decreases to zero for contracts with a forward period of more than three years. Thus, no long-term price signals are currently emerging from forward markets. In addition, the currently most common contract type requires a continuous supply over an entire year. This is neither compatible with the intermittent character of renewables nor with the flexible resources that are used to counterbalance the intermittency of renewables.

A reason for this decrease in liquidity is that the individual benefit from long-term contracting is and will remain limited. The demand-side does not see an economic need to secure supply a long time ahead of delivery. Consumers trust that the regulator will *de facto* hedge them against the risk of physical shortage ('regulatory paternalism'). Moreover, security of supply is and will likely remain a public good, because it is difficult to selectively disconnect consumers in a meshed electricity network in times of physical shortage (non-excludability). For bilateral contracts, there is also a counterparty default risk, which results in a cost of guarantee, i.e. the amount compensated if one counterparty terminates the contract early. It grows exponentially with the delivery date, which is why most bilateral contracts tend to be short- to medium-term arrangements.

Long-term contracts with a regulated counterparty could address this issue. If properly designed they can reduce uncertainty, and therefore the cost of capital. Generally, these contracts could focus on capacity or energy, or a combination of both. In a centralised design, this could lead to the creation of capacity auctions– for conventional or renewable capacity or both. Long-term contracts for energy would resemble modern renewable support schemes, albeit amended by more competitive elements. A competitive bidding process for price discovery and regional adequacy assessments should be the rule to ensure cost-effectiveness.

Clarification in existing legislation could reduce the barriers to establishing competitive long-term contracts. To this end, forthcoming legislative proposals on a new electricity market design and the forthcoming policy framework for renewables could make explicit reference to the advantage of competitively determined long-term contracts to promote decarbonisation and ensure security of supply.

Moreover, authorisation processes for implementing new mechanisms are often arduous and approval periods can take several years. Approval could be streamlined and shortened, if the necessary prerequisites for introducing such mechanisms were merged into one piece of legislation. Secondly, it would be advantageous to have a set of EU framework rules in place for the design of these contractual agreements, including guidance on length, types of instruments and participation of cross-border resources. If executed, both these points may lead to a more efficient implementation process of mechanisms ensuring decarbonisation, security of supply, increased investor certainty and support for the completion of the internal market.

1. About the importance of long-term price signals

The power sector is a rather capital-intensive business with long investment cycles, because plants operate for 20 years or more. For this reason, a stable framework is needed in which investors are confident that costs can be recovered in reasonable payback times. Price signals and long-term confidence in these signals are an essential ingredient for cost-effective investment decisions in generation capacity. In the absence of long-term price signals, it is more likely that inappropriate investment or divestment decisions are taken, i.e. too-late decisions or technology choices that turn out to be inefficient in the long run.

In this context, the underlying question is how to allocate risks between private investors and the public. Risks have costs irrespective of whether the public takes it via regulation or whether investors do. However, by allocating risk to the party best able to manage it, these costs can be reduced.

If confidence in long-term price signals is assured, the financing costs of an investment will be lower, *ceteris paribus*. In a competitive market, this will translate into lower costs for consumers. This fact is well-recognised for renewables, but is applicable to back-up capacity as well. In a low-carbon economy, the cost of capital has a proportionally greater impact on total costs than it had in the past. This is because resources such as wind and solar power have high upfront but close-to-zero operating costs. Back-up capacity has a similar cost structure because upfront costs have to be recovered from a progressively lower number of hours of operation.

In this report, we argue that the current market design is not necessarily the most suitable to handle a high share of both low-carbon and back-up capacity and to ensure an adequate level of back-up capacity, especially not in times of declining or stagnant demand for conventional resources.

This is of particular importance because the European power sector is heading precisely this direction: the EU's clean energy commitments mean that in 2030 half of generation will come from renewables, mostly supplied by wind and solar. Moreover, 50% of conventional capacity could be on stand-by for 80% of the time in 2030, thus mainly serving as back-up. Finally, the next decade will be marked by a continuous decline in *net* demand, i.e. a decline in total demand net of renewables. This will put pressure on wholesale market revenues, lowering confidence in the conditions for recouping operating and investment costs.

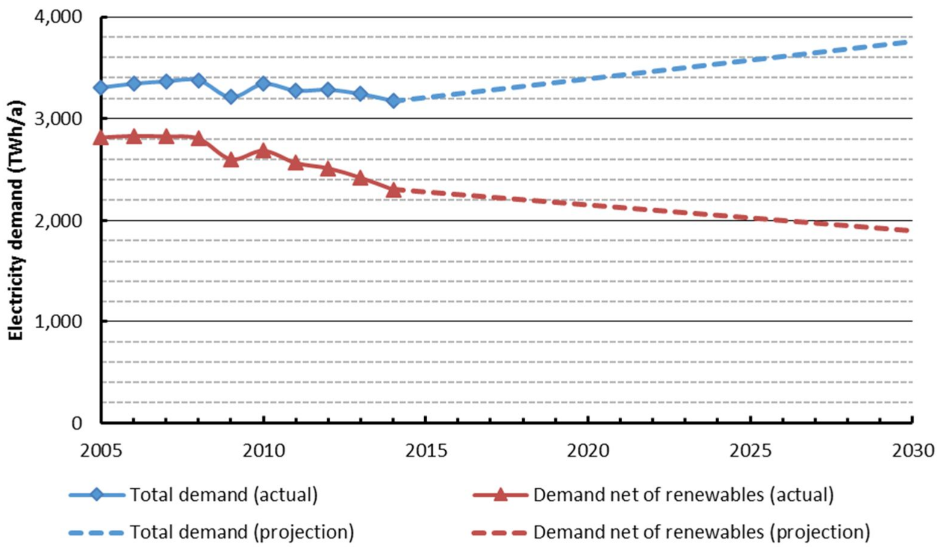
1.1 The EU power sector: Future trends

Implementing the EU 2030 climate and energy framework[2] will define the main direction for the future development of the EU power sector. While the policy framework does not state what the overall objective of 'at least 27% renewables by 2030' means for the power sector, one

[2] In October 2014 the European Council decided on a new set of policy targets for 2030. The framework includes binding targets for (i) domestically reducing greenhouse gas emissions by 40% below 1990 levels and for (ii) increasing the share of renewables to at least 27% as well as an indicative target to improve energy efficiency by at least 27% compared to "business-as-usual" scenario.

can expect that the share of renewable *electricity* will rise from 27% in 2014 to 49-51% in 2030, based on current[3] projections.[4]

Figure 1. Total electricity demand and demand net of renewables (EU-28, 2005-30)



Source: own elaboration based on Eurostat (2016) and Resch et al. (2015).

Intermittent resources such as wind and solar will be driving this increase: in 2030, 60-75% of renewable power will be supplied by these technologies. Consequently, the share of wind and solar in total power generation is expected to be around 38%. By the end of 2014, these two technologies had a 14% share in gross electricity production.

Even assuming further technology cost reductions of renewables, their ability to recover full costs under the current market framework, which is based on short-term price signals, will be subject to high uncertainty. Already today, intermittent renewables tend to earn less than the average market price, i.e. the higher their production, the lower the market price they receive. Ultimately, this is because their production is determined by the availability of wind and sun – their highest production output is unlikely to coincide with peak electricity demand. Moreover, there is empirical evidence that their market value decreases with increasing market share (see Figure 2). This is typically referred to as cannibalisation effect.

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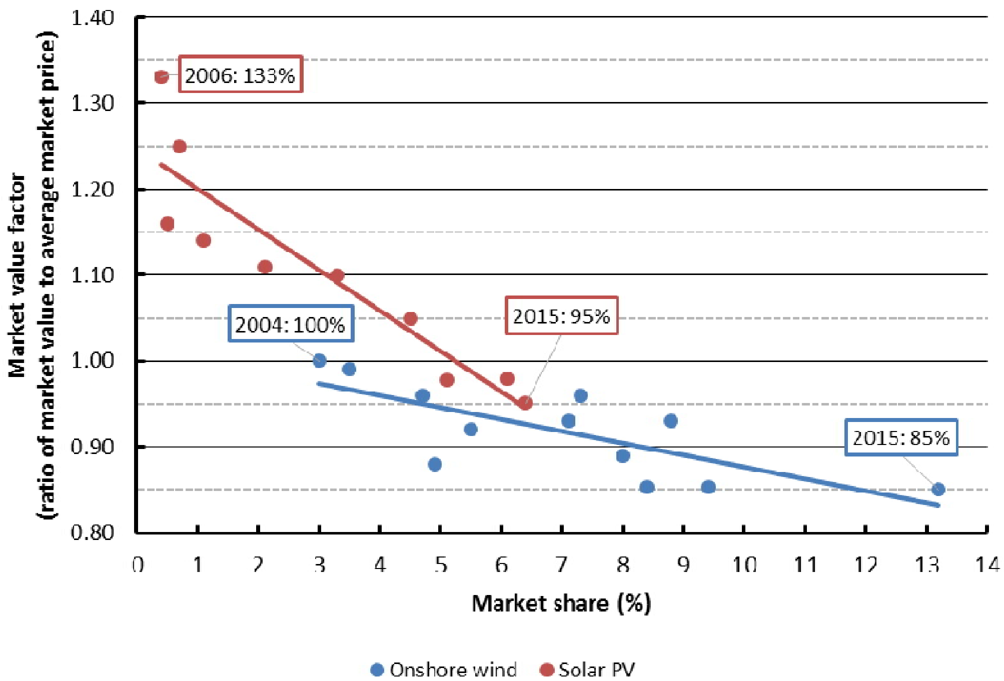
[3] See SWD(2014) 15 final.

[4] See Resch et al. (2015).

Figure 2. Market value of onshore wind and solar PV in Germany (2004-15)



Source: own elaboration based on Hirth (2013), EPEX (2016) & ENTSO-E (2016).

The shift towards more renewables has two major implications for conventional resources. First, electricity demand net of renewables will decrease by around 400 TWh compared to 2014 according to current estimations (see Figure 1). This decline is equivalent to the size of the Italian and Dutch power system combined. Second, the maximum required *firm* capacity to serve demand will also decrease, but not nearly as strongly. This is due to the weather-dependent availability of wind and solar: cloudy, windless day might coincide with peak electricity demand. For these events, sufficient firm capacity must be available.[5]

The combination of the two effects entails that firm capacity will be utilised less often, i.e. running hours decrease. By 2030, roughly 50% of conventional capacity could be on stand-by for 80% of the year, thus mainly serving as back-up. Their risk profile will be similar to today's peaking plants: fixed and investment costs would have to be recovered from revenues created during a very low number of running hours, i.e. a higher-than-ever dependency on rare scarcity events, implying a high uncertainty of future cash flows.

Another challenge is that the exact *level* of back-up capacity required is subject to greater uncertainty than today, because this level depends on the pace of deploying renewables and its mix as well as technological developments. It is not trivial to forecast the pace of deployment, because this development is policy-driven. Policy targets for renewables are set as a share of total demand. To maintain a projected pathway for the share of renewables, an

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[5] In practice, a resource adequacy assessment will be carried out to estimate how demand-side resources can reduce the need for firm capacity.

unexpected change in total demand (denominator) would have to be matched by a change in the pace of deployment (numerator). In practice, such fine-tuning is both difficult to implement and may ultimately result in a stop-and-go deployment process, which is politically undesirable.

Under the current market framework, investment decisions for a large part of the fleet – renewables and back-up capacity – will therefore be subject to significant uncertainty and this will be reflected in financing costs. Consequently, some investment decisions for back-up capacity might be postponed while waiting for a clearer outlook of actual consumer needs and energy policies, leading to exacerbated boom-bust cycles. For existing back-up capacity, this uncertainty results in an increased risk of mothballing or early closure for economic reasons, i.e. when fixed operation and maintenance costs can no longer be covered. Instead, investments in renewables may be taken despite high financing costs – because capacity must be added to meet policy targets. This, however, results in higher-than-necessary costs for consumers, meaning that the same result could be achieved at lower costs with an adapted market framework.

1.2 A decline in demand is similar to an increase of low-marginal-cost generation

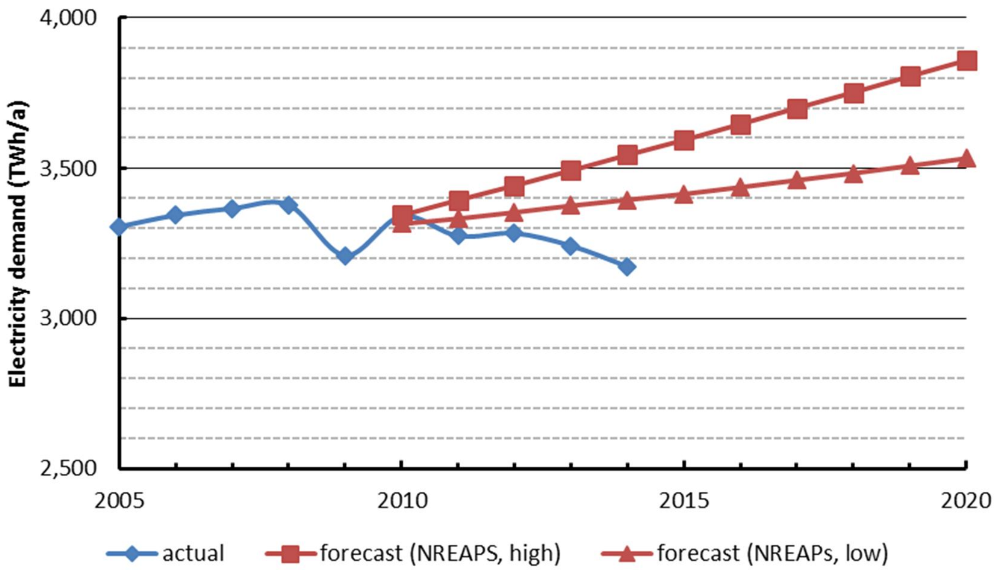
A long period of declining demand generally poses challenges for recouping investments under the current market framework. A drop in demand puts pressure on wholesale market revenues, because prices are set by the bid of the marginal unit. An increase in generation from low-marginal-cost resources such as wind and solar is comparable to a decline in demand: wholesale prices decrease, because high-marginal-cost units are displaced. This is typically referred to as merit-order effect.[6]

As a result, new plants will be unable to recover their fixed and investment costs. This affects all plant types, including low-carbon resources, not just peak load generators. The magnitude of this effect largely depends on the extent and duration of the decline in demand. In the 2030 context, the development of both total and net demand will be significantly driven by policy, e.g. by electrification initiatives as well as targets for efficiency and renewables, but also by taxes and tariffs on electricity vis-à-vis competing energy carriers such as oil and gas, which dominate the transport and heating sectors. Consequently, long-term price signals for generation assets are more difficult to be provided by the market.

The current period of declining electricity demand and increase in low-carbon generation provides some useful insights into the potential magnitude of the problem of recouping investments. In 2014, total electricity demand in the EU-28 was 7-10% below projections and 6% below the pre-crisis level (see Figure 3). This shows the kind and magnitude of the uncertainty facing investors, rendering the experience gained from past scarcity practically irrelevant when it comes to forecasting future scarcity events.

[6] See Sensfuss et al. (2008) and Sáenz de Miera et al. (2008).

Figure 3. Expected vs. actual electricity demand in the EU-28 (2005-20)



Source: own elaboration based on Eurostat (2016) and NREAPs (2010).

This has affected both the market prices and economic performance of power plants. A case study for the German market reveals that full cost recovery will not be possible for any recently built plant, if the current trend continues. This would also apply to low-carbon generation from wind power, if it were not subsidised. In 2014, spot market profits of a modern gas-fired unit were not even sufficient to cover annual maintenance costs, let alone recoup the investment. The 2014 cash flow of a modern coal-fired plant was more than 60% below the required level for full cost recovery. Needless to say, this has damaged the general investment climate.

2. Long-term price signals in today's market design

There is general consensus that there are several benefits to contracting electricity in advance of delivery. First, they create more predictable cash flows, which lessens investment risk and diminishes the boom and bust cycles associated with the construction of new power stations and with maintaining a sufficient level of existing plants online. Second, consumers benefit from less volatile retail prices because electricity is purchased ahead of delivery rather than on a fluctuating spot market. Third, long-term price signals promote competition by facilitating the entry of new market players. This was one of the reasons why the European Commission approved the British capacity remuneration mechanism. Fourth, long-term arrangements are a cost-effective way of promoting low-carbon resources, provided that a competitive bidding process is used for price discovery. This is due to their capital-intensity: technologies such as wind and solar face high upfront but close-to-zero operating costs. Costs mainly occur in the planning and construction phase, but there is limited room to reduce costs once a wind turbine or solar panel has been deployed.

In the current market framework, long-term arrangements originate from bilateral contracts, which can also be tradable.

2.1 *Bilateral long-term contracts*

A bilateral contract is an agreement between a buyer and seller to exchange electricity on negotiated terms. These terms typically include, but are not limited to, the contract length, price per unit of electricity and times of performance. The price can be fixed or indexed, for instance to the spot market price of electricity, or the price of a fuel. These contracts give both parties price predictability for a period of time and allow buyers to reduce their exposure to future fluctuating spot prices. In order to respond to short-term changes in demand, bilateral contracts are typically complemented by option contracts or spot market purchases. This way, buyers can hedge their risk for the majority of their purchases through long-term contracts, but also respond to short-term changes in consumer demand.

Bilateral long-term contracts generally face the challenge of a counterparty default risk, which results in a cost of guarantee, i.e. an amount that is compensated, if the contract is annulled. The guarantee generally increases with contract length. For this reason, most bilateral contracts tend to be short- to medium-term agreements with a forward period of five years or less.[7]

Another reason for the limited forward period is the uncertainty regarding the approval process. Bilateral long-term contracts are likely to be subject to approval by the European Commission to ensure that these contracts do not foreclose the market.

In recent years, a prominent example of a bilateral long-term contract was the Exeltium project in France, founded by industrial consumers to provide a stable and competitive electricity price for the electro-intensive industries over a long period. EDF offered to deliver electricity for a 24-year period under a take-or-pay contract. It was agreed that 311 TWh of electricity would be supplied over that period at a price indexed to the operating costs of EDF's nuclear power plants.

This bilateral agreement, suggested by EDF and Exeltium, was approved after five years of negotiation with the European Commission, in March 2010. While this example may not be representative for other EU member states due to the relatively high market concentration in France, it highlights a major challenge of bilateral long-term contracting: uncertain approval procedures.

2.2 *Tradable long-term contracts*

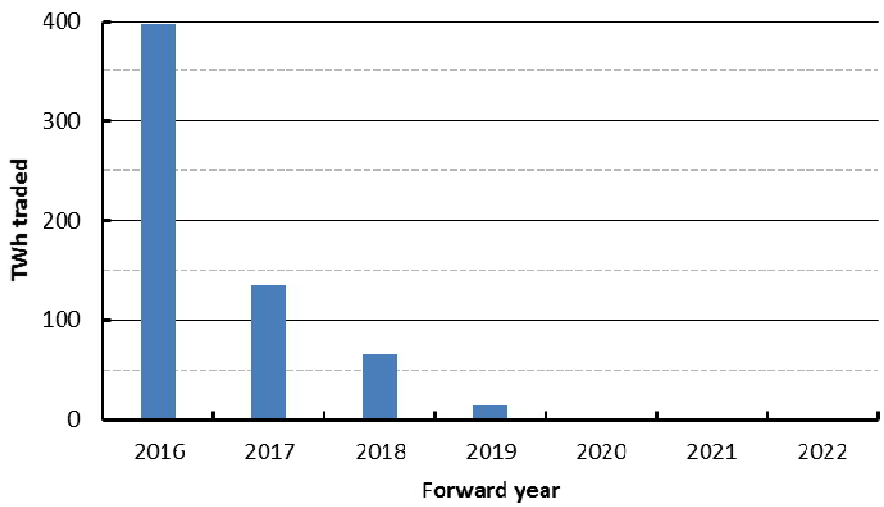
An alternative to bilateral contracting are forward electricity markets, which essentially are central marketplaces where a buyer can secure electricity generation ahead of delivery from a seller (generator). Unlike bilateral contracts, these contracts are tradable, meaning that the price is transparent, thus reducing information asymmetry between market participants.

[7] The traded volume for contracts with a forward period above four years roughly amounts to zero, see ICIS (2016).

On today's forward markets, the most popular contract types have a duration of one year and offer various forward periods. A forward period defines the year of delivery and can be any future year following the year the contract is traded. Market liquidity, however, tends to decrease with increasing forward periods.

The most liquid market in the EU is the German forward market. Practically speaking, today's forward markets offer tradable contracts, but no tradable *long-term* contracts. This is illustrated in Figure 4. In the trading year 2015, contracts agreed for the forward period 2016 was 65% of German gross electricity production in 2014. Contracts secured for the forward year 2019 are already negligible at 2% of German gross electricity production in 2014. Consequently, the long-term predictability of revenue streams for new generators remains limited under this system.

Figure 4. Volume of forward contracts in the trading year 2015 in the German power market (product: Phelix-Base-Year-Future)



Source: own elaboration based on EEX (2016).

One reason for this decrease in liquidity is that risk premiums grow exponentially with the delivery date. There are no suitable long-term hedging instruments[8] – neither for relevant production cost factors (price of coal, gas, carbon), nor for the risk of a regulatory intervention, or for the counterparty default risk. As a result, the current demand of end-consumers for long-term contracts is close to zero.

It is worth pointing out that the current products are neither suited to trade renewable electricity in forward markets nor to trade flexible resources that are used to counterbalance the intermittency of renewables. This is because the agreements are based on a production schedule that is defined *ex ante*. Example schedules include a constant production over the whole year (so-called base-year-future) or a constant production during all peak hours of a year (so-called peak-load-year-future). Such a production schedule is not compatible with the

[8] In this context, a forward period exceeding five years can be considered long-term.

intermittent nature of renewables and consequently neither to the output of flexible back-up resources. For this reason, new products have been proposed by power exchanges but it remains unclear who would be the buyer of such contracts. Moreover, assuming that buyers will be found, market liquidity would still decrease with increasing forward periods, for the same reasons as discussed earlier. Thus, no long-term price signals would emerge.

3. Possible ways forward

3.1 Facilitate bilateral long-term contracting

Bilateral long-term contracting can be facilitated by offering hedging instruments for relevant cost factors, because risk premiums grow exponentially with delivery date.

In this context, one important cost factor is the cost of guarantee. It results from the risk that one of the contracting parties terminates the contract early. The cancellation of contracts may, for instance, be triggered by an unexpectedly strong decline or increase of future market prices, possibly caused by a regulatory intervention, making the negotiated price uncompetitive for one counterparty. An option to facilitate bilateral contracting would be to socialise the cost of this guarantee, meaning that the implications of extreme *changes* in the overall price level would be shared among all consumers and thus not considered in the bilateral cost of guarantee.

In practice, market players (generators, retailers, end-consumers) that decide to enter into long-term arrangements would not have to sign the full guarantee due to not having to cover the full spectrum of future prices but only those prices with a high probability of being realised. The difference between the full cost of guarantee and the guarantee paid by the signing parties would then have to be socialised. It would only come into effect, if these improbable price levels were realised.

At this stage, this option is only a theoretical proposal. While the Italian regulator had started a public consultation on the matter in 2008, it was not followed up, i.e. no concrete piece of regulation or legislation was proposed.[9]

Socialising the cost of guarantee would probably increase the liquidity of tradable bilateral contracts with a delivery date of 2-3 years in the future. Yet it is unlikely to impact the trade of contracts with later delivery dates because demand largely remains short-sighted, with no (economic) need to secure electricity supply a long period in advance of delivery. One of the major underlying reasons is regulatory paternalism: consumers trust that the regulator will *de facto* hedge them against the risk of physical shortage. Moreover, reliability clearly is and will likely remain a public good because it is difficult to selectively disconnect consumers in a meshed electricity network in times of physical shortage (so-called non-excludability). The individual benefit from long-term contracting is and will therefore remain limited.

[9] See AEEGSI (2008).

3.2 Long-term contracts with a regulated counterparty

A complementary measure could be to introduce long-term contracts with a regulated counterparty. Generally, one could design contracts for capacity or energy or a combination of both. In a centralised design, this could lead to the creation of capacity auctions – for conventional or renewable capacity or both. Long-term contracts for energy would resemble modern support schemes for renewables, albeit based on more competitive elements than in the past. In general, centralised systems should be based on a regional[10] adequacy assessment and use a competitive bidding process for price discovery to ensure cost-effectiveness.

If contracts were organised in a decentralised way, this would mean obliging retailers to enter into long-term agreements. In practice, this leads to certificate systems. Previous experiences with decentralised setups have been rather mixed, both at EU and international level.

In the EU, there is evidence from renewable energy support systems that certificate systems offer less certainty regarding revenue streams than direct contracts with a regulated counterparty. This was one reason why the UK changed its renewable support from a certificate system ("Renewable Obligation Certificates, ROCs") to direct contracts ("Contract-for-Difference, CfD") in 2013.

From a retailer's perspective, imposing long-term contracting obligations (for instance, firm capacity or renewable energy to be purchased under long-term contracts) may result in a disproportionate volume risk, and then in an incentive to limit the duration of the capacity and renewable energy contracts, rendering them less effective. Moreover, this could give an unfair competitive advantage to new retail entrants, as they would not be bound to high-cost, legacy contracts when they enter the market. For these reasons, a centralised approach is more likely to achieve the objective of providing long-term price signals.

3.3 Legislation

Currently, a variety of existing pieces of legislation govern rules for long-term contracts. This includes Directive 2005/89/EC (Security of Supply), Directive 2009/72/EC (Internal Electricity Market) and the Guidelines on State Aid for environmental protection and energy 2014-2020.

Under the Electricity Directive 2009/72/EC, a member state can set up new capacity, if the market fails to guarantee sufficient investment. Similarly, under the Directive 2005/89/EC, measures may be used to ensure security of supply. These measures include "contractual guarantees, capacity options or capacity obligations as well as non-discriminatory instruments such as capacity payments."

Finally, contract arrangements and regulations are considered state aid when a contract meets four conditions: first, it must provide an economic advantage. Second, it must favour a certain

[10] A *regional* assessment takes into account to which extent neighbouring member states contribute to security of supply.

undertaking and be selective. Third, it must be state funded or be consumer funded but with some state involvement. Fourth, it must distort competition and affect cross-border trade.

Under current legislation, long-term contracts are subject to case-by-case approval decisions with varying approval times. The UK proposed capacity auction was considered state aid due to meeting all four above-mentioned conditions. After much negotiation, it took one month for the Commission to approve the mechanism. In France, the Exeltium project took five years of negotiations to receive approval from the Commission. Long decision processes tend to be detrimental to investment.

Clarification of existing legislation is needed to reduce barriers to establishing competitive long-term contracts. Upcoming legislative proposals on a new electricity market design and the forthcoming policy framework for renewables could make explicit reference to the advantage of competitively determined long-term contracts to promote decarbonisation and ensure security of supply.

More generally, approval processes for long-term contracts could be streamlined and shortened if the necessary prerequisites for introducing such mechanisms were merged into one Directive rather than being spread across multiple directives and the Guidelines. Secondly, it would be advantageous to have a set of EU framework rules in place for the design of these contractual agreements, including guidance on length, types of instruments and participation of cross-border resources – in short: an updated EU Target Model. If executed, both these points may lead to a more efficient implementation process of mechanisms that ensure decarbonisation and security of supply, as well as increase investor certainty and support the completion of the internal market.

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With the formation of Energy Climate House (ECH), CEPS has established an independent centre of excellence within its premises aimed at consolidating its work on energy and climate change. Against the evolving energy environment, researchers associated with ECH authoritatively analyse the most salient challenges facing the energy and related sectors, notably due to climate change. The analysis is approached from a pan-European and policy-oriented perspective and the responses are formulated in a global context.

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- Energy Policy
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- To build collaborative networks of researchers, policy-makers and business representatives across the whole of Europe.
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