cerre Centre on Regulation in Europe

REPORT

Monica Giulietti
Chloé Le Coq
Bert Willems
Karim Anaya

SMART CONSUMERS IN THE INTERNET OF ENERGY

FLEXIBILITY MARKETS AND SERVICES FROM DISTRIBUTED ENERGY RESOURCES

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info@cerre.eu
www.cerre.eu

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About the authors

Monica Giulietti is a CERRE Research Fellow and Professor of Microeconomics at the University of Loughborough's School of Business and Economics, where she heads the Economics Discipline Group focusing primarily of energy economics and regulation. Previously, she worked at the universities of Warwick, Nottingham, Aston and Exeter. Throughout her career, she has frequently published in international journals and conducted research work for several governmental institutions and organisations.

Chloé Le Coq is a CERRE Research Fellow and Professor of Economics at the University Paris 2 Panthéon-Assas and at the Stockholm School of Economics (SITE). Her research interests include industrial organisation and behavioural economics, especially topics related to energy markets, anti-trust policy and social innovation. She has held visiting positions at the University of Purdue, at the University of California Berkeley Energy Institute and at the National Singapore University.

Bert Willems is a CERRE Research Fellow and Associate Professor of Economics at the University of Tilburg. He is also a Senior Member of the Tilburg Law and Economics Center (TILEC), research associate at Toulouse School of Economics (TSE) and Vice-Chairman of the Benelux Association for Energy Economics (BAEE). He holds an MSc in Mechanical Engineering and a PhD in Economics from KU Leuven.

Karim Anaya is Research Associate in Energy Economics at the University of Cambridge. Her main areas of interest include future regulation of electricity distribution and transmission networks, electricity market reforms, and sustainable and green energy technologies. She has also worked as a consultant for different organisations such as the United Nations and the World Bank. She holds a PhD in Energy Economics and a Master's degree in Technology Policy from the University of Cambridge.

Executive Summary

In light of new EU market rules adopted as part of the Clean Energy Package, responsive and energy-efficient consumers are likely to play a crucial role in the challenging transition to a low carbon energy system. This is especially true for *smart consumers* who have access to distributed energy resources (DER) assets, such as demand response, solar photovoltaics, storage, electric vehicles and heating appliances. With the 'internet of energy', interconnected smart consumers can trade on both sides of the market, either directly or through an intermediary such as an energy service provider, an aggregator or an energy community.

Understanding the necessary conditions for the development of local energy markets with the active participation of DER is essential. Most techno-economic models predict that electricity markets will increasingly rely on decentralised generation, demand response and localised system management. These new commercial and regulatory challenges will require a smarter and more flexible system.

The report focuses on the business opportunities and regulatory challenges emerging in the 'internet of energy', in which local consumers, producers and system operators (TSOs and DSOs) trade increasing amounts of DER.

Following an introductory assessment of general trends and key drivers of electricity consumption, **this report analyses several international case studies representing innovative business models and regulatory arrangements where DER are actively involved.**

One of the issues identified is the problem of externalities arising from the activity of new market actors. While the emergence of aggregators as new market players can facilitate and promote the supply of flexibility services, it can also generate inefficiencies in the system. These inefficiencies may be caused by unplanned imbalances in the system (for which financial compensation will be required) or by limiting the ability of traditional suppliers to provide a stable and reliable supply to retail consumers (by cherry-picking consumers with the most profitable load profile). To correct for this potential externality some form of compensation would be required which correctly accounts for the opportunity costs and lost revenues incurred by retailers.

Trading platforms have emerged as systems that can facilitate an efficient use of DER. However, the evidence analysed raises doubts as to whether sufficient financial benefits will be available to consumers in order to motivate their engagement with a potentially complex system which might require the modification of longstanding habits. Bringing together smart meter technology, blockchain and apps could lead to energy transactions being tailored to reflect both the attributes of distributed energy resources and the preferences of consumers and prosumers. However, transaction costs and unobserved costs incurred by consumers will have to be negligible. If not, the differential between a Feed-in-Tariff (FiT) or other subsidies and the market price will be squeezed to such an extent that only non-price factors (e.g. altruism, localism, environmental preferences) will drive consumers' willingness to participate in P2P systems.

Despite the expectations about wide-ranging opportunities offered by blockchain as a decentralised payment system, doubts remain about its suitability for the energy system. Furthermore, general concerns remain about public acceptance of this new system in relation to the protection of privacy and data management issues which can arise with automated systems.

The report also discusses the different proposals for DSO-TSO interactions that allow the trade of flexible services provided by DER under different regulatory and market contexts, in the United Kingdom, Australia, New York and Europe. We observe that in all

these cases an expansion of the DSO's roles, capabilities and coordination with the TSO is required. However, the analysis of the different approaches shows that most jurisdictions have not yet identified their preferred organisational set-up, including *inter alia* whether a central coordinator is necessary, and whether this should be the DSO, TSO or a third party. The applicability of one case or another will depend on each jurisdiction's existing regulatory environment, market structure and needs. **A cost benefit analysis should help to identify the relative costs of different options**, but many benefits and costs are hard to quantify. Key differences across Member States, such as the number, size and independence of the DSOs, should be taken into account in such a study.

The research confirms that the current network tariff regime is not optimal in a future smart energy system and that tariffs should be more directly linked to costs. A more advanced tariff structure becomes feasible in a smart electricity network: tariffs can become time- and location-dependent and could change in response to local network congestion. To achieve this goal, the report highlights some of the trade-offs that are faced in setting tariffs, and makes a number of recommendations.

One of these recommendations, which is not dependent on smart meters, is to increase the capacity tariff (€/kW) while reducing the volume tariff (€/kWh). This is beneficial as marginal costs are more closely determined by capacity needs and less so by energy volume. Another important point is that DSOs could also rely on ancillary service markets for flexibility, in which they procure local flexibility services from distributed energy resources, either directly or through aggregators. The proper functioning of those flexibility markets requires clear baseline consumption and production levels. Those baselines are ideally based on network quantities that are contracted between network users and the network operator and will therefore require a network tariff which specifies a demand (or supply) profile with penalties for deviations from this profile.

In addition, the abolition of net-metering and a shift towards capacity tariffs may reduce cross-subsidisation from poor consumers to rich consumers and will improve the fairness of the tariff structure.

The report however warns that, in the long run, when the costs of storage and local generation are expected to drop further, local energy communities might decide to partially or fully disconnect from the distribution network and operate on a stand-alone basis. The cost of the distribution network will then have to be covered by the remaining network users who will see their energy bills increase as a result. **This could lead to a "death spiral"** where more customers leave the distribution network (unlikely in northern Europe), network assets become stranded, the distribution network becomes obsolete and goes bankrupt, and only small island grids remain.

The report concludes by considering the importance of creating the right incentives for DSOs in the context of the digitalisation of smart networks. This task faces a number of challenges which may require a new regulatory framework, but may also entail significant changes in the market structure and the allocation of responsibilities. **The report lists both the challenges (e.g. capital vs operational costs, new tasks and new skills, prevention of cross-subsidies and discrimination, innovation, etc.) and concrete remedies, including three different market structure options for DSO-TSO cooperation.**

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INTRODUCTION

1. Introduction

In several jurisdictions worldwide, policymakers are actively discussing the role that smart and energy-efficient consumers can play in the challenging transition to a low-carbon energy system, particularly in relation to their ability to provide flexibility services, independently or through intermediaries. This report investigates the business opportunities and regulatory challenges emerging in the 'internet of energy', in which local consumers, producers and system operators trade increasing amounts of distributed energy resources (DER). Part of this emerging landscape are smart consumers, who can either trade themselves, or via intermediaries (retailers, aggregators, or communities). However, several studies have shown that traditionally, residential consumers have not actively participated in retail markets. Thus, questions about the mechanisms via which consumers offer their resources to the market are critical for energy markets with active participation of distributed energy resources. In order to address these questions, the report considers the role of price and non-price signals and the characteristics of emerging markets for DER, with trading platforms and energy communities allowing buying and selling of distributed energy products and services.

As energy systems become increasingly decentralised and characterised by high penetration of intermittent sources, distributed networks and DER themselves need to become smarter so that a range of markets for flexibility can be facilitated. In turn, centralised generation and the TSO role in the system are likely to be diminished, while new market platforms and business models will be established, creating challenges for traditional utilities and regulators. This report seeks to investigate these challenges and identify potential solutions, by reviewing the evidence of demonstration projects and regulatory interventions that have recently emerged as a result of the increasing decentralisation of energy systems. The report has three main objectives. First, to investigate the design of existing local energy markets and trading platforms, including the incentives schemes to trigger consumer participation, from selling excess generation to the grid to peer-to-peer trading. Second, to assess the role of TSOs and DSOs in promoting the development of efficient markets with distributed energy resources. Third, to identify some of the regulatory challenges that may arise as a result of the transition to a decentralised energy system with a high penetration of renewable generation.

This report reviews evidence about the existing projects involving consumer engagement in energy markets through participation in demand response schemes or ancillary services markets. We also consider examples of regulatory reforms aimed at creating the conditions for the development of efficient markets for flexibility services, by offering appropriate incentives for DSOs and TSOs to optimally procure such services at the lowest economic and environmental cost. The case studies presented in the report provide recent examples of DER trading, either with the grid or, through private wire systems in US and European jurisdictions.

The report first provides an overview of the market trends and the legal framework established by the European Commission in the recently-approved Clean Energy package (CEP). This section also discusses how the increased penetration of intermittent renewables and DER have made both supply and demand conditions less predictable compared to a centralised system dominated by dispatchable technologies. Section 2 summarises the key features of the EU's CEP, by briefly describing the directive's provisions and guidelines relating to consumers engagement in the energy market and to the larger role that DSOs are expected to play in a more interactive and decentralised energy system. Section 3 discusses the main findings from the academic literature and official reports, and provides a description of the key features of several case studies of innovative business models and regulatory arrangements, relating to markets where DER are

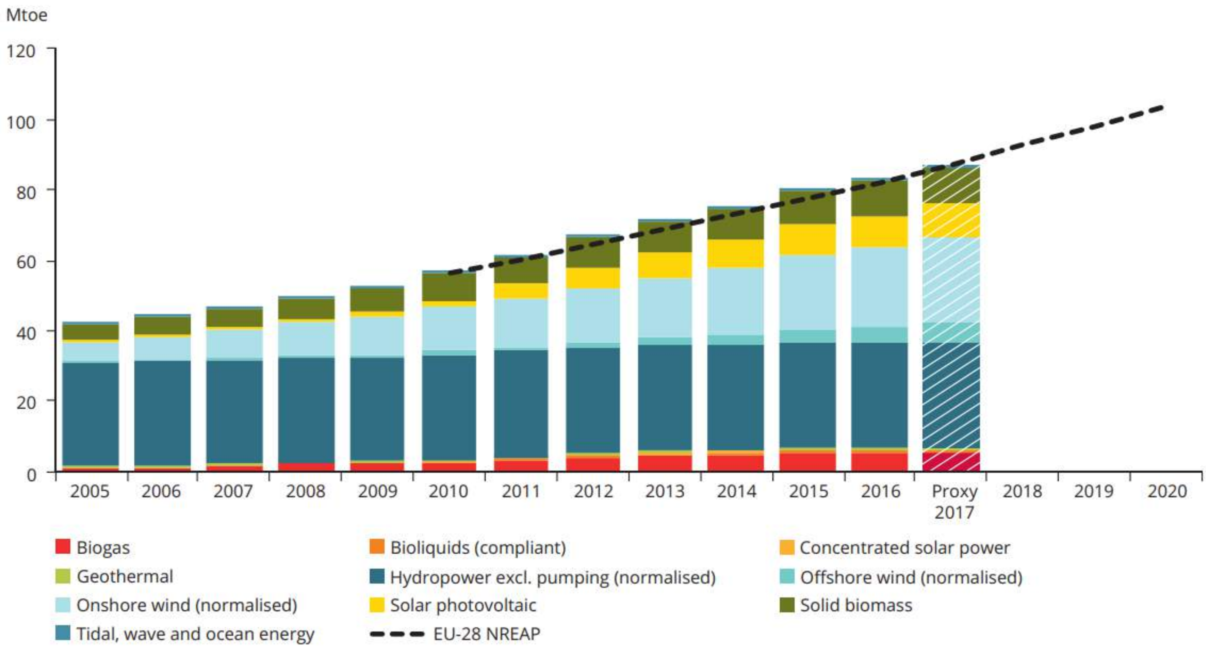
actively involved. Some key lessons are identified. Section 4 evaluates the different approaches of the interaction between DSOs and TSOs in key jurisdictions, in order to promote the participation of DER in the provision of balancing and ancillary services. Section 5 explores the trend in network regulation with a focus on distribution networks and the impact that these can have in the deployment of the internet of energy. Section 6 closes with some conclusions and key recommendations emerging from our analysis.

1.1. General trends

Trend 1: An increased amount of weather-dependent power supply

The shift of electricity production from conventional, fossil-fuel based electricity supply to a system dominated by renewable and clean energy sources is one of the pillars of the EU's climate strategy. Figure 1 shows the increase in renewable energy sources for electricity production in the European Union.[1] Renewable energy sources contributed to 29% of the EU's electricity production in 2016 and its CO_2 output from fossil fuel use has decreased by 10% since 2005 (EEA, 2018).

Figure 1: Renewable energy source development in the EU



Source: EEA, 2018, Figure 2.5, p.22

The greatest share of renewable production comes from wind energy, solar energy and hydropower. All of these production types are intermittent, meaning that their output is volatile and depends on hard-to-predict outside factors such as weather conditions.

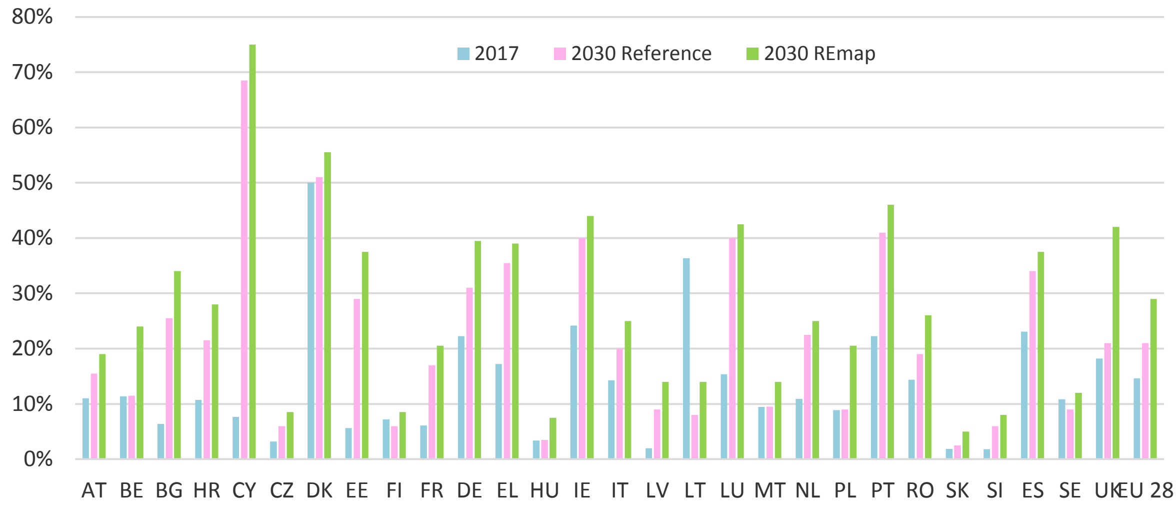
The increased reliance on intermittent renewable energy sources (I-RES) raises some questions. In particular, it is unclear how a European weather-dependent electricity system will continue to develop as this dependency may severely affect security of supply. In a recent paper, Ravestein et al. (2018) analyse the impact of climate change on future electricity production, given different

[1] Note that this figure comes from the EEA 2018 report on renewable energy in Europe (see Figure 2.5 p.22). It shows the actual EU energy renewable consumption from 2005 to 2016 as well as the 2017 estimated consumption.

scenarios of renewable generation capacity in the EU. Specifically, they find that the difference in weather conditions caused by the North Atlantic Oscillation (NAO) - one of Europe's most important drivers of weather variability - can induce median differences of 20-30% in the yields of I-RES in high wind production regions. These findings underscore how weather will be a very important variable in any high-renewables scenario.

Moreover, this effect of weather dependency will be unevenly distributed across the EU, as can be seen in Figure 2.

Figure 2: Variable renewable energy share in total electricity generation by country



Source: Eurostat database, IRENA (2018). Own elaboration.

The figure shows the share of intermittent generation in 2030 under a reference case (i.e. the continuation of existing policies) as well as a more ambitious case reflecting the realisable technology potential. It shows that some countries, such as Cyprus, Denmark, Portugal or Ireland, will be affected more by the volatility introduced by weather phenomena. Meanwhile, countries such as the Czech Republic, Slovakia and Slovenia will continue to rely heavily on dispatchable generation sources.

Finally, note that an increase in weather dependency will not occur solely on the production side; it will impact both sides of the market, as the demand for electricity becomes increasingly volatile due to the growing use of electric heating.

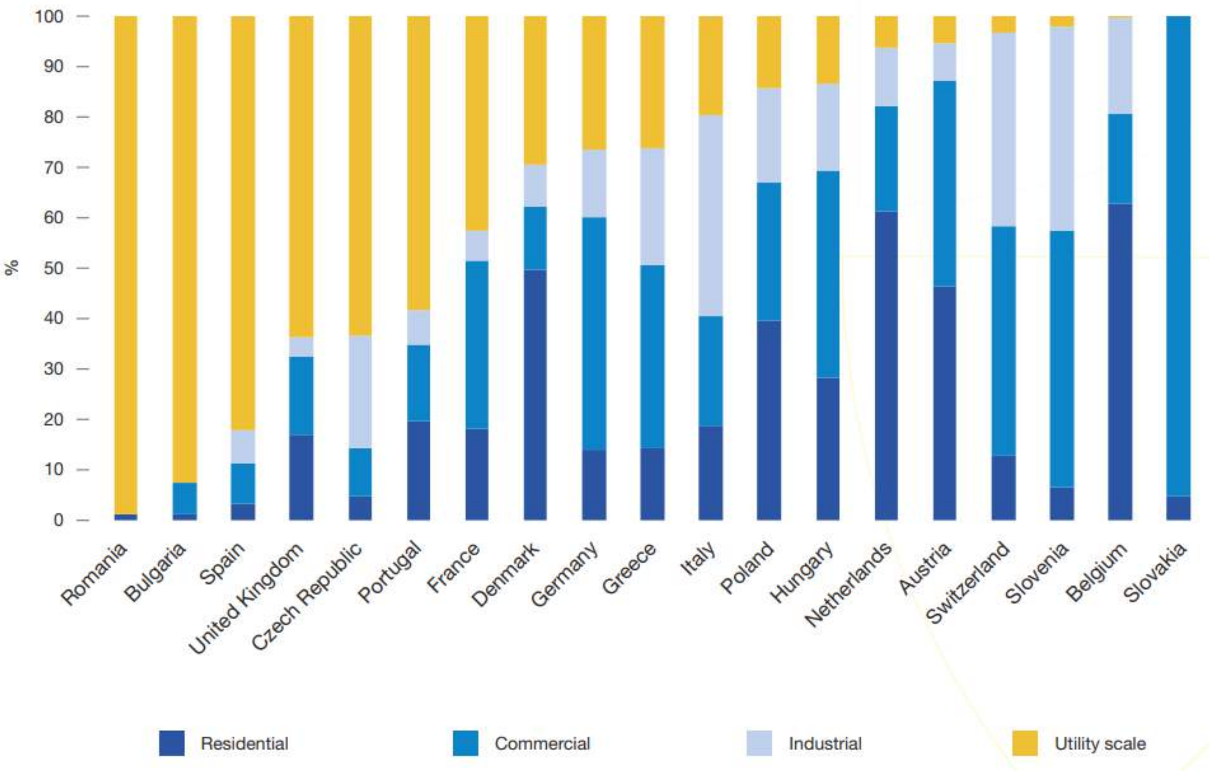
Trend 2: Growing number of distributed energy resources

A second noticeable trend is the development of distributed generation, which enables consumers to become *prosumers* by selling their surplus electricity to the grid. The most common type of distributed generation is rooftop photovoltaic (PV) solar power. Figure 3 shows the share of residential PV in comparison to total solar production in different countries.[2] It shows that while

[2] This figure comes from the Global Market Outlook for Solar Power (2018-2022), see Figure 27 p.72 and provides an overview of the European solar PV total capacity in 2017.

residential PV has a small share of total PV production in countries such as Romania or Spain, it represents a large share in Belgium, the Netherlands or Austria.

Figure 3: Comparison of solar PV segments



Solar Power Europe, 2018, p.72

Overall, the technically feasible potential for rooftop PV in Europe is extremely high with a total PV potential of 500 GW in EU urban areas but also extremely unevenly distributed across Europe (Huld et al., 2018).

Change of paradigm and value of flexibility

These two changes (among others) have led to a change in the supply-demand paradigm. For a long time, even after liberalisation and regulation of the European electricity market, power markets were designed with the assumption that supply should follow the demand. Indeed, demand for electricity has historically been stable and proven to be inelastic in the short run. [3]

But the development of decentralised production as well as the increased weather dependency of energy supply is currently pushing for a new paradigm, where demand is adjusting to the intermittent supply. Indeed, supply has become less elastic. A large of share of traditional power plants are being phased out. While "clean" electricity sources such as wind or solar PV are inherently intermittent, storage capacity is unlikely to fully compensate supply volatility, at least in the short term. The viability of a future green power market crucially depends on different innovative ways to increase the elasticity of demand.

[3] Even though, consumers were still actively involved (through their balancing responsible parties).

This switch in paradigm has led to an empowered, flexible consumer (or prosumer) the so-called "smart consumer'. This new actor will provide value not only to the household itself but to all participants in the power market.

First, the active consumer can greatly contribute to the security of the electricity system. In the current centralised system, the TSOs are struggling to transmit the electricity produced by intermittent sources, to the load centres that are often located far away (see for example Germany or Sweden). In order to avoid congestion, they have to intervene in the market with costly actions. For instance, in Germany, total congestion management[4] has increased from €58.6m in 2010 to €859.4m in 2016, with a peak of €1141m in 2015 (Joos and Staffell, 2018). By increasing the share of distributed generation and storage, pressure on the transmission system could be relieved and the frequency of congestion events could be reduced.[5]

Second, clean but intermittent electricity generation could realise its full potential in a more flexible system. Currently, spikes in renewable generation can lead to the curtailment of wind or solar power plants if they generate at times of low demand (e.g. high wind speed during the night). In a system in which consumers provide distributed storage (i.e. through their EV-batteries, for example) and react to price signals through smart meters, this potential would not be wasted as households could shift their electricity consumption into hours of high generation.

This load shifting would also be desirable from a market efficiency standpoint. Currently, a significant part of electricity demand is inelastic throughout the day and unresponsive to price signals. In a system where consumers can react in real-time to price signals, the volatility of electricity prices would be reduced. For example, electric car owners would refrain from charging their batteries during peak hours since high electricity prices would disincentivise them from doing so. However, this would not be the case for fast charging because customers would want to charge their vehicle quickly, then the potential for smart charging is very low (CERRE, 2019b). Additionally, more reactive consumers would add some competitive pressure on the dominant producers.

Finally, the emergence of the prosumer could lead to an increase in renewable energy capacity as the incentive to invest in rooftop PV and storage technology would be higher.[6] Such investment may be done for savings reasons but also for so-called "warm glow" reasons - the emotional reward that households receive for directly contributing to the environment.[7] Allowing self-production, direct trade between consumers and coordination within energy communities, may activate consumers.

1.2. Clean Energy Package

European energy markets have been liberalised since the second half of the 1990s[8]. Several European Regulations and Directives provide the regulatory framework for the internal energy market, which are then implemented by Member States. They have been revised regularly, and the European Commission has just finished its third overhaul, the 'Clean Energy for all Europeans'

[4] Total costs comprise: total curtailment compensation payments, net costs of redispatch and costs of reserve plants.
[5] Distributed generation may also increase congestion in the (distribution) network and require additional investments, if generation is insufficiently responsive to network congestion. Wolak (2018) reports empirically how additional solar power increases the distribution costs in California.
[6] Note that under a cap and trade program with a constant CO_2 cap, decentralized production will not affect total CO_2 emissions, but might make more stringent future caps possible.
[7] See Andreoni (1990) for a definition of warm glow. The emergence of energy communities also suggests that some customers are interested in acquiring a certain level of autarky from the grid.
[8] For further details about progress with liberalisation in the EU see Pollitt (2019) and Chyong (2019).

package.[9] In this section, we discuss how EU regulation affects energy consumers and also highlight some recent developments.

The focus of the first three energy packages (1996-2009), was on founding the internal energy market: the introduction of competition for generation and supply, ensuring non-discriminatory access to distribution and transmission networks, improving cross-border trade and establishing a governance structure (e.g. national and international regulators). The position of small energy consumers - households and small and medium-sized enterprises - has only gradually received attention. Where earlier regulations focused on consumers as rather passive agents requiring protection, newer iterations view consumers more as active market participants.

Consumers were still assumed to be rather passive in the Second Electricity Directive (2003/54/EC), which obliges Member States to take measures regarding customer protection and public service obligations. It also allowed Member States to introduce measures for Demand-Side Management (DSM). The original goal of Demand-Side Management was to improve energy efficiency on the demand side, thereby reducing the need for additional investments in production or networks. Demand Side Management already existed in the pre-liberalisation period as a requirement for the regulated vertically integrated utilities. Under the Directive those responsibilities could be given to the regulated DSOs. It was defined (Art. 2.29) as a global or integrated approach aimed at influencing, *"the amount and timing of electricity consumption, to reduce primary energy consumption and peak loads by giving precedence to energy efficiency, or other measures".* The system operators are well placed to trade-off network investment and the cost of DSM projects. Moreover, as they are typically not selling energy products, implementation of DSM measures by system operators does not distort competition. However, DSM provides only limited incentives for innovation of business models by suppliers. In the Recast Electricity Directive, Demand Side Management is no longer mentioned.[10] The focus has shifted towards consumer responsiveness. Coordinating network and production capacity with consumer demand while at the same time improving system efficiency is being addressed by more active participation by consumers in energy markets.

Energy consumers are treated as active participants, starting with the Energy Efficiency Directive (2012/27/EU).[11] Their role is developed further in the Clean Energy Package. Central to this development is the promotion of Demand Response. Demand Response is defined in the recast Electricity Directive (Art. 2.20) as, "*the change of electricity load by final customers from their normal or current consumption patterns in response to market signals, including in response to time-variable electricity prices or incentive payments, or in response to the acceptance of the final customer's bid to sell demand reduction or increase at a price in an organised market as defined in point (4) of Article 2 of Commission Implementing Regulation (EU) No 1348/20141, whether alone or through aggregation".* The concept of organised markets is defined in "Commission Implementing Regulation (EU) No 1348/2014" and is very broad. It covers any system in which multiple third-parties buying and selling interests in energy products, are able to interact in a way that results in a contract. It includes exchanges, brokers and other intermediaries.

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[9] This fourth package is also known as "The Winter Package" or "Clean Energy Package" and was initiated in 2016.
[10] Improving Overall Energy Efficiency remains one of the main goals of the EU climate goals. The Energy Efficiency Directive (2018) allows member states to impose Energy Efficiency Obligations on the basis of objective and non-discriminatory criteria on energy distributors and retail energy sales companies. In 2015, five countries had Energy Efficiency Obligations Schemes: Denmark, France, Italy, Poland and the UK. https://www.eceee.org/policy-areas/EE-directive/energy-efficiency-obligations/. Other member states rely on alternative methods.
[11] In particular, Article 15 imposed a number of requirements. The Energy Efficiency Directive is amended in the Clean Energy Package (2018/2002/EU).

Important in this definition is that consumers react to market signals and that their response reflects short term deviations from normal consumption levels.[12] The definition also distinguishes implicit demand response, where consumers observe prices and adjust their demand accordingly and explicit demand response, where consumers - possibly through intermediaries - bid into organised markets and participate directly in the price formation process.

The Clean Energy Package consists of a new energy rulebook[13] covering four directives and four regulations. The most relevant for the Internet of Energy are the following:

- The amending Directive on Energy Efficiency (2018);[14]
- The new Electricity Regulation (2019);[15]
- The amending Directive on Electricity (2019).[16]

The Clean Energy Package brings forth an updated market design for electricity markets and introduces new measures regarding dynamic pricing, the market access of demand response, the role of aggregators and energy communities and the regulation of TSOs and DSOs.

Providing consumers with the correct prices

A first set of measures aims at increasing *implicit demand response.* To implement this, consumers should face dynamic prices, namely time-varying energy prices and transmission tariffs that reflect market scarcity and smart metering systems that continuously measure energy consumption by individual consumers are required.

Annex XI of the Energy Efficiency Directive (2012/27/EU) states that network or retail tariffs *may support* dynamic pricing for demand response measures by final customers, time-of-use tariffs, critical peak pricing, real time pricing and peak time rebates. The recast Electricity Directive requires that the national regulatory frameworks *enable* suppliers to offer dynamic electricity price contracts, and that Member States ensure that final customers with smart meters installed can request to conclude a dynamic electricity price contract. The directive defines dynamic electricity price contracts in article 2.15 as "*an electricity supply contract between a supplier and a final customer that reflects the price variation in the spot markets, including in the day-ahead and intraday markets, at intervals at least equal to the market settlement frequency*" (Energy Efficiency Directive (2012/27/EU).

Article 19 of the recast Electricity Directive requires Member States (or national regulatory authorities) to strongly recommend electricity undertakings and other market participants to optimise the use of electricity, inter alia, by providing energy management services, developing innovative pricing formulas and introducing smart metering systems that are interoperable, in particular with consumer energy management systems and with smart grids [...]. Member States are required to ensure the implementation of smart metering systems that assist in customer

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[12] In the Energy Efficiency Directive (2012/27EU) the term 'demand response' was not yet crystallised and defined as "*a mechanism to reduce or shift consumption to improve energy efficiency.*"
[13] An overview is provided at https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/clean-energy-all-europeans
[14] Directive (EU) 2018/2002 of the European Parliament and of the Council of 11 December 2018 amending Directive 2012/27/EU on energy efficiency (Text with EEA relevance.) PE/54/2018/REV/1.
[15] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (Text with EEA relevance.) PE/9/2019/REV/1.
[16] Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (Text with EEA relevance.) PE/10/2019/REV/1.

participation in their territories, possibly subject to a cost-benefit assessment. A cost-benefit assessment should be revaluated at least every four years (preamble, 53).[17]

Consumer access, aggregators and energy communities

A second set of measures focuses on active demand response, where consumers and small business can directly participate in energy markets. The principle of market access of consumers through aggregation, or individually, was established in the Energy Efficiency Directive (2012) and supported by specific measures in the new Electricity Directive, which define the roles of aggregators and energy communities.

Article 15.8 of the (2012) Energy Efficiency Directive had significant relevance with regards to explicit demand response: it required Member States to encourage demand side resources (DSR) to participate alongside supply in wholesale and retail markets, and to ensure that TSOs and DSOs treat demand response providers, including aggregators, without discrimination on the basis of their technical capabilities. The article also required Member States to, inter alia, define technical modalities for participation in balancing, reserves and other system services markets on the basis of the technical requirements of these markets and the capabilities of demand response, including the participation of aggregators.

In article 2.18, the Electricity Directive defines aggregation as *"a function performed by a natural or legal person who combines multiple customer loads or generated electricity for sale, purchase or auction in any electricity market"*, while article 2.19 defines an independent aggregator as *"a market participant engaged in aggregation who is not affiliated to the customer's supplier".* Article 17 of the Directive requires Member States to *allow* final customers, individually or through aggregation, to participate alongside producers in all electricity markets, in a non-discriminatory manner. Member States are required to ensure that in producing ancillary services, TSOs and DSOs treat market participants engaged in the aggregation of demand response in a non-discriminatory manner alongside producers on the basis of their technical capabilities.

Importantly, the national regulatory frameworks are required to provide aggregators with the right to enter electricity markets without consent from other market participants, to have non-discriminatory, transparent rules that assign roles and responsibilities to all electricity undertakings and customers and to make rules about data-exchange between market participants and finally, to establish a conflict resolution mechanism between market participants.

In the original proposal, aggregation services would not pay any compensation to other market participants, but this is no longer the case in the last version of the text, when other parties are directly affected by *demand response activation*. Member States may require electricity undertakings or participating final customers to pay financial compensation to other market participants, or to the market participants' balance responsible parties, if those market participants or balance responsible parties are directly affected by demand response activation. Note that indirect effects, for instance through targeting specific consumer types, does not require compensation. Market participants engaged in aggregation will be financially responsible for the imbalances they cause in the electricity system (17.3(d)). However, there is also a requirement for a, "provision for final customers who have a contract with independent aggregators not to be

[17] Art. 20 of the Directive and Annex III determine those minimal standards. Meters should provide accurate measurement of actual consumption and self-generation, real-time information should be made available without additional cost, and the system should allow metering and settling at the same time resolution as the imbalance market.

subject to undue payments, penalties or other undue contractual restrictions by their suppliers;" in 17.3(e).

Similar requirements to facilitate aggregation of distributed demand and supply are put forward in the Electricity Regulation: it states in its principles (article 3(e)) that consumers' and small enterprises' market participation must be enabled by aggregation of generation or consumption. The same Regulation's article 6.1 indicates that all market participants should have access to balancing markets, either individually or through aggregation.

Note that **consumers can participate in *all* organised energy markets**. So, this includes not only the day-ahead and the balancing markets, but also the ancillary services markets and capacity markets, unless technical limitations prevent it. Organised energy markets also include all derivatives products (forward and option markets) and contracts offered by independent brokers. In order to participate in these markets, consumers may use an aggregator, but the Directive also allows them to participate without such an intermediary. The Directive foresees that aggregators may be required to pay financial compensation to other market participants (e.g. retailers) directly affected by DR activation.[18] This is an important requirement as aggregators may, depending on the market design, impose negative externalities on suppliers. Aggregators may, for example, "cherry pick" consumers with demand profiles, which are more favourable than the average consumer (see section 3 for a more detailed discussion).

The recast Electricity Directive defines **'citizen energy communities**' in article 2.11 as a legal entity based on open, voluntary participation and controlled by members or shareholders who are natural persons or local authorities. A citizen energy community's primary purpose is providing environmental, economic or social benefits to the members or shareholders of the community, or to the local area where it operates. This community may engage in generation. Member states *may* grant citizen energy communities the right to manage distribution networks in their area of operation and establish the relevant procedures. (Art. 16.4).[19]

Article 16.3 of the Directive obliges Member States to ensure that citizen energy communities can access all electricity markets, are treated in a non-discriminatory manner, are financially responsible for the imbalances they cause in the electricity system and that they are treated like active customers in accordance with article 15.2(e). According to article 16 of the Directive, Member States are required to set a legal framework that ensures that participation in these communities is voluntary, protects the shareholders' rights and ensures that shareholders, or members, are allowed to leave such a community.

If a citizen energy community manages a distribution network, then they are entitled to make agreements with the relevant DSO or TSO to which their network is connected. The community then has to pay appropriate network charges at the connection points between their network and the distribution network outside the community. It is upon Member States to determine how those network charges will be determined in practice. The same article (16.4(d)) requires that customers

[18] The Directive limits those compensations, as they should not limit market entry or flexibility (Art. 17.4).
[19] The Renewable Energy Directive Art 2(16) defines a slightly narrower concept: a 'renewable energy community'. As the citizen energy communities, it is a legal entity with open and voluntary cooperation, effectively controlled by members or shareholders (natural persons, SMEs or local authorities) and which primary purpose is not financial profits but rather environmental, economic or social community benefits. Renewable energy communities have to be located in the proximity of the renewable energy projects that are owned and developed by the legal entity, and the renewable energy community can produce, consume, store and sell *renewable energy*, share *renewable energy* within the community and access all suitable markets.

connected to the distribution network operated by a community shall not be harmed or discriminated against.

Hence, citizen energy communities could in some member states fulfil the (partial) role of DSOs and of a supplier. In order to become a citizen energy community, the community needs to be controlled *by natural persons or local authorities*. It does not necessarily have to participate in distributed generation and it can generate environmental, economic or social benefits to the community or the area in which it operates. Note that there are no explicit requirements for members to be physically close to each other - however the scope of the community has to be local. For-profit communities are not strictly ruled out and neither are private companies with minority shareholders in the community. Although communities are allowed to manage the distribution network, network ownership is not covered under the definition.

Increased role of DSOs

The Clean Energy Package also adapts regulation in recognition of the larger role that DSOs are expected to play in the future.

According to article 52 of the new Electricity Regulation, DSOs shall cooperate through a *European Entity for DSOs* - "EU DSO entity" - in order to promote the completion and functioning of the internal market in electricity and optimal management and a coordinated cooperation of DSOs and TSOs. DSOs who wish to participate shall become registered members of the entity. Article 55 describes the tasks of the EU DSO, which are quite extensive: from coordinating operation and planning of transmission and distribution networks, facilitation of integration of renewable energy resources and distributed generation and direct and indirect demand response, to digitalisation of distribution networks (smart grids and smart meters), cyber security and data management. According to the preface of the Regulation, DSOs may require regulatory safeguards to ensure neutrality in their functions, since they may often be vertically integrated companies that are also involved in supply or other services. The Regulation states that the EU DSO is needed to improve the efficiency of the electricity distribution networks within the EU and to ensure cooperation with TSOs and the European Network of Transmission Systems Operators (ENTSO) for Electricity.

Article 57 of the Electricity Regulation requires DSOs and TSOs to cooperate in planning and operating their networks, in particular exchanging information and data, and they must cooperate to achieve coordinated access to resources such as demand response. Article 28 of the same regulation requires TSOs to cooperate through ENTSO for Electricity at Union level. Article 30 obliges TSOs to establish regional cooperation within the ENTSO for Electricity and specifies that the regional coordination centres shall complement the role of TSOs.

The recast Electricity Directive affirms the larger set of tasks of DSOs in chapter IV. Article 32 of the Directive obliges Member States to provide the legal framework required to allow and incentivise DSOs to procure services in order to improve efficiency in the distribution system. The same article requires regulatory frameworks in Member States to enable DSOs to procure services from resources such as *demand response* in transparent, non-discriminatory manners. DSOs are required to define standardised market products of the services acquired in *ensuring effective participation of all market participants*, including demand response. Distribution system operators shall cooperate with TSOs for the effective participation of market participants connected to their grid in retail, wholesale and balancing markets according to article 31.9.

Box1: The status of demand response regulation EU markets before the Clean Energy Package

One the goals of the Energy Package is to improve demand response in EU markets. Although demand response was already foreseen in the Energy Efficiency Directive in 2012, this was not yet operational in many countries as seen in the studies by SEDC (2017) and JRC (2016).

SEDC (2017) reviews the status of demand response in 18 countries in 2017. It concludes that most markets are open to demand response, but *regulatory barriers* hampered growth in a number of countries (e.g. requirements that are unadjusted to enable demand-side participation), in almost all countries, had problems with measurement, verification and payment schemes (transparency, multiple baseline methodologies, measurement of energy consumption)

The European Commission's Joint Research Centre's (JRC, 2016) confirms those results. It highlights that in several countries independent aggregators cannot offer demand side resources, (no means to measure or pay for those resources, and markets that are closed.)

Since 2017, member states have worked hard on removing barriers for distributed energy resources, but full market access has not been achieved.[20]

[20] For instance, in Italy some recent initiatives are opening new opportunities for DR in the Ancillary Services, see: https://lightbox.terna.it/en/distributed-resources-UVAM. In the Capacity market, a new scheme has been approved for DG and demand units will be allowed to participate. SmartEN (2018) describes the situation for the balancing markets.

02

FROM CONVENTIONAL TO SMART CONSUMERS

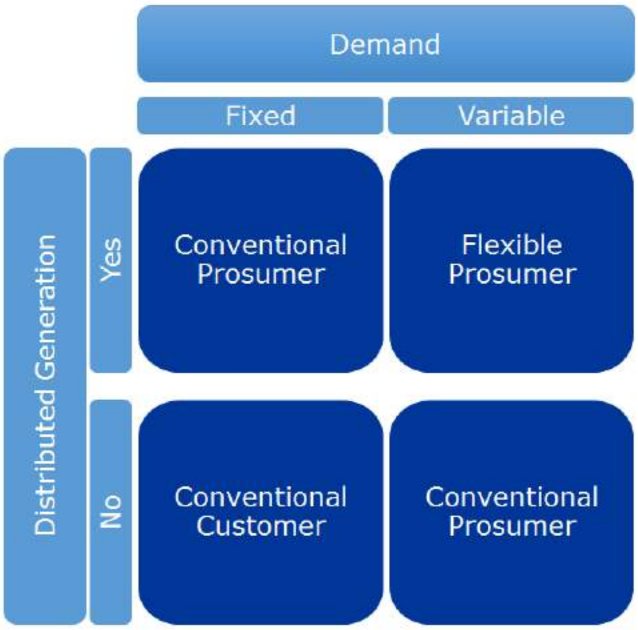
2. From conventional to smart consumers

In this section, we focus on what drives consumer behaviour in electricity markets. The quest to find the drivers of consumer behaviour in electricity markets is of interest for both researchers and policymakers. The consumers' role is changing, from simple price-takers, more and more of them are now actively participating in the market through demand side management and micro-generation. At the same time, preferences for clean energy may transform customer willingness to pay and their perception of electricity as a homogenous good. However, the experience of liberalised retail markets shows the importance of inertia in customer behaviour that may prevent the afore-mentioned trends from materialising.

2.1. The different consumers

There are different types of demand (and hence consumers) that can be summarised in Figure 4.

Figure 4: Consumer types based on available technology



Source: adapted from Kubli et al., 2018

Additionally, smart consumers are part of energy communities. An energy community – as we have discussed above – can be a group of households or industrial consumers from a well-defined geographical area (e.g. building, apartment blocks, technology hub…) that agree to jointly invest in photovoltaic panels or a wind turbine. Each member of the energy community has to contribute to the investment of the common power installation and not of a particular energy production unit.[21]

[21] See section 1.2 for the "legal" definition of an energy community in the EU.

Note that energy production in excess will be sold outside the energy community. The surplus is re-injected in the public grid and compensated, depending on the country, at feed-in tariffs or the hourly price realised in markets (e.g. net billing schemes).[22]

To conclude, households/industrial consumers may be attracted by financial incentives to gather in energy communities, but the incentives should be in line with the complexity of creating viable communities. There is a need for regulation that provides guidelines to define and monitor energy communities by specifying their roles, rights and responsibilities.

2.2. The key drivers of electricity consumption

There is a large body of literature discussing the factors that affect electricity demand. Many drivers have been proven to affect electricity consumption: price, available information, switching and search costs, social norms, or even individual preferences for green energy. We briefly discuss these different factors in the following subsections.[23]

Price as the right signal

Electricity fulfils the law of demand in that higher prices lead to a reduction in demand even though the degree of elasticity varies between different type of consumers. Field experiments showing a negative price elasticity of electricity demand go back to Battalio et al. (1979) and Caves and Christensen (1980), who estimated that rebates and real time pricing can lower electricity demand as well as peak shifting. While these early studies had small sample sizes, their findings have generally been confirmed by more recent studies with larger sample size (e.g. Faruqui and George, 2005), or focusing on markets outside of the United States (e.g. Japan in Ito, Ida and Tanaka, 2018).

Switching costs and loss-aversion

The liberalisation of the retail market for electricity that took place in many countries around the year 2000 offers various insights into the behaviour of customers in power markets. Defeuilley (2009) examines this first wave of liberalisation and argues that the reforms did not allow for efficient markets due to switching costs.[24] Indeed, Sweden, Great Britain and Norway were – at that point – the only countries with switching rates above 25%. Even in these countries there were large price differences between incumbents and new entrants, suggesting that there was an active market of consumers reacting to price signals) and a larger inactive market of consumers remaining loyal to the incumbent. Yang (2014) analyses the low probability of Danish customers switching to a new electricity retailer, despite the liberalisation of the retail market and switching being relatively easy. He finds that relationship management is the main driver in changing electricity retailer, while economic benefits and psychological attachment have little power. He also mentions the role of a regulated and relatively cheap default tariffs.

The low switching rates in retail contracts may also be the result of behavioural bias such as loss-aversion. Indeed, Nicolson et al. (2017) conducted an experiment with a representative sample of British energy bill payers to determine the viability of introducing time of use tariffs. They found that while more than a third of the surveyed customers were willing to switch to time of use tariffs, the actual switching rates were negatively affected by loss aversion. That is, customers, when

[22] Note that for small projects "net metering" might be more profitable than a FiT in most countries. See Status of support schemes in Europe: https://www.ceer.eu/documents/104400/-/-/80ff3127-8328-52c3-4d01-0acbdb2d3bed
[23] A thorough summary of part of this literature can be found in the review article by Hahn and Metcalfe (2016).
[24] Switching costs consist of search costs (i.e. identifying and comparing suppliers), learning costs (i.e. developing relations with the new supplier) and transaction costs (i.e. negotiating and contracting with the new supplier).

deciding to switch suppliers or contract type, care more about potential losses than potential benefits. Mulder and Willems (2019) found mixed results for the Netherlands. Yearly switching rates (15% per year) and product innovation in particular in green electricity was relatively high (50 green products and 20 grey products are offered by the seven main retailers) and consumers were willing to pay a premium for green energy. However, a large fraction of dormant consumers never switched (40% of the market).

The impact of available information

Information about residential electricity consumption often leads to a reduction in electricity demand. Gans, Alberini and Longo (2013) found that providing households with meters that allowed them to track their consumption in real-time reduced usage significantly. In another study, Schwartz et al. (2013) showed that households reduced their consumption after being notified that their electricity consumption was being monitored even though they did not receive any instructions to reduce their usage. Similarly, Allcott and Taubinsky (2015) found that informing consumers about the cost and efficiency benefits of energy-efficient lightbulbs increased the purchase of these types of lightbulbs. Meanwhile, a later study by Allcott and Sweeney (2017) found that providing information on efficiency alone did not increase the purchase of energy efficient water heaters while a combination of price incentives and information increased the market share of these heaters. A recent field experiment by Bollinger and Hartmann (2017) found that information treatments alone are successful in reducing long term demand, but only in combination with automation technology do they lead to changes in short-term elasticity.[25]

Social Comparison

Using social norms in combination with information about one's own energy use can lead to a reduction in electricity usage. In a large experiment Allcott (2011) found that sending home energy reports which compare customers' consumption to that of their neighbours could reduce energy consumption by an average of two percent. Similar results were reported by Ayres et al. (2013) who found that home energy reports decrease electricity consumption in a sustained way. According to Herberich et al. (2011) price and social norms affect the decision to invest in energy efficient technology (in their case: efficient light bulbs): the price affects how many light bulbs are bought, while social norms affect the decision to purchase any efficient light bulbs at all. However, Dolan and Metcalfe (2015) found that while social norms and pricing are both effective in reducing consumption on their own, the combination of both eliminates the effect. Likewise, the study by LaRiviere et al. (2014) showed that the framing of energy reports matter to their effect: people reduce their consumption when the social goods component of their actions is stressed. Lastly, Ito, Ida and Tanaka (2018) argue that moral incentives only reduce energy consumption in the short run but have no long-term effect.

Preference for green energy

Consumers generally exhibit a willingness to pay higher prices for electricity produced by green and renewable forms of generation. There is a large body of literature estimating this willingness to pay in a variety of settings. Based on these studies, Sundt and Rehdanz (2015) conducted a meta-regression analysis of the existing literature. They found that the willingness to pay for renewable energy differs by source with hydro-power being the least valued. Furthermore, people with information about the type of power plants substituted by renewables exhibited a higher willingness to pay. In the descriptive part of their paper, the authors further argue that the

[25] Note that Jessoe and Rapson (2014) find that price incentives alone lead to a lower reduction in electricity use than when the same price incentives are combined with an information treatment.

willingness to pay is higher in settings where consumers are richer, younger, have lower current electricity prices and are more concerned with environmental issues. Similarly, Grilli et al. (2017) conducted a meta-analysis which revealed that the share of renewables, current level of CO_2 emissions and the replaced energy source affected the willingness to pay for green electricity. Meanwhile, Ma et al. (2017) found in a similar study that the differences in their meta-regression analysis were driven by differences in experimental design rather than true factors affecting the willingness to pay. In addition, consumers' preferences for greener solutions often translated into (1) 'a feel good decision' of changing the service provision to consume green energy or (2) taking the active decision of investing in renewables or being part of energy communities.

Offer flexibility services

In a modern-day electricity system, there is an interest in incentivising prosumers to offer flexibility to the grid, in order to adjust to the higher volatility in supply that arises from the increased reliance on intermittent generation. Bollinger and Hartmann (2017) showed that pricing signals combined with automation in end-use systems have the potential to create a short-term elasticity of electricity demand.

In a recent experimental study, Kubli et al. (2018) worked with owners of PV plus storage, electric vehicles (EV) and heat pumps. They investigated their willingness to participate in flexibility programmes that would allow the utility to access their devices. They conclude that there is generally a significant potential for participation. However, they also found that owners of heat pumps are less willing to participate in these programmes than the other two groups. Additionally, they found that EV owners were unwilling to participate in a programme that allows their charging level to drop too much. Other studies show that EV owners (see Parsons et al. (2014)) or residential consumers (see Richter and Pollitt (2018)) might need to be compensated substantially to participate in smart energy markets. However, the full potential of electric vehicles and their role in providing flexibility to the grid (i.e. as storage) is not currently exploited. The vehicle owner would not only need to connect the vehicle into the grid even while not charging, which may result in additional payments, but also would need to have agreements with aggregators or other market participants for the use of batteries (CERRE, 2019b).

It is also possible that consumers were reluctant to sign up for demand response as they underestimated the individual and societal advantages and that they requested a relatively high financial incentive to participate. Interestingly, Roth et al. (2018) compared households that co-own distributed generation with those that do not and found some evidence that households that sell electricity to the grid are more willing to participate in demand response programmes. They argued that this was due to the financial incentives for efficient consumption that selling excess electricity provided. Another barrier to the participation in demand response could be distrust in the energy company, as argued by Stenner et al. (2017).

03

BUSINESS MODELS AND MARKET PARTICIPANTS

3. Business models and market participants

The emergence of decentralised energy systems and the increased penetration of distributed non-dispatchable technologies has created new business opportunities for existing and new market players in the energy sector. These include traditional energy retailers, prosumers, aggregators, energy services companies and citizen energy communities. New and existing players are starting to operate in different markets across the energy system and across time, although an organised market for flexibility is not clearly defined or established yet. Such an organised market would facilitate flexibility through different and potentially competing services, such as storage, demand side response, virtual power plants and ancillary services, at different times and under different system conditions (e.g. see Brunekreeft et al. 2016).

Some flexible services could evolve by subscription (i.e. to 'energy/heat as a service' model). Digitisation may give rise to new product service models where the user 'rents or pays per use' for a device including maintenance and support and eventually including a lump sum for its consumption. Other services such as renewable power, heating and EV charging could emerge, purchased in a bundle or in part from commercial housing companies, for example when renting an apartment or from energy services companies (ESCOs).[26]

Among the participants in the markets for flexible generation and demand response we will consider aggregators, trading platforms, microgrids and citizen energy communities, in an attempt to identify their business models and the regulatory challenges that their activities are likely to generate. Despite decentralisation, during the transition to a decarbonised system, some centralised technologies will remain relevant to ensuring security of supply and affordability. For this reason, better integration between energy markets at different scales will be required in the short-to-medium term.

Much attention has focussed on the emergence of independent aggregators as economic agents, providing consumers with access to energy markets. In order to provide these services, they will need to coordinate production and consumption decisions made by a large number of individual consumers or prosumers. Retailers and independent aggregators carry out similar functions: they schedule power procurement or production, balance market positions, settle market transactions and bill customers for their services. Indeed, traditional retailers across the United States and Europe are starting to offer DER aggregation services. Generally, these services are offered mainly to industrial and commercial consumers with fewer examples of engagement with residential consumers and prosumers.

Three main models have been identified to help integrate prosumers into the grid: prosumer-to-grid (including aggregation), peer-to-peer trading (via trading platforms and in microgrids) and prosumer community group or citizen energy communities (Hirsch et al., 2018). According to Stadler et al. (2016), the main value streams, targeted by private microgrids and energy communities, include demand response, power export and net metering, resiliency and local energy markets.

In the electricity sector, recovery of legacy network cost has become a pressing issue, especially given the emergence of DER, whose generation is organised at the local level in microgrids and/or

[26] For a discussion of recent developments for ECOs see: https://www.iea.org/topics/energyefficiency/escos and http://publications.jrc.ec.europa.eu/repository/bitstream/JRC106624/kjna28716enn.pdf

energy communities. To address concerns around the potential impact on the most vulnerable members of society, whose consumption is dependent on the existing centralised system and may end up paying a disproportionate amount of network costs, existing forms of subsidy for RES such as net metering and network-use charging (fixed Vs variable, energy Vs capacity charges, etc. which will be discussed in section 5.1), need to be reconsidered (Gautier, 2018; Schittekatte et al., 2018; Bennato et al., 2019). Further distributional concerns relate to the potential financial implications for poorer consumers (who are dependent on existing, traditional infrastructure) as a result of investment carried out by wealthier communities, which allows them to achieve energy efficiency and lower costs, but might generate local congestion problems or indirectly increase the financial burden on the rest of the local residents. These issues will be discussed in more detail in section 3.5 below.

3.1. Retailing and aggregation

As discussed in section 1.2, when considering emerging business models in the energy space, a distinction between aggregators and retailers may not be required, as aggregation can be seen as a function carried out both by traditional/incumbent suppliers and by emerging companies adopting more innovative business models. However, the more specific concept of independent aggregators[27] is likely to apply to those emerging actors in the energy services space that are able to aggregate demand and generation across different users, independently from established suppliers.

The prevailing business models for flexibility delivered by consumers or buildings are demand response (DR) and virtual power plants (VPP) including generation units, storage and ICT systems. While implicit demand response can be delivered via retailers through dynamic pricing, explicit demand response and access to energy markets for virtual power plants requires some form of aggregation.

Ma et al. (2017) highlighted the importance of incentive programmes, national regulation and market structure in promoting participation in the flexibility market by prosumers (including buildings). They considered the case study of Nordic countries, where DR participation was open to small consumers (in most cases this is implicit participation via price-based programmes e.g. Time of Use tariffs as part of a retailers' supply contract), while only large consumers can access the wholesale market. According to their analysis, under the current regulatory system, the highest value to the aggregation market would come from implicit DR programmes run by retailers. However, they noted that the provision of DR services by consumers in Nordic countries could come via aggregators or VPP business models, in the presence of a regulatory framework. This would create incentives to help TSOs/DSOs to encourage consumers to participate in the DR/aggregation market, with clearly defined monetary benefits and financial support aimed at promoting technology adoption. However, if promoting automatic DR system is thought to be the most efficient way to provide flexibility to the system, then issues of privacy and public acceptance will need to be addressed.

Hall and Roelich (2016) discuss the challenges faced by aggregators and energy services providers more generally in the context of the UK market, by highlighting the substantial risks associated with the provision of flexibility services in terms of being appropriately compensated for the value provided to the system. They pointed out that there was still uncertainty about the monetary value

[27] According to Art. 19 an independent aggregator is '*a market participant engaged in aggregation who is not affiliated to the customer's supplier*'.

of these services to final (residential) consumers, in the presence of high contracting costs in this relatively underdeveloped market.

A recent example of an aggregator in the UK is Open Energi, which operates as a VPP (Dynamic Demand 2.0) involving mainly industrial and commercial consumers.[28] They rely on a platform that connects, controls and aggregates distributed energy resources such as on-site generation and energy storage systems in an automated process. This allows them to support their customers in accessing balancing markets, such as firm frequency response or renewables balancing reserve and in undertaking automated trading, based on day-ahead, intra-day and real time pricing. This broad range of activities is facilitated by a regulatory framework that allows and promotes DR and independent aggregators' activity.

For most energy consumers, retailers have responsibility for aggregating their load, procuring and scheduling consumption and production. Retail tariffs are the main investment and operation signal for distributed energy resources. While there is some evidence, as discussed in section 2, that consumers adjust their consumption in reaction to short term changes in prices, Burger et al. (2019) identified some potential barriers to participation, such as the existence of transaction costs, limited attention and risk aversion for retail consumers. For these reasons, new entities, such as aggregators, may need to offer contracts, hedging strategies and demand management to attract residential consumers.

The emergence of independent aggregators and other new entrants into the market is likely to stimulate competition, as they can offer attractive contracts to the most flexible consumers/prosumers, whose load can be profitably used to exploit arbitrage opportunities in the wholesale market, or in the ancillary services market. This will create system externalities requiring some form of compensation by aggregators to other retailers. The issue of compensation for the externalities generated in the system as a result of market participation, which involves withdrawals and input of energy into the system, raises questions about the correct assessment of the level of costs imposed on retailers, as a result of such market activities. While the wholesale market price could be considered as the correct opportunity cost, as it reflects the cost of procuring electricity for the average retail consumer, the loss of retail consumers with the most profitable profiles might be associated with more substantial revenue losses for traditional retailers.[29] The current EU regulation however does not require consumers to seek the permission of retailers before entering into contract with aggregators for the provision of DR. The motivation for this is likely to be related to the objective of promoting new entry into the retail market and of increasing competition across suppliers. Indeed, it is expected that technological innovation and changes in rates may increase the potential for competition at the retail level, creating value via differentiated products and services. While consumers do not need their retailers' permission to engage with new entrants in the current regulation, there is however a requirement that independent aggregators compensate other parties for the direct effects of demand response activation on other market participants.

Burger et al. (2019) also noted that a variety of arrangements in the US and EU mean that DNOs and DSOs can, in some cases, compete with retailers. In some jurisdictions DNOs might share

[28] See: https://www.openenergi.com/wp-content/uploads/2018/04/open-energi-dynamic-demand-2-0-service-overview.pdf

[29] In order to prevent such cherry picking, the compensation scheme should not correct for the average consumer profile, but for the consumer profile of the particular market segment that consumers belongs to. If such compensation scheme is not present, then retailers may be forced to use real time prices to prevent cherry picking, but might hollow out the function of retailers as insurance providers.

asset ownership with (partially) unbundled competitive affiliates, but the authors state that where distribution has been unbundled from retailing, regulators must ensure DNO/SO neutrality by keeping DSOs' ownership separate from retailers/aggregators.

3.2. Microgrids and trading platforms

The Internet of energy is understood to be a network of connected devices allowing the efficient management of the energy system by collecting, analysing, monitoring and exploiting real-time data (Zhou et al., 2016). In this complex, connected energy system several actors and technologies are involved including prosumers, aggregators, microgrids and trading platforms, which can all be based on blockchain technology.

The Microgrid Exchange Group developed the following microgrid definition*:*

> '*[…] a group of interconnected loads and DER within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid ... A microgrid can connect and disconnect to the grid to enable it to operate in both grid-connected and island mode*' (Ton and Smith, 2012).

When security of supply is an issue microgrids are preferred to virtual power plants as they can operate island mode (Hirsch et al., 2018). According to Mengelkamp et al. (2017), '*microgrid energy markets allow small-scale participants, such as prosumers and consumers, to actively trade energy within their community in (near) real time'*.

Microgrids facilitate the sharing of renewable resources and allow for better utilisation of generation and load resources. For this reason they are expected to generate lower energy consumption costs, once established and integrated into the system. However, microgrids differ in their institutional features (e.g. industrial and commercial, community, military etc.) and in the range of assets and ITC systems they rely on, so they adopt different business models and target different revenue streams. Central to the financial viability of the microgrid and the success of its business model is the control platform (Asmus and MacKinnon, 2016), as will be discussed in section 3.4.

The emergence of microgrids in the energy systems of different countries raises both legal and regulatory issues regarding how these new entities should be treated in comparison with existing market players. The regulation of microgrids will have to deal with two key issues: 1) should they be considered as distribution companies and subject to regulation? 2) how will they fit in the existing legal system? (Hirsch et al., 2018). From a regulatory point of view, microgrids are likely to be considered as utilities serving a variety of customers and may therefore be subject to regulation on tariffs and capital investment. They may also be obliged to comply with consumer protection law. Hirsch et al. (2018) suggested that their vertically-integrated nature may be problematic in deregulated and unbundled markets. Another potential social welfare issue relating to the emergence of independent microgrids is the problem of fewer consumers having to pay for infrastructure costs, but this problem might be overcome by a 'pay for performance' renumeration system for traditional utilities. Traditional utilities in US are starting to see microgrids as a way of offering new services to their customers and in increasing reliability.

Two Scottish islands in the UK have created microgrids that rely on local power from RES. In order to achieve a sustainable energy system, the Isles of Eigg and Gigha have invested in large-scale renewables and battery capacity. In order to supply total energy demand, Eigg has adopted a diverse set of smaller renewable technologies such as hydroelectric (112kW), wind turbines (24kW) and a solar array (50kW). Gigha meanwhile, has invested in four relatively large-scale wind turbines (4MW). Realising the grid constraints following installation of the fourth wind turbine, Gigha reinforced their systems with battery technologies. Both isles have installed batteries to support and manage system demand, with a host of 48V lead acid batteries introduced in Eigg and a 1.68MWh vanadium redox flow battery in Gigha. in addition to alleviating grid congestion, Gigha's battery is expected to provide several key services such as backup supply, flexibility and voltage control). The two island communities have so far benefitted from either decreased electricity bills (Eigg) or increased income generated from greater utilisation of local generation and ancillary services (Gigha).[30]

An innovative partnership is pushing the boundaries of this business model through the realisation of "smart energy islands". The European Regional Development Fund have provided Hitachi, Moixa and PassivSystems with £10.8m to co-finance the bringing together and management of renewable and low-carbon technologies using IoT (Smart Energy Islands, 2019). The project aims to deliver a framework for sustainable islands, which can also be replicated in rural regions, through the integration and optimisation of renewables via an IoT platform (Hitachi), smart batteries (Moixa)[31] and demand-side management hubs (PassivSystems). The project will be developed on the Isle of Scilly, a region that suffers from expensive energy bills and high rates of fuel poverty. These issues are, in part, tackled through the increased level of self-consumption of domestic solar. Noting that this electricity is paid for at a subsidised rate, the 10 households with solar panels on the roofs of their homes continue to contribute to local infrastructure. What is more, the regional and licensed energy supplier, the Isle of Scilly Community Venture, has created a local energy tariff to ensure that the financial benefits of local electricity consumption are shared as part of the community development project. Transport has also part subsidised through the introduction of 25 charge points, supported by 10 solar arrays, in order to provide fuel for 10 communal electric vehicles. The project aims, by 2050, for a 40% reduction in energy consumption, a 40% increase in local renewable generation and a 40% switch to electric vehicles.

Ahl et al. (2019) pointed out that expectations have been set on the ability of P2P microgrids, possibly blockchain-based, to deliver value both to consumers and to the energy system. However the technological innovations supporting these new market organisations require appropriate changes in the institutional and regulatory framework that currently supports the energy system. They subscribe to Mengelkamp et al.'s (2017) view that the lack of appropriate regulation represents a key challenge for the development of local energy markets. Similarly, Wu and Tran (2018) ed the significant development potential in the application of blockchain in a decentralised energy sector, but also discuss the existing limitations in terms of a lack of suitable regulatory guidance for this technology, in addition to technical and skills challenges.

One example of these regulatory limitations is the absence of clear guidelines on the participation of microgrids in markets for ancillary services. Institutional factors play an important role in this context as the financial benefits of participating in a microgrid with P2P depend on available alternative opportunities, such as feed-in-tariffs (FiT) or net metering arrangements. This was an important factor in delaying the development of P2P trading in the Brooklyn microgrid, one of our case studies in section 3.4. Additional regulatory issues include clarification on acceptable

[30] Sources: http://www.communityenergyscotland.org.uk/news/20-may-2015-bbc-costing-the-earth-goes-to-eigg.asp
https://islandsgoinggreen.org/about/eigg-electric/
http://www.communityenergyscotland.org.uk/gigha-battery-project.asp
http://www.redtenergy.com/case-studies/gigha-utility-scale-storage
http://www.esru.strath.ac.uk/Documents/MSc_2015/Breen.pdf
[31] https://www.current-news.co.uk/news/moixa-begins-battery-roll-out-on-isles-of-scilly-project

ownership and partnership models, as well as licensing requirements to trade energy and renewable certificates legally (Ahl et al., 2019).

Blockchain technology is considered suitable to support the development of P2P trading schemes (NERA, 2018a). Blockchain-based platforms can help to reduce congestion on the network, and they can create financial opportunities for small scale renewables. In the energy sector this technology could also eliminate the need for wholesale-to-retail intermediaries and facilitate switching suppliers, using platforms that will allow new entrants to act as competitive suppliers.

The electricity market may be one of the most immediate use cases for blockchain technology. Electricity markets, where sales and purchases are cleared in aggregate on centralised trading platforms, are similar to financial markets where blockchain technology is currently used. One of the main features of blockchain based systems is the absence of a central marketplace where all trade takes place, instead there is a chain of trades which need to be tracked. In electricity there is an entity in place that keeps records (for technical reasons), and which is regulated (to prevent rent extraction)[32].

This technology allows for a decentralised network of prosumers, trading electricity with reduced institutional oversight that could, in theory, be organised without a utility (Livingston et al., 2018). A system of P2P transactions has been developed by two Austrian companies Verbund and Salzburg AG allowing tenants to exchange shares of electricity generated from their roof through an app. The Dutch project Jouliette is a blockchain-supported showcase microgrid that was developed as a collaboration between a sustainable office park, a DSO and an energy solution developer (NERA, 2018a). This is discussed as one of our case studies in section 3.4.

An example of a new retail supplier, which aims to offer more choice and transparency to final consumers, is the Grid+ platform in Texas. It claims it can provide lower variable costs as billing and settlement become automated and efficient. Customers pay for their electricity in real-time by using the cryptocurrency stored on their Smart Agent. In the short term there will also be lower marketing expenses. In the long term, Grid+ hopes to support P2P electricity trading, allowing energy to be traded locally. Indeed, the majority of electricity-related blockchain projects involve P2P schemes, with some examples discussed in section 3.4. However, it is important to point out that cryptocurrencies are subject to extreme fluctuations in value and are therefore are not yet a very effective means of payment

Pilot blockchain-based projects aiming to deliver flexibility services include TenneT, based in the Netherlands and Germany, and the UK's Flexibility marketplace, based on the demand response Electron platform. The TenneT project provides flexibility services to the grid by relying on storage from either EVs or residential storage systems, namely batteries linked to solar PV generation. A consortium of partners including retailers, DNOs and aggregators is seeking to commercialise the platform (NERA, 2018a). Electron is a DR platform offering a marketplace for assets to respond to pricing signals. It consists of a shared Meter Registration Platform for all UK gas and electricity supply points that facilitates faster switching and a flexibility trading platform - a common trading venue for all DR action.

Blockchain is also considered a tool to organise grid transactions as well as reducing costs. Additionally, a centralised electricity market, based on blockchain technology, could handle an increased number of transactions thereby enabling prosumers and households to participate in the

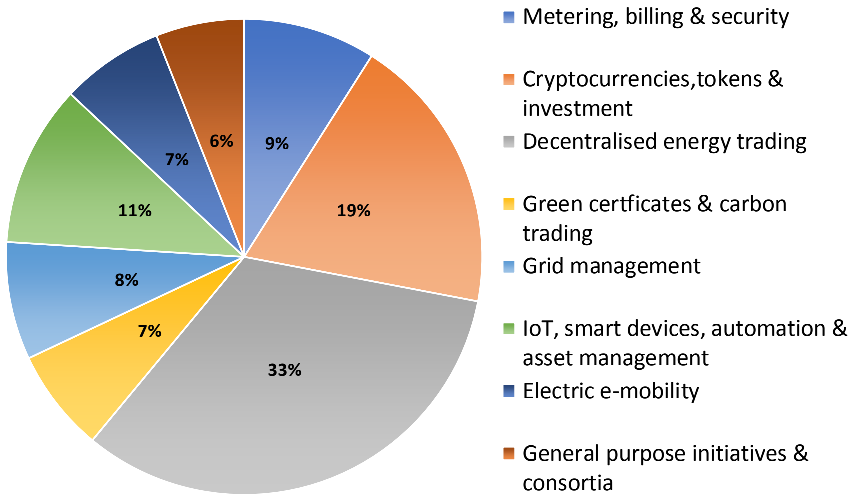
[32] For further details on the economic features of blockchain based systems, see: https://www.nber.org/papers/w25407

market. For example, Germany's Enerchain (enerchain.proton.de) seeks to reduce the costs of wholesale trading through a decentralised order book that can be accessed by other traders (Livingston et al., 2018).

Finally, utilities could use blockchain in a variety of ways to simplify their operations, including transparency, billing or automation purposes (Andoni et al., 2019). This may also allow for more switching behaviour as assets are currently managed through disconnected databases belonging to each individual company. Blockchain would allow the connected recoding of transactions such as tests, asset movement, asset changes and asset payment (World Energy Council, 2018). For example, US energy retailer, Drift is developing a blockchain-based platform that will enable it to act like a competitive energy supplier in deregulated markets. Drift leverages distributed ledger technology, machine learning and high-frequency trading to directly link independent power generators with residents and small and medium-sized enterprises (NERA, 2018a). Another example is Grid+ which is developing an automated, Ethereum-based platform that will serve as a retailer in deregulated energy markets. By automating billing and settlement, Grid+ aims to provide customers with "nearly frictionless access to the wholesale market." (NERA, 2018a)

Given all these applications, it is not entirely surprising that there has been a lot of recent activity regarding the intersection of blockchain and energy – despite its uncertain future. By March 2018, there were already 122 energy sector organisations involved in blockchain technology, and 40 publicly-announced deployed projects. The total investment in blockchain-based energy projects between April 2017 and March 2018 was €240m (NERA, 2018a). Between March 2017 and March 2018, start-ups raised over $300m for ventures applying the technology in an energy market setting. At the same time many traditional energy companies, both in the electricity (e.g., E.On, Tokyo Electric Power Company) and oil and gas (e.g. Shell, Statoil) industry, are investing in blockchain technology (Livingston et al., 2018).[33]

Figure 5: Current use of blockchain in electricity markets



Source: Andoni et al., 2019, p. 156

[33] For an overview of start-ups and other companies using Blockchain see the Appendix of Livingston et al., 2019, and Andoni et al., 2019.

There are however some barriers to the adoption of blockchain in electricity markets. First, the existing grid and system provides reliability and monetary benefits that prevent the switch to a pure P2P network (Livingston et al., 2018). Specifically, the existence of economies of scope and scale may persist even after blockchain is introduced, so remaining beneficial to maintaining the existing market structure, even though small independent communities might arise (NERA, 2018a). Also, a P2P market is dependent on residential customers becoming prosumers. However, previous experience in giving residential customers a choice with regard to their electricity provider has shown that 60% of customers remain with their default provider despite financial incentives (World Energy Council, 2018).

The key limitations of blockchain technology, in energy applications, have been identified as the low number of transactions per second, as well as the lack of scaled commercial applications, potential security risks and the still limited, public acceptance. However, methods to improve the technology are active and ongoing (NERA, 2018b).

3.3. Community energy

The movement towards more decentralised energy systems has been driven, in part, by the rapid technological change in small-scale energy generation and storage and the more effective exploitation of ICT. This technological change has allowed new business models and new economic players to emerge, including citizens' energy communities. The implications of this economic and social activity are currently not fully understood, and such entities are monitored, supported and regulated in different ways within existing regulatory frameworks.

Energy communities represent an important new player in the context of decentralised energy systems, as organisations that invest in, maintain and operate local energy systems. They can participate in the local energy market and can provide support to the distribution and transmission networks through the provision of ancillary services. In different countries and in the scientific community, different definitions of 'community energy' are accepted, reflecting the variety of energy-related projects and activities undertaken by local communities with different levels of Government support (Brummer, 2018).

Brummer (2018) reviews the experience of energy communities in Germany, the UK and the US identifying the main benefits they bring for the local and national economy, as well as any barriers to the development and growth of community energy (CE). Among the key benefits of CE, the authors highlight the creation of new social capital, the strengthening of community links and facilitating public acceptance of new renewable technologies. The evidence from those countries surveyed by Brummer indicates that the inability to achieve an efficient size for the activities and assets, limits the ability to produce sufficient surplus to cover the project's costs. Also, in the UK, access to initial funding represents significant challenge for the establishment of energy communities. Individual and community-wide financial benefits are recognised as crucial for the feasibility and resilience of CE. A minimum size of generation assets can also be a significant barrier to access to a supplier licence, which might be needed in order to supply energy to community members, but on the other hand a large generation capacity could limit the CE's ability to participate in Government support schemes, such as the UK's FiT. Finally, CE development can be hindered by complex legal processes and ineffective, and often uncertain, support schemes. In the UK and Germany, the lack of market access is highlighted as a key barrier to the financial viability of CE, as a result of market structures that are biased in favour of big companies with centralised generation. High connection costs to the distribution network are also a significant challenge for CE. The current limitations of CE and potential solutions will be discussed further, as part of the lessons learned from the emerging experiences, in section 3.5.

Koirala et al. (2018) investigate the specific area of CE storage, highlighting the role played by this technology in supporting a more efficient use of distributed energy generation from local energy communities, as well as identifying the key technological and societal challenges of integrating CE storage into the wider energy system. In particular, they highlight the importance of financial viability of the community's DER, and the role that storage can have in promoting it, together with improved efficiency and increased security of supply. They draw evidence from the experience of energy communities such as Feldheim and Sonnen in Germany, where CE storage has been used to provide balancing and ancillary services to larger energy systems, creating synergies between the local and national system. For example, Energiequelle (a wind turbine developer) supported the Feldheim energy community in developing 10MWh energy storage, used for local balancing and also to provide frequency regulation for the TSO.

Interestingly the Bannister House Estate[34] and the Trent basin[35] communities in the UK have seen the involvement of private sector energy services companies (Verv Energy and Smartklub) in supporting the development of business models for these communities, which may prove to be financially sustainable. Other energy communities or municipalities in the UK, such as Bristol and Barnsley, have promoted the involvement of local network operators in the management and coordination of the local energy system (DSO model) and are developing further engagement between energy communities and DSOs to find mutually beneficial opportunities.

3.4. Case studies of DER market participation

Regulatory reform: the California DRAM and DER programmes (U.S.A)

DRAM (Demand Response Auction Mechanism) is an initiative (trial) that encourages the participation of third parties, such as DR aggregators, in the provision of DR capacity via a pay-as-bid auction. DRAM is seen as an alternative to bilateral negotiations, specifically Aggregator Management Portfolio – AMP, or other non-competitive mechanisms for DR offerings, and is ruled by the California Public Utilities Commission (CPUC). The DRAM programme allows the participation of DR aggregators (third party providers) with customers (residential and non-residential) in the Investor Owned Utilities[36] (IOUs) service area, with 20% of total of total procured DRAM bids by each IOU having to come from the residential sector and specific budgets for each IOU.[37] Four DRAM pilot projects have already been concluded.[38] The CPUC has authorised a 5-6 year extension of DRAM, subject to improvements in the programme's design and oversight procedures, to monitor progress.

Under this approach, DR aggregators bid directly in the CAISO market through a Scheduling Coordinator (SC) and the utility (IOU) acquires the capacity (system, local, flexible capacity). DR aggregators offer different demand response products such as Proxy Demand Resources (PDR), Reliability Demand Response Resources (RDRR) and receive capacity (resource adequacy) payments by IOUs. Capacity may vary by month.[39] IOUs claim credit for the capacity and are not

[34] See www.hackneyenergy.org.uk/bannister-house
[35] See www.projectscene.uk
[36] There are 3 IOUs in California: Southern California Edison (SCE), Pacific Gas and Electricity (PGE) and San Diego Gas and Electricity (SDGE).
[37] In latest auction: US$ 6m (SCE, PGE) and US$ 1.5m for SDGE.
[38] These are: 2016 DRAM (Pilot 1), 2017 DRAM (Pilot 2), 2018-2019 (Pilot 3) and 2019 (Pilot 4). For further details about type of product, delivery period, budget, procurement targets, others, see Anaya and Pollitt (2018, Annex 3).
[39] There are specific obligations for the IOUs in California in terms of Resource Adequacy (RA). A way to acquire RA is also via DR, among other methods. Commission DR requirements to qualify for Resource Adequacy (RA) require the DR resource to offer into the CAISO energy market under the CAISO must-offer obligation for DR. See: https://www.pge.com/en_US/large-business/save-energy-and-money/energy-management-programs/demand-response-programs/2018-demand-response/2018-demand-response-auction-mechanism.page

involved in CAISO market settlements. The selection of offers is subject to: (1) a cap of long term avoided cost of generation for 2019 set at $113.20/kW-year and (2) a simple average August bid price cap. The minimum bid size depends on the DR product (100 kW (PDR), 500 kW (RDRR) per month) with a maximum bid per month of 10 MW.

CPUC (2019) established six criteria for the evaluation of the programme used to assess progress so far. From the first four projects the following observations can be made: DRAM has promoted the engagement of new participants (Demand Response Providers) and new consumers (mainly residential), many of whom had not previously participated in other programmes. However, it was unclear whether the new participant firms could be considered "viable", as out of the seven new sellers in DRAM 1 and 2, only three fulfilled the full terms of their contracts. The other terminated or reassigned their contract.). Between 74-95% of the customers that participated in DRAM 1 and 2 had never participated in an IOU DR programme previously in California. The capacity price offers were competitive for the biggest two IOUs, in comparison with the long-term avoided cost of generation, but there were mixed results for SDGE. DRAM bid prices were generally not competitive in the energy market, compared with prices of IOUs who were better at scheduling DR resources. In terms of contract obligations, improvements were observed over time, but the results are still inconclusive, with 65% of contracted capacity in 2016 and 97% in 2018. Mixed results were also observed regarding the performance of DRAM resources in terms of their ability to respond to dispatches by CAISO.

Some important lessons can be learnt from the pioneering experience of the DRAM programme, particularly with respect to market design considerations. A high level of concentration was observed in the DRAM market and for this reason the CPUC is thinking of imposing a limit of 25% of DRPs share for the two largest ones and a lower percentage for SDGE. A requirement for deposits to be made up-front, as well as the imposition of bid fees may also be introduced, to discourage bidders from making declining offers.[40] Adjustments in the price cap might also be required to improve offer valuation,[41] while improvements in the penalties and incentive performance schemes are also being considered.

The set-aside quota for residential customers (20%) has also generated concerns as it may inhibit fair competition, so that a reduction of the set-aside is currently being evaluated. Challenges in the registration of residential customers via DRPs were also encountered such as the high number of requirements/steps involved, in comparison with the IOUs DR programmes and with other programmes from other jurisdictions, such as The Electric Reliability Council of Texas (ERCOT),[42] limited the enrolment of residential customers. IOUs might also have an inherent advantage as it is much easier for them to obtain key data for their own customers and enrol them in the IOUs DR programmes. Customer recruitment costs are also among the main barriers in the successful development of the programme.

Even though a decline in the DRAM auction bid prices over time was observed in the three first DRAM pilot solicitations (PG&E, 2017, p.30), DRAM bid prices and resources were not competitive with those in the wholesale markets. Indeed, DRAM resources were found to be less active and

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40 Declining offers refer to those offers from bidders that were shortlisted but then decided to withdraw their offers (during the selection process or after being selected).

41 In the selection of offers, a simple average August bid price cap was set as a filter or screen for offers. The new recommendation is to replace the price cap based on Long-Run Avoided Costs (LRAC) with a Net Market Value (NMV) cap based on the adjustment of this value.

42 For instance, the requirement of "utility account number to enrol in DR programs" can be a limitation, with a 84% drop-off in customer enrolments. In ERCOT, the utility account number is not required for enrolling customers.

were re-scheduled far less frequently - during the CAISO system peak load hours - than other resources. A lack of information about awarded contracts - including administrative costs - has generally been observed in different auctions mechanisms from California, including DRAM. Therefore, the CPUC has now suggested publishing information about awarded DRAM contracts and administrative costs, starting from the next DRAM series.

The DER initiative, also introduced in the CAISO market, allows the participation of aggregated DER - as a new type of market resource[43] - in the wholesale energy and ancillary services markets. Programmes with participation of aggregated DR in the wholesale market already exist across CAISO and other ISOs/TSOs, however this considers a no-export rule on DER. This represents a pioneering programme which other ISOs/RTOs are trying to follow with the support of FERC.[44] A deep coordination between TSOs and DSOs is one of the key challenges in enabling the aggregation of DER (CAISO, 2018). However, an initial evaluation suggests that the programme, as implemented by CAISO, has not worked as expected, particularly in relation to the level of participation of DER aggregators (Gundlach and Webb, 2018). Several barriers to the development of the programme have been identified (Gundlach and Webb, 2018) including: regulatory barriers, such as DER aggregation still being treated as conventional generating facilities, economic barriers including low revenue expectations and/or the existence of alternative revenue streams (i.e. NEM and wholesale PDR/RDR programmes) and technical barriers associated with complex metering capability and the need to balance supply and demand considering two-way flows.

Transactive energy: the Brooklyn Microgrid (U.S.A.)

In 2016, the first transaction between consumers in a P2P energy platform (Exergy - XRG) took place on President Street in Brooklyn, New York (LO3 Energy, 2016). Exergy utilises Ethereum Blockchain software to allow consumers to trade energy locally, using PayPal, while chronologically securing the transaction in an immutable and irreversible shared ledger. The joint venture led by LO3's start-up, TransActive Grid and app developer ConsenSys, originated by linking up five consumers with another five prosumers willing to buy and sell electricity, respectively, on President Street (New Scientist, 2016).

The project expanded to sixty solar sites, involving 500 households, by the end of 2017 (NERA, 2018).[45] LO3 Brooklyn Microgrid (BMG) is seeking approval from New York authorities for a regulatory sandbox to allow its marketplace.[46] BMG, a benefit corporation, although running on a for-profit basis, aims to support local environmental and social initiatives.

The microgrid treats individual assets as 'nodes' within the power system that deliver a variety of value streams such as flexibility, capacity and frequency regulation that can be shared bilaterally (Exergy, 2019). Exergy refers to the value garnered through such bilateral exchanges as "transactive energy" which can help reduce combustion and distribution losses by incentivising those value streams that lead to a more efficient energy system. The value streams, therefore, are not denominated in kWh in the traditional sense, but reflect the 'tokenisation' of the type of service provided by the contracted unit of energy.

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[43] Each aggregation has a minimum of 0.5MW. Aggregation can be composed of DER with one or multiple pricing nodes. If the aggregation includes DER located at different pricing nodes, then the aggregation is limited to 20 MW.
[44] The tariff revision to support the participation of DER in CAISO markets was approved by FERC in June 2016 (Docket N. ER 16-1085-000).
[45] Exergy creates a marketplace which exists across traditional infrastructure. In other words, the platform consists of a physical layer and of a virtual layer. The virtual layer allows energy to be transacted across the existing distribution infrastructure run by Con Edison, the independent system operator. The Brooklyn Microgrid only decouples from the grid in emergency situations. For further details, see https://www.brooklyn.energy/
[46] For further details, see https://microgridknowledge.com/brooklyn-microgrid-regulatory-sandbox/

Each site member requires an app, must take XRG tokens to a smart meter and install the TAG-e G2 blockchain device to transfer data. Together the technologies can monitor the electrons generated and/or traded. Electricity can be traded autonomously in near real-time, providing prosumers with the opportunity to sell electricity within the community at a profit, rather than to the utility, in exchange for net-metering credits deducted from the following month's energy bill (Power Technology, 2017; Medium, 2019). Profits raised from trade are expected to remain within the community and electricity can even be gifted to others in the system such as family or friends, or donated to low-income households (New Scientist, 2016).

The app will allow members to set preferences, further tailoring the automated contracts. The visibility to both microgrid members and the local network ensures the 'seamless' balance of electricity within the system (Exergy, 2017). Likewise, visibility of the source - where and from whom electricity is transacted - can lead to the price differentiation of electricity supply (Exergy, 2017). For example, consumers could set the preference to purchase their neighbours' surplus electricity, at a premium or discount, and only purchase electricity from the cheapest traditional supplier if their neighbours are unable or unwilling to sell at the buy price.

Furthermore, autonomy of supply and demand can potentially provide security to communities faced with an increase in the occurrence and severity of extreme weather events caused by the growing climate crisis. In New York, utilities manage the operation of distributed systems, giving traditional suppliers control over whether or not solar PV can generate power at a time of crises (Power Technology, 2017). An initial aim of the project was to incorporate technology that would protect local communities in the event of an emergency.

The circular economy: De Ceuvel Microgrid (Netherlands)

The Spectral and Alliander[47] partnership exemplifies how community energy, microgrids and trading platforms could coalesce. The project, located in De Ceuvel, Amsterdam, is a private, behind-the-meter smart-grid, promoting sustainable local urban living and the creation of a "circular, resource-based economy" (Spectral, 2019).

Funded by a start-up grant of €250,000 and a €200,000 bank loan in 2012 (NYT, 2014),[48] the community, comprising 16 office buildings, a café, a bed and breakfast and a greenhouse, has sought to become self-sufficient. Most of the offices are equipped with solar PV panels, 150 in total, generating around 36,000 kWh of electricity per annum (De Ceuvel, 2017,[49] providing enough electricity to power most of the office heating systems and residual electricity used for other services, exports or to generate tradeable tokens.[50]

By September 2017, the community adopted Jouliette, named after the unit of energy, the Joule. Jouliette is a P2P token, which can only be used within the De Ceuvel ecosystem, that facilitates the management and trade of energy as well as the purchase of other goods and services. Blockchain-based technology enables members to make secure transactions, either manually or

[47] Spectral is a smart energy services company. Alliander is a large DSO.

[48] Interestingly, the 9-year payback of the loan does not rely on the stream of value generated by the solar panels, but the payments made by tenants of the workspaces of €65 per square meter per year (NYT, 2014).

[49] Sharing 36,000 kWh of electricity between 16 office buildings is equivalent to 2250 kWh (with no residual power). Allocating 2,000 kWh per office would issue 4,000 kWh for other services, for example. This is not wholly unrealistic if the office space has a high efficiency rating and is resident to micro businesses whose activity takes place primarily during the day.

[50] Compared to cryptocurrencies, such as Bitcoin, tokens do not require as much energy to generate. This is due to the fact that cryptocurrencies require 'miners' who utilise increasingly advanced processors to solve algorithmic puzzles in order to create a secure ledger within the Blockchain (The Economist, 2018). Tokens instead are not mined but created, and traded, per unit of electricity generated by the solar panels.

automated, between “virtual currency wallets” without the need for an intermediary (Metabolic, 2019; Smart Stories, 2019, see also section 3.2). All transactions are decentralised, transparent and automatically verified within the community, while the value of the energy tokens, unlike cryptocurrencies, reflects the utilitarian value of a commodity, electricity (Mulligan, 2018).

Members can trade Jouliette tokens for goods in the De Ceuvel community, e.g. at the café (BSM, 2018). A single Jouliette token is worth 0.1 kWh (De Ceuvel, 2017). Note that in the Netherlands prosumers can sell surplus, or unsynchronised, electricity to the grid in exchange for the FiT of 0.099€/kWh.[51] This implies that an americano (€2.60) in the De Ceuvel café is worth up to 260 tokens. Future services such as local banking and car sharing are expected to be exchanged for tokens within the microsystem.

Access to the Jouliette platform provides members with the necessary functionality to manage their energy transactions. The transactions and power-flows of electricity between members of the community and the grid can be monitored in real-time. This is made possible by high-resolution data and machine learning, allowing members to visualise their current and forecast energy consumption and production. The blockchain platform (MultiChain) provides both permission free access to the public as well as secure private access to known members validating the suppliers and consumers of local generation (Spectral, 2018; Andoni et al., 2019).

During Phase 2 of the project (May 2018), Spectral engaged with the De Ceuvel community in “participatory sessions” to shape the rules of the Jouliette platform (Spectral, 2019b). According to Spectral (2019), the private nature of the smart grid allows the community to trade electricity, unbound by existing market barriers. Despite the fact that we are interested in the electricity trading potential of this project it should be noticed that the project’s survival was threatened due to the lack of a gas connection in the development. Indeed, the New York Times (2014) reported the potential illegality of the system, since there is no gas connection at the site (NYT, 2014).[52] EU legislation requires that all citizens have a guaranteed electricity connection and not necessarily a connection to a gas grid, which sheds doubt on the validity of the claim of illegality (European Commission 2019), while Dutch regulation used to require a gas connection but is now being reconsidered. Moreover, due to the temporary nature of the workspaces and accommodation, people are unlikely to be at risk or vulnerable because of a lack of access to a gas supply.

The De Ceuvel project aims to expand the smart grid to the surrounding Buiksloterham neighbourhood. Despite gaining an exemption from microgrid regulations, providing the opportunity to trade energy behind the meter, expanding the smart grid will, “require even more careful navigation of the regulatory environment, exploitation of legal loopholes, and certain use-cases [will not] be possible given existing market conditions” (Spectral, 2018). The potential and feasibility of future, rapid expansion of this microgrid is therefore unclear.

Adoption and engagement: the Verv trading platform (UK)

Building on the Verv Home Hub (VHH) capabilities,[53] Verv has developed a blockchain-based energy trading platform (VTP) that aims to incentivise adoption and sustain engagement. A central

[51] See http://www.res-legal.eu/search-by-country/netherlands/single/s/res-e/t/promotion/aid/premium-tariff-sde/lastp/171/

[52] In comparison, De Ceuvel was blocked by the City of Amsterdam from collecting and supplying drinking water due to the complexities involved in becoming an official provider (NYT, 2014).

[53] The VHH is a non-intrusive load monitoring device with an ultra-high sampling rate, recording data approximately over 1 million times that of a typical smart meter. According to Centrica, smart meters are “pretty dumb” in comparison (The Times, 2017). The sampling frequency allows for real-time device recognition by identifying unique

pillar of the trading platform is the ultra-high sampling rate of the VHH, which aims to generate more accurate forecasts of consumer behaviour (demand) and electricity generation[54] (supply). What Investment (2017) suggests that the VHH capabilities will allow consumers to purchase electricity at the lowest price, similarly to foreign exchange markets. It is not clear however that such an arrangement will provide some insurance against price increases.

Driving forward P2P adoption therefore is the potential gain from trade arising from the differential between feed-in tariffs (FiT) and retail energy prices. Verv suggests that prosumers will be incentivised to sell their electricity to supplement other prosumers' and consumers' demand for a premium (above the FiT) and for a discount (below the retail price) – a so-called 'win-win'. For example, the UK export tariff post on 31st July 2012 was 5.38p/kWh and, in 2018, the UK's average variable unit price for electricity was 15.1p/kWh (Ofgem, 2019; BEIS, 2019a). It is envisioned that prosumers will "meet in the middle… including transmission and distribution fees", selling electricity to peers at around 11p/kWh (Medium, 2018a; Verv energy, 2018a: 14).

Participation in P2P schemes needs to be sustainable in a subsidy-free and fair energy system. According to the Solar Trade Association (2019), a fair price either reflects the wholesale cost, which averaged at around 6p/kWh in 2018, or the system sell price, which in the same year followed the FiT at 5.4p/kWh. Following the closure of the UK's FiT (31st March 2019), suppliers with more than 250,000 customers[55] will soon be required to purchase surplus renewable electricity at a non-zero price – the 'smart export guarantee' (BEIS, 2019b). Several suppliers have responded to this call, including a new entrant in the retail market, Octopus Energy, which offers to purchase electricity at the wholesale rate or a fixed rate of 5.5p/kWh (Solar Trade Association, 2019). Despite the prevailing differential between the FiT and retail price P in the short-medium term, the benefits will be squeezed by transmission and distribution costs D, transaction costs T and unobserved costs U. Therefore, for prosumers to be willing to trade with their peers rather than export surplus electricity to the grid, and for their peers to find this offer more attractive than the market price, the following relationship must hold: $FiT + D + T + U < P$.

Verv identifies a mixed approach to minimise T and U. Crucially, blockchain will reduce transaction costs, bypassing intermediaries and allowing consumers to digitally track and authenticate transactions. Free access to the platform will be funded by Verv's initial token offering (ITO) and revenues accrued by aggregating and monetising data. The free Verv app allows consumers with a VHH or a smart meter to register to the Verv trading platform (VTP), broadening the scope of the trading platform. However, the VHH provides adopters with a transactional advantage as they will be able to operate at "the grid-edge" by "trading faster and further ahead" (Verv energy, 2018a).

To further avoid transaction costs, Verv introduced local aggregators into the VTP, thereby avoiding the additional cost of brokering transactions in the public token (VLUX) exchange. The purchase of VLUX tokens will be automated via the VTP and exchanged for fiat (e.g. GBP) in a specific locality (100-500 households, according to postcode) to reduce the complexity of the blockchain ledger. The transaction fee will be set by the local aggregator and absorbed into the sell-price.

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energy signatures. The technology uses remote firmware updates (Verv energy, 2019) and is compatible with other smart devices (e.g. Alexa). The next generation technology also integrates a consumer access device (CAD), connecting the VHH to a smart energy meter using a Zigbee communications chip, which can seek and switch to the cheapest energy tariff rates – a crucial development for P2P trading – and based on early trials this feature is expected to reduce annual energy bills by around £80 (Medium, 2018a).

[54] Using demand data, satellite imaging, weather forecasts, cloud cover, opacity and geolocation data, for example.

[55] Smaller suppliers can opt-in.

The Verv app is designed to reduce unobserved costs (e.g. hassle) by maximising benefits and minimising costs through automated trading. The app will optimise trading based on the attributes of technologies such as battery capacity and consumer preferences (e.g. min/max sell/buy price). The VTP system identifies a window for trade hours in advance. A smart contract is then forged by matching the sell-price, set by prosumers and traditional suppliers, to the buy price, set by consumers and prosumers, and the transaction is complete upon receipt of payment per kWh. Deep learning AI and neural network matching algorithms further reduce the need for consumer engagement: "…the AI algorithms should be able to learn… patterns of engagement with energy trading. Rather than requiring ongoing input…, it is anticipated that the algorithms will learn how the user interacts with the platform… that ensures long-term, sustainable customer engagement." (Verv energy, 2018a).

Community energy: the Banister House Estate, London & Project SCENE, Nottingham (UK)

Repowering London spearheaded a community energy scheme based in Hackney's Banister House Estate (London, UK) by installing solar panels on 14 tower blocks, to provide power to communal areas, while exporting most of the electricity to the grid.[56] Following this first CE project, Repowering London and Verv implemented a trial of 40 Verv home hubs (VHH) installed in households, together with communal batteries, that allow surplus electricity to be stored and traded between flats (Green Running, 2017). Verv completed the UK's first physical P2P trade of energy using blockchain in April 2018 (Verv energy, 2018a), representing 1kWh of surplus electricity traded from one tower block to another (Medium, 2018a).

At present it is not clear how the property rights will be allocated, nevertheless the partnership between Verv and Centrica[57] will explore how to conduct "fair and transparent" billing using blockchain and analyse the transactions that take place between peers and energy suppliers such as British Gas (Verv energy, 2018a). This represents an interesting trial due to the involvement of the UK's largest energy supplier. The blockchain-based energy trading platform will allow for a secure record of transactions in real-time (Medium, 2018b).

Verv envisions creating an almost self-sustaining energy community using the functionality of VHH and the Verv Trading Platform to provide bill reductions to households, many of whom purchase energy using relatively expensive pre-payment meters (Medium, 2018a; Medium, 2018b). Combining the several streams of value mentioned above, plus the option for consumers to opt-in to demand-side response services as well as the ability to sell and manage their data with third parties, (Medium, 2018a) suggests bills could fall by 50% by 2020.

The Trent Basin's Project SCENE in Nottingham involves a 500-home energy network and relies on a digital assistant system to promote optimal energy use. It includes Europe's largest shared battery (2MWh). Smartklub is the ESCo operating the system and was involved in developing the new business models required for the community, and in creating a viable energy service company to operate the low carbon money saving offer on behalf of the residents. Smartklub design and

[56] Launched in 2015 by the residents of Banister House Estate, Repowering and Hackney Energy. The 102kWp solar array is the largest community energy social housing scheme. The scheme has raised over £149,000 as part of a community share offer and aims to cut carbon emissions by almost 700 tonnes over a 20-year lifetime (Repowering, 2019).

[57] Centrica has invested £1.9m into Verv (Verv energy, 2018b). Additional funding has been awarded as part of Ofgem's Regulatory Sandbox (over £100k) - thereby exempt from usual regulation - and BEIS' Energy Entrepreneur's fund (£215k) to simulate a UK-wide blockchain-based energy trading solution (Global Energy News, 2017; Green Running, 2017). £1.1m in equity was raised in an initial round of crowdfunding, via Crowdcube, followed by £768,420 in 2019.

manage their ongoing energy operations to save money and carbon while using the latest renewable technology and transport solutions.

Appendix 1 summarises the business model cases discussed in the previous sections.

3.5. Discussion and lessons learned

The evidence from the literature and the case studies discussed in this section have highlighted some important features of the new economic agents and organisations emerging in an energy sector currently in transition.[58] The emergence and widespread adoption of low carbon technologies and ICT technologies, which can support market transactions, has opened up opportunities to improve the system's efficiency by engaging traditionally passive users. Across different countries, projects and demonstration activities have been developed to prove the commercial viability of new business models relying on the innovative use of technology aimed at promoting consumer engagement and the provision of flexibility services. Different levels of success have been observed, related in part to the institutional and market characteristics of the countries where these projects were developed. These emerging technological and business opportunities are, however, also leading to questions about the potential challenges associated with changes in the competitive market conditions and with the social welfare impact of these new ways of operating and engaging with the energy system.

One of the potentially challenging issues that will need to be addressed in order to guarantee fair and competitive market conditions is the problem of externalities arising from the activity of new market actors. While the emergence of aggregators as new market players can facilitate and promote the supply of flexibility services, it can also generate inefficiencies in the system, not only by causing unplanned imbalances, for which financial compensation will be required, but also by limiting the ability of traditional suppliers to provide a stable and reliable supply to retail consumers, by cherry-picking consumers with the most profitable load profile. To correct for this potential externality some form of compensation would be required that correctly accounts for the opportunity costs and lost revenues incurred by retailers. The determination of the correct cost reference for such externalities will be a challenging task because the obvious choice of wholesale price, as a measure of opportunity cost, does not reflect the business conditions under which retailers operate in a 'flexible system', as in this emerging marketplace, business-as-usual is not clearly defined. Additional externalities could arise from microgrid operations at the local level, which however could be avoided through effective coordination with DSOs and with appropriate cost-reflecting charging mechanisms.

With respect to the emergence of trading platforms as systems that can facilitate an efficient use of DER, the evidence provided in this section does not clarify whether sufficient financial benefits will be available to consumers in order to motivate their engagement with a potentially complex system that may require the modification of lifetime habits. Bringing together smart meter technology, blockchain and apps could lead to energy transactions being tailored to reflect not only the attributes of distributed energy resources, but also the preferences of consumers and prosumers. However, transaction costs and unobserved costs incurred by consumers will have to be negligible, otherwise the differential between a FiT or other subsidies and the market price will be squeezed to such an extent that only factors other than price, such as altruism, localism and environmental preferences, will drive consumers' willingness to participate in P2P systems.

[58] It is important to note that, in our analysis of business model cases, we have been unable to gather sufficient evidence about the different taxation regimes to which the different projects are subject. Therefore, we are unable to assess opportunities for monetary gains which arise from favourable taxation regimes in the cases examined.

Despite the expectations about wide-ranging opportunities offered by blockchain as a decentralised payment system, doubts remain about its suitability for application in energy systems. Furthermore, concerns remain about public acceptance of this new system in relation to the protection of privacy and data management issues linked to automated systems. Zhou et al. (2016) talk about the importance of value-tapping for microgrids/energy communities in order to achieve financial viability, as well as willingness to participate from the point of view of individual consumers. In this context energy communities represent an interesting organisation as, beyond financial viability, they also value the creation of social capital, and can generate wider benefits to participants, including autonomy from the central system and the promotion of energy democratisation,[59] namely more widespread control over fuels for generation, energy consumption and access to energy. Furthermore, energy communities can help shape and design the "rules of the game", becoming active rule makers rather than rule takers. In this context P2P platforms not only transfer units of power but also bargaining power to their participants.

More generally Governments and regulators should attempt to assess the likely impact of new business models for distributed energy generation and emerging suppliers of non-traditional energy services on social welfare. In particular, they should address potential distributional issues associated with the exclusion from access to innovative technologies and additional costs that could be borne by consumers tied to traditional network, who are likely to be among the most vulnerable in society. Indeed, the investment costs of the technologies involved in decentralised energy systems could prevent low-income households from becoming active market participants, potentially widening the gap between the haves and have-nots through a transfer of wealth from retailers and aggregators to more wealthy households.

Care should be taken that the business models of microgrids do not rely on exploiting inefficiencies in the pricing structure of the distribution network operator (e.g. too high Feed in tariffs, net metering). In the short run this will just shift costs to vulnerable users without creating social gains, and in the long run it becomes unviable once those inefficiencies in tariff structure have been addressed. We discuss the role of the design of tariffs in section 4.

As one of the barriers to CE's development has been identified as the inability to achieve efficient scale, the participation of private partners (retailers, energy service companies, investment firms, aggregators, DSOs, or housing cooperatives) in the CE might be useful in providing funding and know-how. However, the Directive's definition of energy communities as legal entities with open, voluntary participation and controlled by members or shareholders who are *natural persons or local authorities* limits the business models that may be available to private parties under a CE framework. For instance, risk sharing and co-ownership of assets with private parties might become difficult. We therefore expect that some (larger-scale) community projects will not take the legal status of an energy community, and that the energy communities will be more appealing in those situations where CEs are primarily established in order to make a community independent from established suppliers and traditional utilities, and create local bottom-up participation in energy markets. It is also important to point out that that the efficiency gains from these types of organisations could arise from the avoidance of transaction costs associated with participating in organised markets rather than from a reduced use of resources.

[59] Lemon et al. (2015) discuss these issues in the context of local Government policies aimed at generating energy savings and carbon reductions. They identify significant financial and co-ordination constraints as limiting factors in the pursuit of energy policy objectives which make it more difficult to achieve financial and environmental gains compared to the opportunities to create social value. The authors state that these barriers are likely to apply more broadly to local energy initiatives emerging in response to national energy and environmental policies.

Member states might decide to allow communities to act as a DSO or to purchase/lease assets from existing DSOs. In our case studies we did not encounter this kind of independent operation, and this is somewhat unexplored territory. In principle such a Community Network should satisfy equivalent requirements as any network operator: maintain reliability and quality standards, not favour its own members (with respect to network access and tariffs), charge according to its costs, and might have obligation to connect households to its network. Such a Community Network will also have to coordinate its network investments with neighbouring DSO/TSOs, to avoid network duplication.

Setting up the appropriate governance structure (association, company) and regulatory framework for a Community Network is not straightforward. A light-handed regulation for small-scale initiatives, with clear minimal standards, could be allowed in a transitionary phase. If in that case an established DSO provides a fallback option, then the DSO should receive a compensation for the insurance it provides.

04

TSOs AND DSOs AS BUYERS

4. TSOs and DSOs as buyers

4.1. Coordination between DSOs and TSOs

The uptake of DER and the unlock of their capabilities for providing flexible resources is disrupting the conventional way how distribution and transmission networks operate and the way how customers interact with their respective utilities (AEMO, 2019a).

On the one hand, the unlock of DER capabilities introduces more options for system operators to balance the system (to match demand and supply) and to procure ancillary services (market and non-market ancillary services)[60] and congestion management services,[61] to reduce the need for network investment and to integrated higher levels of renewable generation (especially solar PV and wind). However, the integration of more DER within the grid also creates more challenges to the operation of the networks (e.g. increase in thermal and voltage limits). EVs will also increase the demand for electricity, however the potential that this increase may have on the power system (assuming full penetration of EVs) varies across countries.[62]

On the other hand, customers have the chance to play a more active role by adjusting their consumption/generation in response to price signals, then lower household electricity bills are expected. Aggregators, suppliers and other parties such as local energy communities are also increasing the participation of active customers in the provision of flexible services (i.e. demand response) offered locally or to the grid (wholesale market). Innovation is also helping to the development and deployment of technology that facilitates DER integration (IRENA, 2019).

Then in order to facilitate the integration of DER and to reduce the impact that this can have on both networks (distribution and transmission), distribution utilities and TSOs need to enhance their roles or to adopt new ones (i.e. system operation in the case of distribution utilities) and to improve key capabilities (i.e. DER forecasting) in order to manage and dispatch DER efficiently. For instance, in California DER forecasting for distribution planning is mandated since 2017.[63] Different disaggregation methods (for DER forecasting at distribution level) are being explored. These methods vary depending on the type of technology (e.g. PV generation, electric vehicles, energy storage, etc.), its maturity and available data (SCE, 2018).[64] In the UK DER forecasting for distribution planning has not been implemented yet.

The next section explores the responsibilities of the DSO and the TSO in procuring ancillary services from DER and proving DER market access (to for instance the wholesale market). Should DSO and TSO share responsibilities, or should they be allocated to one of the parties? Do we need

[60] Despite the expansion of DER, their participation in the wholesale market is still very limited and mainly concentrated on the provision of demand response. Different countries and jurisdictions such as the UK, New York and California are testing (via pilots) DER capabilities to be used in the wholesale market. However, many of them operate under regulatory sandboxes. Some examples of these initiatives are Power Potential in the UK that allows the participation of DER in the provision of reactive power support to the system operator (Anaya and Pollitt, 2018) and the case studies from California such as DRAM and DER discussed in section 3.
[61] Congestion management can take different forms. It may happen when there is not enough transmission capacity to transmit generation due to (1) a rare generation or consumption situation or to (2) the inability to reinforce the grid infrastructure on time. This can be mitigated by asking market parties to place location-specific flexibility bids (TenneT, 2018).
[62] For instance, among eight selected European countries, Italy would be the most affected with a share of current total consumption of 48% and Norway the less affected with around 8% only, but considering the share of current household consumption instead it would be 208% and 25% respectively (CERRE, 2019b, p. 11).
[63] See: https://drpwg.org/wp-content/uploads/2017/04/Ruling022717.pdf
[64] California is one of the leaders in the USA in introducing DER for distribution planning. Other states are also following its steps such as Nevada and Minnesota.

instead a third party providing an independent platform to facilitate coordination? We will answer those questions by looking at some current proposals for organising markets.[65]

4.2. Looking at different proposals for DSO-TSO interactions for DER integration

This section discusses different approaches that are currently being evaluated at country level (Australia, the UK) and supported by the energy network associations in each country. The other case is a state-level initiative from New York, that is among the pioneers in proposing a new role for the distribution utility to integrate and trade DER using a distributed system platform (DSP). The last case discusses briefly a recent study for the European transmission and DSOs' associations regarding the market arrangements (between DSOs and TSOs) for congestion management and balancing services.

Australia and three different frameworks for DER dispatch

Australia is among the world leaders in decentralised generation. According to ENA (2018), in the next few years, Australia will be the country with the highest rate of decentralised generation, followed by Germany. Then it is imperative to create an appropriate framework to facilitate its integration and maximise the benefits. The Energy Networks Australia's Electricity Network Roadmap 2017 has estimated important savings from an early transition that favours DER integration. For instance, by 2050 ENA-CSIRO (2017) foresees that there will be a reduction in system spend (AU$101b),[66] household electricity bill savings (AU$414 pa.),[67] reduction of network charges (by 30%, 2016 basis),[68] among others. In the current economic dispatch situation, traditional market customers (transmission connected load/retailers, generating units above 30 MW) operate directly in the market. Small generators may participate but on a non-schedule basis[69] and those below 5 MW cannot participate in the market unless they affiliate with a retailer or become one. In the ancillary services market, those services can be offered directly by generating units (excluding small generator aggregator) and by loads (transmission connected, retailers, aggregator DR provider). On the other hand, network support can be agreed between DER aggregator/retailer and the utility, then a bespoke agreement is applicable in this case (AEMO-ENA, 2018a). In light of these facts and in order to find better ways to integrate DER into Australia electricity grid, Energy Networks Australia and the Australian Energy Market Operator (AEMO) launched the Open Energy Networks project in 2018. The project proposes among other things, three options for the future interaction between the Distribution Network Service Provider (DNSP) and AEMO. In all the cases, the aggregator/retailer allocates dispatch among DER providers and financial settlements remain between AEMO and the retailer. A fourth option has been recently proposed (hybrid approach) as an outcome of the continuous consultation workshops. This option emerges as a result of different concerns that the three options may have in terms of complexity of the model (option 3), conflict of interest with the two roles of the distribution utility (option 2) and

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[65] In the different approaches to be discussed, ESO/TSO may refer to AEMO, NGESO or NYISO.
[66] This figure is estimated by comparing the counterfactual and The Roadmap scenario regarding electricity system total expenditure by 2050, estimated in AU$988b and AU$888b respectively. These refer to cumulative figures (in real terms). Total expenditure comprises costs regarding centralised generation, connected on-site generation, distribution, transmission and off grid.
[67] A similar approach is used for household electricity bill savings (comparison of both scenarios) with two sources of savings: (1) a reduction of the need for expenditure on network capacity replacement or expansion and (2) a more efficient utilisation of capacity.
[68] Due to the possibility to buy grid services from DER customers, it is possible to avoid the need of AU$16.2b in network investment by 2050, reducing average network bills by 30%.
[69] According to AEMO this has been the case considering that the aggregate size of DER is still small, but a central dispatch process would be needed if the aggregate size increases importantly, as predicted.

the management of the market and system (both at transmission and distribution) by one single entity (option 1). The final recommendation will take into account the results of a cost benefit analysis on each of the four models, among others. A brief explanation of the four options is provided below.

Option 1 (Single integrated platform)

AEMO, the Australian Energy Market Operator, is responsible for operating and managing the central market platform and for balancing the whole electricity transmission system. Under this approach aggregators/retailers/VPP platforms[70] interact with the central platform and send their bids to it. AEMO optimises the dispatch of DER in NEMDE[71] taking into consideration transmission network constraints and distribution/local network constraints (information provided by the DNSP to the central market operator). Depending on the evaluation, AEMO may proceed to economically dispatch DER along with other resources such as transmission connected load, large scale generation, etc. This approach represents an extension of AEMO's role in the wholesale market and envisages a "one-stop shop" with a single entry to the markets.

Option 2 (Two step tiered regulated platform)

In this case, there is a distribution level platform operated by the distribution network service provider (DNSP).[72] The DNSP is then responsible for the optimisation of DER dispatch. The DNSP evaluates the bids received from aggregators/retailers considering distribution network constraints. Information about aggregated bids at each transmission connection points is sent to AEMO which includes the aggregated bids in the NEMDE dispatch optimisation. After determining the dispatch targets, AEMO gives this information to the DNSP who then proceeds with the disaggregation of the dispatch targets to each aggregator considering their respective bids. This would require an expansion of the DNSP roles and new capabilities/resources. In addition, a change in the way in which DNSPs are funded would be required.

Option 3 (Independent DSO)

In this case, an independent DSO (iDSO) is proposed. The iDSO is in charge of optimising DER dispatch considering the DNSP technical limits. A single iDSO would be needed for each distribution network. Under this approach, the iDSO receives the bids from the aggregator/retail and optimises DER dispatch considering distribution constraints, then provides the aggregated bids to AEMO. AEMO proceeds with the NEMDE dispatch optimisation. Finally, the iDSO is the one that allocates DER dispatch among aggregators according to bids. This is the option that provides the greatest level of decentralisation, with less conflict of interest and at the same time the one with the most complex solution with multiple interfaces between iDSO and DNSP (to inform about distribution network constraints, real time network status, operational forecast), and between iDSO and AEMO (to inform about co-optimisation and aggregated bids, schedules) (AEMO-ENA, 2018b).

Option 4 (Hybrid platform) – New Proposal

A single central market platform, operated by AEMO, is proposed under this approach. In this case AEMO not only organises and operates the central market but also optimises all DER bids,

[70] Aggregators are not allowed to participate directly in the market. They need to be affiliated with a retailer or to become one.
[71] NEMDE (National Electricity Market Dispatch Engine) is the software developed and used by AEMO to maximise value of trade subject to different constraints. However, under specific circumstances (that results in NEMDE fail to solve), a constraint relaxation procedure (set by AEMO) can be applied. For further details, see: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Dispatch-information
[72] This refers to the electricity distribution utility.

managing and communicating distribution network constraints (two-sided market platform). For this purpose, a distribution services market (DSM) platform is required and operated by AEMO too, instead of the DNSP. The distribution utility (or DNSP) provides operating envelopes[73] to assist in market bid development. Operating envelopes are expected to be static at the beginning but will become dynamic (estimated in shorter timescales) when DER visibility improves (AEMO, 2019b).

The UK and five future DSOs[74] worlds

The participation of DER in the wholesale/ancillary service markets is still limited in the United Kingdom and mainly concentrated on demand response services provided by industrial or commercial customers (residential participation is null), aggregated capacity or as individual units. At distribution level, we observe bespoke arrangements and those provided based on connection arrangements. Most recently a market-based approach has been proposed for allocating flexible capacity using an online platform Piclo (formerly known as Open Utility).[75]

The BEIS/Ofgem Smart Systems and Flexibility Plan launched in July 2017 aims to deliver a smarter and more flexible energy system that enables consumers to benefit from the use of energy at lower prices and to reward them for being flexible (by altering generation/consumption). Based on this initiative, a more active participation of DER in the provision of flexible services is expected. Benefits of the transition to a smart energy system in the UK are estimated to be in the region of up to £40bn by 2050.[76] The UK's Energy Networks Association (ENA) is working on the Open Networks Project which lays the foundation of the smart grid in the UK, in line with the Smart Systems and Flexibility Plan. The project involves the collaboration of different stakeholders such as Ofgem, BEIS, UK and Ireland's electricity network operators, among others. The ENA Open Networks Project explores the different architectures for integrating and managing smarter and decentralised energy systems. There are five workstreams associated with this project. Workstream 3[77] explores the DSO functionalities that allow the integration and use of DER services and that supports the optimisation of the investment and operation of the system. In July 2018, ENA released a consultation document and presented different approaches of 'Future Worlds' for the implementation of the enhanced DSO functions.[78] A short description of Future Worlds is presented below. In all cases, DSO and ESO are responsible for the strategic design of their respective networks. In addition, flexible services can be provided by three different parties: DER, customers (load) and local energy communities.

[73] "Operating envelopes indicate to customers the export and/or import limits that they must operate within for safe and secure running of the network" (AEMO 2019b, p. 26).
[74] In Great Britain, the traditional electricity distribution utility is called "Distribution Network Operator (DNO)". The switch from DNO to DSO implies new capabilities related to active management, better DER visibility and market operation, among others. In the rest of Europe, electricity distribution utilities are called DSOs.
[75] Piclo is a trading platform that helps network operators contract flexible services from different energy resources. Providers of flexible services need to register their assets on Piclo. Scottish and Southern Electricity Networks (SSEN) has become the first DNO in the UK to procure flexible services using this platform with a fully commercial contract (before, this contracted capacity from flexible services was allowed via trials only with two DNOs: UK Power Networks and SSEN). See: https://www.current-news.co.uk/news/piclo-pens-milestone-flex-agreement-with-ssen
[76] See:https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/568982/An_analysis_of_electricity_flexibility_for_Great_Britain.pdf
[77] The other workstreams are not fully independent of Workstream 3 but are related to it to some extent. These are Workstream 1 (T-D investment and planning), Workstream 2 (customer service), Workstream 4 (network access and charging arrangements) and Workstream 5 (communications with stakeholders).
[78] The Smart Grid Architecture Models (SGAMs) were used for the identification of specific roles of key parties within each Future World. See: http://www.energynetworks.org/assets/files/Modelling-DSO-Transition-Using-SGAM_Issue2.1_PublicDomain.pdf

World A: DSO coordinates

In this world, the DSO has a central role in the procurement and dispatch of DER and other customers connected to its network that offer their services for distribution network constraint management, for services required by the ESO[79] (regional, national) and for those required by neighbouring DSOs. Pre-defined power exchange schedules for power flow, which reduces the level of transmission constraints, are agreed between the DSO and ESO. Then, the DSO behaves as a non-commercial aggregator or as another transmission connected party that is able to offer services (from DER, customers, others) to the ESO under a non-discriminatory approach along with those services offered by transmission-connected services providers such as generators, loads and storage. The DSO needs to establish its own settlement system to confirm the delivery of the services provided.

World B: Coordinated DSO-ESO procurement and dispatch

In contrast with World A where there is only one entry to procure services from DER and other customers (via the DSO), here those services can be procured directly by the ESO as well as using a non-discriminatory approach. There is a central ancillary services market for flexibility resources that are connected to the transmission and distribution networks. The DSO and ESO would need to work together with a higher level of coordination (in line with the increase in the number of active DER) in order to ensure efficient procurement and optimal dispatch.

World C: Price-driven flexibility

This architecture introduces price flexibility arrangements, rather than just contracted flexibility arrangements like those in World B, that allow the parties to change demand or generation in response to energy prices and network signals. World C has been proposed considering Ofgem's reform of electricity network access and forward-looking charges.[80] The figure of a central market for the procurement of ancillary services applies here also, similar to World B (in both transmission and distribution) and also the need for coordination between both system operators to optimise procurement. However, considering that in this case the parties would respond to enhanced prices and network signals, less need for system operator intervention would be expected. World A, B, D and E could be adapted based on the price-driven flexibility principle from World C.

World D: ESO coordinate(s)

Similar to World A, with only one entry where the ESO has the central role and acts as the market facilitator for all DER.[81] The DSO communicates with the ESO about its requirements (for short and long term services). ESO presents to service providers both types of requirements to optimise overall procurement and dispatches both. The ESO is responsible for the settlement process too.

World E: Flexibility co-ordinator(s)

Information on service requirements from the DSO and ESO is provided to the Flexibility Coordinator which acts as the independent and neutral market facilitator. A common platform is used for this purpose. The Flexibility Coordinator can be represented by a national entity or by one or more regional entities.

[79] In this case, ESO refers to National Grid, the electricity system operator from Great Britain (NGESO).
[80] See: https://www.ofgem.gov.uk/electricity/transmission-networks/charging/reform-network-access-and-forward-looking-charges
[81] This could be limited to a minimum value (i.e. DER connected at HV rather than those connected at LV).

One of the actions associated with Workstream 3 was an independent Impact Assessment of the Future Worlds described above. Baringa Partners was appointed to deliver the Impact Assessment. In the identification of costs and benefits of each World, they took into account the way in which each of them can help avoid network investment, reduce the costs of balancing services and avoid the need for new generating units.[82] For the qualitative analysis they considered a set of 30 criteria identified by the ENA and stakeholders. Results from the Impact Assessment suggest that there is not a preferred Future World but there are pros and cons associated to each one, especially in terms of complexity of operation, cost and time of implementation. The study also suggests that the Future Worlds are even more viable when combining World C within each of the others (A, B, D and E). The study shows that by 2030, Worlds A and B perform relatively better than the others. However, by 2040 and 2050, due to greater and available gross benefits (more mature Worlds), the performance of the Future Worlds is similar (Baringa, 2019).

It is important to note that the proposal of the five worlds is dependent on the initial structure of the UK industry (i.e. with DNOs/DSOs and one ISO). For instance, in the case of Malta there is no TSO and there is one DSO (Enemalta), in Ireland and Northern Ireland transmission and distribution activities are bundled (ESB and NIA respectively), while in Greece there is a single DSO (Hedno).

New York: the implementation of Distributed System Platforms (DSP)

Reforming the Energy Vision (REV) is the key energy strategy for New York launched in 2014 by the New York Department of Public Service Commission (NY DPS, 2014). REV envisions a customer-oriented regulatory reform, where utilities will have the capability to actively manage and coordinate different distributed resources, to achieving the Commission's policy objectives. REV mandates the distribution utilities to act as an interface among individual customers and among customers and the bulk power system. Distribution utilities are required to act as Distributed System Platform Provider (DSPPs) for trading distributed resources.[83] The DSPP therefore represents the aggregator of aggregators. The six larger investor-owned utilities (IOUs) from New York are required to implement the DSP within their networks and act as DSPPs.[84] REV discusses how important it is to have some degree of harmonisation in products and services across the DSPP. Demonstration projects are currently being implemented by the IOUs in order to trial new business models (new revenue stream opportunities), new technologies and approaches to assess value. The projects are continuously assessed by each utility.[85] For further details about REV and detailed functions of the DSPP see Pollitt and Anaya (2016).

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[82] Benefits were identified considering two of the National Grid's Future Energy Scenarios (FES): Community Renewables and Two Degrees. In terms of costs, the study includes in the analysis technology costs, interface costs, resource costs and business charge costs, among others (Baringa, 2019).

[83] The transition to a DSPP is via incremental steps with a clear set of long-term goals and objectives. Under the DSPP model, additional services can be traded such as value-added services offered by the distribution utility and other providers (NY DSP, 2014).

[84] The Commission has identified five DSPP roles: (1) *Planning functions* - DSPP responsible for planning and designing the distribution system considering the integration of DER as a primary means of meeting system needs; (2) *Market functions* – DSPP able to understand the net benefits of DER in order to enable effective investment decisions, to craft the main products and services in order to capture the monetizable values in the market, and to provide pricing structures for DER products and services (i.e. market-based, tariff-based, or contractual); (3) *Energy efficiency*: DSSP to integrate energy efficiency in system planning optimising the economic value of energy efficiency expenditures for all customers; (4) *Advanced distribution management systems*: DSPP able to forecasting load and dispatching resources, and balance supply and load both in real time; and (5) *Communications infrastructure*: DSPP to develop communications networks capable of supporting smart grids (NY DSP, 2014).

[85] The list of pilot projects can be found at:
http://www3.dps.ny.gov/W/PSCWeb.nsf/All/B2D9D834B0D307C685257F3F006FF1D9?OpenDocument

Even though the Commission states that the DSPP role rests better in the distribution utility, there are some critics to this approach. The Commission states that an independent party would be redundant, inefficient and unnecessarily costly because many of the DSP core functions would be integrated with utility planning and system operation (NY DSP, 2015, p. 45).

One of the main criticisms is related to the conflicts between DER providers and the distribution utility, considering that the latter has total control over access and use. Many of the distribution utilities that operate in the USA also own generating units, which may jeopardise the effectiveness of the competition process. Then an Independent Distribution System Operator (IDSO) would be recommended instead, allowing third parties to fairly and fully participate as providers in a competitive distribution energy market (Wellinghoff et al., 2014). However in the case of New York, some limitations of DER ownership by IOUs have already been set. Among the circumstances for the consideration of utility ownership are (NY DSP, 2015, p.70): *"(1) procurement of DER has been solicited to meet a system need, and a utility has demonstrated that competitive alternatives proposed by non-utility parties are clearly inadequate, or more costly than a traditional utility infrastructure alternative; (2) a project consists of energy storage integrated into distribution system architecture; (3) a project will enable low or moderate income residential customers to benefit from DER, where markets are not likely to satisfy the need; and (4) a project is being sponsored for demonstration purposes"*. It is important to mention that in the case of energy storage, the Commission supports their implementation and operation on the utility's system but makes clear that utility ownership at the customer location should not be necessary (NY DSP, 2015, p. 69). Other jurisdictions in the USA are less strict in terms of DER ownership. In California for example, the Commission allows utility storage of up to 50% of the total amount of energy storage to be procured by the IOUs, across the three domains (transmission, distribution and customer side of the meter). The energy storage target is 1,325 MW by 2020 with installations required no later than 2024 (CPUC, 2013).

The European DSOs and TSOs associations: DSO-TSO coordination in congestion management and balancing

The report performed by the European DSOs and TSOs associations (ENTSO-*E* - E.DSO, 2019) evaluates the interaction between both system operators for congestion management[86] in distribution and transmission and system balancing[87] considering a market-based approach.[88] The report focuses on flexible services provided by third parties only, at all voltage levels.[89] The report suggests that the long-term view of system operators is to use a market-based approach for allocating flexible services, instead of compulsory limitation procedures. In contrast with the cases discussed above (Australia, the UK, New York), this one considers the interactions between TSOs and DSOs for the provision of two types of services such as congestion management services and balancing services. Three different options are evaluated:[90]

[86] Congestion management relates to physical congestion with a focus on active power. Among other types of congestions are market and structural congestion. For further details, see Commission Regulation (EU) 2015/1222 at https://publications.europa.eu/en/publication-detail/-/publication/b91aa370-3293-11e5-9f85-01aa75ed71a1/language-en
[87] Reactive power management (non-frequency ancillary services) has not been analysed in the report.
[88] Among the other solutions are: technical, tariff, connection agreement and ruled-based solutions.
[89] The study identifies a toolbox that comprises different types of solutions, however only the market-based approach is evaluated.
[90] In our report, the discussion of the different options is focused on the level of interaction between the TSO and the DSO.

Option 1: Separated TSO and DSO congestion management

The DSO congestion management market is separated from the TSO congestion management market. However, the TSO may have a separated market for balancing, or a joint one (balancing plus congestion management). Then, two single entries are observed for congestion management. Separated governance is observed in this approach too (no agreement needed between the two operators) however coordination between the TSO and DSO is more difficult (interaction between two Merit order list(s) –MOLs-[91] is required) in order to avoid discrepancies (i.e. double activation of the same asset).

Option 2: Combined TSO and DSO congestion management, with separated balancing

A common process for congestion management is created considering the TSOs' and DSOs' needs. Market parties are exposed to one single entry for congestion management services and one for balancing. The TSO and DSO need to coordinate and to agree, among others, the product specifications suitable for both system operators' needs, then coordination between TSO and DSO looks more efficient than in Option 1.

Option 3: combined balancing and congestion management for all system operators together

Here there is a single entry for both markets, congestion management services and balancing (integrated market-based process) where all the bids are combined. In comparison with the other two options, this is the one with more complex implementation (overall optimisation and bid selection system) and more complex settlement rules to be agreed between system operators and market parties.

Other key recommendations are related to the type of product to ensure that they comply with system operators' needs; are well-defined and come with some level of harmonisation to facilitate the exchange between markets) and platform options (easy access, good interoperability, avoidance of interference and conflicts, technology and hardware agnostic). The report also suggests the creation of a common flexibility resources register for data information exchange,[92] which contains information about the flexibility services provided to system operators, and is visible across all them.

4.3. Discussion and lessons learned

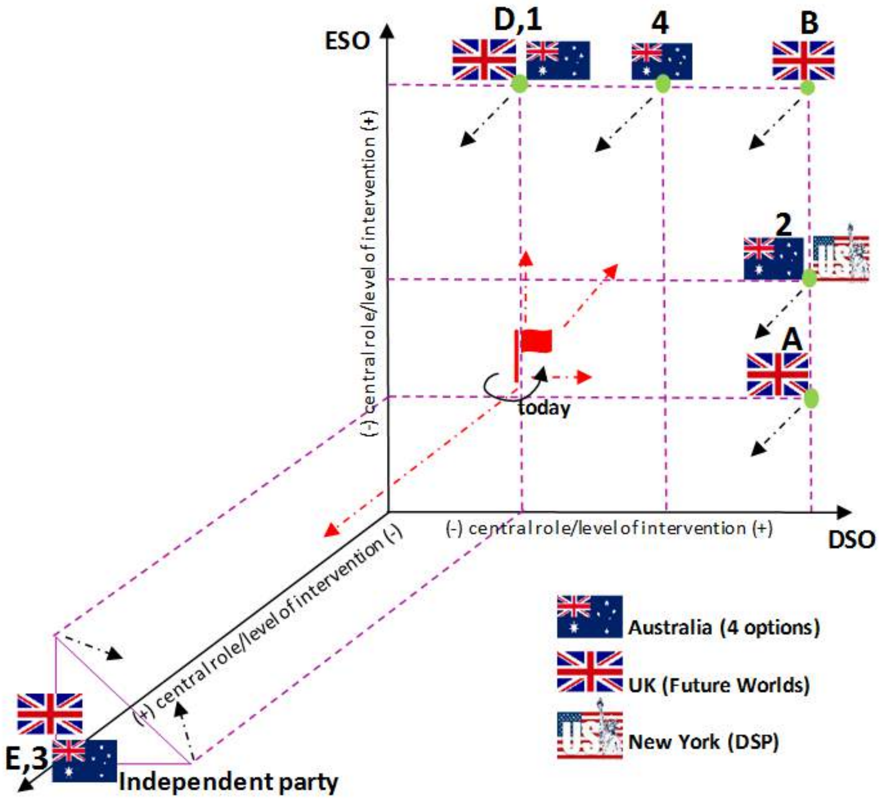
This section discusses the different proposals for DSO-TSO interactions that allow the trade of flexible services provided by DER under different regulatory and market contexts, in the UK, Australia, New York and Europe. The one from Europe (proposed by the distribution and transmission system operators' associations) is the only one that evaluates the interaction considering the type of product to be offered (congestion management and balancing services). We observe that in general, the proposals have some similarities. Fig. 6 summarises them.[93] The red flag depicts the current situation, with very low participation of flexible services (from DER) in both transmission and distribution. The red arrows indicate the potential directions of DSO-TSO future interactions.

[91] A MOL is "*a list of electricity bids sorted in order of their bid prices, used for the activation of those bids*" (ENTSO-*E* - E.DSO, 2019, p. 44).

[92] System operators would be responsible to check the connection data provided by the units connected to their networks.

[93] We only include those from Australia, the UK and New York. World C from the UK was not considered in the analysis because it refers to price flexibility arrangements that can be incorporated in the rest of the worlds.

Figure 6: Summary of DSO-TSO coordination/interaction initiatives (Australia, the UK and New York)



For example, two of the initiatives propose the creation of an independent party (iDSO in Australia – Option 3, Flexibility Coordinator in the UK – World E). In comparison with the other options/Worlds, this is the less biased and the most decentralised, but also the most complex and costly, with potential duplicability of capabilities (the independent entity would need to perform balancing/constraint management activities, that are among the main functions of system operators such as AEMO and NGESO). At the same time, this will also require high levels of coordination between the independent party and each of the system operators. The other common option is when AEMO/NGESO has the main role in procuring flexible services. This is represented by point D, 1. In this case, coordination with the DSO is still needed (to inform its requirements). There is one single entry to interact. In this case AEMO/NGESO is seen as an unbiased entity too, with the expertise in procuring different services. However, this option can be costly due to the complex interfaces that are required to coordinate the status of the network (i.e. network constraints) with the DSO. A similar approach is observed in Option 4, with a single market platform managed by AEMO (via a two-sided market platform). However, in this scenario, DSOs have to inform about the operating envelopes for DER (static first and then dynamic), then a larger level of intervention by the DSOs may be expected.

The other option refers to World A when the DSO has the main role in the procurement and dispatching of flexible services, but coordination with NGESO is still required to correctly manage distribution and transmission constraints. In World B we observe that both system operators are responsible for procuring and dispatching flexible services. In this case a high level of coordination is expected between both. An intermediate approach is observed in Option 2 from Australia and the case of New York (DSP). In this case, the DSO will still be responsible for the procurement and dispatch of flexible services from DER and also needs to coordinate with AEMO. In the case of New York, the distribution utility acts as the interface between DER and also between retail DER and the system operator (NYISO).[94] However, it is expected that the high level of intervention of DSOs or ESOs depicted in Fig. 6, decreases over time (black arrows) due to the use of more sophisticated techniques such as artificial intelligence and, machine learning, that can improve demand forecasting. According to Kufeoglu et al. (2019), artificial intelligence, machine learning and deep learning are tools that help to monitor, forecast and schedule energy generation and consumption.

We observe that in all the cases an expansion of the DSOs roles and capabilities and coordination with the ESO is required. Policymakers have not yet identified their preferred option, except for the case of New York where the DSO became the DSPP and was mandated by the New York Commission. The DSPP also acts as a *Market Maker* for distributed energy resources and interfaces with the TSO. The applicability of one case or another would depend on each jurisdiction (country, state), its regulatory environment, market structure and needs. The idea of performing a cost benefit analysis, such as the one performed by Baringa in the UK, may help to identify the relative costs of selecting either option. However, key differences such as the number and size of the DSOs should be taken into account, especially in Europe. In countries such as Germany around 878 DSOs operate, however the majority of them (797) have less than 100,000 customers.[95]

The application of a common framework for all the DSOs (i.e. World B) regardless of their size may not be the most appropriate option (initially), considering that many of the DSOs are very small and do not have the capability to respond efficiently in the procurement of flexible services. For small DSOs the option of having an independent party (that manages a group of small DSOs that operate within the same region) is a possibility. The other aspect is related to unbundling rules. DSOs with fewer than 100,000 customers are not subject to unbundling rules, so conflicts of interest may occur[96] if the DSO has the central role in the procurement and dispatch of flexible services from DER. However, some exceptions may apply if we talk about energy storage in Europe and in some jurisdictions from the USA such as those already discussed for New York. For further details about unbundling rules in the European context see section 5.2.

[94] An important observation is that the dual participation of DER in both the wholesale and distribution market simultaneously is not currently allowed under the current NYISO wholesale market rules. The Commission is working on the new rules that allow these resources the flexibility to meet both the wholesale and distribution needs maximising benefits to consumers (NYISO, 2019, p. 18).

[95] https://www.bundesnetzagentur.de/SharedDocs/Downloads/EN/Areas/ElectricityGas/CollectionCompanySpecificData/Monitoring/MonitoringReport2017.pdf?__blob=publicationFile&v=2

[96] Conflict of interest may exist if DSOs also operate generating units (similar to the electricity distribution utilities in the USA). However, DSOs with bundled activities (i.e. D+R) would not be a problem.

05

NETWORK REGULATION

5. Network Regulation

In this section we study how network regulation, and in particular that relating to distribution networks, might affect the development of the internet of energy. We highlight two topics: (1) the network services tariff, and (2) the regulation of network operators.

5.1. Network tariff

Network operators are regulated monopolies that recoup their costs by charging network users a set of tariffs for their network services. In the past, tariffs for residential customers consisted mainly of a flat energy charge proportional to the volume taken from the network (€/KWh) and a small connection charge (€/connection). The European Commission (2015) indicates that the energy component is above 69% of the final network bill.[97] It is broadly recognised, in policy and academic circles alike, that the current tariff structure may not be optimal in a future smart energy system and that tariffs should become more directly linked to costs. One suggestion is that the size of the energy volume component might need to be reduced and that the capacity component (€/KW) should become more important. CEER (2017) reports:

> *Both the European literature review and the answers to the EC public consultation on Energy Market Design (question 15) indicate a general support for a move towards capacity based charging, with the option of a hybrid of capacity and consumption based charging to incentivise a change in consumer behaviour.*[98]

But also more advanced tariff structures become feasible in a smart electricity network: tariffs can become time and location dependent and can change in response to local network congestion.

In the next subsection we highlight some of the trade-offs in setting tariffs and derive some recommendations.

Tariff principles

The determination of network tariffs typically involves a trade-off between objectives. Tariffs should among other things:[99]

- Lead to economic efficiency: Prosumers have the right incentives to invest in and operate distributed energy resources. Hence efficiency includes both static and dynamic efficiency.
- Satisfy the budget constraints of the network operator and provide a stable income for the network operator.
- Be equitable and fair. This could mean that the largest shoulders bare the largest costs, that network users do not receive undue cross-subsidies, that the risks and benefits are well shared between network operator and network users, or that consumers in similar situations are treated similarly.
- Be practically and politically implementable and not too complicated to administer.

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[97] European Commission. (2015). *Study on tariff design for distribution systems*. https://ec.europa.eu/energy/sites/ener/files/documents/20150313%20Tariff%20report%20fina_revREF-E.PDF
[98] See for instance also European Commission (2015), and Eurelectric (2016).
[99] Longer lists with more subtle variations of different criteria can be made, but this list represents some of the main trade-offs. See also European Commission (2015), section 3, Bonbright (1961) and Pollitt (2018).

Those objectives are often conflicting. For instance, economic efficiency requires that network services are priced at marginal costs. However, network operators are natural monopolies: the average cost of providing network services decreases with the amount of energy distributed. Hence under marginal cost pricing the network operator will incur losses. This violates the second condition of satisfying the budget constraint.

Marginal cost pricing in its most drastic implementation implies different prices for each location and time period and prices that vary according to the level of local congestion. This requires real time meters to be present, which is not yet the case in all Member States and might therefore not be practically implementable. It may also lead to different prices for households that are connected to different feeder lines, even if they are located in the same city. This could be seen as unequal treatment, and therefore unfair. Different fairness criteria may conflict as well. Protecting vulnerable consumers might require cross-subsidies between consumer groups, which leads to inefficient pricing.[100]

Current tariff becomes unsustainable

The rationale for the historical tariff system, where tariffs are mainly based on the volume of energy consumption, was that it provided a good balance between fairness, efficiency and feasibility. Efficiency requires that prices correspond to the marginal cost of energy services. Lacking smart meters, short run marginal costs were hard to obtain, so long term marginal costs were used. Those long term marginal costs depend on the additional investment required to cope with growing *peak demand*. Hence, ideally a household should pay a tariff that corresponds to its contribution to peak demand. Its contribution is determined by its consumption level at times when aggregate network flows are highest. A capacity tariff (€/kW) would achieve this goal. As load profiles for residential consumers used to be very similar, charging consumers based on electricity volume was a very good proxy for the peak capacity requested by each consumer. Pricing at marginal costs would break the budget constraint of the network operator, and some remaining unrecovered costs, would still need to be paid for by consumers. This was done by increasing the tariff above the long term marginal cost. By setting a mark-up on consumption volumes, richer consumers with larger consumption would pay a greater share of the unrecovered costs, hence the broadest shoulders would carry the largest load. Given that consumption was very inelastic, efficiency losses associated with setting this mark-up were small, and were not considered.

Under this traditional pricing scheme, production by small DER would often be accounted for as "negative load". That means that it would be subtracted from total consumption. Lowering the net electricity consumption would lower the retail and distribution bill of households with distributed energy resources. Under this system, households receive an implicit compensation for decentralised production that is equal to the sum of their energy retail price and distribution tariff. This principle, sometimes also called "net metering", is relatively simple to administer and provides additional incentives for self-production, which was seen as a bonus.

A tariff system based on energy volume is, however, not future proof. With the internet of energy, those tariffs need to be adjusted, for several reasons.

Demand profiles of consumers are no longer similar with the introduction of new technologies such as electric vehicles, local battery storage and heat pumps, see Simshauser (2014), Kufeoglu and

[100] Pollitt (2018) looks at four different pricing principles (cost reflective pricing, traditional public service pricing, platform market pricing and customer focused business model pricing) and highlights how they all reflect different objectives and trade-offs.

Pollitt (2019). The total energy consumption is therefore no longer a good measure for network costs that consumers impose on the network. This will typically lead to inefficiencies and could lead to cross-subsidisation, which are especially harmful if they occur from poor to rich households.

In a case study for the Australian market, NERA (2014) compares the marginal network cost caused by households with air-conditioning to the network tariffs they pay. They show that the marginal costs are 2.4 times higher. The reason is that air conditioning has a direct impact on the system's capacity needs because its use is contemporaneous with aggregate peak demand. This implies that consumers with air-conditioning pay less than their marginal cost, and that they are cross-subsidised by consumers without it. Hence, the tariff is inefficient and places a burden on consumers that are likely to be poorer.

A similar argument exist against distributed generation in combination with net-metering (Brown and Sappington, 2017). Net metering assumes implicitly that the avoided network costs for distributed generation are equal to the marginal network cost for additional consumption. This is often not the case. Distributed generation may reduce energy losses in the network, but it requires additional investment in smart systems to facilitate integration. Moreover, network capacity might not be reduced one for one, as peak demand still needs to be met by the grid at times with little decentralised production. Hence net-metering is inefficient. It also implies a cross-subsidy of households with distributed energy sources by those without them. The latter are often vulnerable households without sufficient finances to invest in decentralised generation, or without property to build upon. A combination of net metering along with a high penetration of distributed generation may lead to a volatile income stream for the network operator, as its income would depend on the number of sunny days.

The supply and demand of distributed energy sources is expected to become more elastic, both in the short run (operational decisions) and in the long run (investments in new equipment). Given the higher elasticity, setting tariffs above or below marginal costs reduces efficiency to a larger degree, as demand and supply quantities react more to tariff changes. Hence it becomes more important to set prices closer to marginal costs and carefully establish how the non-covered costs should be collected.[101]

Smart meters and smart grids allow for a richer tariff structure than was possible in the past, and have lowered the cost of more innovative tariff designs. Direct information provision to customers and the automation of operational decision in expert systems (e.g. smart thermostats) make these richer tariff structure more palpable for end-users.

Required changes in tariffs structure

Given the higher demand and supply elasticities, grid tariffs need to become more closely aligned to the marginal network cost to improve efficiency. A first improvement, already possible without a smart meter, is to increase capacity tariff (€/kW) while reducing the volume tariff (€/kWh). This is beneficial, as marginal costs are more closely determined by capacity needs and less so by energy volume.

Given that the network is a natural monopoly, setting tariffs equal to marginal cost will not cover the full cost of the network operator. Mark-ups will have to be set-upon the part of demand that is the least elastic. This is likely to involve connection charges (€/connection point) or additional capacity charges (€/kW). In 2005, the Netherlands switched to a system where all grid costs are

[101] Brown and Faruqui (2014) discuss the different options for cost recovery in more detail.

covered by connection charges for small households. Those connection charges do not depend on actual consumption or production and therefore do not influence production or consumption decision of prosumers.[102]

Net-metering is gradually being phased out in Europe, with separate tariffs being recommended for consumption and generation. In their white paper on regulation, ACER and CEER (2017), state:

> *"[…] European Energy Regulators recommend that, in Article 15 of the Electricity Directive, the reference to, "cost reflective, transparent and non-discriminatory network charges, accounting separately for the electricity fed into the grid and the electricity consumed from the grid" for prosumers be further developed to exclude the possibility of net metering."*

Having separate consumption and generation tariffs provides the network operator also with more regulatory instruments to cover its network costs, which is more efficient (Brown and Sappington, 2017).

The availability of smart meters allows to set tariffs on the basis of *short run* marginal costs. This will be effective in alleviating congestion by reducing or time-shifting demand and or supply. This could be achieved by Locational Marginal Prices (LMP) at the distribution level.[103] Along the same dimension also Time-of-Use tariffs, where the transmission tariff depends on pre-determined time slots,[104] or critical peak tariffs, where the tariffs are higher during a small number of hours, indicated by the network operator, could be used.[105]

As an alternative to dynamic network tariffs, a DSO could also rely on ancillary service markets for flexibility in that it procures local flexibility services from distributed energy resources, either directly or through aggregators. The good functioning of those flexibility markets requires clear baseline consumption and production levels. Those baselines are ideally based on network quantities that are contracted between network users and the network operator and will therefore require a network tariff which specifies a demand (or supply) profile with penalties for deviations from this profile. Alternatively baseline levels are based on some averaged consumer profiles, but this is likely to lead to some form of gaming.

Abolishing net-metering and shifting to capacity tariffs will reduce cross-subsidisation from poor customers to rich consumers with air-conditioning and PV installation and improve the fairness of the tariff structure. However, some tariff changes might harm vulnerable consumers as well. They may for instance not be able to invest in equipment that supplies flexibility and end up paying more than other consumers. Moreover, a fixed connection charge (€/connection) will, in relative terms, be more costly for small consumers. For a more in depth discussion on fairness in distribution networks see Lu and Waddams Price (2018).

In the long run, when the costs of storage and local generation are expected to drop further, then local energy communities might decide to partially or fully disconnect from the distribution network

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[102] Schittekatte et al. (2018) model the consumer decisions in response to different tariff structures and show that a capacity charge (which does not differentiate between consumption and production) might lead to overinvestment in storage facilities by households.

[103] Locational Marginal Prices are typically used at the transmission level, but not at the distribution level. Technological progress might make this feasible at distribution level. See Schweppe et al. (1988) and Hsu (1997).

[104] In Spain, consumers can opt for Time-of-Use tariffs for their network uses. Preliminary evidence by Fabra et al. (2019) suggests that Spanish households adjust their consumption to those Time-of-Use prices.

[105] Borenstein (2005) shows significant long-run efficiency gains of real-time pricing compared to a flat price. He also indicates that Time-of-Use pricing can only capture a small fraction of those gains, as prices correlate poorly with the periods with critical peak demand, whereas Critical Peak Pricing captures a significantly larger share of those gains.

and operate on a stand-alone basis. The cost of the distribution network will then have to be covered by the remaining network users who will see their energy bills increase as a result. This could lead to a "death spiral" where more customers leave the distribution network (unlikely in northern Europe), network assets become stranded, the distribution network becomes obsolete and goes bankrupt, and only small island grids remain. This is not necessarily efficient: as consumers base their connection decisions upon a tariff that includes a compensation for stranded assets, which are no longer economically viable, then they disconnect from the network too often.

5.2. Setting the correct incentives for distribution operators

The integration of DER and the digitalisation of smart networks poses challenges for the DSO. These new challenges are likely to require a new *regulatory framework*, but could also imply that the market structure and allocation of responsibilities has to change. The next subsections list a number of challenges and possible remedies.

Challenges

Capital vs. operational costs – Distribution system operators face a trade-off between further expanding their network to deal with larger and more volatile demand, or to use their existing network more efficiently and actively manage the flows on the network, for instance by procuring storage or flexibility form network users.

New tasks require new skills – At the distribution level many new tasks and goals have to be achieved. Distributed Energy Resources must be integrated, localised congestion needs to be managed, ancillary services have to be procured and new market players (e.g. energy communities, aggregators) need to be accommodated. Secure data infrastructure and communication platforms need to put in place. Those tasks may go beyond the skills of a small independent DSO, and it seems likely that large economies of scale will need to be exploited in order to operate efficiently.

Preventing cross-subsidies – A regulated DSO that is vertically integrated with a retailer may be able to cross-subsidise its retail arm. This could lower the capital costs of this retailer and distort competition. If the future cost structure become more complex, it might become harder to allocate costs to specific functions and prevent cross-subsidisation.[106]

Prevent discrimination – The future DSOs will have to procure ancillary services from market participants. Hence, the DSO will become an active market participant on the energy market. In order to guarantee a level playing field for all market participants, a vertically integrated DSO should not favour its own affiliate over its competitors.

Innovation – The internet of energy is still in its infancy. Technology standards and interoperability requirements are still being developed, the market design has not yet crystallised and regulation (both national and EU-wide) is being developed as we go along. Distribution companies are intermediaries between many players, the enablers of the energy transition. For them to play this role, they need to have the freedom and incentives to innovate and take risks.

Limited empirical evidence – Worldwide there are no good large scale examples on how the electricity sector should be organised (structure, regulation, technology) in order to integrate DER efficiently and equitably. The new European market design and regulation in this area remains untested.

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[106] Willems and Ehlers (2008) discuss when cross-subsidies can be considered anti-competitive.

Possible remedies

No EU harmonisation, but encourage learning – We do not see a clear rationale for harmonising regulation Europe-wide yet. Instead it is important that we learn from experimenting with different forms of regulation in Member States. Hence there is a value in variety. However, we might want to harmonise reporting requirements to improve mutual learning. Also, with respect DSO tariffs, we do not favour harmonisation; as the marginal costs for distribution networks differ across countries and different preferences exist across countries with respect to fairness.

Regulation open to innovation – Member States should be encouraged to provide temporary deviations from existing regulation for small scale experiments (regulatory sandboxes). To promote innovation subsidies may be required, especially if there are regulatory spill-overs between DSOs, as we would expect too little investment in innovation otherwise.

Regulation and market structure are interwoven – The regulatory framework will ideally depend on the market structure that is chosen (see section 4.2 for examples of market structures). Below we highlight three possible options.

Option a: High powered incentive regulation of a large unbundled DSO

One option to deal with some of the challenges above is to give a DSO a lot of flexibility but provide it with strong incentive regulation. An example of such regulation could be a price cap with a quality bonus and an efficiency improvement component.[107] Under incentive regulation the NRA will not approve each individual decision by the DSO but will set monetary incentives. [108]

Once the DSO has the right incentives, it could determine for instance its own tariff structure and procure ancillary services under long term contracts. In order for DSOs to make the trade-off between capital costs (new network capacity) and operational costs (procuring flexibility) the DSO could be regulated on the basis of total expenditures (TOTEX).[109] DSOs will have to cooperate with TSOs in minimising production costs. This requires an incentive scheme where the profit of the DSO depends on the performance of the TSO (and vice-versa).[110]

This type of high-powered incentive regulation might not work whenever the DSO is part of a vertically integrated utility.[111] This could be due to the fact that the DSO's profit will only be small fraction of the integrated utility, and the regulatory incentives may in some cases conflict with the overall incentives of the company. Furthermore, as the DSO makes a lot of discretionary decisions under high-powered incentive regulation, it could discriminate against its competitors.[112]

Ownership unbundling of the DSO will imply that the new DSO loses some know-how which was available in the vertically integrated firm. A small (ownership) unbundled DSO might therefore not be up to the tasks, and several smaller DSOs may have to merge. Unbundling will therefore drastically change market structures and its implementation is likely to take considerable time.[113]

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[107] Price cap regulation has been used in the UK and the Netherlands, under an RPI-X regime.
[108] Armstrong and Sappington (206) section 3.1 highlights the benefits of flexibility in regulation in combination with incentive regulation.
[109] For instance, in the Netherlands DSOs are benchmarked against each other on the basis of TOTEX. By benchmarking companies, the regulator creates virtual competition between the regulated companies.
[110] This type of regulation depends on the theory of incentives in teams (Groves, 1973).
[111] Léautier and Thelen (2009) provide empirical evidence that a combination of incentive regulation and unbundling is required to improve investment decisions. See also Kim et al. (2017) for a discussion of a potential contractual framework that allows DSOs to have the primary economic responsibility for system balancing.
[112] The Netherlands requires full ownership unbundling of DSOs. Most member states require legal or functional unbundling, CEER (2018).
[113] In the Netherlands, the unbundling of DSOs took more than 10 years.

Some member states have introduced ownership unbundling requirements, while these are not being considered by others.

Option b: Bring some market activities of the DSO to the TSO level

An alternative option is to shift some tasks currently performed at the distribution level to the TSO. The TSO could for instance manage local congestion on the distribution network and procure local ancillary services.

The advantages of this set-up is that synergies between the DSO and TSO level can easily be achieved, and that the know-how on setting-up and managing markets is already present at the TSO level. One of the disadvantages is that if distribution assets are still owned by the DSO then the coordination of local investment decisions and operational decisions becomes harder.

Option c: Comprehensive regulation of vertically integrated network operators[114]

In some Member States, DSOs are part of vertically integrated utilities. Vertical integration could help coordination between the different levels of the value chain, especially distribution and retail. For instance, the retail arm of an integrated utility could co-own storage facilities and share some of the risk with DER. Such an integrated utility is also likely to have sufficient economics of scale (and scope) and know-how to set-up local markets.

The downside is that vertical integration could generate concerns about the potential limitations to effective competition, as discussed in section 3.1. NRAs control will therefore have to be more comprehensive and leave less flexibility to the DSOs than under incentive regulation (Option a). The procurement of local ancillary services will have to follow strict rules, guaranteeing a level playing field. Softer unbundling requirements (such management unbundling, information sharing requirements, technical protocols) may also need to be strengthened to make this option workable.

[114] Brunekreeft (2015) discusses the economic trade-offs of unbundling. Unbundling improves competition between market actors but might reduce coordination between retailer/generator and network operator.

06

CONCLUSIONS AND RECOMMENDATIONS

6. Conclusions and recommendations

Demand for electricity has historically been predictable and price inelastic in the short run. However, the deployment of decentralised and weather-dependent generation pushes for a new paradigm where demand adjusts to intermittent supply. This paradigm reduces the pivotal role played by centralised generation and TSOs in the energy systems, requires a smarter and more flexible system (both technically and economically) and introduces new commercial and regulatory challenges. This report investigates these challenges and identifies possible solutions by reviewing the evidence from the literature and recent case studies.

Regulations and Directives have played and continue to play an important role in the evolution of the European internal energy market. The "Clean Energy for all Europeans package" is the fourth set of rules established in order to promote the establishment and strengthening of the internal market and addresses the challenges of the energy transition. The Clean Energy Package brings forth an updated market design for electricity markets and proposes new principles regarding dynamic pricing, market access for demand response, the role of aggregators and energy communities and the regulation of TSOs and DSOs. The package has established a general framework, but it leaves practical implementation to Member States.

Below we summarise some of the key findings and our main recommendations.

Opportunities for smart consumers

Demand side management and micro-generation have allowed consumers to participate more actively in the market. Indeed, the development of distributed generation, which enables consumers to become *prosumers* by selling their surplus electricity to the grid, is becoming important. There may be direct financial incentives for households/industrial consumers to be flexible, and they can participate directly in the energy market or through aggregators. Recently, we have witnessed the development of energy communities. Energy communities represent an interesting organisation as, beyond financial viability, they also value the creation of social capital and can generate wider benefits to participants, however they continue to face challenges in terms of financial viability, related, at least in part, to their inability to achieve an efficient scale. However, the associated regulatory framework is relatively vague. More guidelines to define and monitor energy communities should be in place. There is a need for specifying their role, rights and responsibilities to their members and the wider energy system.

(New) drivers for electricity consumption

It is well-known that energy consumers respond not only to price signals. Results from the liberalisation of the retail market offer various insights (rather than a clear and unique trend) into the behaviour of customers in power markets. For example, the different degrees of elasticity across consumers, the switching costs or the available information could all explain some customer inertia. More recently, customers' preference for green energy has impacted the electricity market, where buyers may be willing to pay higher prices for electricity produced by renewable generation. There are also financial schemes being developed to incentivise prosumers to offer flexibility to the grid, in order to adjust to the higher supply volatility which arises from the increased reliance on intermittent generation. Finally, higher rates of electric vehicles penetration will increase electricity consumption. Smart charging can help with this by allowing a better distribution of charging over time, then reducing the use of the grid during peak hours.

Key facts about new business models' viability

Projects and demonstration activities relying on innovative use of technology have been developed to promote consumer engagement and the provision of flexibility services. However different levels of success have been observed. While the emergence of aggregators as new market players can facilitate and promote the supply of flexibility services, it can also generate inefficiencies in the system. To correct for these inefficiencies, some form of compensation would be required that correctly accounts for the opportunity costs and lost revenues incurred by retailers. The evidence provided in this report regarding the emergence of trading platforms as systems that can facilitate an efficient use for DER does not clarify whether sufficient financial benefits will be available to consumers in order to motivate their engagement with a potentially complex system. Furthermore, despite the high expectations about wide-ranging opportunities offered by blockchain as a decentralised payment system and several emerging examples of blockchain based applications, doubts remain about its wider applicability in the energy system. As a result of our review of new business models, we have been able to identify some potential enablers for their financial viability such as technological options, favourable tariff schemes and environmental concerns. However, the lack of sufficiently-detailed data, the small size and voluntary nature of the projects and the different tariff structures applied in different countries make it difficult to assess whether the projects can be successfully scaled up to support the emergence of broader smart system. Since many of these projects are financed with public funds, we would recommend the development of guidelines for reporting on the results of the projects, possibly similar to the reporting rules introduced by the US Department of Energy for publicly funded projects, so that lessons can be learned from existing projects for future developments.[115]

Allocating responsibilities between DSO-TSO

Our analysis of the different approaches from Australia, the UK, New York and Europe (DSOs and TSOs associations) shows that most jurisdictions have not yet identified their preferred organisational set-up, including *inter alia* whether a central coordinator is necessary and whether this should be the DSO, TSO or a third party. The applicability of one case or another will depend on each jurisdiction's existing regulatory environment, market structure and needs. A cost benefit analysis may help to identify the relative costs of different options, but many benefits and costs are hard to quantify. Key differences, such as the number, size and independence of the DSOs, should be taken into account in such a study as they differ significantly across Member States.

Overhaul of tariff system

With the internet of energy, traditional network tariffs need to be adjusted and become more cost reflective. Demand profiles of consumers are no longer similar across different consumers as a result of the introduction of new technologies, such as electric vehicles, local battery storage and heat pumps. The total energy consumption is therefore no longer a good measure for network costs imposed by consumers on the network. Incorrect tariffs will hamper the efficient development of a smart energy system. Given the higher demand and supply elasticities, grid tariffs need to become more closely aligned to network costs that consumers impose on the network.

In a first instance we propose a change a tariff structure where the capacity component increases to the detriment of the volume component and accelerating the abolishment of net-metering. Having separate consumption and generation tariffs also provides the network operator with additional regulatory instruments to cover its network costs. The introduction of smart meters

[115] See for instance Cappers et al. (2013) for guidelines within the Smartgrid.gov program: https://www.smartgrid.gov/recovery_act/overview/consumer_behavior_studies.html

provides opportunities to further enhance network tariffs: a time-of-use tariff or tariffs where local congestion is reflected in the network tariff on an hour-by-hour basis. Aligning tariffs with network costs will alleviate some of the existing concerns about fairness and equity, where rich suburban homeowners with rooftop PV are 'subsidised' by other network user, but other concerns persist regarding access to smart technology for low income consumers.

Smart DSO regulation

The larger role of DSO in the future energy system will require more comprehensive regulation. Given the speed of the developments, incentive regulation where the regulator steers on outcomes and leaves flexibility to the DSO may be more appropriate than command and control regulation. In order for DSOs to make the trade-off between capital costs (new network capacity) and operational costs (procuring flexibility) the DSO may need to be regulated on the basis of total expenditures (TOTEX). DSOs will also have to cooperate with TSOs. This requires incentive schemes where the incentives for the DSO will depend on the performance of the TSO and vice-versa. DSOs should be granted sufficient freedom and incentives to experiment and innovate (i.e. regulatory sandboxes). DSO also play an important role in supporting innovation by market participants. Transparency and long-term predictability on the rewards for local ancillary services and accommodating market access by different market actors will be key.

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Appendix 1: Key features of case studies and projects

Features of Case studies				
	Brooklyn Microgrid	**De Ceuvel Microgrid**	**Hackney Bannister House/Verv**	**Project SCENE Trent Basin**
Location	California (USA)	Amsterdam (NL)	London (UK)	Nottingham (UK)
Assets	5 prosumers (and 5 consumers) in 2016, expanding to 60 solar sites in 2019	150 solar panels, offices (letting spaces), Jouliette platform	102kWp solar array, 40 Verv Home Hubs, communal batteries	2.1MWh communal battery, urban solar farm, GSHP, 500 low-carbon homes
Services	'Tokenisation' of capacity, flexibility, frequency regulation, P2P energy trading	'Tokenisation' of P2P energy trading, purchase of local goods/services	P2P energy trading	Frequency response, load shifting, triad avoidance
Partnership /Ownership	ConsenSys, LO3, TransActive	Alliander, Spectral	Centrica, Repowering London, Verv	A.T. Kearney, Blueprint, Loughborough University, Nottingham University, Siemens, Solar Ready, Smartklub, Urbed
Financing		Start-up grant (€250,000), bank loan (€200,000)	149,000 community shares, £1.9m Centrica, £100k (Ofgem Regulatory Sandbox), £1.87m (Crowdfunding, Crowdcube)	£10m community energy project (funded predominantly by Innovate UK), £100m housing development

Features of other projects					
	Feldheim Community	**Grid+**	**Isle of Eigg**	**Isle of Gigha**	**TenneT**
Location	Feldheim (Germany)	Texas (USA)	Eigg (UK)	Gigha (UK)	Germany and Netherlands
Assets	10 MWh battery, 74.1MW wind turbines, DH network, Biomass Plant	Total assets worth $27.7m.	184kW renewable fleet (hydroelectric, wind turbines, solar array), 70kW backup generators, cluster of 48V lead acid battery	1.68MWh Vanadium redox flow battery, four 1MW wind turbines,	150+ Tesla EVs, 100+ domestic batteries, TenneT platform
Services	Frequency response, grid congestion and curtailment management		Backup supply, local energy supply, smart metering	Arbitrage, backup supply, local energy supply, flexibility, frequency response, network capacity, STOR, voltage control	Flexibility, frequency response, grid congestion and curtailment management
Partnership /Ownership	Community led, support from Brandenburg and European Development Fund	Automated settlements, P2P energy trading	Eigg Electric Ltd., local residents and Eigg Heritage Trust		IBM, Sonnen E-Services, Vandebron
Financing	€12.8m investment	36.4m Grid Tokens, 45,000 ether, 584 Bitcoin, $125,000	£1.66m (European Regional Development Fund), local financing		

Appendix 2: Glossary

AEMO Australian Energy Market Operator (Australia), manages the National Energy Market (NEM), facilitates retail contestability, and responsible for national transmission planning.

AI Artificial Intelligence

AMP Aggregator Management Portfolio (California)

BEIS Department for Business, Energy & Industrial Strategy (UK)

BMG Brooklyn Microgrid (USA)

CAD Consumer Access Device, a relatively simple internet bridge between a smart meter and a cloud platform.

CAISO California Independent System Operator (California)

CBA Cost Benefit Analysis

CE Community Energy

CEER Council of European Energy Regulators (Europe). Not-for-profit organisation in which Europe's national regulators of electricity and gas voluntarily cooperate to protect consumer' interests and to facilitate the creation of a single, competitive and sustainable internal market for gas and electricity in Europe

CEP Clean Energy Package (EU) Set of 8 directives and regulations

CPUC California Public Utilities Commission (California) Regulator

DNO Distribution Network Operator (UK), company owning and operating distribution network.

DNSP Distribution Network Service Provider (Australia), company owning and operating distribution network.

DR Demand Response

DRAM Demand Response Auction Mechanism (California)

DRP Demand Response Provider (California)

DSO Distribution System Operator (Network owner and System Operator)

DSP Distribution System Platform (New York)

DSPP Distributed System Platform Provider (New York)

E-DSO European Entity for DSOs (EU)

EEA European Environment Agency (EU)

ENA	Energy Networks Association (UK)
ENA	Energy Networks Australia (Australia)
ENA-CSIRO	Energy Networks Australia and Commonwealth Scientific and Industrial Research Organisation
ENTSO	European Network of Transmission Systems Operators
ENTSO-E	European Network of Transmission Systems Operators for Electricity
ERCOT	Electric Reliability Council of Texas
ESO	Electricity System Operator
EV	Electric Vehicles
FERC	Federal Energy Regulatory Commission (USA) Federal regulator
FES	Future Energy Scenarios of National Grid (UK)
FiT	Feed-in Tariff
HV	High Voltage, Typically the transmission network
ICT	Information and Communication Technology
iDSO	Independent Distribution System Operator
IOU	Investor owned utility (USA) (In contrast to Public Owned Utility)
IRENA	International Renewable Energy Agency
I-RES:	Intermittent Renewable Energy Sources
ISO	Independent System Operator (mainly US), Operates system, does not own network
ITO	Initial Token Offering
LV	Low Voltage, Typically the low voltage distribution network
MOL	Merit Order List. A list of electricity bids sorted in order of their bid prices, used for the activation of those bids”
NAO	North Atlantic Oscillation
NEMDE	National Electricity Market Dispatch Engine (Australia) Name of dispatching optimization program
NGESO	National Grid ESO (UK)
NY DPS	New York Department of Public Service Commission (New York) Regulator
NYISO	New York Independent System Operator (New York)

OFGEM	Office of Gas and Electricity Markets (UK) Regulator
P2P	Peer to Peer
PDR	Proxy Demand Resources (California)
PGE	Pacific Gas and Electricity, Utility
PV	Photovoltaic
RA	Resource adequacy (USA) Reliability standards
RDRR	Reliability Demand Response Resources (California)
RES	Renewable Energy Source
REV	Reforming the Energy Vision (New York)
RTO	Regional Transmission Operator (USA) Cooperation of several ISOs
SC	Scheduling Coordinator (California) (Similar to balancing responsible party in EU)
SCE	Southern California Edison, Utility
SDGE	San Diego Gas and Electricity, Utility
SGAM	Smart Grid Architecture Models (EU), A framework to describe the system architecture of smart grids. Developed by the Smart Grid Cooperation Group, consisting of CEN (European committee for standardization), CENELEC (European Committee for Electrotechnical Standardization) and ETSI (European Telecommunications Standards Institute).
SSEN	Scottish and Southern Electricity Networks (UK), Utility
ToU	Time of Use pricing
TSO	Transmission System Operator
VHH	Verv Home Hub: load monitoring device
VLUX	Public Token Exchange
VPP	Virtual Power Plants, aggregation of small distributed energy sources who jointly bid into the market as a virtual power plant.
VTP	Verv Trading Platform

Centre on Regulation in Europe

Avenue Louise, 475 (box 10)
1050 Brussels, Belgium

+32 2 230 83 60

info@cerre.eu

cerre.eu

@CERRE_ThinkTank