The Future of Energy Infrastructure

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Challenges and Opportunities Arising from the R-Evolution of the Energy Sector

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2.1 Introduction

Energy plays a fundamental role in our daily lives, being at the basis of all the economic activities. Transportation, communication, lighting, heating/cooling, conservation and distribution of food, hospital and industrial processes are all examples of activities that need energy (Smil 2017). Electricity, in particular, is fundamental in order to support economic and social progress and to build a better quality of life, especially in developing countries.[1]

Nowadays the energy sector is undergoing major transformations. The rapid deployment and falling costs of clean energy technologies, the growing share of electrification in consumption, climate change awareness and the action of policymakers to decarbonize the economic system: these are some of the trends that will be disrupting the fundamentals of the sector and the status quo of its players over the next few years.

We address this as a "r-evolution".

Indeed, on the one hand the above-mentioned transformations represent the evidence of a much-needed evolution towards a more sustainable, smarter and more flexible energy system. This evolution will take several years to complete as the bulk of our energy technologies are often either the result of long-term investments (e.g. natural gas networks) or represent the dominant solution in the industry (e.g. internal combustion engines). New cleaner technologies like wind, solar PV, biogas and electric vehicles have a long way to go before replacing existing technologies. In fact, according to the International Energy Agency (IEA),

[1] According to the International Energy Agency (IEA), over 120 million people worldwide gained access to electricity in 2017, reducing the total number of people without access to below 1 billion.

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in 2017 fossil fuels accounted for 81% of total energy demand, a level that has remained stable for more than three decades.

On the other hand, both the climate change agenda and technological progress have triggered a revolution on an unprecedented time scale for the entire energy industry, with radical implications for all the actors involved. As noted by Helm (2017), it is not just one specific technology; it is a revolution that touches each and every part of energy production and consumption. Developing an understanding of these changes is a fundamental task for all asset managers or financial players who aim to include energy infrastructures in their portfolios.

The purpose of this paper is to identify the key trends of the "r-evolution" which are occurring within the energy sector and to draw some potential conclusions for investors. We start our analysis with an overview of the global energy balance and its evolution over time, highlighting the relevant changes taking place in oil and natural gas markets, the growing electrification and the expansion of renewables. Then, we focus on the electricity industry, describing the key trends that are shaping its fundamentals, especially in Europe. We pay specific attention to electricity because of its greater role in all the decarbonisation scenarios. Moreover, the evolution of the electricity industry is having a great impact on the whole energy sector.

We also highlight the economics behind these changes, describing how they are affecting energy supply and existing infrastructures. In particular, we illustrate the impact of renewables (notably wind and solar) in the electricity generation mix and the challenges and opportunities brought about by their deployment (e.g. the reduced profitability of conventional power plants, like coal). This analysis aims at providing the reader with a broad picture of the main transformations occurring in the sector and the main challenges and opportunities to watch for in the next few years.

Subsequently, we investigate the revenue model and performance of the main European utilities, highlighting the differences between network-only companies (i.e. transmission system operators—TSOs) and other utilities (e.g. energy suppliers). This analysis aims at understanding whether utilities, gas and electricity TSOs represent a worth investment for infrastructure funds. Lastly, the final part of the paper is dedicated to draw some conclusions for financial investors and to provide some indications for their portfolio allocation strategy.

2.2 An Overview of the Global Energy Balance

In order to grasp some of the challenges surrounding the sector we first analyze the evolution of the energy mix over time.

Figures provided by the IEA (2018a) show that fossil fuels (coal, oil, gas) have played a dominant role in global energy systems, and continue to do so. When Arabic countries set up the first oil embargo in 1973, oil accounted for 47% of total primary energy consumption, gas for 16% and coal for 24%. In total, fossil fuels contributed 87% of global primary energy consumption. The oil embargo of 1973–74 caused price hikes, fuel shortages and induced governments to introduce public measures to conserve energy (so-called "Austerity"). All of this generated

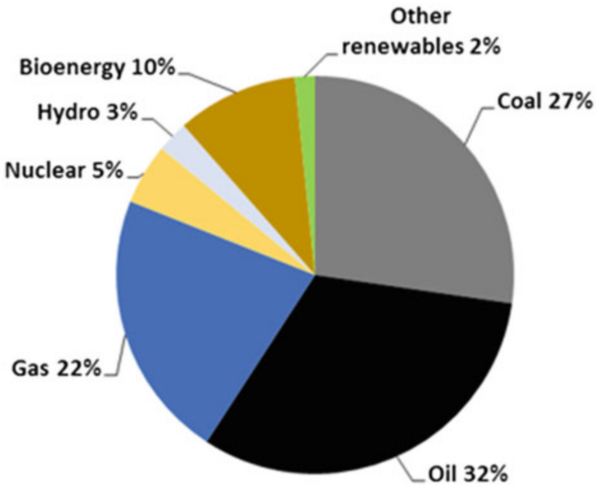


Fig. 2.1 Global primary energy consumption fuel mix in 2017 (Source: Authors' elaboration of data provided by IEA 2018)

public awareness of dependency on foreign energy resources and spurred the search for alternative sources of energy, especially in the US.

However, more than 40 years later, in 2017, the overall share of fossil fuels in global energy demand was still 81%. Furthermore, this share was calculated on higher demand (14,050 million tons of oil equivalent (MTOE) in 2017, compared to 5681 MTOE in 1973). This means that the consumption of hydrocarbons in absolute terms has significantly increased over the past decades (IEA 2018a). In other words, we can affirm that the entire energy sector currently depends on fossil fuels almost as much as it did in the past, as shown in Fig. 2.1.

Global energy demand is expected to continue growing over the next few years, making the displacement of fossil fuels in the energy mix a tough challenge. According to the last IEA's World Energy Outlook, energy demand will increase by 25%[2] from now to 2040, mainly driven by population growth, urbanization and economic growth in non-OECD countries, especially in Asia (Baccelli 2020). In this regard, for instance, global oil consumption has increased more than 5 million barrels per day (mb/d) since 2015, and it is expected to surpass the threshold of 100 mb/d by the end of 2018.

As a consequence, policy-makers now have a crucial role as they are called to harness the transition towards a sustainable energy system, favoring investments in cleaner, smarter and more efficient energy technologies. To date, after the Paris Agreement on climate change, 187 nations committed to limit global average temperature increases to 'well below' 2° above pre-industrial levels. In particular, each country submitted plans, the so-called 'nationally determined contributions'

[2]According to the IEA, energy demand growth would be twice as large in the absence of continued improvements in energy efficiency (IEA 2018).

(NDCs), setting targets for emissions reductions by 2030, relying primarily on increasing the share of renewable energy and of (near) zero-carbon sources (e.g. fossil fuels with carbon capture, utilization and storage).

However, some studies suggest that meeting the NDC emissions targets will not be enough to achieve the well-below 2 °C objective of COP21 (WEF 2017a). Thus we might expect a review of NDCs earlier than expected.

In general, it is necessary to achieve a large-scale shift in our global energy. To put the world on a well-below 2 °C pathway, it is necessary to completely decarbonize power generation and extend electrification to a wider set of activities. This in addition to more effective government policies and large-scale public and private investment. Achieving decarbonisation targets involves scaling up finance, most of all for long-term investment in infrastructure, low-carbon technologies and energy efficiency across all sectors and regions of the global economy (OECD 2017). In particular, according to IRENA (2018), in order meet the climate goals by 2050, a $120 trillion investment is required in all the sub-sectors of the energy system.

2.2.1 Oil

Predictions on oil prices and key fundamental shifts in the oil market have always had a very poor track record. Specifically, the idea of peak oil has been repeatedly reaffirmed throughout the 20th and 21st centuries and every time these predictions failed for several reasons, notably the discovery of new reserves and technological improvements (e.g. fracking).

In this section, we briefly discuss the major challenges that are having a relevant impact upon the sector.

In this regard, one massive technology advance, i.e. fracking, has recently transformed the fossil fuel industry, changed geopolitics, brought new companies into the market and significantly affected oil prices (Helm 2017). Due to the efficient exploitation of vast reserves of shale oil (and shale gas), in fact, the United States has become the world's largest producer of fossil fuels. What's more, this country is now on its way to achieving energy independence within the next few years. The IEA estimates that shale (or tight) oil production in the United States might double by 2025, providing around 75% of the global increase in oil production up until that year.

Shale production is a worldwide game changer and it is already altering the balance of power, especially in the Middle East. Here oil exporter countries, in particular Saudi Arabia, no longer have the ability to rebalance supply and demand. Hence, they are losing some of their political influence.

Another main challenge for the sector is rising awareness of climate change, which particularly among financial investors has created concerns regarding huge stranded assets in the industry (Caldecott 2018). As a result, the financial community is now putting more pressure on the top management of major oil and gas companies, demanding information disclosure and business model adaptation.

Finally, other factors are reshuffling the fundamentals of oil demand for transport, such as the diffusion of electric vehicles (EVs), the introduction of more restrictive fuel efficiency standards for cars and, as illustrated by Baccelli (2020), the use of alternative fuels (i.e. biofuels for road transport or liquefied natural gas—LNG and other fuels for maritime transport).

The actual impact of such changes on the oil industry is subject to a huge degree of uncertainty. However, according to recent IEA forecasts (2018a), oil demand is expected to peak only after 2040 in the absence of additional significant commitments to improve vehicle fuel efficiency and more prohibitive policy measures, especially those aimed at reducing plastic use.

According to the figures provided by IEA (2018), most oil is currently used for transportation, especially by road (i.e. cars, buses and trucks).

Looking at the future, over the next few decades, oil demand will be mostly driven by the petrochemical sector, whose consumption has nearly doubled since 2000. Specifically, this sector is estimated to grow by 5 mb/d despite efforts to encourage recycling (IEA 2018a).

Intuitively, emerging economies are driving demand of many products (e.g. personal care items, food preservatives, fertilisers, furnishings, paints and lubricants for vehicles) whose manufacture require chemicals derived from oil and natural gas. As a result, almost all new refining capacities under development today integrate some petrochemical processes (IEA 2018b). This appears to be part of a long-term strategy both to seek additional margins and to hedge against the perceived risk of a peak in global oil demand.

The use of oil for transport, instead, is expected to peak in the middle of the next decade (IEA 2018a). On the one hand, nearly 90% of the cars, trucks, motorbikes and buses on the road are currently fuelled by oil and the number of vehicles is estimated to grow, as populations in emerging countries become wealthier. On the other hand, oil demand growth in transport will be offset by the rapid electrification of the sector, the development of more fuel-efficient automobiles and the use of alternative fuels (i.e. biofuels and natural gas). In particular, the increasing fuel efficiency of the internal combustion engine will play a major role in containing oil demand growth in the next few decades (IEA 2018a).

New mobility services including leasing, sharing and hailing, as well as the application of new technologies such as platooning (i.e. the linking of two or more trucks in a convoy), automation and connected vehicles, will all likely have a major impact on mobility (IEA 2018a).

Overall, electrification and the digitalization of mobility services and the increase in vehicle and logistics efficiency might eliminate almost 15 mb/d of additional oil demand in 2040 (IEA 2018a).

However, as highlighted by the Carbon Tracker Initiative (CTI), all the predictions about oil demand might be mistaken as the penetration of electric vehicles in the market could be more rapid than most analysts are projecting. The future size of the EV fleet, which is the most significant variable determining the potential displacement of oil demand, is subject to many inter-relating economic, political and behavioral factors. Consequently, there is a wide range across energy industry projections for the growth of the EV fleet.

According to CTI forecasts (2018a), 2 million barrels per day of oil demand could be displaced by EVs in the 2020s, and this number could hit eight mb/d by 2030. This, in turn, may have a disruptive impact on the industry.

In addition to this, a critical issue in the oil industry is represented by the reduction in new upstream oil investments. Due to financial pressures, in fact, oil and gas companies have drastically reduced their exploration activities. In 2018 they represented "just 11% of global upstream spending, the lowest share ever" (IEA 2018b). As a result, there has already been a drop in new oil discoveries, which, in turn, may result in oil spikes, and increased volatility in the coming years, thus further incentivizing the shift from oil.

2.2.2 Natural Gas

Natural gas has been advocated as a potential "bridge fuel" during the transition to a decarbonized energy system, due to the lower carbon dioxide it emits during combustion compared to other fossil fuels (i.e. oil and coal) (Levi 2013). However, natural gas is facing intensified competition from renewables. Moreover, this industry is not exempt from major changes that are challenging the status quo of its players and the fundamentals of the market.

Shale gas deployment in the United States and the rise of liquefied natural gas (LNG) are the most relevant factors driving the transformation.

As already highlighted in Sect. 2.2.1, the United States has experienced significant increases of oil and natural gas production in recent years underpinned by new technological developments, such as hydraulic fracturing and horizontal drilling combined with advancements in seismic imaging and surveying technologies. In particular, the United States was able to unlock vast reserves of "tight" oil and gas found in geological formations "previously thought to be inaccessible and nonviable for conventional development and production" (Newell and Prest 2017).

As a result, shale gas production has increased exponentially over the past few years and the United States is now transitioning from the biggest world consumer and importer of oil and gas into an energy superpower. In fact, according to IEA (2018a), shale gas production, especially in the US, will rise by 770 billion cubic meters (bcm) from now until 2040.

The abundance of cheap gas on the market, made possible by such technological advances, has also prompted the economic viability of LNG trade. LNG trade has, in fact, significantly expanded in volume (i.e. 293.1 million tonnes in 2017) and has reached previously isolated markets. Moreover, higher volumes might be expected as additional liquefaction plants come online over the next few years (IGU 2018).

LNG demand is constantly on the rise, especially in Asia (notably China, South Korea and Japan). In particular, China is on track to become the world's largest gas-importing country, with total gas demand that is expected to triple to 710 bcm by 2040, mainly due to resolute policy efforts in supporting economic growth and improving air quality. In this regard, China is supporting a concerted coal-to-gas switch as part of the drive to “turn China’s skies blue again.”

With regard to the European Union, it is currently the world’s largest importer of natural gas, and continued declines in domestic production will turn into more imports, unless new targets for efficiency and renewables will be able to offset part of the demand. In particular, the combination of domestic resource depletion and the objective of further diversification away from traditional suppliers (i.e. Russia) creates new opportunities for LNG imports.

LNG over the past few years has risen at an annual rate higher than the growth of either global production for indigenous consumption or international pipeline exports. In 2016, in fact, LNG’s share of global gas trade was around 9.8%, while pipeline exports counted around 20.8%. LNG and pipelines are considered, to some extent, in competition and perhaps mutual exclusive. However, the presence of a pipeline network is crucial for inland transport of natural gas from the LNG terminal to the demand centers. In addition, many existing pipeline systems require the supply of LNG to face the natural decline of supply from nearby gas fields, or in order to increase the diversification of supply options (Schwimmbeck 2008).

The power sector is currently the largest consumer of gas. Prospects vary widely by region, but retirement of coal-fired capacity and strong demand for electricity create space for gas-fired power generation to expand in many developing economies in the coming years (IGU, Snam, and BCG 2018). Moreover, the resilience of gas in the power sector, especially in the EU, is primarily a result of the closure of 50% of coal-fired capacity by 2030, along with reductions in nuclear power (IEA 2018b).

However, as highlighted by the IEA (2018a), with renewables-based capacity set to almost double by 2040, the business case for building new gas-fired power plants is more and more challenging. As a result, the industry sector, notably the chemical industry, is expected to become the main source of growth in natural gas demand in the next few years.

At present gas is mainly used in energy-intensive industries that require high-temperature heat. According to IEA (2018a) gas demand will rise in light industries where policy impetus is gaining ground to curb emissions. Particularly, natural gas will be utilized more often not only as a source of energy for processes but also as feedstock for chemicals.

Finally, natural gas demand for transport is assumed to increase (i.e. nearly triple by 2040), a result of policy efforts to promote compressed natural gas (CNG) and LNG-fuelled vehicles, especially in China. LNG use in shipping is also expected to grow due to International Maritime Organization regulations to reduce the sulfur content in marine fuels, though its share in the overall fuel mix for shipping is modest (Baccelli 2020).

2.2.3 Renewables

Renewable technologies have grown notably over the past few years. In particular, according to UNEP and Bloomberg New Energy Finance (BNEF), from 2004 to 2017 the additional capacity increased at a rate of 9% and related investments at 14%.

In 2017 investments in renewable technology decreased to $333 billion. On the contrary, as highlighted by (UNEP-BNEF 2018), the total capacity installed in renewables and other low-carbon technologies in the same period increased. This trend is due to a drop in the cost of clean energy technologies; in fact, prices have fallen 83% since 2010. This will be further illustrated in Sect. 2.4.

As a result, in terms of annual capacity, renewable installations now contribute for most of total new capacity installed.

In terms of share of the global energy fuel mix, renewables now account for 10.4%, a figure which has nearly tripled since 1973. The largest consumption of renewable energy in absolute terms is for heating. In particular, bioenergy (mainly biomass) accounted for 10% of global heating consumption in 2017.

As a result, bioenergy is also the main renewable energy source globally (IEA 2018a).

The share of renewables in the transportation sector, which is less significant (i.e. 3.4%), is represented mainly by biofuels.[3]

However most of renewable energy expansion occurred in the electricity sector. Renewables,[4] in fact, have gained a relevant share in the power sector, accounting for almost 25%[5] of global electricity consumption in 2017, as illustrated in Fig. 2.2.

According to the IEA (2018a), the share of renewable technologies is expected to increase to almost 30% by 2023,[6] with hydropower accounting for 16% of global electricity demand, followed by wind (6%), solar PV (4%) and bioenergy (3%). In addition to that, Bloomberg New Energy Finance estimates that almost 50% of electricity will be generated by solar and wind by 2050.

In some countries renewables already in some instances account for 100% of electricity consumption, or even more. For example, energy from renewable sources made up 103.6% of Portugal's electricity consumption in March 2018, according to data from the country's power grid operator REN. Intuitively, excess electricity can represent an additional source of revenues when, like in this case, it can be exported to neighboring countries. Scotland reached record levels in 2017, with renewables contributing to 68.1% of its electricity. Denmark often produces around 100% of its

[3]Renewable electricity used for rail and road transport (i.e. electric vehicles) is growing, but is currently low compared to biofuels (IEA 2018a).

[4]Specifically, solar PV and wind are the technologies that saw the greatest growth over the past seven years (IRENA 2018).

[5]In Europe, renewables, including hydro, accounted for 30% of total electricity generation in 2017.

[6]The renewables' share of the electricity fuel mix is also estimated to grow to over 40% by 2040 (IEA 2018). In addition, renewable technologies, mostly solar PV and wind, will supply over 70% of global electricity generation growth in the period 2018–2023.

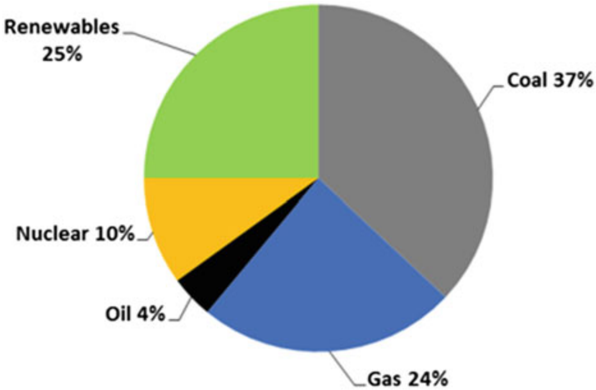


Fig. 2.2 Global electricity generation—fuel mix in 2017 (Source: Authors' elaboration of data provided by IEA 2018)

own needs from renewable sources if favorable weather conditions permit. Norway and Iceland do the same thanks to hydropower and geothermal heat.

In other words, we are definitely moving from an electricity system where most power is generated by fossil fuels to a system with two-thirds renewable energy by 2050, "ending the era of fossil fuel dominance in the power sector" (BNEF 2018a).

2.2.4 Electricity

Electricity is considered as the source 'of choice' to pursue decarbonization goals and combat climate change (Helm 2017). Over the past two decades, global electricity consumption has grown by 3% annually, more than any other source, and faster than the total final consumption. Electric power currently accounts for 19% of total final energy consumption, compared to just over 15% in 2000. What is more, power is expected to expand its share of final energy use at least to 24% by 2040 globally (IEA 2018a).

Demand for electricity continues to grow, especially in developing economies (notably China and India) even though nearly one billion people still have no access to electricity. The power sector now attracts more investments than oil and gas combined. Specifically, in 2017, power sector investments were $750 billion, higher than investments in oil and gas for the second consecutive year. Moreover, investments in electricity networks (i.e. transmission and distribution) rose to more than $300 billion (accounting for 40% of the power sector investment), its highest level in nearly a decade (IEA 2018b).

With specific regard to the electricity generation mix, the largest share of power is currently produced from coal but this situation is destined to change.

According to the IEA (2018a), global coal demand actually peaked in 2013/2014. Indeed, after the Paris Agreement on Climate Change, governments, utilities, industry and financial institutions committed to stop investing in coal (Capgemini 2017).

In Europe, for example, after the UK and France, also the Netherlands, Italy and Portugal announced coal phase-outs. At the time of writing, the debate in Germany, Europe's largest coal and lignite consumer, is still ongoing.

However, we are still far from achieving the total phase-out of coal at a worldwide level. Particularly, while the coal fleets in the USA and Europe are older (i.e. 42 years on average), and nearing the end of their life, Asia's coal plants are just 11 years old on average, "meaning that they still have decades left of operational life" (Hook et al. 2018). Asia, especially China, has 2000GW of new coal-fired power plants that are operating or under construction. This figure is more than 10 times the capacity of the EU. According to the IEA (2018a), these new plants will significantly hamper attempts to achieve emission reduction goals.

As already mentioned in Sect. 2.2.3, renewables have grown significantly in recent years. Hydropower is currently the main renewable energy source of the electricity mix. However, solar PV and wind are growing fast and will cover most of the generation growth of the coming years.

Electricity generated from nuclear, the second-largest source of low-carbon electricity after hydropower, has stagnated over the past two decades. Its share of generation has declined from 17% in 2000 to 10% in 2017 (IEA 2018a). In this regard, the nuclear fleet is ageing. There are currently 413 GW of nuclear capacity in operation worldwide and more than 60% of the fleet is over 30 years old[7] (IEA 2018a). In advanced economies, where most nuclear capacity is located, about two-thirds of the fleet is older than 30 today. In some countries, many projects have already received lifetime extensions on nuclear power plants. Other countries, like Hungary, Czech Republic and France are reviewing plans to prolong the lifetimes of the reactors.

Besides the need to extend the lifetime of most of the reactors, the nuclear industry is facing further challenges. In particular, following the 2011 accident at Fukushima in Japan, and relative safety issues, anti-nuclear public sentiment that now become the major concern for countries. As a direct result, Germany, Belgium and Chinese Taipei have decided to phase out nuclear power.

Furthermore, market dynamics are threatening the financial conditions of both existing reactors and prospective investments in new reactors. Low wholesale electricity prices, due to the increasing penetration of renewables and low gas prices, are making it difficult to justify the additional capital needed to maintain and refurbish reactors (notably in the United States and in the European Union).

These developments are straining nuclear plants that had previously been granted lifetime extensions. Several reactors in the United States announced that they will close prematurely as a result of prevailing financial conditions. According to IEA (2018a), without further lifetime extensions and new builds, the share of nuclear in generation capacity will drop substantially. For instance, in the United States, nuclear power would sink from 20% of electricity generation in 2017 to around

[7]The original reactor design lifetimes of most of these plants were between 30 and 40 years.

7% by 2040. In the European Union, although currently the largest source of generation, nuclear would plummet from 25% of generation today to 5% by 2040.

The source of power that could benefit more from the phase-out of coal and from the reduction of nuclear power, at least in the short term, is natural gas. In the UK, for instance, the share of gas in power generation increased from 29.5% in 2015 to 42.4% in 2016 prompted by its increasingly competitive prices and the closure or conversion of some coal-powered plants. Similarly, in Germany, new gas-fired power plants started to operate due to competitive prices and the progressive phase-out of nuclear plants (Capgemini 2017).

Today, cheap gas is also a threat to new nuclear power plants and less efficient, older plants. Recent advances in power plant technology and the currently low price of natural gas have led to increasing efficiency and cost reduction of new natural gas-fired turbines. New natural gas combined cycle power plants can be built for about one-sixth the cost of a new nuclear plant, and run with almost twice the efficiency. What's more, these new plants can be developed in smaller increments, making them easier to finance (Rhodes et al. 2017).

All of this has led to a significant rise in investments in new gas-fired capacity in recent years, especially in the United States. Utilities and independent power plant developers have announced plans to invest over $110 billion in new gas-fired power plants through 2025 (RMI 2018a).

However, natural gas-fired power plants are not the only resource options capable of replacing retiring capacity. Indeed, they are facing increasing competition from renewables, as we will discuss further in Sect. 2.4.

2.3 Key Trends in the Electricity Industry

Electricity systems used to be characterized by centralized control, large "conventional" generation plants and "passive" distribution grids with unidirectional energy flows to final consumers. In the last 15 years, technological innovations, environmental constraints and a changing economic and regulatory setting have resulted in a profound transformation in this structure. All this has significant impacts on the economic viability of current market designs and the business models of market players.

We are witnessing a paradigm shift in power systems. In fact, several sectors and applications are being powered more and more by electricity, switching away from fossil fuels. In addition, an increasing amount of energy is being generated locally and connected directly to distribution networks. Also, energy storage technologies, similarly to solar PV panels, are undergoing dramatic cost reductions. These factors are poised to revolutionize the nature of electricity dispatch and transport. The electricity generation mix is changing considerably in favor of renewables. For example, in the European Union 30% of electricity generation came from renewables, including hydro, in 2017 according to figures provided by Agora (2018). Consumer attitudes are evolving, becoming more active and interested in value-added services. New sectors (i.e. Oil and Gas, Automotive and ICT) are

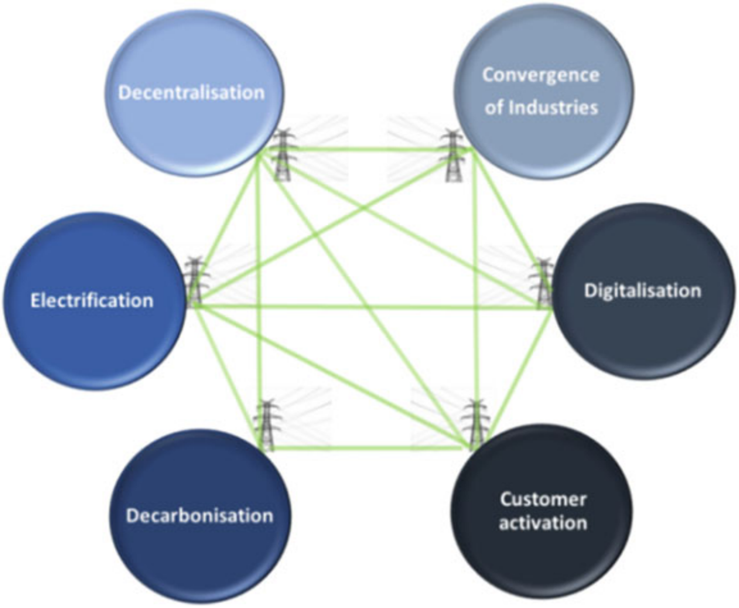


Fig. 2.3 Key trends shaping the electricity industry (Source: Authors)

converging into the electricity industry, creating new opportunities but also multiplying the number of actors and consequently competition (Venzin and Konert 2020).

We have identified six major trends which are reshuffling the industry. These trends are global and as such we provide examples from all over the world, even though our main focus is Europe. Figure 2.3 offers a graphic representation of these six trends, which are often highly interconnected.

We now describe each of them, highlighting how they are affecting the European electricity system (although they are applicable to the US system as well).

2.3.1 Decarbonization

The term "decarbonization" refers to the trend of reducing the presence of fossil fuel in the economy and in particular in the power sector. This trend, mainly driven by policy objectives, is confirmed by the evolution of the EU electricity generation mix. According to Agora (2018), the share of conventional fossil fuels (i.e. coal, lignite, natural gas and other fossil fuels) has decreased by 7.7% over the past 8 years, from 52.1% of 2010 to 44.4% in 2017. Specifically, those with the highest emissions (i.e. coal and lignite) accounted for 24.7% of the EU electricity output in 2017, decreasing from 29.2% in 2010.

Albeit the reduction has not been dramatic so far, the share of fossil fuels in the electricity mix is expected to continue decreasing, especially with regard to coal. This is a result of its phase-out, which has already been planned in some European countries, as illustrated in Sect. 2.2.4.

According to Capgemini (2017), in 2017 in Europe, decommissioned fossil fuel generation capacity was 2.2 GW for fuel oil, 2.2 GW for gas and 7.5 GW for coal.

Several factors prompted the beginning of the decarbonization process in Europe. For example: technological innovations and the reduction of the costs of low carbon technologies, which allowed the development of large renewable power plants and the diffusion of energy efficiency technologies, policy action, changes in consumer behavior.

In particular, policy makers had a fundamental role, introducing subsidies, feed-in tariffs, emissions and efficiency requirements, and incentivizing the diffusion of renewable energy and energy efficiency. Since 2007, the European Union has committed to reaching the so-called 20–20-20 targets. Specifically: (i) to reduce greenhouse gas emissions by 20% compared to 1990s levels, (ii) to achieve the 20% share of renewable energy over energy consumption, (iii) to make a 20% improvement in energy efficiency, when compared to the projected use of energy in 2020.

For the years after 2020, the EU has adopted the following objectives: by 2030: (i) a 40% cut in greenhouse gas emissions compared to 1990 levels, (ii) at least a 32% share of renewable in energy consumption, (iii) at least 32.5% energy savings compared with the business-as-usual scenario. In addition to that, the EU has set itself the long-term goal of reducing by 2050 greenhouse gas emissions by 80–95%, when compared to 1990 levels.

In order to achieve these goals, the EU is leveraging on a combination of different factors, such as: the electrification of sectors which traditionally rely on fossil fuels (i.e. transport and heating); the diffusion of renewable; improvements in energy efficiency, especially in buildings; and the use of alternative carbon-neutral fuels (hydrogen, biofuels, etc.).

In particular, the diffusion of renewables plays a crucial role for achieving the goals of the EU. Besides representing a source of economic growth and job opportunities for Europeans, in 2015 renewables contributed to gross avoided greenhouse gases (GHG) emissions the equivalent of the emissions of Italy (EC 2017).

As illustrated by Staffell et al. (2018), combined capacity of renewables has indeed overtaken total fossil fuel power capacity installed in the UK. In particular, renewables in the UK reached 41.9 GW in the third quarter of 2018. Meanwhile, available capacity from fossil fuels fell to 41.2 GW,[8] with around one-third of plants being retired over the last 5 years. Wind had the largest share of renewable capacity, around 20 GW, followed by solar with 13 GW.

[8]The amount of electricity generated from fossil fuels was still greater in the third quarter of 2018, generating around 40% of the UK's electricity, compared to 28% for renewable sources (Husseini 2018).

In terms of share in the European generation mix, in 2017 renewables accounted on average for 20.9% of the electricity consumption. The share of renewables (including hydro) increased to 30% of the total (Agora 2018).

According to Eurostat (2017), in tandem with supply-side policies, the EU has launched a number of initiatives which aim to increase the efficiency of energy use, reduce energy demand and attempt to decouple it from economic growth (i.e. a rise in the GDP). Several instruments and implementing measures are utilized in this field, including the promotion of co-generation, the energy performance of buildings (whether private or public buildings), district heating and cooling (which are expected to play an important role in some regions), and energy labelling for domestic appliances.

In particular, energy efficiency technologies are key players in favoring the decarbonization of the economy, increasing the EU's competitiveness and security of supply. Moreover, energy efficiency technologies are the cheapest way to reduce greenhouse gas emissions. According to WEF (2017a), in fact, avoiding a kilowatt-hour of demand is typically cheaper than supplying that demand by any other available resource. In addition, the IEA estimates that every dollar spent on energy efficiency eliminates the need for more than $2 in supply investments. As such, 90% of the Paris Agreement's NDCs rely on energy efficiency to deliver their commitments.

According to data provided by the European Environment Agency (EEA), between 1990 and 2014, final energy efficiency[9] rose by 28% in the EU-28 countries at an annual average rate of 1.4% per year, driven in particular by improvements in the industrial sector (+1.8% per year) and households (+1.7% per year). In 2015, the European Union energy demand entered into a positive trend and in 2017, energy demand in the EU rose by 1.5%, corresponding to stronger economic growth. However, the increase in energy demand was less pronounced than the rise of the GDP over the same period. As a result, energy efficiency continued to improve (IEA 2018a).

Despite the apparent success, energy efficiency improvements are challenged by long replacement cycles for appliances and equipment (nine or more years). In addition, these improvements are largely dependent on technological innovation and incentives (IEA 2018c). Energy efficiency is also complex to achieve because of cultural habits and due to the fact that decisions are often taken at a local level. Sometimes there is also a high number of parties involved with divergent interests (Capgemini 2017). Moreover, low energy prices penalize investments in energy efficiency related projects, reducing the attractiveness for investors.

Furthermore, the overall impact of energy efficiency on the future of electricity demand is complex because it reduces the cost of powering appliances. This may lead some consumers to buy larger appliances or run them for longer than they

[9]Energy efficiency is measured by energy intensity, the amount of energy used to produce a unit of output (i.e. primary energy demand per unit of global GDP).

otherwise would, hence consuming more electricity, a phenomenon known as the ‘rebound effect’ (Sorrell et al. 2009).

2.3.2 Electrification

The term “electrification” means the trend by which the consumption of energy is increasingly equating to consumption of electricity, as already highlighted in Sect. 2.2.4. At a European level, figures provided by Eurelectric (2018) show that direct electrification represented the 22% of final energy consumption in 2015, varying across different sectors and countries. This rate is expected to rise from at least 38% to 60% in 2050, based on different scenarios (Eurelectric 2018).

Such a process is strongly aligned with the European policy objectives in terms of decarbonization, by enabling a greater proportion of total energy demand to be met by electric power generation from low-carbon energy sources such as solar and wind (WEF 2017b). Indeed, in terms of power generation, the EU production mix is expected to change considerably in the coming years in favor of renewables. For example, according to Eurelectric (2018), removing the barriers to adopting electric technologies together would enable EU to cut emissions by 80–95% between now and 2050.

Among the four economic sectors of energy use: (i) residential, (ii) commercial, (iii) transportation, and (iv) industrial, the one with the highest rate of direct electrification is commercial. In fact, commercial buildings recorded a maximum level of 66% in the Iberian Peninsula (Eurelectric 2018). Nonetheless it is the transportation sector that is undergoing the most disruptive transformation.

The global electric car stock has been growing since 2010 and surpassed 3 million units in 2017, after crossing the 1 million threshold in 2015 and the 2 million threshold in 2016 (IEA 2018d). Particularly, electric cars sales in 2017 were over 1 million units worldwide. China is currently by far the largest electric car market, accounting for more than half of such vehicles sold in the world in 2017. In terms of market share, instead, Norway has achieved the most successful deployment of electric cars with a 39% market share. This result is mainly due to the introduction of government incentives which dramatically boosted the sales of EVs. Norway is followed by Iceland, with an 11.7% electric car market share, and Sweden with 6.3%.

In terms of the outlook for EVs, BNEF (2018b) estimates that 55% of new car sales worldwide will be EVs by 2040. By that date, with around 559 million cars on the road, EVs will represent 33% of the global car fleet. Instead, sales of ICE vehicles (i.e. with internal combustion engines) will slow. According to BNEF (2018b), the number of ICE vehicles sold per year (gasoline or diesel) is expected to start declining in the mid-2020s, as EVs gain shares in the market.

The electrification of transport is also fundamental in order to achieve the EU policy goals in terms of GHG emission reduction. According to data provided by the European Environment Agency, in 2015, the transport sector contributed 25.8% of total EU-28 greenhouse gas emissions. Passenger cars and light-duty vehicles account for the majority of the transport segment GHG emissions.

Switching away from fossil fuels in this sector is crucial for combating climate change worldwide. This is due to the fact that rising incomes in developing countries prompt individuals to seek access to personal mobility. As a result, we might expect that car ownership will significantly increase, augmenting the current fleet of 1.2 billion vehicles (Exxon Mobil 2017). In Sect. 2.2.1 we mentioned that new mobility services (e.g. car sharing) may partially offset this increase, but their overall effect is subject to a great deal of uncertainty.

However, the diffusion of EVs entails both challenges and opportunities. One of the main challenges brought about by the advent of this technology is that, as electric cars on the road continue to multiply, there will be a need for private and publicly accessible charging infrastructure. According to BNEF (2018b), the outlook for EV sales will be influenced by how quickly charging infrastructure will be developed.

According to the IEA (2018c), a relevant aspect related to EV charging stations is that, being integrated in the electricity system, they are subject to power sector regulation.

Depending on the specific regulatory approach of a given country, and whether legislation considers EV charging stations as a retailer or as a distributor of electricity (i.e. network company), the regulatory environment can facilitate or limit the possibilities for utilities to invest or own charging infrastructures. In Germany and the United Kingdom, for instance, network companies are not allowed to operate charging infrastructure (Hall and Lutsey 2017). The rationale is that utilities receive regulated revenues from network operations, and as such they can obtain a regulated revenue stream also from charging infrastructure. This gives these companies an unfair competitive advantage. Relaxing some of these restrictions can promote the expansion of charging infrastructure.

Another challenge related to the diffusion of EVs lies in the fact that higher shares of electric cars represent a potential source of stress for the grid since the capacity required at certain times and locations may have consequences for both adequacy and quality (e.g. if a significant number of EVs were being charged at the same time) (Boßmann and Staffell 2015). Hence, a greater understanding of EV charging patterns and technologies will thus be necessary to ensure their appropriate integration into the grid (especially distribution grid).

On the other hand, according to BNEF (2018b), the diffusion of EVs will contribute to the integration of renewables into the grid. Particularly, the electrification of transport (as well as air conditioning) will allow greater penetration of renewables, since their demand may fit well with the production profile of a solar plant.

Great opportunities also derive from the fact that EVs may draw electricity from the grid or emit stored electricity back into the grid to help balance resources (e.g. through vehicle-to-grid technologies (V2G)). In other words, electric vehicles represent a good example of a potential demand-side revolution (IEA 2018a). The extent of the interaction is technically almost unlimited but, as highlighted by several experts, it also depends greatly on economic evaluations, the efforts for improving customer participation and the supporting policies (Eurelectric 2018; Karlsruhe Institute for Technology 2013).

2.3.3 Decentralization

The term “decentralization” mainly refers to the rapid growth of distributed energy resources (DERs), energy supplies and power sources that tend to be smaller than the typical utility-scale sources. They are usually connected to the lower voltage levels (distribution grids) and close to final customers (demand centers). The importance of decentralization as a game changer is evident if we think about the fact that the expansion of DERs will force a shift away from the centralized, one-way electrical grid.

Traditionally, the electricity system has been characterized by large-scale centralized generation plants, which carried electricity to final customers through the grid. Power flows used to be unidirectional, from the high voltage transmission grid to the final customers connected to the grid. We are now witnessing a paradigm shift in power systems with an increasing amount of energy being generated locally and connected directly to distribution networks, from solar panels on people’s roofs to small power plants.

By combining small-scale solar, small-scale batteries and distribution-grid-level demand response, we can obtain a measure of the proliferation of decentralization in the future electricity system (BNEF 2018a). According to Bloomberg New Energy Finance forecasts regarding the decentralization of selected countries, Australia will have the highest rate, with as much as 45% of total capacity located behind the meter by 2040. Germany is the European country with the highest expected decentralization ratio of over 30%.

Decentralization as well as all the other trends represent both opportunities and challenges for the entire electricity system. On one hand, distributed energy resources (DERs) such as storage and advanced renewable technologies can help facilitate the transition to a smarter grid. Theoretically, the overall system could become more resilient and enable small and large power consumers alike to produce most of the electricity they need locally. All of this may also make it possible to defer capital investments to maintain and upgrade grids (WEF 2017b).

On the other hand, the transition makes the real-time balancing of the power system more difficult (ENTSO-E 2019). This in turn means that guaranteeing the security and the quality of supply is more complicated, a task carried out by the transmission system operator (TSO).

The massive deployment of renewables which are connected at distribution level would be beyond the direct control of the TSO. The result would be more uncertainty and volatility, with higher risks of sunk investments over time and potential problems of cost recovery via the tariff system.

For instance, solar PV and wind output is reducing the demand on the transmission system in the UK and due to very high distribution connected generation, the UK system operator National Grid saw day-time minimum demand falling lower than the overnight minimum. This happened on two occasions, on the eighth and ninth April 2017, but this kind of phenomena are likely to reoccur if there are high PV days with wind and high temperatures (National Grid 2018).

Another main feature of this new system is the presence of final users who produce (and soon store) energy on their own, the so-called "prosumers". This is the case of households that installed rooftop PV panels (possibly with integrated battery storage). Instead, for the commercial sector, in most cases we refer to emergency back-up systems that can be used to provide additional electricity in periods of high prices or when there is a need for grid management. Industrial prosumers often have their own plants that deliver electricity and heat at the same time (cogeneration or CHP). These plants can be profitable because of higher efficiency and lower tax burdens.

Besides great opportunities, the shift from consumers to prosumers has also raised some key economic challenges to policymakers and regulators. One of the most pressing ones is how network charging should evolve as more distributed generation is deployed on consumer premises. In particular, network costs (and the policy support charges) tend to be quasi-fixed, i.e. the level is not directly related to the amount of energy being consumed. Since grid tariffs are usually volumetric (kWh charge) and prosumers consume less energy from the grid, network costs will be shifted to other customers when the share of prosumers grows, unless the regulatory frameworks evolve. In other words, the effect of prosumers will lead to rising network charges on remaining users, with re-distributional effects among customers (Friedrichsen et al. 2015). Obviously the more electricity is self-generated and self-consumed, the stronger this effect becomes. Therefore, this relationship is sometimes referred to as the "death spiral effect" (Mountouri et al. 2015). Furthermore, the impact of PV self-consumption may be particularly intensive in some specific geographic areas, leading to regional inequality.

All of this suggests the need to modify network tariffs to take into account higher cost causality in power systems with significant shares of (renewable) decentralized generation (Friedrichsen et al. 2015; RMI 2014).

The economic implications go beyond consumer welfare. In fact, unless network tariff design changes, energy companies may experience a significant drop in revenues. As most of the renewable production is consumed locally, this net offtake of energy can be expected to decrease with increasing penetration of renewables. Reviewing and updating current network tariffs is vital in order to promote the transition towards a more decentralized energy system while fully recovering all grid costs.

2.3.4 Customer Activation

The trend identified as "customer activation" refers to the fact that consumers are evolving: they are becoming more active both as consumers and as producers. Regarding their role as consumers, they are more aware of the possibilities offered by the market in terms of prices and added-value of services. This is proven by the increasing rate of switching and by the greater use of online comparison tools (now available in 22 of the EU countries). The average annual switching rate in the EU28 countries was 6.2% in 2015, higher than the average from 2009 to 2015 which was 5.3%. In the United Kingdom, the first liberalized market in Europe, the switching rate of domestic consumers trended upward from 11% in 2014, to 18% in 2017. At the same time, digitalization and new technologies such as the internet of things and smart meters allow customers to take control of the devices they use. They can monitor their consumption and vary it according to their needs and to market signals (demand-side response). With the huge amount of data on consumer behavior, utilities for their part can formulate energy offers that suit their customers best (i.e. improving customer experience).

In this regard, both residential and institutional customers also more and more often demand products and services that are both "green" (i.e., environmentally friendly) and "smart" (i.e., internet-connected, communicating, and automated) (RMI 2018b).

Customers are also taking on the complementary role of producers. Thanks to the spread of decentralized renewable energy, they can produce power and consume it, store it (through distributed storage technologies) or emit it in the grid. In other words, electricity, together with the digitalization, have made a paradigm change possible.

Changes in consumer behavior (households, energy-intensive industry, heating and the transportation sector) may also add to the flexibility needed by the system (i.e. through demand-side response solutions). Household consumption, in particular, has been highly inflexible so far. However, with the introduction of smart metering and automation, this may change, even if the overall contribution from the demand side will depend principally on technological development.

More broadly, digitalization opens up the opportunity for millions of consumers to sell electricity or provide valuable services to the grid (IEA 2017).

2.3.5 Digitalization

The integration of digital technologies into the electric system is a key change.

According to IEA (2017), investments in digital technologies by energy companies have increased significantly over the last few years. For example, global investment in digital electricity infrastructure and software was USD 47 billion in 2016.

The digitalization of the energy system can bring benefits to all energy players. The so-called Digital Revolution will result in the modernization of the grid, making it smarter and more resilient. This phenomenon can also help reduce the frequency and duration of power outages, restore service faster and prevent damages and problems, lowering operation and maintenance (O&M) costs. Consumers can better manage their own energy consumption and costs because they have easier access to their own data. Grid companies can increase integration of renewables, lowering operational costs that fall within the tariff. Utilities can develop new services, and consequently add new sources of revenues. Moreover, making the demand for electricity ‘intelligent’ means that capacity can be provided when and where it is most needed. This paves the way for a cleaner, more affordable, and more secure energy system.

More pragmatically, digitalization means data. According to the Boston Consulting Group (BCG), smart meters and other energy management devices, are expected to be installed in 60% of homes by 2019. Eventually, these devices will be capable of generating a massive stream of detailed data about energy consumption patterns, almost in real time, which will be critical to new business models and will facilitate customer engagement (BCG 2014). New digital tools will also enhance customer experience on several dimensions, such as improving customer service through better access to more information and by enabling customers to flexibly manage their electricity demand (WEF 2017b).

Building up digital skills and technology, also through acquisitions, is vital to successfully face the new challenges and to compete in the new arena. According to GTM Research (2016), in the next 5 years, utilities around the world will spend more than $2 billion annually on analytics solutions and service integration.

A critical issue related to digitalization consists in the fact that digital disruption creates new threats, such as the possibility of cyberattacks (see also Gatti and Chiarella 2020). The first confirmed power outage triggered by a cyberattack was in December 2015 in Ukraine. More than 250,000 customers lost power for more than 6 hours. Although its impact was not as widespread, a second power outage in December 2016 was more dangerous since it used a modular, automated cyber weapon capable of inflicting multiple types of damage to a much larger number of power grids.

In that regard, grid companies are far more vulnerable than in the past. This is due to their highly interconnected digital infrastructure, which enables real-time visibility into power outages, lets customers manage electricity consumption from their smartphones, and deploys sophisticated tools for energy management. All this exposes these companies to possible cyber threats, and they must overcome several obstacles in order to minimize this risk. For example, there are continually evolving business and technology requirements, a widespread shortage of qualified personnel, additional risks associated with third-party relationships, and the need to enable the entire workforce to participate in managing cybersecurity risks. In addition, it is vital that power companies intensify their collaboration with third parties to establish appropriate levels of security within the utility ecosystem, and to implement supply chain risk management programs.

2.3.6 Convergence of Industries

More companies currently belonging to other industries are integrating their business models as “energy companies”. New industry partnerships are being formed, as large incumbent organizations recognize that they need access to more digital skills in their workforce (WEF 2017b).

This convergence is disrupting the way power companies usually operate and will force a transformation in organizational capabilities, business models, market structure and design (Venzin and Konert 2020). Strategies that may have worked in the past no longer will; there will be a proliferation of new entrants into the market. What's more, in coming years the leading actors in the electricity industry may be companies we have never heard of (Helm 2017). In this regard, one of IDC Energy Insights predicted that by 2020, non-utility companies and digital disrupters will seize 20% of the retail energy market.

One of the most relevant converging trends is impacting the power sector and ICT. According to BCG (2014), by 2020 nearly everything in a home will be capable of generating data that can be monitored online and through a device. We have already seen that digitalization gives rise to huge opportunities for the entire sectors. Besides new opportunities, however, this convergence is also intensifying competition. Energy retailers have demonstrated much less sophistication in their data capabilities than companies in other sectors (BCG 2014). Especially in the US, major technology companies like Amazon, Google, and Apple are competing fiercely for the "smart home" space, fighting for market share to provide home assistants, smart thermostats, and software platforms to integrate many different kinds of devices (RMI 2017). More and more often, established companies including IBM, SAP, Microsoft, Intel and Cisco are offering technologies (such as predictive maintenance) and services. At the same time, numerous start-ups are seeking to exploit the new opportunities in the market. In 2017 there were more than 360 companies offering Internet of Things platforms, according to IOT Analytics, a Hamburg-based research group.

Another relevant converging trend is between the power and automotive sectors. We have already analyzed how electrification is reshaping the transportation sector. EVs are becoming progressively more competitive due to the declining costs of batteries, which have more than halved in the recent years and will result in a relevant upsurge of the electricity demand expected in the coming years. In particular, most major automakers offer at least one electric option or outline plans for electrification.

Another example of convergence between the power and automotive sectors is provided by Tesla, which in 2016 acquired SolarCity, a company specialized in the production of solar panels for the retail market, for $2.1 billion. Tesla made this acquisition at a time when it was believed that the goal of Tesla was to become a mass automobile manufacturer. On the contrary, residential solar is a perfect fit as part of an energy company's offerings, which in addition to electric cars also includes solar PV and battery storage (GTM 2017). In this regard, another Tesla product is the Powerwall 2.0, a powerful battery designed to hang on the wall and provide power to the house, as it is specifically designed to work with Tesla's solar panels and car chargers.

Following the example of Tesla, other automotive companies, including some European ones, have also recently entered into the power storage market. Enel in the meantime has developed a National Plan for the activation of an electric vehicle charging infrastructure, which envisages the installation of around 7000 charging stations by 2020 to reach a total of 14,000 stations by 2022 (Enel 2017).

Another converging trend is leading more companies that identify as "oil and gas companies" today, to integrate their business models as "energy companies" (WEF 2017a). Electrification of transport and heating, for example, may create a bridge between the oil & gas and electric power sectors, a bridge which both collaborators and competitors will cross. Moreover, new technology companies, especially in the power sector, are looking for patient capital. Meanwhile, oil and gas companies, with the capital and longer time horizons, are looking for opportunities to diversify in the face of uncertainty over fossil fuel demand from transportation and broader climate policy. In that regard, several oil & gas companies are more frequently investing in low carbon technologies and renewable projects.

2.4 The Economics Behind the R-Evolution

In the previous sections we analysed the key trends that are reshuffling the fundamentals of the energy sector and, in particular, the electricity industry. One of the most disruptive transformations is the rapid deployment of renewable technologies which is causing major challenges among market players. We now highlight the economics behind these changes, to provide the reader with an understanding of the factors that are prompting this R-evolution.

We start by analyzing how renewables were introduced and how they became fully competitive with other sources of energy. Then, we highlight how electricity is sold in the market (the so-called merit order) and what impact renewables have on other technologies (notably conventional power plants). Finally, we focus on some side effects related to the rising share of renewables in the electricity mix (i.e. negative prices).

2.4.1 The Competitiveness of Renewables

The deployment of renewable technologies has been mainly driven by policymakers (i.e. through the introduction of subsidies and emission reduction targets). According to REN21, last year 87 countries had targets in place for renewables (REN21 2018). Specifically, Europe has led the renewable technology expansion at global level thanks to the introduction in the early 2000s of the first targets for 2020. Policy mechanisms used to provide support for the deployment of renewables, especially at the beginning of their expansion, included: feed-in-tariffs (FiTs), but also market premiums, grants, green certificates and investment tax credits.

Progressively, we moved from more rigid subsidy schemes to competitive auctions with higher levels of competitiveness in the market. To date, incentives for renewable energy sources (RES) are in place only in "new" markets that want to stimulate their development or in markets characterized by specific technologies which are not yet mature.

In recent years, indeed, auctions and other awarding mechanisms based on competition have become the main support mechanisms for renewables (e.g. schemes in which a tendering entity calls for the lowest bid to produce electricity). One of the main advantages of such schemes is to allow governments to specify how much renewable capacity they want to build, and eventually other characteristics of the new plants. This, in turn, allows governments to plan their transition to renewables in line with the targets they have set (Leger et al. 2018).

Moreover, auctions enhance cost transparency and increase competition, especially in contrast to predefined feed-in tariffs. Not secondary, auctions contribute to achieve important savings. For example, in Italy, the cost for supporting wind turbines in 2017 was on average 66 €/MWh, compared to about 180 €/MWh in 2011. Similarly, the cost for solar was on average 41 €/MWh in 2017 compared to 134–289 €/MWh in 2011 (Enel Green Power 2018). Auction mechanisms are also often described as being "capacity-neutral," as bidders can propose coal-or gas-fired power if they want to.

However, in practice, wind and/or solar almost always won the auctions because of their zero fuel cost. In 2017, more than 20% of new solar projects that received support were selected on the basis of competition, together with about 30% of onshore wind and 50% of offshore wind projects (IEA 2018a).

Chile, the second electricity market to be liberalized in 1991, after the UK, represents a case in point for renewable auctions.

As illustrated by IRENA (2018) over the past years, in the Chilean auctions (technologically neutral) renewables plants have been increasingly competitive, replacing conventional generation.

Auctions have also contributed to driving down margins in the value chain (Leger et al. 2018). For example, recent renewable energy auctions have been won by record low solar and wind bids.

If policy support and subsidies had a fundamental role in initially helping renewables come into play, several factors have boosted the competitiveness of renewable technologies in recent years. Technological improvements, for instance, have played a fundamental role, leading to higher performances and cost reductions (IRENA 2018). In this regard, the size of the turbines went from around 2 MW in 2011 to around 3 MW in 2017 while the efficiency of solar panels rose from 14% in 2011 to about 18% in 2017 (Enel Green Power 2018).

Escalating economies of scale in manufacturing, vertical integration and consolidation among manufacturers are also fundamental to cost reductions. Moreover, continuous efficiencies are being achieved through bigger projects. For example, larger and more efficient wind turbines are set to significantly reduce the cost of onshore and offshore wind generation (BNEF 2018a). Competitive procurement and the emergence of experienced large project developers are other recent drivers that are supporting the diffusion of renewable technologies. Real-time data and 'big data' have enhanced predictive maintenance and reduced operation and maintenance (O&M) costs.

All of this is unlocking further performance improvements and cutting O&M costs, hence reducing project risk and significantly lowering the cost of capital

(IRENA 2018). As a result, the levelized cost of electricity (LCOE) for renewable technologies has constantly declined. Now it is close to the lowest level of the fossil fuel cost range, meaning that electricity from renewables might soon actually be cheaper than from most fossil fuels (Lazard 2017).

The learning rate, the cost reduction per doubling of deployed capacity, for the main solar and wind technologies (i.e. the LCOE reduction for every doubling in global cumulative installed capacity) is characterized by remarkable cost declines for the electricity produced by these technologies. For example, as highlighted by BNEF (2018a), the price of silicon PV modules plunged from \$79/W to \$0.37/W in 2017. This curve describes a learning rate of about 28.5%.

The corresponding figure for wind turbines is about 10.5%.

The enhanced attractiveness of renewables is also proven by the fact that more and more medium-sized Commercial & Industrial (C&I) clients are signing renewable Power Purchase Agreements—(PPAs).[10] There are many different types of PPA structures, based on the regulatory design of the relevant electricity market, the corporate buyer's strategy and the capability of the off-taker (WBCSD 2017, 2018).

Customers choose renewable energy sources for two main reasons. The first is the fact that renewables are becoming cheaper than any other source of energy, as illustrated by Lazard (2017). The second reason is sustainability. Large private companies are moving toward a sustainable business choice by setting targets in terms of renewable energy supply. This situation is convincing more and more customers all over the world: not only large corporations but also even medium-sized companies are participating in the growing market for PPAs through renewable energy.

Meanwhile, developers are diversifying their activities towards C&I to offset the growing competition on the auction price. The most successful market for corporate renewable procurement through PPAs is in the US where volumes rose to 2.9GW in 2017, mostly driven by high-tech companies like Apple, Google and Facebook. However, recent years have seen a growth in corporate renewable PPA deals in Europe (Wind Europe 2018a). Albeit not comparable with the US, the volume and demand for corporate renewable PPAs has tripled in the last 3 years (BNEF 2018a; Wind Europe 2018a).

Companies sourcing renewable electricity in Europe come from various sectors, demonstrating that the trend is widespread and dynamic. All this plays an important role in driving investment in renewables and contributing to global climate objectives (IRENA 2018). Over the period 2017–22, average global generation costs are estimated to further decline by a quarter for utility-scale solar PV; by almost 15% for onshore wind; and by a third for offshore wind (IEA 2018e). Bloomberg New Energy Finance even estimates the levelized cost of an average PV plant will fall 71% by 2050, to around \$25/MWh.

[10]In general, PPAs are contracts that allow Commercial & Industrial clients to buy electricity produced by renewable technologies.

Thanks to nosediving costs and supportive government policies, IEA forecasts that renewables will account for almost two-thirds of global power capacity additions to 2040 (IEA 2018e).

2.4.2 The Merit Order Effect

In this section we analyze the way electricity is sold in the market, the so-called merit order, and the effect of renewables (and other market forces) on the profitability of conventional power plants in Europe.

Most competitive electricity markets are auction-based, meaning that companies that run power plants participate in the auction in order to provide electricity on the market. In particular, they place bids in the auction to provide electricity at a certain time for a certain price. These bids are collected and arranged in order by price, to make sure that the lowest-cost power plants are dispatched first and the most expensive power plants are last (hence the name "merit order"). This market-based system is designed to deliver the lowest-cost electricity to consumers (Rhodes et al. 2017).

With regard to conventional power plants, they are often categorized by the type of load (energy supply) which they commonly provide: baseload, intermediate or peaking. Generally, different types of plants are used to meet each type of load. Baseload plants are typically lower cost nuclear or coal plants. These technologies generally meet the constant demand on the system and even though their output levels can be altered, "it is usually more economical for them to run at close-to-full capacity at all times" (DOE-EPSA 2016).

Intermediate load plants, often gas-fired and including combined-cycle plants, are sourced to meet the daily variations in demand. More recently, low gas prices are prompting the use of natural gas combined-cycle (NGCC) plants as baseload plants. Where available, hydroelectric units also serve as baseload or intermediate load plants. Finally, peaking generators meet the more extreme spikes in demand and are often used for only a few hours of the year. Peaking generators are typically "simple cycle" gas turbines or older gas- or oil-fired steam generators. Peaking plants are relatively inexpensive to build but are more expensive to run because they are generally less efficient than other types of plants or use more expensive fuel. In planning and daily operations, system operators tend to choose the mix of generators that allows them to meet demand economically (DOE-EPSA 2016).

The impact of renewables on the system is disruptive because sources such as wind, solar and hydro have no fuel costs: the energy they produce is free. In other words, their marginal operational cost is near zero. Since in competitive markets the price for electricity is determined by the marginal cost of the last power plant that has to be switched on to meet demand, a higher renewable penetration leads to a decrease in the wholesale price of electricity.

The other major effect of a higher penetration of renewables is that they push out other generators such as nuclear, natural gas and coal, reducing the dispatchment of their energy into the grid.

Fig. 2.4 EUA prices (€/tCO2) (Source: Authors' elaboration of data provided by EEX 2018)

The merit-order effect is particularly evident for coal. In other words, not only public and private commitment are straining the coal industry but also market dynamics. On one hand, renewables have started to compete with fossil fuels without subsidies. As such, this is significantly lowering the profitability of traditional fossil-fuelled generators (Genoese and Egenhofer 2015). On the other hand, cheap natural gas prices are "pushing out of the market" coal-fired power plants, especially in the United States (Fell and Kaffine 2017). As a result, in 2017, coal was surpassed by natural gas as the main source of energy in the electricity generation mix in the United States. What is more, coal will shrink further as old coal plants retire and are replaced by cheaper renewables and natural gas.

Coal usage for power generation is progressively decreasing in Europe as well. Recent reforms of the EU Emissions Trading System (ETS), adopted by the European Parliament, have contributed to raising the price of European Emission Allowances (EUA). In recent years the price per ton of carbon was too low to encourage carbon-free investment. Now, instead, as shown in Fig. 2.4, the price of carbon emissions entered in a positive trend, potentially driving investments towards cleaner or relatively cheaper sources of energy.

The rising costs of carbon emission allowances, in turn, is reducing the competitiveness of coal generation on the market. This is emphasized by the Clean Dark Spread, the difference between electricity's spot market price and the cost of electricity produced with coal plus the price of related carbon dioxide allowances[11] (Capgemini 2017). While from 2012 until 2015, the Clean Dark Spread was positive, the rising price of carbon negotiated on the EU ETS is driving down coal profitability.

[11]The Clean Spark Spread is the same indicator but it refers to electricity produced with gas.

Deteriorating economics and stronger climate policies are squeezing coal generation, closing power plants and threatening huge stranded asset costs (CTI 2018b). The symbolic beginning of the end for coal generation in Europe occurred in April 2017. This was when the United Kingdom, birthplace of the coal-fired Industrial Revolution, ran without coal for 55 hours then for another 76 hours a week later (Bloomberg 2018). Britain's last coal power station will be forced to close in 2025, as part of a government plan to phase out the fossil fuel to meet its climate change commitments.

Despite all the factors undermining the economics of coal power in the EU (falling renewable energy costs, air pollution regulations, rising carbon prices, and the public commitment to phase out coal) only 27% of operating coal units in the EU are planning to close before 2030. According to CTI (2018b), these generation assets could become unusable by 2030 (i.e. stranded assets). Therefore, the EU could avoid €22 billion in losses by phasing out coal power in line with the Paris Agreement. 54% of coal for merchant energy (energy sold in the market), in fact, produces negative cash flows and makes units reliant on lobbying to secure capacity market payments (CTI 2018b). In particular, the coal units operating in Germany could avoid losing €12 billion by retiring early, while units in Poland could avoid losing €2.7 billion. The UK has proportionally lower negative stranded value due to the fact it already has a phase-out policy. Phasing out coal will contribute to preserving the financial interests of utility shareholders by avoiding value destruction. Italy and Slovenia have positive stranded value of €480 million and €740 million, respectively. To a much lesser degree, Portugal, Romania, Ireland and France are also in the same situation (CTI 2018b).

As we have already mentioned, the source of power that could benefit most from the phase-out of coal, at least in the short run, is natural gas.

However, natural gas-fired power plants are not the only resource options capable of replacing retiring capacity. Utility-scale renewable projects, thanks to sharp cost reductions, are becoming increasingly cheaper and have now started to compete with fossil fuels in auctions, based on a pure cost competition (i.e. without FiTs).

Moreover, developers and grid-operators have demonstrated the ability to offer "clean energy portfolios" (i.e. renewable energy, including wind and solar, and distributed energy resources, including batteries). This means they can provide many, if not all, of the grid services typically supplied by thermal power plants, and often at net cost savings (RMI 2018a).

In particular, according to BNEF (2018a), thanks to the ability to switch on and off in response to grid electricity shortfalls and surpluses over periods of hours, stand-alone batteries are starting to compete with open-cycle gas plants.

As highlighted by RMI (2018a), which compared costs of gas-fired power plants against optimized, region-specific clean energy portfolios of renewable energy and distributed energy resources (DERs), in some cases, clean energy portfolios may cost less to build than CCGTs cost.

In other words, the same technological innovations and price declines in renewable energy that have already contributed to early coal-plant retirement are now threatening to strand investments in natural gas (RMI 2018a). This refers specifically to investments in gas-fired power plants currently proposed or under construction, and has significant implications for investors in gas projects, especially utilities.

2.4.3 Negative Prices

A remarkable effect of the deeper penetration of renewables is that it may lead to greater volatility in power prices, because of the higher exposure to weather conditions (even though weather forecasting has significantly improved over the past few years). Moreover, extremely high and extremely low prices are expected to occur, in the absence of a more rapid deployment of storage and other technologies (i.e. demand-side response).

In this regard, another challenge introduced by renewables is more frequent negative prices of electricity sold in the power exchange over time (where allowed). This may happen, for instance, when high renewable power supply exceeds demand and producers bid their electricity for negative prices.

The rationale of this behavior is that most of the renewable energy fed into the grid has a minimum guaranteed price (FiTs). In that case it is opportune to bid a negative price when prices are zero or already negative for other reasons. Since renewable power producers are not paid if they don't feed electricity into the grid, it makes sense to bid a negative price.

From the perspective of social welfare, it might be cheaper if output from windfarms could be curtailed (capped) when it is too high. When intermittent power producers are allowed to bid prices below their (zero) marginal costs, the market becomes very distorted indeed.

In this regard, in 2017 the number of hours with negative power prices in Germany escalated by around 50% to 146 hours. The average negative power price was minus 27 euros per MWh (Amelang and Appunn 2018).

The phenomenon of negative prices also occurred in other markets characterized by a high penetration of renewables, like the United States. According to data provided by CAISO, the California system operator, in that state in 2015 the phenomenon of negative prices was recorded more than 7700 times. Forecasts estimate this imbalance will grow over the next few years, as more electricity enters the grid from renewable sources (WEF 2017a).

At a first glance, negative prices are signaling that there is no more space for conventional generation to be installed in those specific areas where they occur.

Moreover, negative prices can be considered a price signal to owners of traditional coal and gas plants to shut down production for a period, even though many of the facilities are not designed to switch on and off quickly. In this regard, conventional power station operators, which are either losing money or at least losing profits during times of negative prices, may decide to keep their plants running for several reasons. These reasons can be technical, for example the power plant can be too inflexible to change its output, or the cost of shutting down and starting up again can be too expensive.

Conventional power station operators may have the obligation to provide contracted balancing power to keep the grid stable or provide re-dispatch power. Alternatively, in some cases power production cannot shut down because it serves critical infrastructure (e.g. a residential heating network).

Also, those plant operators which have already sold their power on the longer-term futures market face no extra costs when they let their units run. They are merely losing the profit that they could make by buying cheap power to supply their customers instead of producing their own. Looking more closely, negative prices can be also good news, since "they may provide incentives to utilities to make their power stations more responsive to changing conditions on the power market, or to find new business opportunities by adapting demand" (Amelang and Appunn 2018).

According to Capgemini (2017), another relevant counter-effect of the rising penetration of renewables is the increasing need for flexibility caused by the fact that renewables, especially wind and solar, are intermittent. More precisely, there are two main categories of renewables: renewables with storage (e.g. hydropower and biomass) and those without (mainly photovoltaic solar and wind). The non-dispatch nature of renewables without storage, creates grid disturbances (balancing problems, grid overhaul), leading to extra costs. For example, in 2016 in Southern Australia, around 50% of the electricity was produced by solar PV and wind. However, this level was not sustainable, and the state experienced several blackouts and load shedding (Capgemini 2017). Following these events, in March 2017, the Government decided to spend more than 550 million of Australian dollars (i.e. the equivalent of €333 million) to build a new gas-fired power plant and a large-scale storage battery in order to secure the continuity of electricity supply.

The intermittent nature of renewables may also augment the cost of balancing the system. For instance, the cost of balancing the UK electricity system has doubled in the last 4 years. The amount of flexible generation on the system is a key driver. Balancing costs rise when the output from flexible generators such as gas, coal, biomass and hydro, falls below 10GW (this happens when the output from wind and solar rises). More flexible generation, storage and demand-side response will be critical in minimizing system costs in the future (Staffell et al. 2018).

2.5 Some Trends to Look Out for, in the Coming Years

This section aims at highlighting some trends that financial investors should take into consideration for their portfolio allocation strategy. We will pay specific attention to offshore wind. Albeit not yet a mature technology like other renewables, it is attracting rising interest, especially among financial investors.

Then, we focus on one of the main challenges brought about by the R-evolution: the need for flexibility. We discuss battery storage as one of the most suitable potential solutions for coping with this need, as well as a potential option for financial investors. Finally, we investigate the future role of existing gas and electricity transmission infrastructure, highlighting possible threats and opportunities.

2.5.1 Watch this Space: Offshore Wind

Among renewables, wind power is growing rapidly and attracting escalating investments, especially among financial players such as infrastructure funds. In 2017, Europe installed 16.8 GW of additional wind power capacity (onshore and offshore). In particular, wind accounted for the largest percentage of all new capacity installed in Europe in 2017. With a total net installed capacity of 168.7 GW, wind is currently the second largest form of power generation capacity in Europe, closely approaching gas installations (Wind Europe 2018b).

Specifically, the wind energy industry attracted €51.2 billion in Europe with investments in new wind farms which amounted to €22.3 billion.

In terms of investments in new renewable capacity installed in Europe, excluding solar PV, wind had the largest growth. Technological cost reductions and lower offshore wind investments were the two main reasons for the drop in fresh investments for new capacity, in monetary terms (Wind Europe 2018a).

Offshore wind in Europe, in particular, saw a record 3.15 GW of net additional installed capacity in 2017, corresponding to 560 new offshore wind turbines across 17 wind farms. In total, Europe now has offshore wind capacity of 15.78 GW (Wind Europe 2018c).

According to GWEC (2018), Ørsted (formerly DONG Energy) is currently the largest owner of offshore wind power in Europe, with 17% of cumulative installations. Next in the ranking is E.ON with 8% of installed capacity owned, followed by Innogy (7%), Vattenfall (7%), and Northland Power (4%). The top five owners represent 42% of all installed capacity in Europe.

Some of the largest wind developers, like Ørsted, carry out investments with the aim of bringing in an equity partner (e.g. an institutional investor) as soon as the wind farm is operational. The strategy here is to earn a premium on the book valuation of the project.

In this regard, the sector's progressive maturity and technology competitiveness have brought in a more diverse mix of corporate financial and institutional investors as equity partners in projects. In particular, the financial services industry (i.e. infrastructure funds, pension funds, asset managers and diversified financial services) acquired 70%, of onshore wind assets available for sale (i.e. a total of 4.5 GW), compared to 36% in 2016. Financial actors accounted for 35% of the offshore wind capacity traded throughout 2017 (i.e. 2.9 GW), up from only 27% in 2016 (Wind Europe 2018a).

This trend is largely due to progressive sector maturity, adequate asset size and a risk profile that matches the investment profile of financial investors.

Indeed, financial investors are gaining momentum, especially in the equity mix of offshore wind projects in the EU (Wind Europe 2018c).

For example, according to The Crown Estate (2018), in November 2017 Danish pension providers PKA and PFA purchased 50% of Ørsted's Walney 3 project. This consolidated PKA's presence in the market. The financial service industry is also showing more interest in offshore transmission assets (OFTO) (i.e. cables that are necessary to connect offshore wind farms to the mainland's grid). In the UK, for instance, the ownership structure of these assets, which are allocated through a competitive tender process, highlight the heightened interest of institutional investors and infrastructure funds.

Transmission Capital Partners has the largest slice of the OFTO market with almost a third, followed by Blue Transmission and Equitix.

2.5.2 The Need for Flexibility: Storage

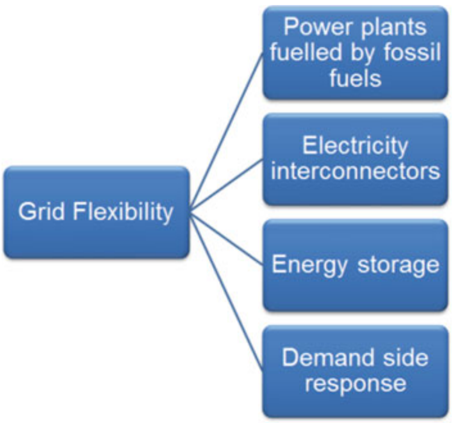
The increasing share of intermittent renewables (notably wind and solar) in the electricity generation mix are causing major challenges in terms of balancing supply and demand. In particular, the penetration of these energy sources is augmenting the need for flexibility.

There are several ways to facilitate the integration of a greater share of renewables in the electricity system while providing the flexibility this requires. Examples are: developing more interconnections across regions, promoting demand response (e.g. implementing “time-of-use tariffs” to trigger higher customer demand response when cheap renewable electricity is available), dispatching “peakers” that are typically simple-cycle gas turbines, able to start up and minutes (or other fossil fuel generators), and using storage facilities. Figure 2.5 offers a graphic representation of the main flexibility options.

As more renewables come online, the need for storage becomes increasingly acute (Di Castelnuovo and Vazquez 2018; Chatham House 2017). Without storage, when too much electricity enters the grid, supply exceeds demand and negative pricing occurs. This can be the case of particularly sunny days and windy afternoons, or days when demand is low.

On the contrary, storage adds flexibility to the system, allowing electricity to be stored and discharged later when it is needed, for example in evening hours or during peaks. In this way, storage offers a way to flatten out the peaks and valleys of supply and to prevent disruptive events.

Fig. 2.5 Flexibility options (Source: Di Castelnuovo and Vazquez 2018)



There are different types of storage systems, primarily pumped water, compressed air, magnetic flywheels, batteries and hydrogen. The first two depend on suitable natural sites (i.e. appropriate geology). In Europe, there are adequate sites for pumped storage. However, most of them have been already exploited (Capgemini 2017).

The technology which is attracting far more attention is Lithium-Ion battery storage (Schmidt et al. 2017). In this regard, we should distinguish between (i) utility-scale storage (in front of the meter) and (ii) distributed storage (behind the meter). The former accounts for the majority of installed storage capacity (so far), providing numerous system functions. The latter, instead, allows customers to store the electricity generated by their rooftop solar panels, for instance, and use it later when needed (RMI 2018a).

As highlighted by the Rocky Mountain Institute (2015), batteries can provide up to 13 services and be sited at three different levels: (1) behind the meter, (2) at the distribution level, or (3) at the transmission level. It is not still clear whether storage (and in particular battery storage) is actually a profitable investment. The reason for this uncertainty is that any attempt at storage valuation requires making assumptions on storage regulation (Zucker et al. 2013). However, regardless of the deployment level, battery storage can add value to the grid.

Energy storage will affect the entire electricity value chain, notably replacing peaking plans, altering future transmission and distribution (T&D) investments, and reducing the intermittency of renewables. For utilities, battery storage will become an integral tool for managing peak loads, regulating voltage and frequency, ensuring reliability from renewable generation, and creating a more flexible transmission and distribution system. For their customers, instead, storage can be a tool for reducing costs related to peak energy demand.

As a result, the global energy storage market could significantly expand from now to 2030, rising from less than 5 gigawatt-hours last year, to more than 300 gigawatt-hours and 125 gigawatts of capacity by the end of the next decade. An estimated $103 billion will be invested in energy storage over that time period (BNEF 2018a). Energy storage, both utility-scale and behind-the-meter, will be a crucial source of flexibility throughout this period and will be essential to integrating mounting levels of renewable energy (BNEF 2018a).

2.5.3 Energy Networks as Both Enablers and Constraints

The European Commission aims to enhance the further integration of electricity markets, especially by amplifying the interconnection capacity (measured in terms of net transfer capacity) out of the total installed electricity capacity in place. Indeed, investing in interconnection at several borders and when economically justified will improve energy security, reduce dependency on imports from outside the EU and prepare networks for renewable energy. All of this also applies for gas. In order to create a fully connected internal competitive energy market and to achieve its energy policy and climate objectives, the European Commission published a list of key infrastructure projects it has denominated Projects of Common Interest (PCIs). Most of them are represented by electricity interconnectors and gas infrastructure projects. In particular, in 2017, there were 173 PCIs, of which 53 involved natural gas, 106 electricity, 4 smart grids, 6 oil projects and 4 carbon dioxide transport projects (Ecofys 2018; E3G 2017). In terms of capital expenditure, 66% of the total refers to projects for electricity transmission, followed by gas transmission with 18%.

The huge investments attracted by these projects raise concern. To be specific, investments in gas infrastructures risk becoming stranded assets as the transition towards a cleaner energy system requires the complete decarbonization of the economy, including natural gas. In our study, we observed that natural gas is starting to regain its competitiveness vis-à-vis coal (see Sect. 2.2.2). In addition, reforms to the emissions trading scheme have already had the effect of ramping up the price of carbon emissions, thereby further encouraging fuel switching from coal to gas. As a result, gas-fired generation in Europe escalated by almost 30% in 2017.

However, some of those plants still struggle to turn a profit as the growth of renewable generation reduces their load factors. Moreover, renewable energy and distributed energy resources, including batteries and demand-side technologies, are becoming reliable alternative sources of fundamental grid services (i.e. generation capacity and ancillary services), typically provided by thermal power plants. All this exacerbates the situation. Energy efficiency, especially in buildings, will also contribute to reduce gas consumption.

On the one hand, investments in gas-fired power plants are already at risk of becoming stranded assets. On the other, investments in gas infrastructures (network, LNG terminals and storage) face a different scenario due to the fact that in 2017 gas-fired generation represented 28% of total gas consumption in Europe (IEA 2018a). In other words, there is a larger share of gas demand, mainly represented by industry and buildings (i.e. gas used for heating) that will remain stable. All of this suggests that gas infrastructure will continue playing a fundamental role in order to serve these customers.

Another explanation for the continuing importance of gas infrastructure is that more LNG is being imported, especially from the US (IGU 2018). LNG volumes in the coming years are expected to grow for geopolitical reasons as well. According to King and Spalding (2018), Europe's regasification capacity, which is now sufficient to cover approximately 40% of its gas demand, will also ramp up quite significantly by 2021. This is the result of expansions that are under way or planned at some of Europe's existing LNG import terminals. All this LNG also needs to be transported through pipelines to final customers.

Moreover, the gas infrastructure may favor the integration of a greater share of renewables. Sector coupling between gas and electricity, which creates new links between energy carriers and the respective transport infrastructure, may facilitate the integration of renewables and help to achieve EU decarbonization goals (GIE 2018; OIES 2018; European Power to Gas 2017; FSR 2018). In particular, the transformation of renewable electricity into other energy carriers such as gas (e.g. synthetic gas, hydrogen) needs to be considered in order to pursue decarbonization goals (DNV GL 2017; E3G 2018; Wind Europe 2018d). For instance, in some sectors such as cement, fertilizers or refineries, power-to-gas is among the few cost-effective emissions abatement options available.

Finally, the gas infrastructure retains a strong role in ensuring security of supply, especially to satisfy seasonal peaks in heating demand that cannot be met cost-effectively by electricity (FSR 2018).

The gas infrastructure will remain a crucial security-of-supply asset for Europe, accommodating seasonal variations in both demand and supply, while alleviating the effects of extreme weather events.

2.6 The Impact of the R-Evolution on European Utilities

In order to fully understand the implications of the trends described in the previous sections for the energy sector, we now investigate the performance of European utilities. The aim of this analysis is to highlight how the transformations occurring in the energy sector are affecting the profitability of current market players. In particular, we start by exploring how European utilities generate their revenues (i.e. their revenue model) and then we look at their performance.

Based on the main source of revenues, we can distinguish between two categories of utilities, both of which we will analyze:

1. Network (or grid) companies;
2. Energy suppliers.

2.6.1 Utilities' Revenue Model

Regardless the energy vector (gas or electricity), network companies are responsible for the transmission/distribution of energy in their control area. As highlighted by Pérez-Arriaga (2013), due to the cost of establishing a transmission infrastructure, such as main power lines (or gas pipelines) and associated connection points, a network company is usually a natural monopoly. It makes no sense at all to develop parallel networks that would compete to provide the service in question. Due to the conditions that make networks a natural monopoly, and because of their key role as the meeting point of demand and supply, networks must be regulated. This regulation must guarantee suitable grid development and efficient market conditions (Pérez-Arriaga 2013). To be specific, according to the current European regulatory framework, the distribution of gas and electricity are activities carried out by companies that may also include other businesses (i.e. energy supply). However, regulation requires that transmission activities must be operated by a separated legal entity. As a result, the regulatory framework has a relevant impact on the business model (and the revenue model) of network companies and their organizations, especially TSOs (transmission system operators).

Looking more closely, we can distinguish the activities performed by grid companies as regulated and non-regulated.

Regulated activities consist in the development of new CAPEX in order to enable the transportation of energy and OPEX for the correct functioning of the system. These costs are covered by a tariff, set by the relative National Regulatory Authority (NRA) and the tariff is paid by final customers on their electricity bill. Moreover, the tariff is set in a transparent and non-discriminatory manner and should guarantee stability and long-term perspectives for network companies, their customers and investors. In general, the tariff amount covers the costs (both operating costs and capital costs) and ensures a return on capital invested. Specifically, the return on capital is the product of two terms, a base (RAB) and a rate of return (WACC), as illustrated by the following formula:

$$RAB * WACC = Return\ on\ capital$$

where:

- The Regulatory Asset Base (RAB) is basically the accounting value of owned assets;
- WACC (Weighted Average Cost of Capital) is determined by means of an evaluation model incorporating various parameters, such as the risk-free rate represented by government bonds, additional compensation for a risk-free rate requested by bond investors, return on equity in view of risk sensitivity.

Besides this main source of revenues (and costs), network companies can also run other activities outside the perimeter of the regulation. These so-called non-regulated activities are not covered by the tariff but respond to market forces and are conducted in a competitive regime. These activities include for example: O&M, EPC, TLC investments, private interconnectors (financed through third parties), consultancy.

Energy supply, instead, includes a set of activities carried out in a competitive regime, as listed here:

- Scheduled energy
- Generation capacity
- Ancillary services
- Market based instruments
- Retail activities

Starting from the first, scheduled energy, we have already discussed the fact that the introduction of renewables has compressed margins for most of the conventional energy suppliers, with coal-fired plants and traditional gas plants being squeezed. These two types of facilities, including efficient CCGT plants, are also facing more and more competition from renewables, distributed generation, and other demand-side response technologies for ancillary services and generation capacity auctions, (the second and the third activities listed above). This is proven by recent auctions in the UK, which highlight the non-economic unviability of coal-fired plants in favor of more competitive CGT plants and renewables (OFGEM 2017).

While revenues from scheduled energy on the market are decreasing due to the higher penetration of renewables, earnings from flexible frequency response are expected to rise. This is in part because these services will become increasingly vital for coping with the intermittency of renewables (AURORA 2018).

However, conventional generators including efficient CCGT plants are increasingly facing competition from renewables and distributed generation and other demand-side response technologies also for ancillary services.

Market-based instruments, such as energy attribute certificates, green certificates, etc. are another potential source of revenues for utilities.

Finally, retail activities include everything utilities do downstream, e.g. energy sales, home management services, energy management services, e-mobility, and so forth. Indeed, the evidence suggests that utilities are increasingly facing competition from new market players (i.e. ICT, automotive or the O&G sector).

2.6.2 Utilities' Financial Performance

In this part of our study we analyze utilities' market performance. In particular, we investigate whether there is any difference between network-only companies (i.e. TSOs) and other utilities (e.g. energy suppliers). The question arises from the fact that, over the past few years, profits from energy supply activities, especially merchant energy produced by conventional power plants, have significantly shrunk. We have already explained the reasons for such a trend in the previous sections (e.g. competition from renewables).

Meanwhile, the spread between financing costs and regulated returns of energy networks has widened, as the former have collapsed and the latter have been generally flat (IEA 2018b). As a consequence, we expect these two trends to be reflected in better performance of network-only companies (TSOs), whose main source of revenues are regulated activities held under a monopoly. This compared to the poorer performance of utilities, which may also have networks, but are more exposed to competition and market forces.

We start our analysis with the performance of the sectorial index, the Stoxx Europe 600 utilities (SX6P), which include almost 30 major listed utilities from all over Europe.

Over the period from October 2008 to October 2018, the European sectorial index for utilities underperformed the Euro Stoxx 50, including most of major European companies by market cap across all sectors, as shown in Fig. 2.6. This confirms that the trends described in the previous sections have been affecting utilities' performance.

As we can observe, utilities performed very poorly, on average compared to the Euro Stoxx 50.

In order to calculate the performance of TSOs, we first mapped both electricity and gas-network-only companies (TSOs) currently operating across Europe, analyzing:

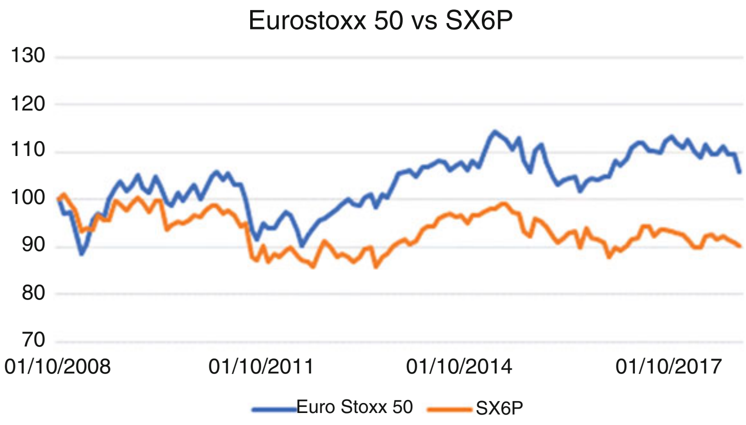


Fig. 2.6 Performance comparison: SX6P Index vs Euro Stoxx 50 (Source: Authors' elaboration of data provided by Bloomberg 2018)

- their exposure to regulated business;
- the shareholder composition of these companies, distinguishing between financial and non-financial;
- the main shareholders (top 10 shareholders, distinguishing between financial and non-financial).

The following charts show the results for electricity transmission system operators of the major EU countries (Austria, Belgium, Denmark, France, Germany, Italy, Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, UK). In detail, Fig. 2.7 illustrates the sources of revenues of European electricity TSOs. These data confirm the fact that regulated activities, which are covered by the tariff, represent the main sources of revenues for electricity TSOs (94% of the total, against 6% coming from non-regulated).

Figure 2.8 highlights that the majority of shareholders of electricity TSOs are non-financial companies, that is, 72% against only 28% represented by various financial actors.

Figure 2.9, instead, offers a graphic breakdown of financial and non-financial shareholders. As we can see, the main shareholder is the government (51% of the total), meaning that the majority of the electricity TSOs we analyzed are state-owned. The second-most represented category of shareholders is still a non-financial actor (i.e. corporation 16%), while the first category of financial shareholder is represented by investment advisors with a share of almost 16%.

In particular, among the most common financial shareholders, Lazard and Blackrock have the highest average share, i.e. 4.9% and 3.1% respectively.

Figure 2.10, Fig. 2.11, Fig. 2.12 show the corresponding figures for European Gas TSOs. As we can see, similar to electricity TSOs, gas TSOs also find their main source of revenue in regulated activities covered by the tariff (92% of total revenues against 8% coming from non-regulated).

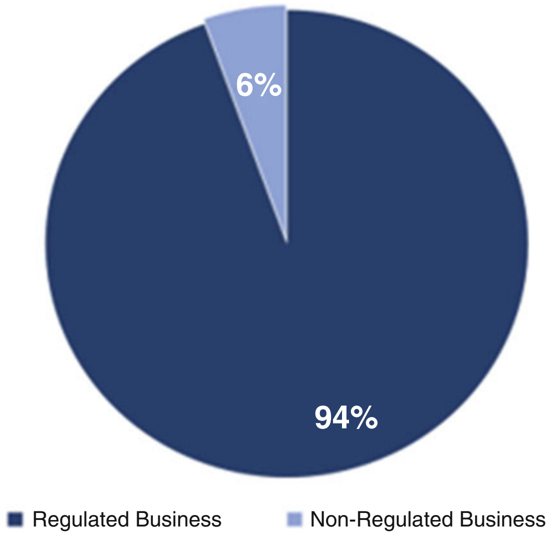


Fig. 2.7 Electricity TSOs' exposure to regulated business (Source: Authors' elaboration of data provided by Bloomberg 2018)

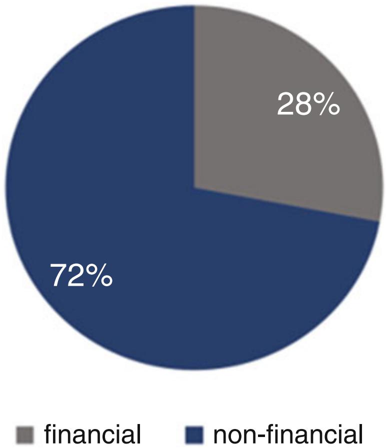


Fig. 2.8 Electricity TSOs' shareholder composition (Source: Authors' elaboration of data provided by Bloomberg 2018)

The main difference between electricity and gas TSOs is represented by the main category of shareholders: for the former, they are corporations, while for the latter they are investment advisors.

Among the most common gas TSOs financial shareholders, Blackrock and Lazard are the ones with the highest average share, i.e. 4.1% and 3.8% respectively.

Listed electricity transmission grid companies included in our analysis are: Terna (Italy), Elia System Operator (Belgium), Red Electrica de Espana (Spain), REN - Redes Energeticas Nacionais (Portugal), National Grid (UK). Listed gas transmission grid companies are: SNAM (Italy), Fluxys Belgium "D" (Belgium), REN -

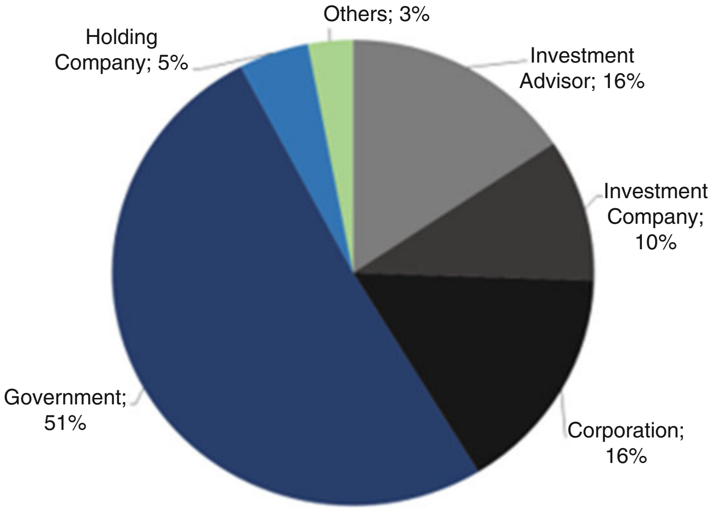


Fig. 2.9 Electricity TSOs' shareholder breakdown (Source: Authors' elaboration of data provided by Bloomberg 2018)

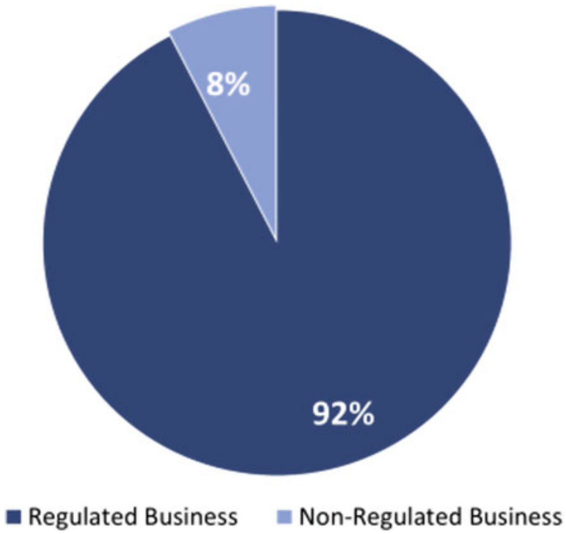


Fig. 2.10 Gas TSOs' exposure to regulated business (Source: Authors' elaboration of data provided by Bloomberg 2018)

Redes Energeticas Nacionais (Portugal), Enagas (Spain), National Grid (UK). Figure 2.13 and Fig. 2.14 show the performance of listed electricity and gas TSOs respectively, against the SX6P Index over the period from October 2008 to October 2018. As we can see, TSOs outperformed the SX6P Index.

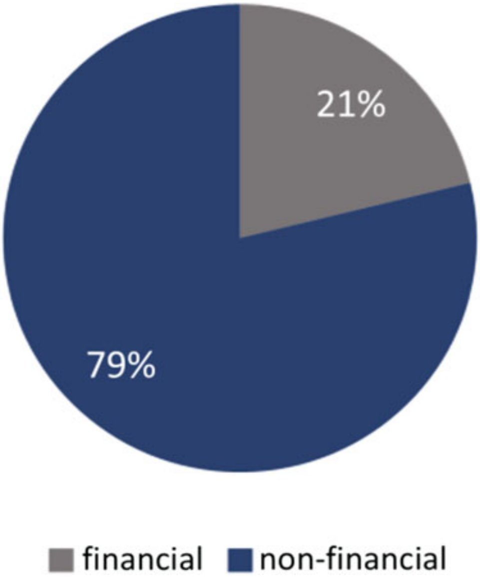


Fig. 2.11 Gas TSOs' Shareholder composition (Source: Authors' elaboration of data provided by Bloomberg 2018)

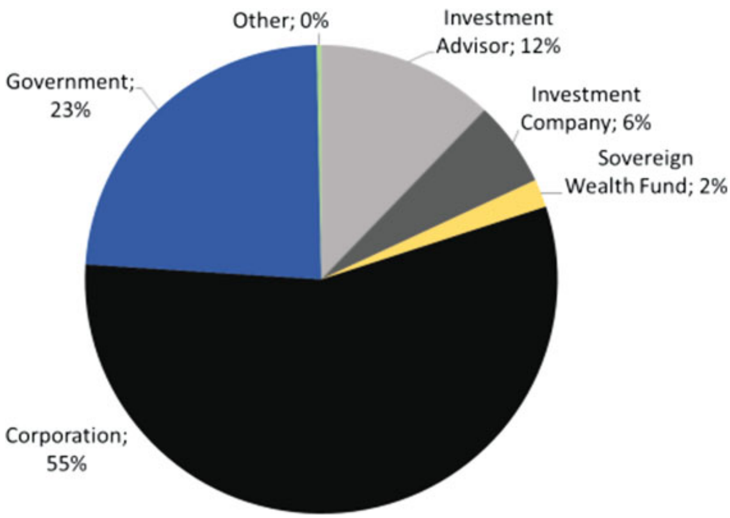


Fig. 2.12 Gas TSOs' Shareholder breakdown (Source: Authors' elaboration of data provided by Bloomberg 2018)

As confirmation of the poor performances of European utilities compared to TSOs, the earnings of the former have shrunk by a third since 2012 (Capgemini 2017). According to the IEA (2018b) this was due mainly to the reduced profitability

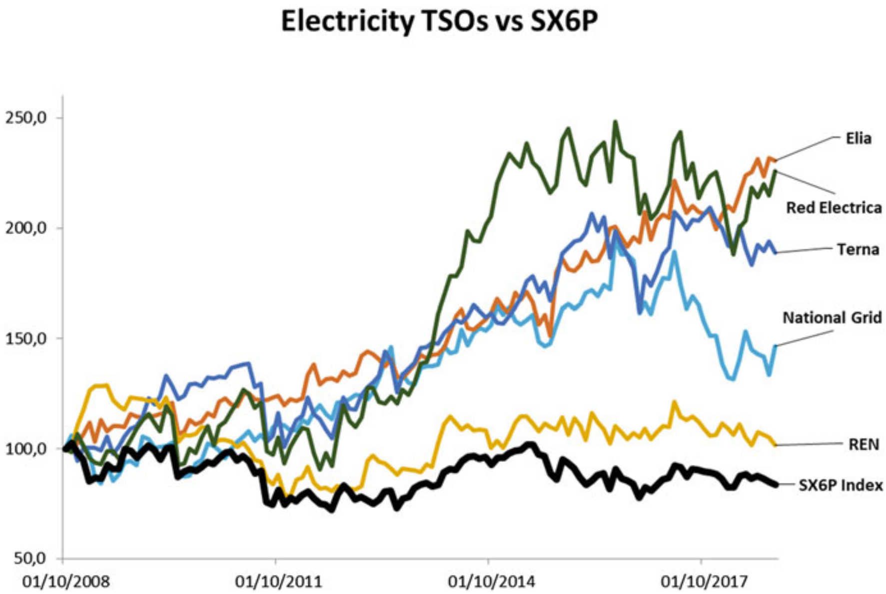


Fig. 2.13 Performance comparison: SX6P Index vs electricity transmission companies (Source: Authors' elaboration of data provided by Bloomberg 2018)

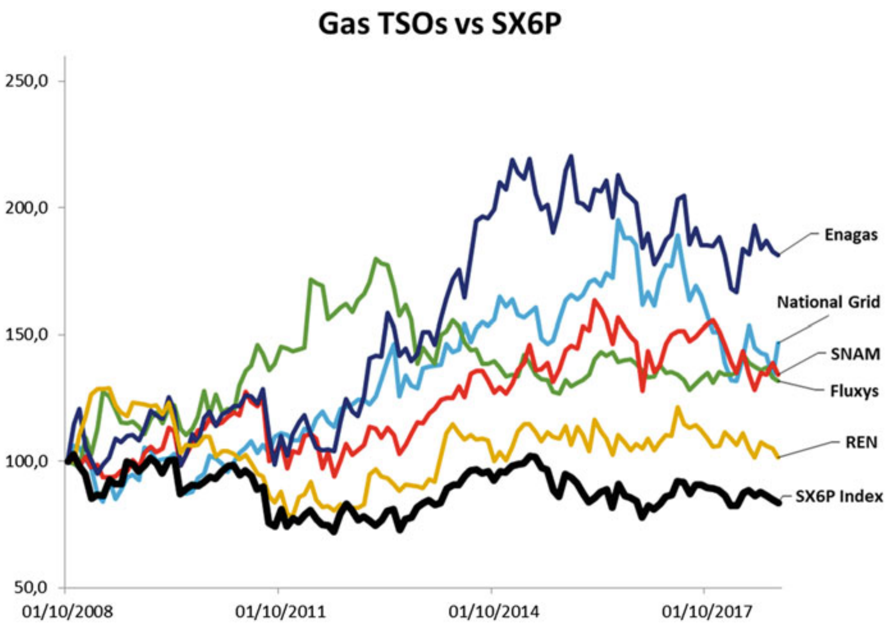


Fig. 2.14 Performance comparison: SX6P Index vs gas transmission companies (Source: Authors' elaboration of data provided by Bloomberg 2018)

of merchant-generating assets exposed to weak wholesale prices, as well as lower revenues" due to the retirements of such plants.

According to Capgemini (2017), utilities across Europe are reacting to the sector transformation by restructuring their asset portfolios to reduce exposure to risk and price volatility. As a result, utilities in mature electricity markets mothballed or even closed down some of their thermal power generation assets while seeking profitable opportunities in other areas, e.g. investments in regulated sectors.

This trend is confirmed by the fact that 80% of utility earnings in 2017 came from segments that offer more stable and predictable cash flows, like networks and renewables, compared with around 65% in 2012 (IEA 2018b). In other words, utilities are trying to improve their profitability shifting from merchant energy (energy sold on the market under competitive regimes), to regulated activities or renewable energy that can guarantee regular cash flows (e.g. through auction-based mechanisms).

In general, there is no single trend in terms of business model adaptations. Utilities are investing in different segments of the value chain, based on their view on the future.

For example, in 2016, RWE created "Innogy" to manage grids, renewables and the retail business, while E.ON formed "Uniper" (recently acquired by the Finnish utility Fortum) to separately manage fossil fuel assets (e.g. gas and coal generation).

Recently, E.ON and RWE agreed upon an asset swap based on which the former will buy the latter's subsidiary "Innogy"; while, at the same time, RWE will acquire E.ON's renewable assets as well as take back the same renewable assets which they had previously carved out with the creation of Innogy.

Some utilities are also increasing customer and service activities (e.g. integrating supply businesses with demand-side services, such as those related to electric vehicles). These companies are trying to achieve better financial discipline, including decreasing debt levels and reducing operational and structural costs (Capgemini 2017).

European utilities continued to review their investment strategies and to transform their business models also through mergers and acquisitions (M&A).

M&A activity increased in Europe by 30% in 2017, as utilities continued to sell-off non-core (mostly fossil fuel-based) assets to adapt their business models (an example here is the divestment of upstream oil and gas assets by Centrica and Ørsted) (EY 2018; ATKearney 2018; McKinsey and Company 2018).

The value of M&A transactions is expected to rise in 2018 and 2019 based on Fortum's acquisition of Uniper, and the asset swap between E.ON and RWE.

European utilities also acquired companies and assets related to digital technologies and distributed energy resources (Capgemini 2017). In the US for example, Enel acquired EnerNOC, a firm specialized in demand management, and behind-the-meter storage operator Demand Energy. In the UK, Centrica acquired REstore, specialized in management and aggregation of demand response capacity from industrial and commercial consumers (IEA 2018b).

There is also some M&A activity in "networks-only" utilities. The value of deals rose considerably in 2017 (BCG 2017). For instance, Macquarie acquired a minority stake in four gas distribution networks from UK National Grid for €5.4 billion. Caisse des Dépôts and Assurance acquired a 49.9% stake in RTE (the French electricity TSO) for €4.1 billion and investors led by J.P. Morgan acquired Spain's Naturgas for €2.6 billion.

2.7 Conclusions

The energy system is currently undergoing an unprecedented revolution. This paper aimed to provide a broad overview of the main transformations occurring in the sector and to develop an understanding of the potential implications for financial investors. In this regard, in our analysis we identified some trends that are set to put a large amount of existing and future assets at risk. In particular, investments related to fossil fuels appear to have the highest degree of risk and uncertainty, depending on the specific fuel, the technology adopted and the market under consideration.

With specific regard to the oil industry, in the coming years, on the one hand the demand for oil will progressively shrink because of the growing penetration of electric vehicles in the transport sector. On the other, oil consumption in industry, and, particularly in the petrochemical sector, will remain relatively stable. As such, subject to lower-than-expected progress in so-called green chemistry, investments in refineries and petrochemical facilities may appear more profitable than other investments in the industry.

The prospect for investments within the natural gas industry are more complicated to assess. In the long run there is a limited growth opportunity for natural gas if the world is to achieve the goal of maintaining the temperature increase to well below 2 °C. In the medium term, gas is considered as a "bridge fuel" during the transition to a decarbonized energy system. This is due to its lower carbon emissions compared to coal and other fossil fuels and the flexibility of gas-fuelled generators in balancing intermittent renewable energy. Also, it should be emphasized that while power generation usually represents the largest share of total gas consumption (32% in Europe in 2017), industry and buildings make up for the remaining part (IEA 2018a). Furthermore, the gas industry is currently trying to diversify its investments by expanding the use of gas in transport (e.g. LNG for shipping) as well as the production of renewable gas (e.g. biomethane and hydrogen). Moreover, the European market design is increasingly aimed at promoting stronger coupling between the gas and electricity sectors, further enhancing the use of gas infrastructure for the integration of renewable technologies (e.g. through biomethane or power-to-gas).

Indeed, because of its flexibility role in balancing renewables and its uses in sectors other than power generation (e.g. industry), natural gas cannot and should not be written off yet from any European scenario. In light of this, gas infrastructures (included LNG terminals, storage and pipelines) may still represent, under certain conditions an interesting investment opportunity, especially for the medium term (for instance in a market with widespread use of gas in the residential sector like Italy).

Focusing on the electricity industry, we mapped the revolution with a framework consisting of six key drivers: decarbonization, decentralization, electrification, digitalization, customer activation and convergence of industries. All of these drivers are completely reshaping the industry across its values chain, with massive implications in terms of economic fundamentals, investment opportunities and business strategies.

Clean energy portfolios, including less mature technologies like offshore wind, may offer valuable opportunities to different types of investors, including private equity firms. Likewise, similar opportunities may be associated with utility-scale solar assets, which have shown the largest cost decline in the last 10 years. Also the recent success story in the US suggests that the expected growth in corporate renewable procurement in Europe may further enhance such opportunities, combined with the more regulated approach, like auction-based mechanisms, which is still dominating.

Electrical energy storage is certainly gaining momentum but, due to regulatory and technologically uncertainty, it is still difficult to adequately estimate its economic value. This is especially true in markets with well-established gas networks. However, we consider that by any standard, energy storage will be the biggest game changer in the years to come, also because it is based on the same technology which is currently dominating in electric mobility, i.e. lithium-ion batteries.

As a result of these developments, conventional electricity generation, especially coal-fired and old gas-fired power plants are increasingly steadily losing profitability. In particular, investments in coal assets seem to be doomed, due to competition from renewables and the phase-out of these plants which is already planned in most European countries.

With regard to nuclear power instead, the fleet is ageing and the industry is facing a proliferation of problems of public acceptance, notably after the Fukushima nuclear power station accident. Without further lifetime extensions and new builds, we might expect a reduced role for the industry in the future. Moreover, nuclear power generation will face more intense competition from renewables coupled with storage, which may also put existing assets at risk in the coming years.

Nevertheless, assets that may be stranded in the long run can be attractive on shorter horizons. For instance, underinvestment in oil assets today could result in supply shortages and asset appreciation in the years ahead. Furthermore, some existing gas-fired power plants, granted by capacity payments, may represent a profitable investment for financial investors.

Recent figures provided by InfluenceMap (2018) indeed, demonstrate that major financial investors, including BlackRock, Vanguard and Axa, had multiplied their holdings in thermal coal by a fifth between 2016 and 2018 (Mooney et al. 2018), in spite of their publicly-announced decarbonization objectives.

We also analyzed the revenue models and performances of European utilities with the aim of understanding whether networks may represent a rather more secure investment for financial investors compared to utilities, that are more involved in energy supply activities. In this regard, we have seen that electricity networks have provided better financial returns, especially with regard to distribution. Indeed these networks still represent the key enablers of this R-evolution as well as the pillars of the European Energy Union.

Europe's largest utilities are responding with different business models to the challenges and opportunities provided by the six drivers. It is not clear yet which of these models if any will be better suited to compete against newcomers from within the sector as well as from "outside", especially oil & gas and ICT.

However, the usual disclaimer applies to our findings as well. In other words, the expected value of any investment in the energy sector will be significantly affected by changes in climate policy (e.g. carbon targets), market design (e.g. capacity mechanisms) and regulation (e.g. the cost of equity permitted by law).

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