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Innovation and incentive regulation to foster EU energy networks integration

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Abstract

The aim of the work is to provide some insight for the development of a regulatory framework that can foster the integration of energy networks (electricity, gas and district heating) across the EU and the consolidation of a sustainable European energy market. To do so, we analysed the regulatory schemes adopted in the UK, Italy, Germany and France, with a special focus on the incentives provided by national regulators to support innovation projects by network operators. For each country, an overview of the projects carried out is reported. We found evidence of limited investments in this technological field until now. However, all four countries have significantly invested in smart grids, storage and conversion technologies, which are key enablers of the integration of energy carriers.

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Introduction

In recent years, the environmental and energy efficiency objectives set by the European Commission in response to climate changes and pollution have steered countries towards a reduction in carbon emissions achieved through an increasing consumption of energy generated from renewable energy sources. In order to cope with the inherent intermittency of such energy sources, that may cause an unbalancing between energy demand and supply, advanced technologies for the conversion and storage of electricity are being deployed, transforming the way electricity, gas and heat are generated, delivered, and consumed. In order to enhance networks' flexibility, reliability and affordability, the technological innovation of the energy sector is moving towards the integration of energy networks (electric grid, gas network and district heating), aimed at the exploitation of the synergies existing between different energy carriers and corresponding network technologies. Moved by environmental and economic drivers, such technological transformation will have relevant business and regulatory implications. In fact, the value proposition of the firms operating in the energy industry is going to change, with the consequent emergence of new business models that take advantage of this network innovation. In addition, these changes pose the question of how the regulation in the energy sector should evolve in order to foster investments and cost-reducing innovation. Since the 1990s, the EU has issued directives to liberalise national electricity and gas markets, in order to allow efficiency gains and lower prices for consumers. Generation and supply – which are potentially competitive market activities – have been horizontally separated to reduce market concentration and vertically unbundled from the network-related transmission and distribution activities. Due to the lack of competition (natural monopoly), transmission and distribution are subject to sector-specific regulation that ensures third-party access and provides incentives to support networks innovation. Whether both operators and customers may benefit from network innovation strictly depends on the established national regulatory approach, which requires a reform to align incentives with desired outcomes. To this end, many European countries have initiated a review of their network regulations by gradually introducing incentive mechanisms based on output measures of firms' performance.

In the following work, the regulatory schemes adopted by four EU member states are examined. We specifically investigate how network operators have responded to the incentives to network innovation provided by the regulatory frameworks of the UK, Italy, Germany and France. On the basis of the evidence provided throughout the work, we want to point out the progress already made in terms of networks innovation – from Smart Grids to storage and conversion – and to provide some hints for the development of a regulatory framework able to address the emerging requirement of networks integration.

The work is structured as follows:

Chapter 1 depicts the current changes characterizing the EU energy sector in terms of new technologies and emerging business models.

Chapter 2 provides a review of the economic literature on regulation of network industries and how it affects investments and innovation.

Chapter 3 remarks on what has been done to incentivize network innovation in the European Union and provides an analysis of the regulatory frameworks of four EU reference countries focusing on how they foster network innovation activities.

1 The technological transformation of the EU energy sector

1.1 Sustainable integration of RES for distributed generation

Over the last years, we have assisted to an increasing penetration of renewable energy sources (RES), such as solar, wind, hydro power and biomass, in response to climate changes and pollution. Due to their affordability, the energy sector faced a drop of electricity selling price, which allows only the most efficient power plants operate profitably in the market.
However, due to weather variability, such energy sources are by nature intermittent, thus causing a potential unbalancing between energy demand and supply. In order to cope with variations of energy generation in the short term and being able to cover the energy demand, the common practice is to oversize the RES power installation. As a result, this may cause an over-production during sunny and windy days, that in turn would require to curtail the excess energy rather than to adapt the demand to the high level of available renewable and affordable energy. Researches estimated that**,** following this practice, about 217 TWh will be curtailed every year by 2050 (DNV GL, 2014).
A potential solution to this energy supply challenge is the integration of the electricity network with other energy systems, aimed at the exploitation of the interdependencies existing between different energy carriers (electric grid, gas network and district heating) and the corresponding technologies.
Indeed, synergies between different networks may be created through several energy conversion technologies, such as Power-to-Gas (P2G), Power-to-Heat (P2H), Gas Boilers (G2H) and Combined Heat and Power (CHP) systems. By converting the excess energy generated to an alternative energy vector, these technologies allow the electrical grid to absorb a larger quantity of renewable energy, while adding economic value to the energy that would otherwise be curtailed. Further, the growth of renewables will be strongly affected by the shift from the centralized distribution paradigm towards a more decentralised or distributed generation (DG) of gas and electricity, that in turn will require the use of demand response (DR) as well as investments into new storage technologies at both transmission and distribution levels, in order to deal with the complexity and problems arising from multi-directional flows of energy in the grid. In a long-term perspective, the development of energy storage systems, such as electric batteries (EB), together with an efficient load management can allow to achieve a greater flexibility in the generation of

power, that in turn can ensure a secure balance between energy demand and supply and optimise the whole energy supply system.

1.2 Drivers of the integration of energy networks

Several environmental, economic and social concerns drive the development of hybrid energy networks, including:

- the transition to a low carbon energy or “decarbonisation”, with a lower reliance on fossil fuels and an increasing generation of electricity from renewable energy sources. In particular, reducing carbon emissions represents a significant challenge in the transport sector, which is going through the transition from internal combustion engine (ICE) to electric and/or hydrogen vehicles;
- the integration of energy carriers may enhance the flexibility of the energy supply network, in response to variations in supply and demand both in the short and long term, through the implementation of systems for the storage/conversion of electricity that provide additional capacity. In addition, the reliability of the system would be enhanced since interconnection results in multiple alternative channels for energy delivery;
- the shift from centralized energy generation and distribution to decentralisation leads to the exploration of new business models and the alignment of the current regulatory arrangements to them. New opportunities may be created for partnerships between traditionally separated energy businesses, as well as for the involvement of new actors along the value chain (e.g. electricity generation by local consumers and communities);
- the development and implementation of new technologies able to generate heat and power simultaneously may significantly reduce energy costs, while also improving the security of the energy supply network. Through the cogeneration of electricity and gas, it would be possible to achieve higher energy efficiency in system operations compared to the separated generation of different energy carriers.

1.3 Combined Heat and Power (CHP) systems and district heating

The Energy Efficiency Directive issued by European Commission in 2012 required each country a complete assessment of the potential of high-efficiency cogeneration and district heating and cooling (CHP-DH), which is seen as important instrument for the achievement of the EU 2020 targets.

Cogeneration systems based on the Combined Heat and Power (CHP) technology enable the simultaneous production of electricity and heat. A further extension of this technology is represented by Combined Cooling, Heat and Power (CCHP) or trigeneration systems, which use the heat produced by cogeneration for heating and cooling purposes.

In order to promote the growth of energy systems that integrate electricity, gas, and heating and cooling energy networks, many countries are currently assessing the potential of decentralized CHP and CCHP units. The development of an advanced and smart energy supply system requires not to optimize these energy carrier networks separately but rather simultaneously, by promoting interactions and potential synergies among them. At the same time, such technology can allow a better integration of RES in the energy system.

In contrast to the traditional separation between production of electricity through the electric grid and heat generation with gas boilers, cogeneration power plants allow significant primary energy savings (up to 40%) and high energy conversion efficiency (around 60-85% depending on the power to heat ratio). The surplus heat generated can be stored, so as to decouple demand and supply.

CHP production technology can be employed in District Heating (DH) networks, that deliver heat from the site where it is generated directly to consumers to meet household's heating and hot water demand. In a CHP-DH network, generators are located close to the end user, so as to reduce losses associated with long distances of transmission. As a result, it leads to an overall performance improvement of the electricity transmission and distribution network.

The main benefits of the CHP technology are:

- minimum losses thanks to power generation performed on site;
- reduction of energy costs thanks to the simultaneous production of heat and power;
- reduction in carbon emissions compared to traditional heat pumps;
- increased energy conversion efficiency due to the use of waste energy in CHP units;
- enhanced demand flexibility;

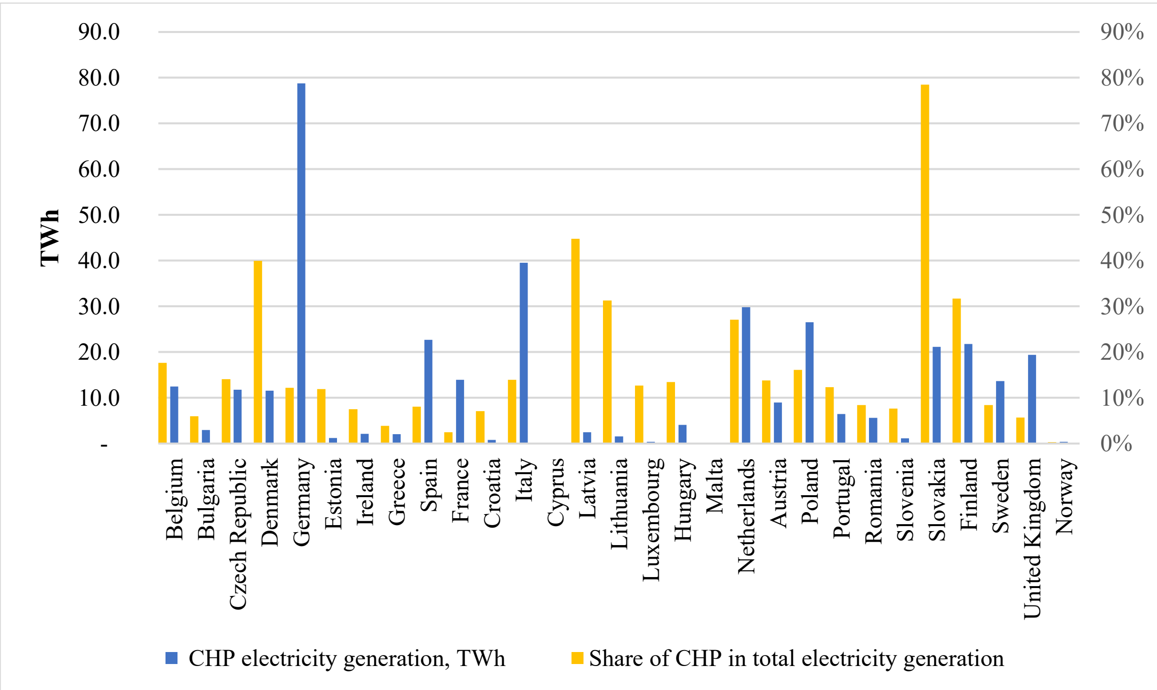
- lower cost for the end user.

However, the development of such efficient energy systems presents some drawbacks:

- high initial capital investment to build the network;
- need to find appropriate sites for generation units to be located close to end users;
- difficulties in establishing a common regulatory system for integrated electricity and heat supply.

In 2015, the European Union generated 11,2% of the total electricity using cogeneration.[1] Germany is at the forefront in terms of amount of energy produced through CHP technology (78,8 TWh), followed by Italy (39,5 TWh). However, these represent less than 15% of the respective total amount of electricity produced in the two countries (see Figure 1). Nonetheless, Germany has set the target to double its electricity cogeneration from 12.2% of the country's electricity by 2020. Currently, Slovakia emerges as the leader by providing 78,5% of its total energy supply through CHP systems.

Figure 1: CHP Electricity Generation by EU Countries in 2015



Source: Elaboration of data from Eurostat database, 2017.

[1] (data source: European Commission, Eurostat, 2017)

1.4 Energy conversion and storage systems

In many Countries, governments and utility regulators provide incentives to encourage investments in the development of systems for the conversion and storage of electricity and support national programmes to foster their growth. In addition, many stakeholders have recognized that the development of storage technologies has the potential to foster the adoption and integration of RES, through the increasing electrification of heat generation and mobility.

1.4.1 Energy storage systems

An energy storage system basically takes the energy and store it for a later use. Examples of these systems are electric batteries (EBs), pumped hydro storage and compressed air storage. Besides cost, the choice between different systems is based on other factors including storage capacity, discharge time, safety and environmental impact.

The seasonal variations which characterize energy consumption on the demand side, and the dependency on weather conditions that make the availability of renewable energy sources (wind, solar, tidal) fluctuate on the supply side, have required the development of energy storage systems in order to manage the mismatch between renewable energy supply and demand in an efficient way.

Storage technologies allow to save the excess energy produced in some periods characterized by low consumption and high level of production, and to ensure a continuous availability of energy even in those periods in which the production is not able to offset demand peaks. As a result, customers are provided with greater flexibility and empowered to manage their energy consumption, while it is possible to maximize the reliability of the electric grid, and to make infrastructure investments more profitable.

Due to its high flexibility and efficiency (around 75-80%), pumped hydro storage represents almost 99% of today's available energy storage. However, the experience already gained in the mobility and consumer electronics sectors have made electrochemical batteries competitive also in the power sector, thanks to the cost reduction enabled by economies of scale.

Along with the positive externalities represented by the societal benefits associated with the sustainable supply of electricity, electric batteries provide firms with quantifiable benefits:

by enabling the provision of multiple services (e.g. PV-EB systems or electric vehicles), EBs may generate multiple revenues streams from the same initial investment. However, the main limitation of electric batteries and many other storage technologies is that they enable the short-term storage of energy, that allows to manage daily/weekly load variations but not seasonal variations of consumption and/or supply. The main barriers to the development of large-scale storage systems are, besides technological limitations, the high investment required and the missed alignment with the current regulatory framework.

What makes storage systems differ with respect to other technologies is that they allow to balance supply and demand across the segments that comprise the value chain, i.e. generation, transmission and distribution. This way, they provide new control systems to promptly respond to fluctuations of electricity input and output throughout the electric grid. Conceptually similar to storage technologies is the role played by the so-called Demand Side Flexibility (DSF) or Demand Response (DR), that consists in the user capability to adapt their electricity consumption, for example, in response to changes in price over time. To this aim, the integration of storage/conversion systems with innovative ICT and modern Smart Meters has the potential to optimize demand management and to improve the overall efficiency of the network.

1.4.2 Power-to-x conversion technologies

The value proposition of power conversion is to create alternative energy networks to deliver heat and natural gas, support the integration of different renewable energy carriers and to achieve the EU target of decarbonisation of the energy system by 2050. However, power-to-x technologies are still not cost-effective to be implemented and further research is needed to reduce conversion costs and gain potential market share.

The most established conversion systems are Power-to-Heat and Power-to-Gas technologies.

Power-to-Heat (P2H): this technology is used for the production of heat from electricity. It can be applied to both centralized and local heat distribution. In the former case, Centralized Power to Heat (CP2H) conversion is used to provide heat to DH networks by means of large-scale heat pumps; the latter case consists in the small-scale conversion of electricity to thermal energy in a decentralized distribution grid based on Local Power to Heat (LP2H) technology.

Power-to-Gas (P2G): this conversion system provides a solution for storing and using the surplus electricity generated, by transforming it into synthetic natural gas (methane). Compared to other available technologies, it minimizes transportation/storage capacity costs and losses. Storage can be provided by a Virtual Energy Storage System (VESS), that allows distributed heat generation and demand flexibility. Although this technology has already been tested, it is still not clear how it will be integrated it in the energy system to promote synergies between the electricity and natural gas grids.

1.5 The evolution of ICT and Smart Grids

The term Smart Grid refers to the use of innovative ICT to enhance system intelligence through the establishment of a bi-directional communication flow between all actors connected to the grid, where the active participation of consumers is made possible. Indeed, consumers are allowed to manage their consumption and, in some cases, to produce energy and become "prosumers" (i.e. both producer and consumer).

The development of Smart Grids has been driven by the shift towards a more distributed energy generation, which requires the integration distributed energy resources (DER), including renewables and energy storage, in the electricity network.

Such technology provides multiple benefits. The deployment of Smart Meters can enhance demand flexibility by providing more information to end-users about their current consumption, resulting in greater energy use efficiency and potentially lower bills. Smart Meters may act as platforms for the provision of new customized services through data collection and manipulation, that enable the creation of dynamic tariff structures (e.g. Time-of-Use tariffs, based on the time energy is being consumed). Overall, Smart Grids improve the cost-effectiveness of the energy management system and make it possible to better cope with peaks in energy consumption. At the same time, the digitalisation and automation of the grid improves its responsiveness to faults and allows automatic system monitoring.

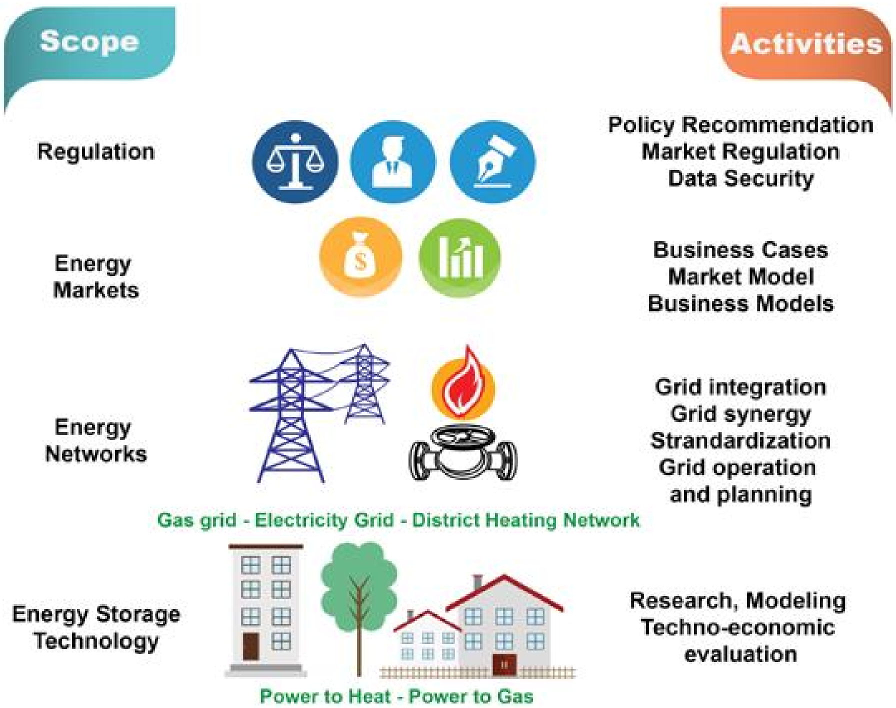
By 2020, the target set by the European legislation for the deployment of Smart Meters is equal to 80% of the whole energy market of each EU Country. In order to incentivize the coordinated effort by all member States, several R&D and pilot programs have been supported to drive the implementation of Smart Grids across Europe, including *Horizon 2020*, *European Electricity Grid Initiative (EEGI), Smart Grid Task Force (SGTF)*, etc.

1.6 The PLANET Project

By 2020, the objective of the European Union Research and Innovation Programme *Horizon 2020* is to reduce greenhouse gas emissions (GHG) by at least 20%, increase the supply of renewable energy up to 20% of total consumption, and achieve energy savings of 20% or more (the baseline is 1990). Since 2014, about 80 billion euros have been used to fund projects to support innovation for the shift towards a more sustainable and integrated energy network and the establishment of an EU Internal Energy Market.

As part of this programme, the PLANET Project (acronym for "Planning and operational tools for optimising energy flows and synergies between energy networks") coordinated by Politecnico di Torino was initiated in 2017 with the aim of developing affordable solutions to support to the accomplishment of the EU internal energy market.

Figure 2: PLANET Scope & Activities



Source: PLANET project presentation.

The project has the objective to integrate conversion and storage technologies (P2G, CHP, P2H, VES) to the current electricity/gas/heat networks for the decentralized distribution of energy. These technologies will contribute to the full integration of RES for the production of green energy and to avoid their curtailment, through the interconnection of energy

carriers. By leveraging on the synergies existing between different energy networks, it will be possible to achieve greater demand flexibility and to match the demand with the intermittent and variable supply of energy from renewable sources (solar, wind, tidal, etc.).
To this aim, PLANET is intended to develop and provide a Decision Support System (PLANET DSS) to policy makers and network operators to facilitate the global coordination of all energy (electricity, gas, heat) networks and conversion and storage assets.
PLANET activities focus on the co-optimisation between four energy networks, namely the electricity distribution network, gas distribution network, virtual thermal distribution network and the DH network. They include:

1. The development and modelling of decentralized electricity conversion systems (P2H, P2G, VES) to optimize energy conversion efficiencies. These activities will range from research work to simulations and test.
2. The development of an ICT system (PLANET DSS) to optimize planning and operations of the distribution grid and to control conversion and storage solutions based on VES systems. This multi-purpose, district-level software suite will allow the optimisation of network connection and integration by providing information about electricity supply and demand on the grid and on the availability of storage/conversion systems.
3. Impact assessment of the deployment of conversion and storage technologies on the current regulatory landscape, policy recommendations and exploration of new market and business models, in compliance with the EU requirements.

Finally, the implementation of innovative business models as part of the PLANET project plan will require the definition and adoption of a new set of rules by national policy makers. These directives should provide incentives to invest to the actors involved, while also ensuring market efficiency and coordination.

1.7 Non-traditional business models

Rapid technological innovation (Smart Meters, advancements in information and communication technology, storage systems), together with social and environmental issues, have fostered the offering of new products and services (or new means for delivering them) in the energy industry. Significant changes in the value proposition of the companies operating in the industry is inherently reflected by the emergence of innovative business

models. Such radical change of the conventionally adopted business models is necessary in order to encourage investments in technological innovation.
The energy market in the UK has been the first to experiment such disruptive innovation. The UK's electricity and gas markets are regulated by the Office of Gas and Electricity Markets (Ofgem), whose role is to protect the interest of consumers by controlling the level of market competition and promoting it where needed. According to Ofgem, the UK's energy market is witnessing a transformation of the so called "traditional" business models, i.e. those regulated by the existing market rules and offering a portfolio of products and services widely recognized by customers, to new business models that are going to radically change the way the energy market currently operates.
Such "non-traditional" business models, that have already emerged in the UK's energy market, have been adopted by both incumbents and new entrants, who are progressively offering new products and services related to the supply and distribution of energy (e.g. smart meters, demand response services, communication and information services, etc.).
Organizations that adopt NTBMs have the potential to rise market's competitive pressure and thus to lower prices and make energy more affordable even for vulnerable consumers. This is possible thanks to the increased demand flexibility that is allowed by the innovative technological solutions introduced. For instance, thanks to advancements in ICT and smart meters, consumers can be better engaged with the market by providing more transparent information or products and services that better address their needs. At the same time, the enhanced energy efficiency can push the move towards a low-carbon energy system, that has been strongly promoted by the European Commission through the Horizon 2020 Programme.
Business model innovation may provide considerable operational and social benefits, including:

- lower bills for customers;
- increase competition in the industry;
- consumer engagement and empowerment;
- greater flexibility of network operations;
- higher energy efficiency;
- reduced negative environmental impact;
- improved security and reliability of energy supply;
- better service quality.

1.7.1 Classification of non-traditional business models

As the cost of energy storage systems will progressively go down, the establishment of innovative business models will offer multiple new sources of revenues for both incumbents and new entrants in the energy industry. As a result, competition is expected to intensify, with the consequent offering of greater consumer choice and the fall in prices.

Following the classification suggested by the UK's regulatory authority (Ofgem 2015), non-traditional business models for the provision of energy services to local (residential) consumers can be clustered into three categories:

- Local energy services (including community-level solutions to local customers);
- Bundled services (provided by specialized energy service suppliers);
- Services involving customer participation.

1.7.1.1 Local energy services

Community Groups

This model consists in the aggregation of energy storage at the community level. Here "community" can be intended either as local geographical area or as community of interests (e.g. group of customers with limited economic means). Community projects and activities are often carried out by non-for-profit local organizations or co-operatives that are engaged with the aggregation of local energy storage, in order to promote self-consumption and lower energy bills paid by consumers. Moreover, these organizations often support community growth by funding local charities and creating employment.

This model provides local communities with significant benefits. From an economic perspective, because of the lower generation and transmission costs faced by local people, who own the community projects. From an environmental perspective, it fosters the generation of energy from RES that are available locally and/or from the waste produced by the community. The overall benefit is shared by the community, which is entirely engaged to better energy management. Finally, the connection between the community and the electric grid is always guaranteed and this enable the sale of energy to the grid.

Municipal Suppliers

Conceived to supply gas and electricity at more affordable prices to enhance competition in the UK's energy supply market, municipal energy companies represent an alternative to the community business model. They are not-for-profit organizations owned by local authorities that offer lower prices – compared to the tariffs of incumbent gas and electricity suppliers – to consumers who are located within their municipality, while being also licensed to supply energy at market prices elsewhere. Examples of municipal suppliers in the UK are *Bristol Energy* and *Robin Hood Energy*.

1.7.1.2 Bundled services

Energy Service Companies (ESCos)

ESCos are companies that deliver multiple services for the management of performance-based projects aimed at the improvement of energy efficiency and/or load reduction of customers' facilities. Such services range from design and financing to operation and maintenance. They make revenues proportionally to the energy savings they generate, based on two possible types of contracts: energy service contracts, for the provision of energy streams such as hot water, or performance-based contracts, for the provision of final energy services such as lighting. The main difference with respect to traditional utility companies, whose revenues are directly proportional to customer consumption, is that an ESCo typically enters performance-based contracts that incentivize it to reduce its customers' energy consumption.

The level of competition and privatization of the energy industry, which varies from one country to another, may hinder the growth of ESCo business model and so the achievement of energy efficiency for two main reasons:

1. higher competition means lower prices, so that utility companies would need to reduce costs by cutting edges on energy efficiency programs;
2. at the same time, customers would pay lower bills and would become less concerned with energy savings.

White Labels/Licensed Suppliers

Companies that operate in the retail energy market, but do not have the license to supply, may act as "white labels" by partnering with licensed energy suppliers to offer tariffs for gas and electricity services to specific customer segments under their own brand.

Partnerships between white labels and established suppliers may reduce barriers for new entrants in the energy supply market. In the UK, in order to increase the level of competition in the industry, dominated by the "Bix Six", i.e. the largest energy suppliers (*British Gas*, *EDF Energy*, *E.ON*, *Npower*, *Scottish Power* and *SSE*) and to lower prices, some organizations have started a collaboration with them (e.g. *Sainsburys Energy* with *British Gas*).

1.7.1.3 Services involving customer participation

Prosumers

The new concept of consumer who does not only consume energy but also produce energy on his own is an example of innovative business model that allows to make profits from the utilization of energy storage facilities. Thanks to ICT and smart meters, consumers are empowered to actively manage their consumption and, sometimes, to even produce energy through solar photovoltaic panels and other technologies. Looking at the future, if prosumers come together on a local (district/neighbourhood) base, there would be the opportunity to achieve economies of scale in local energy generation by integrating storage technologies in the established distributed network, so as to reduce the cost of individual installations. Prosumers can take advantages from self-production and consumption, by using energy storage systems as reserve where to store saved energy, so as to minimize the consumption of energy from the grid, especially during those time intervals in which demand reaches its peak and utility companies typically charge higher prices. However, the connection of energy storage owners to the grid would allow them to cover costs thanks to the additional revenues coming from Feed-In-Tariffs, which represent a guaranteed fixed price at which prosumers can sell the energy surplus produced to the power grid or to other energy consumers. Finally, it must be also observed that the information access provided to consumers by modern Smart Meters creates an arbitrage opportunity for prosumers, who can make revenues by purchasing electricity during time periods in which demand is very low and utility companies charge a low price, while selling it in periods of peak demand.

Peer-to-peer (P2P) Model

Based on the concept of P2P or sharing economy, this business model involves the direct trading of energy between generators, prosumers and consumers, usually within a local electricity distribution system. In a P2P system, each “peer” is enabled to buy or sell energy through online service platforms based on advanced ICT technologies, without need of intermediaries traditionally represented by energy suppliers.

Differently from the traditional unidirectional model for energy distribution, based on the centralized, large-scale generation of energy and its transmission to consumers over long distances, P2P allows multidirectional trading within local geographical areas. The P2P business model has been already adopted in some European Countries. Some examples are *Piclo* in the UK, *Vandebron* in Netherlands and *sonnenCommunity* in Germany.

Aggregators

Organizations like energy cooperatives provide demand-response and storage services by aggregating the costumers they represent and acting as intermediaries between them and the wholesale market in order to obtain low prices when acquiring energy or related services. This business model enhances Demand Side Flexibility (DSF) among local customers, that is the capacity of final users to adapt their current consumption of electricity in response to price changes or incentives over time. Aggregators can send pricing or activation signals through smart grids to end-users whenever electricity prices are very low or extremely high, so as to adjust consumption accordingly. Of course, aggregators should operate without damaging or causing additional costs for other market participants, such as suppliers. Finally, renewable energy aggregators will accelerate the integration of renewable energy sources, reduce energy prices and improve power grid management.

1.7.2 Cost/benefit analysis of business model innovation

The innovation of traditional business models has the potential to disrupt the energy sector by changing the market structure and allowing the entrance of new players able to provide new products and services based on the latest technological advancements. A higher competition can in turn reduce costs and prices. In addition, these new business models can also help to address environmental and social issues, such as the transition to a low carbon network and the current lack of consumer engagement.

Table 1 summarizes the potential benefits and costs that, to some extent, are common to all non-traditional business models that have been analysed. Benefits are not only economic, as it was already mentioned, but include also social aims (such as creation of employment, customer empowerment, targeting vulnerable consumers, etc.) and the positive environmental impact of reduced consumption and network integration. Costs faced by both incumbents and new entrants are related mainly to the infrastructure investment and costs of system innovation, such as coordination, integration and installation expenses. Further, some measures must be taken to cope with possible risks to consumers, for example regarding supply reliability and data security.

Table 1: Benefits and Costs of Non-Traditional Business Models

Benefits	Costs
Intensification of market competition and technological innovation enable lower prices.	High initial capital investment required to implement ICT technologies and infrastructures (e.g. smart meters).
Better management of consumption through consumer engagement (e.g. consumers as prosumers and collective purchasing arrangements) allows bill reduction.	Costs of system integration associated to distributed and intermittent energy generation.
Enhanced social welfare by creating new jobs and making local consumers part of the energy supply system (consumer empowerment).	Decentralization requires additional connections and potential reinforcement of the grid network.
Decentralization of energy generation and distribution network may reduce energy losses and related costs.	The engagement of new market participants (e.g. prosumers) may generate high coordination costs.
Better demand management and enhanced system flexibility allow to match energy supply and demand.	Greater network size may rise management and operating costs.
Fostering process and product/service innovation may drive down costs and enhance consumer choice.	Cost of installation of private wire networks for local communities can be very high.
The achievement of domestic and vulnerable consumers traditionally hard to be reached may foster the economic development of local communities.	Data privacy and security require the deployment of strategies to protect consumers against risks.
Increased community awareness about environmental concerns may support a low carbon economy and the integration of renewable energy sources.	Innovative digital products and services may not be affordable for and accessible to all customers.

The emerging trend results in the management of generation, transmission and distribution of energy at local level. In the future, flexibility services, such as demand response and storage will likely be provided by community energy groups, which are better positioned to bargain with their local community than suppliers, since they better understand the local context and the needs of the people living there. They are also more likely to be trusted by consumers.

However, this model of business poses some challenges. As an example, given that it is unlikely that a community can completely survive "off-grid", i.e. without need to get energy from the electric grid, a way to charge them accordingly must be found. Indeed, it is not only a matter of use of the wire network, but also of maintenance and service costs to be allocated across network users. Finally, even in the case in which the community would remain off-grid, cost would sensibly increase for those consumers remaining in the network. If local energy services (such as community groups or municipal suppliers) will gain sufficient market share, the energy market will shift from the centralized generation and distribution of gas and electricity to a decentralized supply and energy storage system that will be controlled by new players (e.g. prosumers, P2P, local communities, etc.).

2 Regulation and investment – a literature review

The presence of economies of scale and network externalities make gas, heat and electricity distribution natural monopoly activities, which require economic regulation.

Economic regulation is effective when it does not intervene where market competition is meaningful (e.g. generation and retail of electricity), while it regulates those services with stronger natural monopoly characteristics (e.g. electricity transmission and distribution), in order to protect customers' interests and to ensure sufficient investment incentives for network operators to improve infrastructure efficiency and service quality. Any regulatory mechanism can be considered as equivalent to a sequence of contracts – each one lasting for the duration of a regulatory period – between the regulated firm and the regulator, who acts on behalf of consumers.

The regulatory policy adopted by national regulators strongly influences the investment decisions made by firms operating in the energy industry. Nevertheless, empirical evidence about the potentially different effects of alternative regulatory mechanisms (i.e. rate-of-return and incentive regulation) mostly comes from the U.S. and on telecommunications industry (Guthrie 2006).

In this chapter we discuss how regulatory framework and market structure of network industries – and more specifically of the energy industry– are related with investment in infrastructure and investment in innovation and cost-reduction[2], respectively. To this end, we have analysed the way these conceptual issues are discussed in the literature. Table 2 lists the working papers that have been examined.

Table 2: Summary of examined working papers

Paper	Author(s)	Publication date
Innovation and market regulation: evidence from the European electricity industry	Cambini, C., Caviggioli, F., Scellato, G. – *Politecnico di Torino*	2016
Incentive regulation and network innovation	Bauknecht, D. – *European University Institute*	2011
Incentive regulation, investments and technological change	Vogelsang, I. – *CESifo Group*	2010

[2] For example, innovation in the electricity industry is related to the development of new technologies for electricity generation from RES, but also to the construction of highly innovative infrastructures that combine updated technologies with ICT for a more efficient operation of the grid, namely Smart Grids.

Infrastructure investment in network industries: the role of incentive regulation and regulatory independence	Égert, B. – *CESifo Group Munich*	2009
Regulating infrastructure: the impact on risk and investment	Guthrie, G. – *Journal of Economic Literature*	2006
Regulation, competition, and liberalization	Armstrong, M. and E.M. Sappington – *Journal of Economic Literature*	2006
Incentive regulation and competition in public utility markets: a 20-year perspective	Vogelsang, I. – *Journal of Regulatory Economics*	2002

2.1 Rate-of-return regulation

Under rate-of-return regulation, the regulator sets the prices to be charged by the monopolist firm on an annual basis, in such a way to limit its power towards customers while allowing the regulated firm to cover operating costs and to earn a fixed rate of return on capital. It is a “cost plus” mechanism through which the regulator sets the rate of return on assets the firm can earn. This way, the allowed revenues for the next regulatory period equal the sum of expected operating costs, assets depreciation plus the rate of return on capital. The “fair” rate of return is set by the regulator or can be contracted between the regulator and the firm, so as to ensure that the latter will recover the expected investment costs. Subsequently, if the profitability of the firm increases (decreases) as a result of a decrease (increase) in production costs since the last review, price can be adjusted accordingly to match the actual rate of return with the fair rate of return at the request of either the regulator, the regulated firm or consumer representatives. As a result, the timing of price reviews is a function of the profitability of the regulated firm. The main limitation of rate-of-return regulation is that it provides regulated firms with an incentive to overinvest in capital (Averch-Johnson effect) and expand their asset base but not to reduce production costs, thus shifting the risk of cost overruns onto consumers through an increase in prices.

2.2 Incentive regulation

The main reason to provide incentives to regulated utilities is that regulators are imperfectly informed and face asymmetric information, as they are not able to directly observe the firm’s cost opportunities, level of managerial effort and service quality. This information advantage of the regulated operator creates an opportunity for strategic behaviour, as the regulated firm may increase its profits by claiming higher costs than it really incurs. For this reason, over the last twenty years the regulation of electricity and gas markets in most countries have shifted from cost-plus to incentive regulatory mechanisms. Incentive mechanisms usually takes the form of price- or revenue-cap regulation and provide strong incentives to improve productive efficiency as the regulated firm is allowed to keep excess profits deriving from cost reduction. In doing so, these mechanisms deliver significant benefits to costumers.

Price-cap regulation implies that prices that regulated firms can charge are capped for the duration of the established regulatory period. Prices are then adjusted annually by a price cap index (CPI-X) that includes: (1) an inflation rate (Consumer Price Index or CPI) that reflects change in prices of the regulated firm's bundle of services; (2) an X factor that targets the expected firm's efficiency gains relative to industry average productivity.[3] At the end of the regulatory period (usually 3-5 years), a price control is performed to adjust the price index by setting a different level of the X factor. The price-cap mechanism is intended to provide powerful incentives for cost reduction. The power of the incentives comes from the possibility for the regulated firm to retain cost savings above the efficiency target X, and thus to make long-term profits.

Revenue-cap regulation is similar to price-cap regulation in that the regulator places a constraint on the revenues that the regulated firm is allowed to earn (or "revenue allowance") through a revenue cap index that accounts for the inflation rate and the target X efficiency factor. As a result, revenue caps also provide strong incentives to cost reduction and allow to flexibly adjust the prices of the firm's regulated bundle of services. However, revenue caps may encourage firms to inefficiently raise prices above the monopoly level, regardless of societal benefits. At the same time, firms are not incentivized to expand their customer base, but rather to encourage minimal demand per customer through a more efficient consumption of energy, since they would not make any revenue from excess demand beyond the revenue cap. By contrast, a price-cap would limit this behaviour and increase social welfare by inducing firms to raise productivity and lower the prices they charge.

[3] Price-cap regulation often includes other cost-affecting factors that fall outside the firm's control and are typically passed through in retail prices.

2.2.1 Regulatory approaches for cost-effective investment

Incentive regulation should be able to assess the efficient capital expenditures (CAPEX) and operating expenditures (OPEX), ensure an adequate level of quality of service and minimize energy losses. Due to the long duration of the regulatory period, incentive regulation tends to foster short-term investments and network innovation that are aimed at reducing OPEX. Indeed, this allows networks operators to gain higher profits as a result of the reduced costs for the remainder of the current regulatory period. Instead, CAPEX is typically associated to long-term investments, with payback times generally longer than the established regulatory period. For this reason, providing incentives for long-term network investments is more challenging. A trade-off emerges between network expansion or reinforcement (increased CAPEX) and network management and maintenance (increased OPEX). For example, predictive maintenance (increased OPEX) can postpone or avoid the replacement of an asset by extending its useful life (decreased CAPEX). There are two possible approaches to cope with this trade-off:

- “Building block” approach;
- TOTEX-based approach.

Following a building block approach, CAPEX and OPEX are assessed separately and the allowed revenues are set by the regulator to ensure the firm can recover efficient costs that are expected to be incurred in providing the regulated services. Efficient costs are estimated based on a scrutiny of the projections contained in the firm’s business plan and on efficiency benchmarking. Allowed revenues are determined annually as the sum of three “building blocks”:

- return on capital, which represents the opportunity cost of the investment and equals the cost of capital or WACC;[4]
- depreciation, which allow to spread CAPEX over the assets’ useful life;
- OPEX, which include the expenditures the regulated firm incurs in running the business.

While OPEX are directly added to revenue allowance, the computation of return on capital and depreciation goes through the regulatory asset base (RAB), that contains the information on the firm’s net capital invested, assets lives and cost of capital. The main drawback of the

[4] Taxes must also be accounted for in the allowed revenues either as a fourth building block or by computing the allowed return on capital based on the pre-tax WACC.

building block approach is that it encourages firms to overinvest in capital, as expenditures are capitalized in the RAB based only on actual CAPEX; the increase in RAB is translated into a higher firm's return on equity, and thus in a greater revenue allowance.

The TOTEX-based approach was firstly introduced in the UK by Ofgem in 2009. Under this approach, allowed revenues are computed by the regulator based on the assessment of total expenditure, which is the sum of: (a) capital expenditure, including incremental and replacement investments, adjusted for inflation; (b) operating expenditure for network maintenance. Under this approach, regulated firms are provided with equal efficiency incentives to both CAPEX and OPEX savings and to prevent inefficient investment outcome. The regulator sets a fixed share of actual TOTEX that will be capitalized into the RAB ("slow money") – based on an ex-ante estimation of capital and operating expenditures in TOTEX at the start of the regulatory period – while the remainder "fast money" will be fully expensed annually. Consequently, overall cost-effective investments are fostered as the same share of expenditure is capitalized irrespective of the actual share of CAPEX or OPEX in the firm's investments.

2.2.2 Output-based incentive regulation

Since the liberalization of the energy markets, incentive regulation has been focused mainly on the use of inputs (operational and capital expenditures) to promote productive efficiency. However, the technological transformation currently witnessed by the energy sector requires a new approach to foster network innovation and address emerging sustainability concerns (Cambini et al., 2014). To this end, output-based incentive schemes are being introduced in many countries through incentives focusing on output measures of firms' performance (e.g. network reliability, environmental impact, quality of service, security of supply, connection to decentralized generation, etc.).[5]

Output-based incentive regulation is highly effective in promoting efficiency while enabling delivery of outputs to customers and other stakeholders. An output-based scheme requires the regulator to define output targets and, if well implemented, it should incentivize

[5] As it will be discussed in the third chapter, the UK's RIIO model is the most well-known example of output-based regulation, but also the Italian regulator and other regulatory authorities are adopting output-based schemes to incentivize network operators to achieve some performance outputs (especially for quality of service).

operators to achieve these outputs at the lowest cost to customers. Operators are left free to decide how to achieve those targets, which are only reviewed by the regulator at the end of the regulatory period. This approach is preferable to an input-based approach, in which the regulator prescribes how the operators should achieve the desired outcomes. Output-based regulation may potentially minimize inefficiencies in the use of inputs – given the regulator's asymmetry of information – since the firm is left free to take decisions on the use of resources to meet output targets. Operators take advantage of this freedom in working practices through asset management and replacement strategies, which may lead to significant efficiency improvements and ultimately to lower prices for customers. On the other hand, an output-based scheme may hinder cost efficiency by forcing the regulated firm to increase expenditures in order to meet the output targets set by the regulator.

2.3 Regulation and infrastructure investments

After the liberalization and privatization of the energy industry in the '90s, regulators have moved from cost plus mechanisms (e.g. rate-of-return) to incentive mechanisms (e.g. price- and revenue-cap, profit- and revenue-sharing) in order to support the innovation of energy networks by providing incentives for investments in cost-reducing technologies and new infrastructure. Indeed, the effect of regulation on investments is strongly related to the power of the incentives provided, which is directly proportional to the cost savings (increases) the regulated firm retains (shoulders) as a result of the investment made, and inversely related to the risk borne by the firm. Risks and incentives for the regulated firm differ from one type of regulation to another. Cost-plus mechanisms such as rate-of-return regulation generally provide the firm with low risk and weak incentives, while price-cap regulation is by contrast associated with high risks and incentives (Vogelsang, 2010).

Moreover, Armstrong and Sappington (2006) suggests that regulatory regimes differently affect the type of investment made by regulated firms, that is, whether operators decide to invest in network infrastructure update or in innovation and cost reduction. As for infrastructure investments, rate-of-return regulation is believed to result in overinvestment in new infrastructure, while incentive regulation is thought to lead to underinvestment in the long term.

Under rate-of-return regulation, the regulated firm may be encouraged to overinvest in infrastructure with low attention to network efficiency since, being the rate of return on the firm's asset base fixed, the firm faces much lower risk. Whenever the fair rate of return exceeds the cost of capital, utilities would increase their profits by substituting labour with capital, leading to allocative inefficiency (Averch-Johnson effect). At the same time, low incentives to raise productive efficiency would result in increased costs and quality of service.

Under incentive regulation such as price-cap, the regulated firm is instead incentivised to be more efficient and would be better off by achieving cost reductions in the short term, as it can keep the benefits deriving in the form of higher profits, and by reducing quality of service, given the price cap set by the regulator. In order to avoid for the firm to make extra profits by reducing service quality, the regulated price may be adjusted by some quality measure during the regulatory period.

However, more recent literature recognizes that the extent to which different regulatory regimes provide incentives to infrastructure investments significantly depends on their framework arrangement. Égert (2009) identifies three main factors influencing the timing of investments, that expose both rate-of-return and incentive regulation to the risk of underinvestment:

- the regulatory asset base (RAB);
- the frequency of regulatory reviews;
- regulatory opportunism.

2.3.1.1 The regulatory asset base (RAB)

The RAB is the net capital invested by the regulated firm that is recognized by the regulator and represents the base for the computation of the return on investment for regulatory purposes. The investment decision by the regulated firm is affected by the timing of the investments evaluation made by the regulator: a regulator's ex-ante selection of the investments allowed to be included in the RAB may cause the firm to cut back on planned investments; an ex-post investment assessment by the regulator may bias the firm toward the selection of smaller projects involving less sunk costs rather than large projects, as the regulator may not allow the whole investment to be included in the RAB based on information that were not available at the time in which the investment was made.

2.3.1.2 The frequency of regulatory reviews

The timing of investment decisions depends on what happens at the end of the regulatory period, as well as on the length of the regulatory period relative to investment (Guthrie, 2006). Under rate-of-return regulation, operating costs savings derived from the investment are passed though consumers at the next regulatory period, when the firm's investment expenditure is added to the RAB. In the case of incentive regulation, all operating cost savings are retained by the regulated firm, and prices are set independently from the firm's actual investment, which does not affect its RAB. In both cases, investment is likely to occur in the first few years of the regulatory period. As the next price control review is approached, the regulated firm maximizes the investment payoff by postponing the investment to the next regulatory period, as this maximizes the length of time during which it will benefit of lower operating costs. As a result, the lower the frequency of regulatory reviews, the greater the incentive to make innovative and cost-reducing investments.

2.3.1.3 Regulatory opportunism

The lack of a credible commitment to keep prices unchanged after firm's investments generates the threat of opportunistic behaviour by the regulator or "regulatory opportunism". When the regulator can make no commitment, prices will be changed immediately after the firm's investment, thus preventing it from recovering investment costs. Anticipating this behaviour, the regulated firm will either postpone investment or not invest in the first place. Even when the regulator commits to keep prices fixed for a limited period of time, equal to the time remaining in the current regulatory period, at the next regulatory review the regulator can still act opportunistically and reset prices at the minimum sufficient level that allows the firm to carry on their business. The lack of a credible regulatory commitment brings myopic behaviour by the firm when making investment decisions (Guthrie, 2006). In order to minimize the present value of investment expenditure over current regulatory period, the regulated firm would favour a sequence of smaller investments over a single large investment, as doing so allows it to postpone some investment to the next period when costs will be compensated. As a result, the prospect of regulatory opportunism and uncertainty induce the firm not to fully exploit economies of scale in investment. Under rate-of-return regulation, uncertainty is related to the invested capital that the regulator will include in the RAB. Under incentive regulation, the risk of a future change of the price cap based on the regulated firm's current performance may restrain the firm from seeking efficiency improvements deriving from cost-reducing investments.

2.4 The effect of competition and regulation on innovation

As pointed out by Cambini et al. (2016), competition and market liberalization support innovation in network industries (e.g. electricity and gas sector), even if with some limitations. On the one hand, in an intense competitive environment firms are more incentivized to engage in innovative activities aimed at reducing operating costs and increasing efficiency than an unregulated monopoly, as a way to gain market share. This is true in part because the output produced at the industry level is greater under competition than under unregulated monopoly, providing greater potential cost savings from a reduction in marginal production costs. However, as competition becomes more intense, the profitability of inventions decreases providing ground for imitation and reduced innovation effort. On the other hand, high market concentration may foster innovation since a monopolist may use its profit as valuable source to fund R&D activities (Armstrong and Sappington, 2006).

In the last two decades, market reforms introduced liberalization and incentive regulation in the energy sector with the aim of stimulating competition, increasing efficiency and stimulating innovation and infrastructure investments. However, while liberalization and market deregulation have proved to have significant and positive impact on infrastructure investment, the effect of regulatory policy on investment in innovation and cost reduction may differ. Armstrong and Sappington (2006) observe that a regulatory policy that leaves a firm with no extra profit as a result of decreased production costs – as in the case of a cost-plus mechanism, such as rate-of-return regulation – expropriates any investment made by the firm to lower production costs. Instead, a regulatory policy that allows the regulated firm's revenues to diverge from realized costs for a predefined period of time, as in the case of incentive regulation (e.g. price cap), would foster investments in innovation and cost reduction, at least in the short term. At the same time, cost-reducing incentives may induce a deterioration of service quality, that in turn may reduce demand and stimulate competition (Vogelsang, 2002).

2.5 Regulatory approaches to innovation

In order to promote R&D and demonstration activities and innovation in network industries, both cost-plus and incentive regulation can be integrated with specific innovation regulatory mechanisms, that can either follow an input- or cost-based approach or an output or price-based approach (Bauknecht, 2011). The main difference between these two categories of approach is that input-based mechanisms attempt to transfer the input (operating and capital expenditure) risk from network operators to customers, while output-based mechanisms aim at rewarding network operators for their innovation output based on some measures of firms' performance. In discussing these mechanisms, we want to stress that is not sufficient for R&D and innovation to increase efficiency or provide new products or services, but they must achieve that in an efficient way from the social welfare's perspective (i.e. passing on the benefits of innovation to consumers through lower prices as quickly as possible).

2.5.1 Input-based mechanisms

Input- or cost-based approaches are based on the explicit recognition of R&D costs by the regulator when determining the firm's cost base. R&D costs can be treated following two possible approaches:

Pass-through of R&D costs to customers

This mechanism is used by network operators to shift the risk related to R&D activities to customers by directly including their cost into network tariffs. This instrument is likely to be adopted with incentive regulation, while in a cost-plus mechanism such as rate-of-return all costs are inherently passed through. As R&D costs are passed through, they are not included in the costs that need to be recovered by improving efficiency. In addition, as the firm becomes more efficient as a result of the innovation effort, it can benefit from the lower costs during the regulatory period. The drawback of this mechanism is that – if the amount of R&D costs that can be passed through is not capped – the risk is shared unevenly between the network operator and its customers: while they share the benefit of useful innovation, the risk that R&D activities do not produce any result is entirely borne by customers. As a result, network operators are incentivized to perform useful RD&D, but not to be efficient.

R&D cost capitalization

R&D costs, usually regarded as operating expenditure, can be alternatively treated as investment and added to the RAB as capital expenditure. The logic behind this approach is that investments in R&D and innovation typically provide long-term benefits beyond the year in which the corresponding expenditures are incurred. Differently from the previous mechanism, cost capitalization can be used to support innovation both with cost-plus and incentive regulation. The main drawback of this mechanism is that it provides firms with an incentive to inefficiently overinvest in R&D in order to be granted a higher return on investment.

2.5.2 Output-based mechanisms

Output or price-based regulatory approaches to innovation are based on the output of R&D activities and allow the firm to appropriate the benefits of network innovation. Bauknecht (2011) distinguishes three output-based approaches:

Raising the revenue allowance

Through this mechanism, the regulator sets up an increase in the firm's revenue allowance as a function of the innovation output, taking into account the average cost of developing the innovation. Through the higher allowed revenues, this mechanism allows the firm to recover part of R&D costs that otherwise could only be indirectly recovered through cost-savings relative to the imposed revenue cap.

Extend the length of the regulatory period

Under incentive regulation, the regulated firm benefits from the reduced costs allowed by innovation up until the end of the current regulatory period, while at the next period efficiency gains are passed through to consumers in the form of lower prices (imposed by the regulator). By extending the regulatory period, network operators are more incentivized to innovate. However, this mechanism implies also that the benefits of innovations will be passed on to consumers later. In addition, the firm may be also incentivized to postpone the adoption of the innovation, as doing so would also delay the price reduction imposed by the regulator. For these reasons – and given the difficulties in distinguishing the proportion of efficiency improvements derived from a firm's R&D and innovative effort – this approach may be not feasible in practice.

Regulatory holidays

When the regulator cannot make a credible commitment ex-ante to keep the allowed rate of return unchanged after the firm's investment in R&D and innovation, they may rather commit to exempt the firm from regulation for a finite period of time (i.e. regulatory holiday), so as to allow it to temporarily exploit the rate of return generated by successful investments. During a regulatory holiday, there is no cap on revenues and a network operator is allowed in principle to charge monopoly prices in a certain part of the network.

This mechanism does not apply to the electricity sector, where a single network delivers the same service (e.g. distribution or transmission) and network users have no possibility to switch to any alternative network. Also, it would not be possible to temporarily exempt part of the network in which the innovative firm operates from regulation because innovation typically affects the network as a whole. Application of this approach have instead been considered in the telecommunication sector, where different networks compete on the provision of the same or similar services.

3 Innovation and Regulation in the EU energy sector

This chapter aims to provide an overview of what has been done to incentivize network innovation in the EU countries, focusing on the role of Member States' regulatory authorities. This is no easy task due to multiple reasons:

- A lack of a common definition about what exactly amounts to network innovation;
- The difficulty of acquiring data with regard to the innovation effort in each State, both due to the lack of such data and to their availability only in foreign languages;
- The lack of a European database which collects all projects in this area.

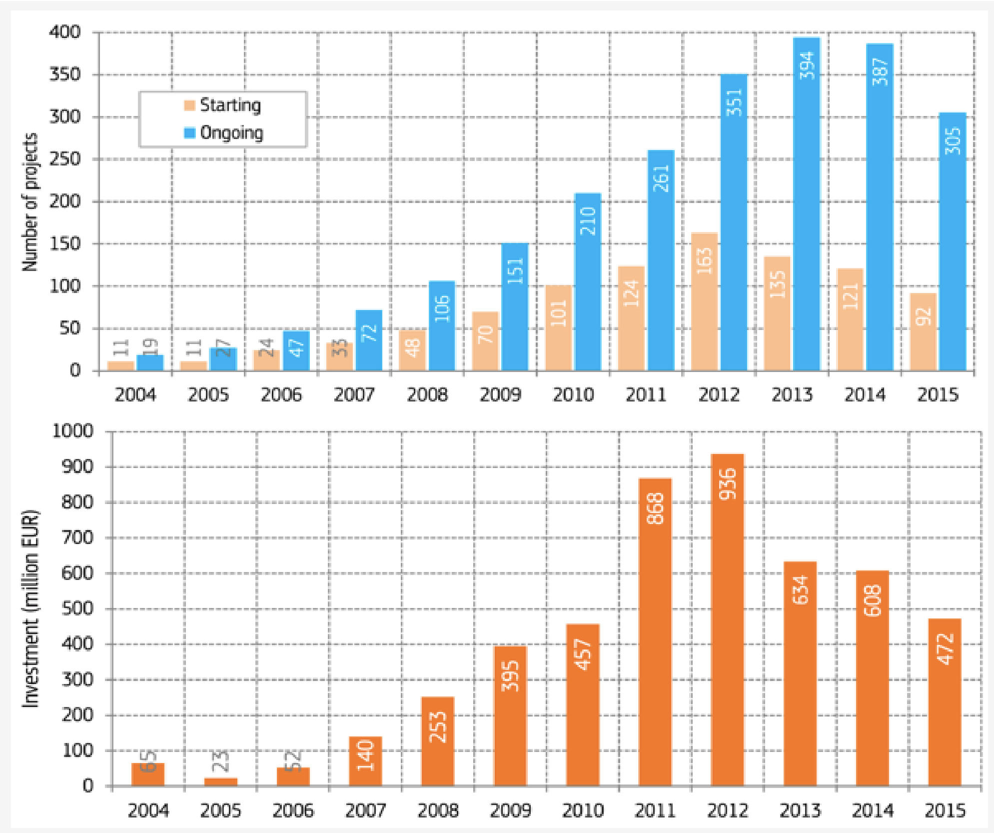
Due to these circumstances such an overview can only be partial, but we believe it can still be useful in providing insight on what has been done up until now and what can be learned from current regulatory efforts to tackle the challenges arising from the need for integration of the energy networks and the consolidation of a sustainable European energy market.

With this purpose, the chapter offers an informed view of Smart Grid investments across Europe, as well as a glance at the EU's funding programme *Horizon2020* and at the contribution it has provided regarding energy efficiency and low carbon technologies. Then, moving from the broader EU perspective to the national level, we portray the regulatory schemes – with a focus on how they deal with innovation – of four reference countries: the United Kingdom, Italy, Germany and France. Particular attention has been paid to the case of the United Kingdom, as we believe it offers the most well-structured regulatory framework which could be used as guidance in defining the regulatory regime of a low carbon, integrated energy sector.

3.1 An overview of Smart Grid projects in the EU

The Joint Research Centre (JRC) is a service of the European Commission which supports EU policy by providing independent scientific and technological advice. Through its constantly updated project database, it provides an overview of the current state of Smart Grid advancements in the EU. It does so by tracking number of projects, project budgets, stage of the innovation cycle, coordinator's country, source of financing, Smart Grid domain. The database is made up of 950 projects carried out in the 28 European Union countries (plus Norway and Switzerland) up until 2015, for a total investment of €5 billion.[6]

Figure 3: (a) Time distribution of projects (b) Time distribution of total investment



Source: JRC, "Smart Grid Projects Outlook 2017".

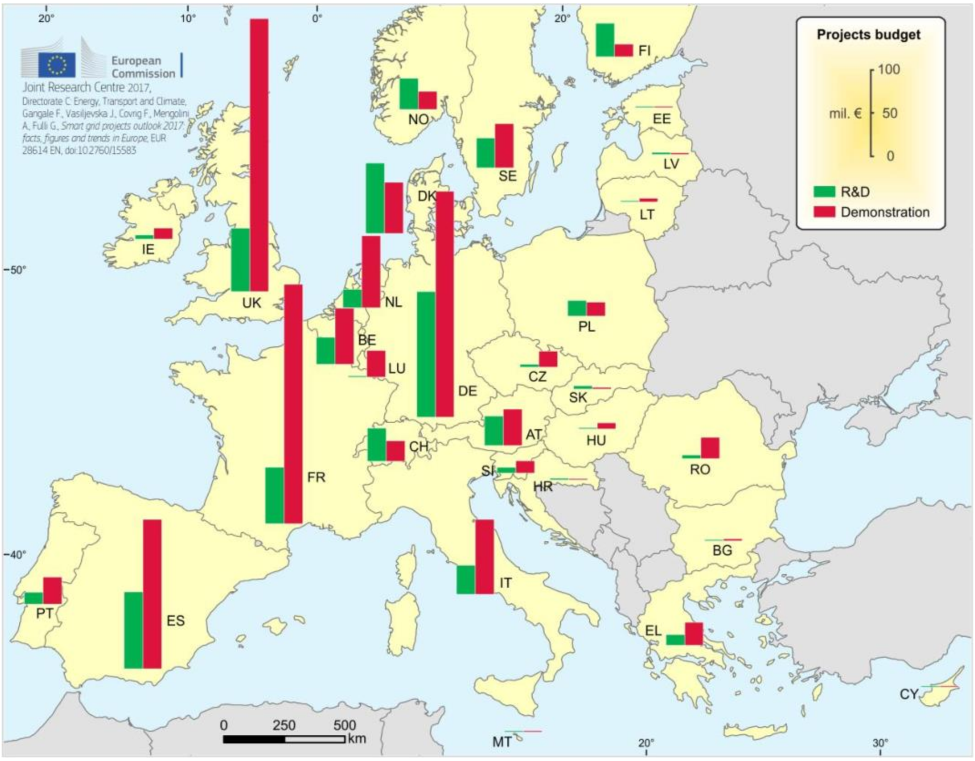
Figure 3 shows the temporal distribution of smart grid projects and of total investments. Until 2012, a constant increase in the number of projects and related investments can be observed. The subsequent drop is partially attributable to the cautiousness of private

[6] All data and figures reported in this chapter come from JRC, "Smart Grid Projects Outlook 2017".

investors due to the trade-off between technological risk associated to the development of new solutions and the perceived economic opportunities; however, the decreasing trend could also be affected by the incompleteness of data relative to the last years.

Of the 950 projects comprising the database, 540 of them are R&D and 410 are demonstration projects. Although R&D projects accounts for a greater share of the database (57%), they make up just 38% of the total investment. This is reflected in the average project expenditure, which amounts to €3.3m for R&D projects and to €9m for demonstration projects. This difference is to be attributed to the fact that R&D activities are typically less costly, since they are aimed at acquiring new scientific or technical knowledge or at investigating new applications of the existing technology, whereas demonstration projects require higher investments for prototyping and testing the technical and market viability of new technologies in a real-life setting.

Figure 4: R&D and Demonstration investments in the EU

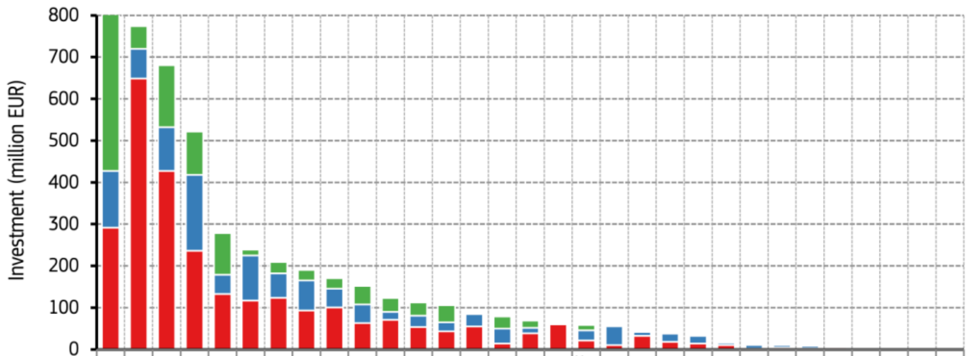


Source: JRC, "Smart Grid Projects Outlook 2017".

As it can be observed in Figure 4, in the majority of Member States the greatest share of the budget is allocated to demonstration activities. However, few countries such as Denmark, Finland, Norway and Switzerland invested more in R&D. This is due to the fact that these countries have dedicated R&D funding schemes and programmes, which also allow easy access to projects data.

When looking at sources of financing for Smart Grid projects, the contribution provided by each country depends on several specific factors, such as the existence of dedicated national funding schemes, of innovation incentives, and to the level of access to European funding by private and research and innovation organizations. The main sources of financing considered by JRC are national funding, European Commission funding and private financing. Funding provided by national regulatory authorities (NRAs) to network operators though incentive schemes (e.g. NIC in the UK) are included within the private financing category. Private investment represents the main source of financing in most of the EU countries: it accounts for 60% of investments for demonstration projects, and 40% for R&D activities. However, just 15% of the projects made use of private financing only. All the rest needed also financial support from national and European funding schemes. This is especially true for R&D projects, which only in 10% of the cases were sustained with private financing only. External funding is very important to incentivize investment and leverage private financing, since the uncertainty makes innovation investment riskier.

Figure 5: Total investment per country by source of financing



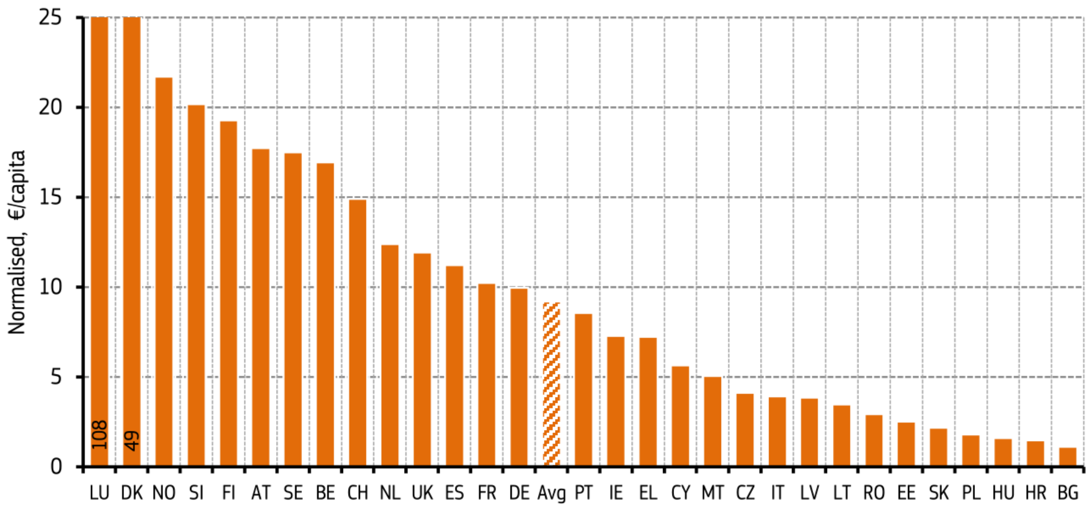
	DE	UK	FR	ES	DK	IT	NL	BE	SE	AT	CH	NO	FI	PT	EL	PL	LU	Non-EU	RO	CZ	SI	IE	HU	SK	LT	BG	LV	HR	CY	EE	MT
Total	809	774	680	522	279	239	209	190	171	152	123	112	106	89	78	69	61	59	58	43	42	34	16	12	10	8	7.7	6.2	4.8	3.3	2.2
National	382	54	148	104	100	14	27	25	25	44	33	31	41	4.2	28	17	0.3	13	2.4	1.3	3.8	0.9		1			0.1		0.1	0.1	0
EC	136	71	105	182	46	108	58	71	45	45	19	27	22	30	36	14	0.5	24	45	9.7	20	19	5.8	8.8	6	5.7	3.4	3.3	3	2.1	1.6
Private	291	649	428	236	133	117	124	94	101	63	71	54	43	55	14	38	60	21	10	32	18	14	10	2	4.1	2.3	4.1	2.9	1.7	1.1	0.6

Source: JRC, "Smart Grid Projects Outlook 2017".

Figure 5 shows that Germany, UK and France dominate all other Member States in terms of total investment. In Germany the greatest share comes from national funding mechanisms, while in UK and France the main source of financing is represented by private investors.[7] Although its total investment is not comparable, it is noteworthy that Italy has made greater use of funding received by the European Commission compared to UK and France.

So far, we have compared investments per countries without considering the effect of factors which may distort results and make comparison unbalanced towards larger states. Indeed, energy network management can entail very different requirements depending, for example, on population size or country geography. If we compare data reported in Figure 5 with that in Figure 6 – where total investments were normalized by population size – a significant change can be observed in the country ranking. An example is offered by Slovenia, a small country with a small population, which moves to a very high position after normalization. An interesting case is that of Luxemburg, which jumps to the first position from being below average. This drastic change depends on the inclusion in the database of a project which included the national roll-out of smart meters, and it is emblematic in showing how country comparisons are difficult to be made as they must take into account a variety of different factors.

Figure 6: Total investment normalized per capita



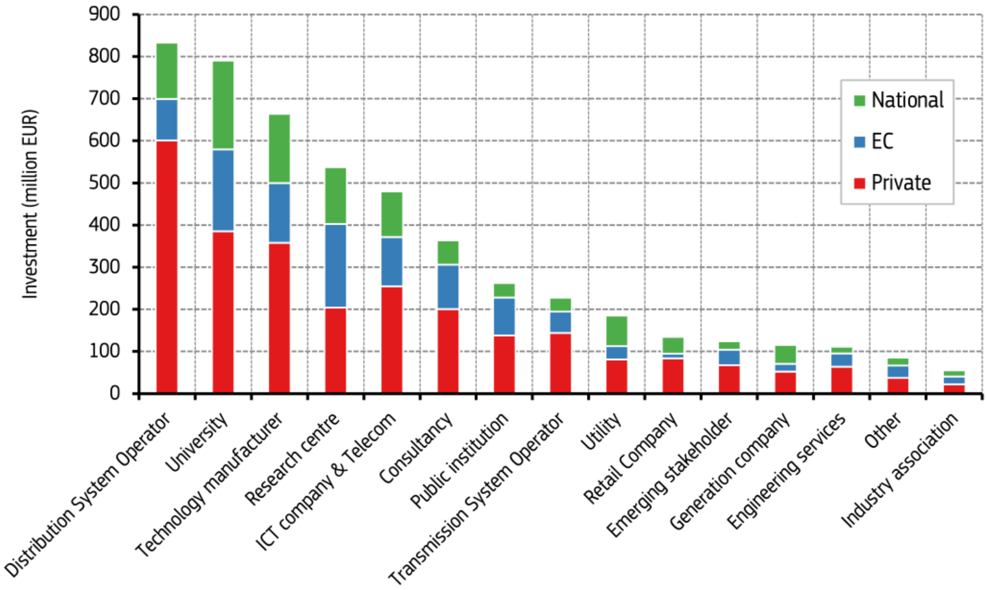
Source: JRC, "Smart Grid Projects Outlook 2017".

With regard to the actors involved, the largest investments come from DNOs and universities (see Figure 7). For most of the stakeholders, project funding comes mainly from private

[7] It should again be noted, however, that JRC considers UK innovation incentive schemes as private financing.

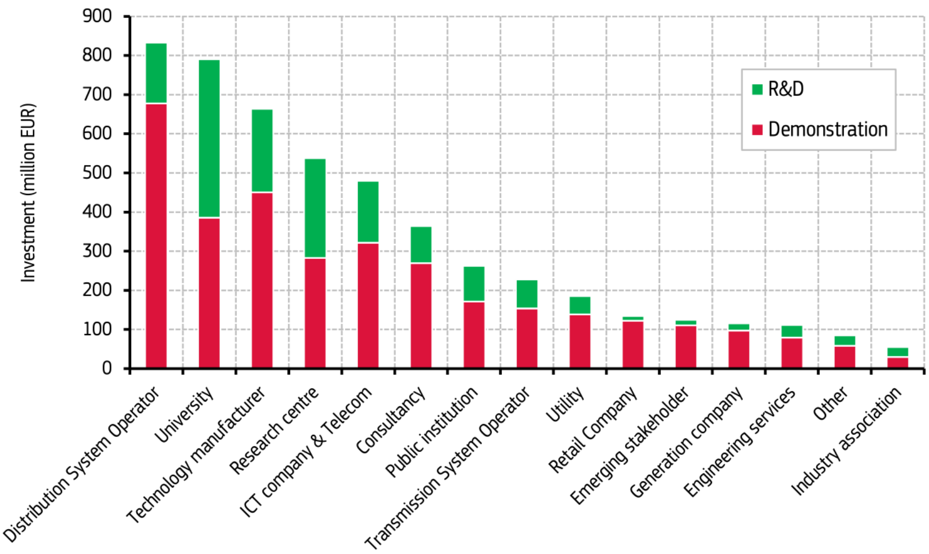
financing. This is especially true for projects run by DNOs, which cover with private funding more than 70% of total expenditures. Research centres, on the other hand, cover only 38% of their total investment with private financing.

Figure 7: Investment by stakeholder category and source of financing



Source: JRC, "Smart Grid Projects Outlook 2017".

Figure 8: Total R&D and demonstration investment per stakeholder

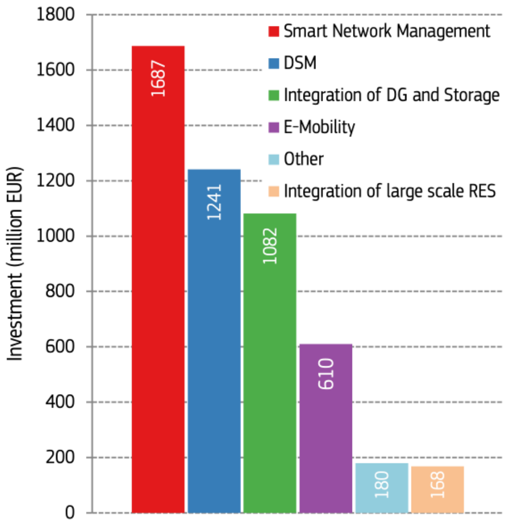


Source: JRC, "Smart Grid Projects Outlook 2017".

For what concerns the stage of the innovation cycle of the project carried out by different stakeholders, Figure 8 shows that the majority of them invests more in demonstration projects (coherently with the observation formerly made). The only exception are universities and research centres, which distribute equally the investment between R&D and demonstration projects.

Finally, Figure 9 displays the amount invested for each Smart Grid domain. Smart Network Management (34%), Demand Side Management (25%) and integration of DG and storage (22%) together account for approximately €4 billion of investments, which amount to 80% of the total. €610 million were invested for the smart integration of EVs into the electricity network until 2015 (E-mobility in the graph).

Figure 9: Total investment per Smart Grid domain



Source: JRC, “Smart Grid Projects Outlook 2017”.

3.2 The EU's funding programme: Horizon 2020

Under the EU's goal to create a fully integrated European energy market and to foster the shift toward a low carbon energy system, the European Commission has issued binding directives to all Member States to reduce carbon emissions and increase the share of primary energy consumption from RES. In this context, the *Energy Roadmap 2050* has been drawn to set long-term goals for the reduction of greenhouse gas emissions by 80-95% compared to 1990, and the achievement of 75% final energy consumption from RES in Europe.

In 2014, the European Commission launched the eighth Framework Programme *Horizon2020* to support research and innovation in all Member States for a period of seven years (2014-2020), providing a total budget of €78.6 billion. *Horizon 2020* funds three categories of projects:

- Research & Innovation Actions (RIA);
- Innovation Actions (IA);
- Coordination & Support Actions (CSA).

The three groups of activities cover all phases of research and innovation, ranging from collaborative R&D and demonstration projects to measures to support the dissemination of results. EU funding per project varies across the different categories, as reported in Table 3:

Table 3: Average and maximum EU contribution per project to each category

	Average EU contribution (€m)	**Max EU contribution (as % of total eligible costs)**
RIA	2-5	100%
IA	2-5	70%
CSA	0.5-2	100%

The majority of projects are collaborative in nature, involving at least 3 entities from different EU Member States. The programme pays particular attention to the societal impact of the results of the funded projects. Indeed, the most substantial pillar (corresponding to 38.53% of the total allocated budget) of *Horizon 2020* consists of projects targeting *Societal Challenges*. Among the wide variety of challenges addressed, the programme targets also the supply of a more secure, sustainable and affordable energy in response to environmental and climate concerns. For this purpose, a total budget of €5.9 billion (nearly 20% of the total budget dedicated to address societal challenges) has been allocated to finance proposals under the "Secure, Clean and Efficient Energy" challenge, through work programmes prepared by the EC every two years. The vast majority of projects under this challenge deal with energy efficiency (EE) and low carbon energy (LCE) technologies. Research activities in these two areas include: reduction of energy consumption and carbon footprint; cost-effective electricity supply; integration of ICT technologies into the electricity grid; smart grids; energy storage technologies; etc.

Table 4: Financial data on EE and LCE projects

Focus area	Number of projects	Average budget (€m)	Cumulative budget (€m)	Max EU contribution (€m)
Energy efficiency	198	2.2	435.6	402.5
Low carbon energy	256	8.9	2,267.2	1,613.8
TOTAL	454	6.0	2,702.8	2,016.2

Table 4 shows the number of projects, the average project budget, how much has been spent, and the maximum EU contribution relative to each focus area up to September 2018. Maximum EU contribution was used as a proxy of actual funding given as this data was not available.

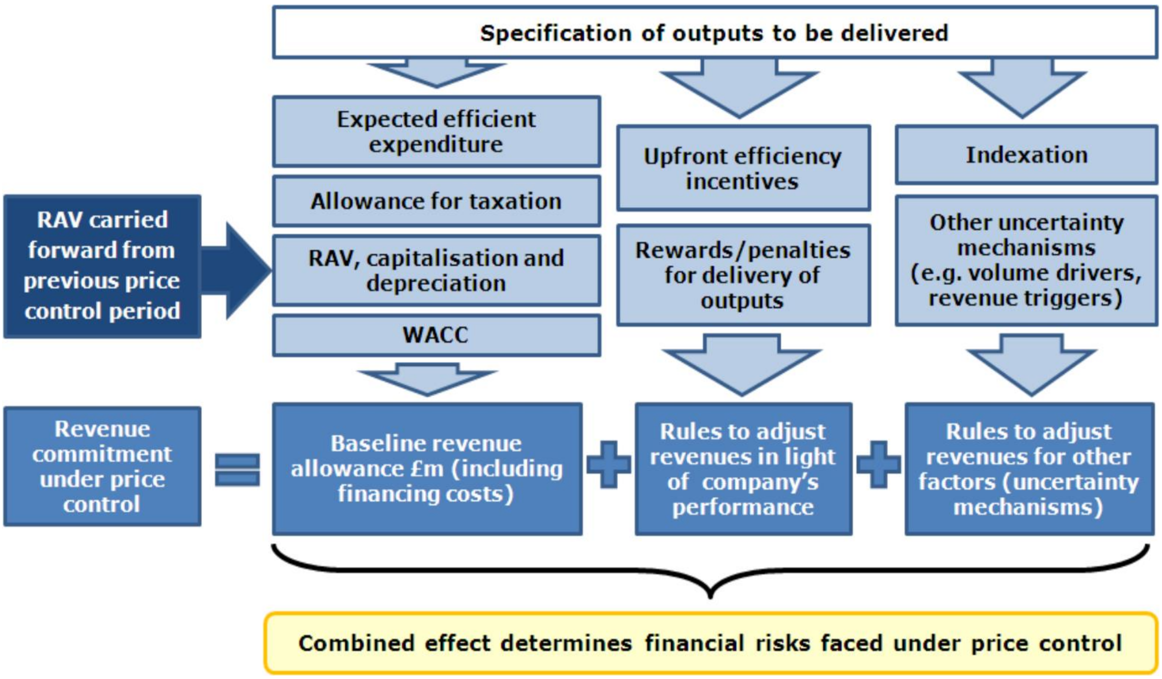
3.3 Innovation in the UK's energy sector – the RIIO model

In the United Kingdom the liberalization process started in the mid '80s with the 1983 Energy Act, which set the country at the forefront of an EU-wide trend. Today the energy market in the UK is fully privatized and liberalized. While district heating networks are not regulated, the electricity and gas sectors are so through a framework based on system legislation, licenses, industry codes, and the action of an independent regulator, the Gas and Energy Market Authority (GEMA). GEMA is responsible for the regulation of the sector and the enforcement of any breaches. It delegates the ordinary administration of its functions to the Office of Gas and Electricity Markets (Ofgem). In 2010, Ofgem introduced RIIO: a regulatory framework to be used in developing price controls for electricity and gas transmission and distribution network companies. The framework, which took effect in 2013, sets a revenue cap which is adjusted through performance and innovation incentives. The model stems from a detailed review of energy network regulation aimed at investigating how to best regulate network companies so as to meet the requirements for a sustainable and low carbon energy sector. RIIO has two main objectives: to assure that network companies play a full role in the delivery of a sustainable energy sector, and to grant the delivery of value for money network services to present and future consumers. The framework sets on achieving these objectives by focusing on an ex ante price control, which establishes the outputs that network companies have to deliver and the revenues they are allowed to earn if efficient; and on time-limited innovation stimuli open to network companies and non-network parties, one for the electricity and one for the gas networks.

3.3.1 The RIIO framework

The RIIO model makes use of an eight-year price control in which annual allowed revenues and required outputs are established for each network company. Every eight years, a comprehensive review is performed by Ofgem. For this time frame, the principles, incentive arrangements, as well as financial elements (e.g. WACC, depreciation and capitalization policies) are fixed. In order to deal with the uncertainty with regard to what network companies need to deliver during the period, a focused mid-period review can take place, with a scope limited to changes to output requirements. During the period, revenue can be adjusted according to uncertainty and efficiency mechanisms, on the basis of criteria established at the beginning of the price control.

Figure 10: The building blocks of the price control



Source: Ofgem. 2010. "Handbook for Implementing the RIIO Model".

As shown in Figure 10, the allowed revenue is based on three elements:

- the baseline revenue, which covers expected efficient expenditures – including financing costs – for output delivery, and which includes allowances for investment in and maintenance of capital assets and taxation;
- the adjustments to reflect company performance in delivering outputs in an efficient fashion;
- the adjustments made during the control period to take into account specified uncertainties outside the company's control but of significant impact to the cost of delivery.

The structure of the price control is such as to ensure that network companies earn higher or lower returns according to their performance. The first price control for electricity and gas transmission and gas distribution runs from 1 April 2013 until 31 March 2021; the first price control for electricity distribution runs from 1 April 2015 until 31 March 2023.

3.3.1.1 The price control review

The price control review process is conducted over a timeframe of 2 to 2.5 years, and it is based on four main stages. In the first stage, through stakeholder interaction, the review team publishes a timetable for the review, identifies the key issues and establishes the outputs to be delivered and the parameters for the price control. This results with the publication of a consultation document to be used by network companies in defining their business plans. In the second stage, the network companies develop the business plans. This document is then scrutinized by Ofgem, with an attention that varies according to the category in which the company is placed. Less intensive scrutiny may include fast tracking a company, finalizing all elements of its price control settlement, thus moving straight to the end of stage four. The companies which are not fast-tracked move instead to stage three, where they are to revise their business plan according to the comments made in the previous stage. The plans are again scrutinized by Ofgem. During this stage, business plans are finalized, and the methodology to be used to set the price control is confirmed. In the fourth stage, Ofgem develops an initial proposal, subject to agreement from the network company, and then a final proposal which is translated into license conditions. The key elements of the proposal are:

- the detailed definition of the outputs the network company is expected to deliver;
- the level of base revenue that the network company is allowed to earn from consumers during the price control period;
- the proportion of total expenditure to be recovered during the year in which it was incurred and the proportion to be capitalized and recovered through the Regulatory Asset Value (RAV), the asset depreciation rate, and the allowed return;
- the level of revenue that the network company is allowed to earn from consumers for the innovation stimulus package;
- the upfront efficiency incentive rate, together with details on how it will be implemented during the price control period.

The model is designed to grant certainty and transparency, and it seeks to avoid ex post adjustments to final proposals to avoid undermining regulatory commitment.

3.3.1.2 Outputs

Outputs are set for the duration of the price control period, with a review of the output requirements taking place mid-period. Primary outputs reflect what the consumer expects regarding the delivery of network services. Network companies are free to determine how to meet these expectations. This process is incentivized by a direct linkage between delivery of the primary output and revenue allowed in the price control. At each price control, Ofgem sets a level of performance for each primary output at which network companies are required to operate (e.g. a set level of availability and reliability). Interaction between primary outputs are considered in determining these levels of performance. If a network company wants to operate at a level which differs from the given one, it has to provide evidence to demonstrate that the alternative level is consistent with the objectives of the RIIO model.

Focusing price controls only on the delivery of primary outputs may be detrimental to providing long-term value for money network services, as it could encourage network companies to only look at cost efficiency during the price control period, without taking into account measures that could reduce delivery costs in the long-term. Network companies are therefore expected to include in their business plans costs related to the delivery of primary outputs in future price control period, providing evidence to support this decision in the context of a long-term strategy for delivery. In doing so, network companies need to link costs in the current period with secondary deliverables – ideally secondary outputs rather than inputs – so as to be held accountable. Secondary deliverables do not reflect consumer expectations with regard to network services, but their need arises from three drivers:

- managing network risk so that decisions taken during the current price control period do not put at stake the delivery of primary outputs in the future;
- projects for delivering primary outputs in future periods which require to take action in the current price period;
- technical or commercial innovation projects that could allow – if successful – benefits in providing network services in terms of value for money in the long-term.

3.3.1.3 Business plans assessment

During the price control review process, each network firm needs to provide a business plan in which it sets out what it intends to deliver to consumers and what revenue it needs to finance it. This plan has to be well justified, demonstrating: focus on output delivery; examination of secondary deliverables; a robust case for the proposals made; consideration of alternative options; a clear link between costs and outputs; a long-term perspective; value for money; and engagement with various stakeholders. Network companies are incentivized to provide well-justified business plans as this makes it more likely for the final price control to reflect what is in the plan. An appropriate business plan is subject to less intensive scrutiny, which can also lead to setting the price control earlier. If a network company does not provide solid evidence to its plan, the final proposal is informed by a greater range of evidence than what originally provided by the firm, including benchmarking evidence. This leads to the base revenue differing greatly from what the company proposes.

Ofgem performs at first an initial sweep to categorize the companies according to the intensity of the following scrutiny. High-level benchmarking of historical total costs and planned costs are used to this purpose. The assessment is proportionate, and it focuses on aspects where more value can be added through regulatory scrutiny. Ofgem reserves the option to carry random detailed inspections, which may relate to the type of cost or to a specific project. Prior to the submission of their business plans, companies do not know the exact form the scrutiny might take. This encourages well-justified plans, instead of ones adjusted so as to perform well on a specific assessment. A financial incentive – the Information Quality Incentive (IQI) – is used to encourage companies to provide accurate expenditure forecasts. IQI is used to set the level of the upfront efficiency incentives, according to differences between a company's forecasts and Ofgem's assessment of its efficient expenditure requirements. Market testing is encouraged – but can also be required by Ofgem if the Authority is concerned with the level of costs or the design of the project – to assess potential benefits arising from having third parties deliver some or all aspects of a project.

3.3.1.4 Incentives

Output incentives

The RIIO model provides various incentives linked to output delivery performance. Their design takes place at the time of the price control review, so that incentives can change across periods, aside from varying by company. The design process and the strength of the incentives are driven by how clearly the primary output has been defined; by the confidence in the measure of primary output performance; and by the importance of achieving that output. Among the issues taken into account during the design process are whether the incentive should be symmetric; whether it should be marginal; its financial or reputational nature; and whether adjustments to revenue should be automatic. Where applicable, financial incentives are preferred due to their stronger impact. In the other cases, reputational incentives are used, such as the publication by Ofgem of network companies' delivery performances. A company that fails to deliver against the agreed primary outputs will face penalties according to the incentives in place, and in the case of persistent failure to deliver it could see its license being revoked.

Efficiency incentives

To encourage network companies to seek out delivery solutions that lead to the lowest cost over the long-term, Ofgem sets a fixed and symmetric efficiency incentive rate for each company, and commits to make adjustments to revenue only via its use, as long as outputs are delivered. This adjustment takes place annually during the price control period. The efficiency incentive allows risk-sharing between the company and society: in case of overspend (underspend), a percentage equal to the efficiency rate of that additional cost (saving) is borne by (earned by) the company, while the rest is passed on to consumers through higher (lower) network charges. This is done partially through a modification of the revenue allowance for the following year, partially via an increase or decrease of the RAV[8]. To avoid a bias towards capital expenditures, the same efficiency rate applies to both CAPEX and OPEX. At each price control review, Ofgem decides on a range for the efficiency incentive rate. The exact value of the rate for each company varies according to their IQI. Setting an appropriate lower bound to the range is important, as if the rate is set too low a company would not be exposed to the costs that derive from overspending, and could be encouraged to overspend to increase its RAV. Ofgem reserves the option to make adjustments to override the efficiency incentive rate mechanics – in exceptional circumstances – to prevent consumers from bearing a proportion of the over-expenditure, if it can prove that the waste was caused by decisions taken by the company which were unreasonable at the time they were made.

Innovation incentives

Since innovation incentives are central to our work, they will be treated in detail in 3.3.2.

3.3.1.5 Uncertainty management

The RIIO model is an ex ante regime, which means that all data used in setting the price control comes with a level of uncertainty. The main drivers of uncertainty relate to outputs, input prices, and volume of activity required. Network companies are responsible for managing normal business risk, so uncertainty mitigation is limited to instances in which it serves to deliver value for money for consumers and to protect the ability of network companies to finance efficient delivery. This is done through the use of: risk sharing through the efficiency incentive rates; the mid-period review; the possibility of reopening the price

[8] Which translates to an increase or decrease of the revenue allowance in future years.

control – in rare cases – where a company's financeability is put a risk by causes beyond its control; and uncertainty mechanisms. Uncertainty mechanisms are used when changes outside of the companies' control and with a significant impact on costs occur. The aim is to limit as much as possible the use of such mechanisms, as they can undermine efficiency incentives, increase regulation complexity, and lead to opportunities to game the system. These mechanisms are defined during the price control review and they allow changes to the revenue allowance both upward and downward. In designing them, particular attention is paid to the way the mechanism is triggered, to the timing in which companies receive the revenue adjustment, and to its interaction with the wider price control scheme.

3.3.1.6 Financeability

The allowed return is set based on a weighted average cost of capital (WACC), where the cost of debt is defined as a long-term average, while the cost of equity is determined through the capital asset pricing model (CAPM). The debt-to-equity ratio in the WACC is determined from a notional gearing – that is, a theoretical debt-to-equity ratio of an efficient company. The notional gearing reflects the risk network companies face, and is determined on a per sector base, although it can differ on a company base if the risks the company faces differ sensibly from the risks of the whole sector. The level of risk is used to derive the amount of equity needed in the notional gearing: the greater the variance in financial returns, and therefore in cash flow, the greater the need for equity to act as a buffer. The actual company's financial structure is left to the company to decide, as this calculation is used only to set the allowed return. The incentive rate, the uncertainty mechanisms, the potential scale of penalties and rewards for output delivery all affect the risk exposure of a firm, and therefore its cost of capital. They are therefore taken into account when setting the notional gearing.

3.3.2 Innovation incentives

The RIIO framework provides a variety of incentives to stimulate innovation: a long price control period; the commitment not to change revenue allowances outside of the agreed mechanisms; an equalization of OPEX and CAPEX; a focus on delivery of outputs. However, a time-limited innovation stimulus for electricity networks and one for gas networks are also included, due to the great need for innovation in developing a sustainable energy sector. For each network, the innovation stimulus consists of three measures: the

Network Innovation Allowance (NIA), the Network Innovation Competition (NIC), and the Innovation Roll-out Mechanism (IRM). These measures took the place of the Innovation Funding Incentive (IFI) and the Low Carbon Networks Fund (LCNF), which were part of the previous price control arrangements.

Figure 11: Electricity Distribution Funding Timeline

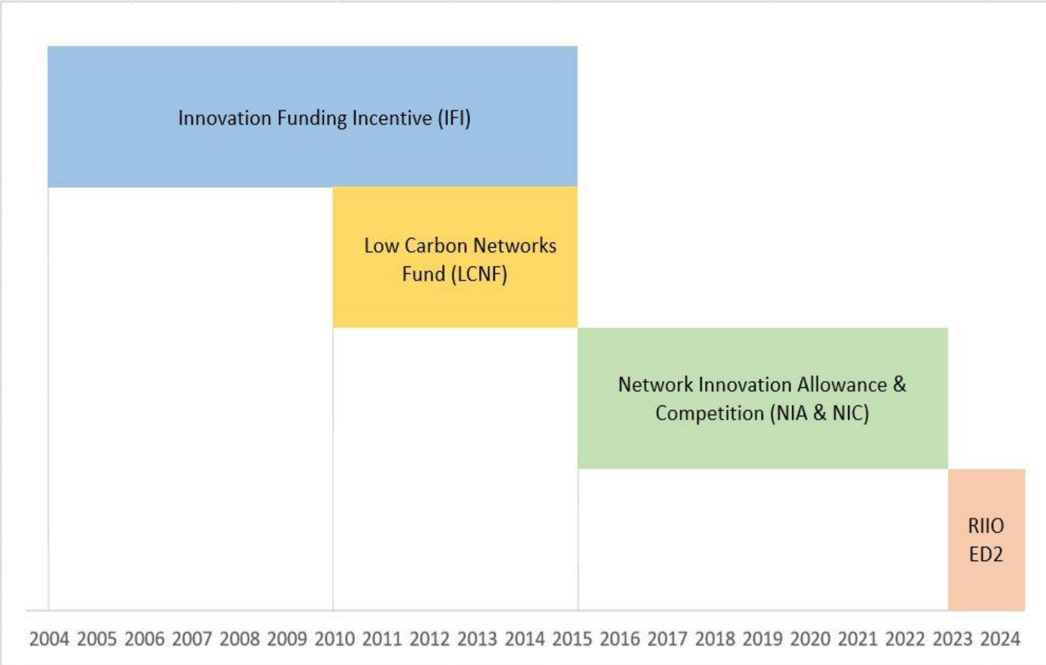


Figure 12: Electricity Transmission and Gas Distribution and Transmission

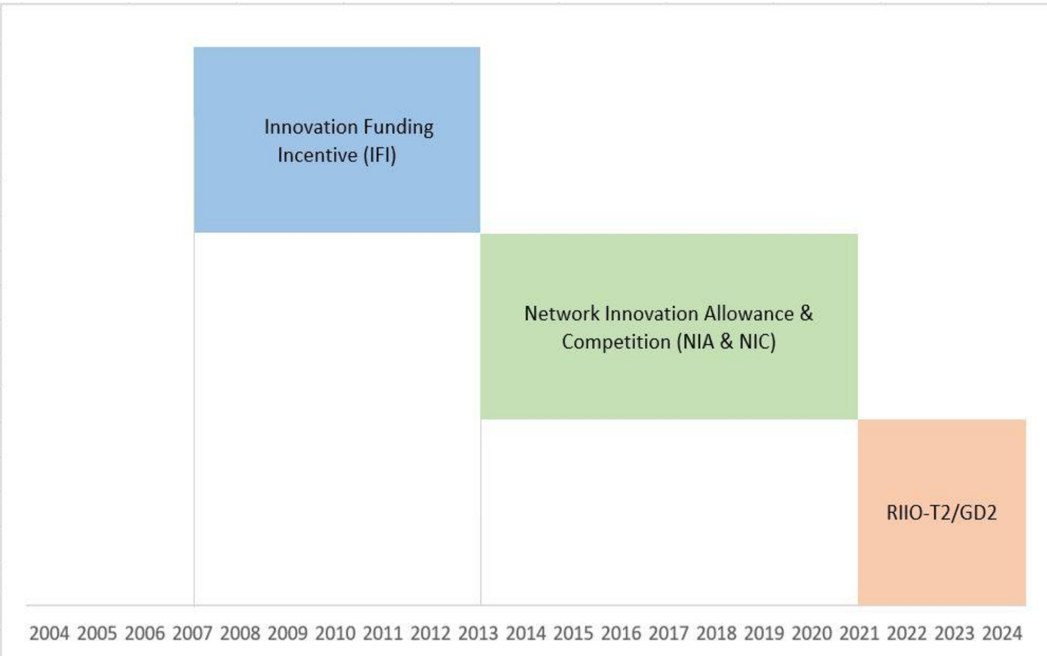


Figure 11 and Figure 12 show the timeline for the innovation funding schemes in the different energy sectors.

3.3.2.1 Previous schemes

The IFI was an incentive mechanism for R&D projects for the technical development of distribution and transmission networks. It ran from 2004 to 2015 for the electricity distribution and from 2007 to 2013 for electricity and gas transmission and gas distribution. Under this scheme, companies were allowed to pass a percentage ranging from 70% to 90% of R&D costs to their customers, up to a maximum of 0.5% of their total revenues. The introduction of the IFI lead to a sharp increase in R&D expenditures by distribution network operators (DNOs).

The LCNF budgeted £500m over the five years going from 2010 to 2015 to support trial and demonstration projects led by electricity DNOs to try out new technology, operating and commercial arrangements. With respect to IFI, LCNF offered greater sums and it financed also demonstration projects. The LCNF introduced two funding tiers: the first tier allowed DNOs to recover part of their costs for small scale projects; the second tier was a competitive process to fund fewer larger scale projects. Under the scheme, DNOs were required to cover 10% of total project costs, which could then be reimbursed in case of successful project delivery. The LCNF budget was split as follows: £80m for first tier projects, £320m for second tier projects, the remaining £100m for discretionary awards for successful project delivery. However, approved funding was roughly half of the budgeted amount.[9] In 2016, Ofgem commissioned an independent evaluation of the LCNF, which estimated net benefits of between £800m and £1.2billion from the scheme once projects were to be rolled-out by the respective companies, with the potential for a six-fold increase in case of a country-wide roll out.

3.3.2.2 The innovation stimulus

The Network Innovation Allowance (NIA) replaced the IFI and the first tier of the LCNF. It was introduced in 2013 for electricity and gas transmission and gas distribution, and in 2015 for electricity distribution. It is an annual allowance for gas and electricity network licensees to fund small R&D and demonstration projects, although there is no minimum or maximum

[9] See (Pöyry and Ricardo 2016).

project size to qualify for NIA. Previous to price control year 2017-2018, the NIA could also be used to recover the bid preparation costs for the NIC. The NIA allowance is added to the base revenue when determining the annual amount the licensee can recover from its customers. This amount is capped at 0.5-1% of base revenues for each company, depending on the quality of its innovation strategy. The actual adjustment to the revenue allowance of a given year is determined as the difference between the total allowed NIA expenditure for that year and the total unrecoverable expenditure, already recovered during that year or previous years of the price control. The allowed NIA expenditure is determined as the minimum between the company's NIA cap and the 90% of the expenses actually sustained that year for NIA projects which qualify as eligible. Eligible and unrecoverable NIA expenditures are defined by the authority in the NIA governance document. For a project to be eligible for funding under NIA, the licensee must register it on a designated portal. Ofgem has to decide on its approval only on special circumstances, otherwise the approval is automatic. The network licensee has to produce an annual report which summarizes its NIA activity. Since NIA introduction, roughly £61m were made available annually.

The Network Innovation Competition (NIC) replaces the second tier of the LCNF, but its scope is broader as it encompasses development as well as demonstration projects. It was introduced together with the NIA. Unlike the NIA, the NIC focuses on projects aimed at granting environmental benefits, and it funds up to 90% of the total project budget.[10] An annual competitive process for electricity and one for gas are run to finance a selected amount of larger projects. In each competition, transmission and distribution operators compete against one another, within the same energy sector. Each company can make up to 4 bids.[11] An independent panel makes recommendations to Ofgem regarding which projects should receive funding. Participation in the NIC is broader than to the other incentive mechanisms: even non-RIIO network licensee are allowed to contribute external funding to a project, although they are eligible to bid for funding only through a network licensee. The fund is designed to provide £70m per year for electricity networks, and £20m per year for gas networks. For a project to be funded, the licensee must show how the innovation creates new knowledge and how that can be shared among network operators; the innovation must

[10] This could go up to 100% before successfully delivery rewards were removed, following the network innovation review of 2017.
[11] A maximum of two bids can result from the network licensee own proposal, the others have to come from non-network licensee proposals.

provide long-term value for money to network customers; and it has to help accelerate the move to a low carbon energy sector or grant environmental benefits. Once Ofgem has selected which projects to finance and by how much – for both the electricity and the gas sectors – each sector's system operator is allowed to recover that allowance from customers through its network charges. It is then the system operator to transfer the respective amounts to the licensees. The transfers are made on an equal monthly basis over 12 months (even though the project may last more than a year), starting from the beginning of the following price control year (the 1st of April).

An overview of NIA and NIC main characteristics is reported in Table 5.

Table 5: Summary of NIC and NIA schemes.

	NIC	**NIA**
Type of projects	Large development and demonstration project with environmental benefits.	Small R&D and demonstration projects.
How is awarded	Companies compete for project funding. An independent panel of experts makes a recommendation. Ofgem decides which projects to fund.	At the start of the price control, a yearly allowance is set according to the quality of the company's innovation strategy (up to 1% of the base revenue).
Financing method	Equal monthly transfers over one year from the SO to the funding licensee.	Increase in the yearly revenue allowance.
Yearly available budget	£70m electricity networks. £20m gas networks.	Approximately £60m.
Incentives given	£165m up to the 4th year of the price control. £200m up to the 5th year of the price control.	£145m up to the 4th year of the price control.

The Innovation Roll-out Mechanism (IRM) is a mechanism designed to adjust allowed revenues in order to fund the roll-out of trialled low carbon or environmental innovations into business as usual to allow licensees to recover the expenditures associated with it. The available IRM budget for a given sector is equal to 1% of that sector average revenue allowance. Only innovation roll-out costs that have not been already incurred can be recovered through its use.

In March 2017, following a network innovation review, Ofgem introduced some changes to the structure of the innovation incentives. To make sure that the innovation projects undertaken by network companies shared a common vision that aligned with GB overall energy strategy, Ofgem required for licensees to jointly develop industry innovation strategies, one for the electricity sector and one for the gas sector. Moreover, network companies were required to make a yearly call for ideas from third parties, so as to increase their participation.

Ofgem declared that a greater scrutiny would be applied to future NIA and NIC projects in the future, to make sure that they would all be network focused. The NIC for electricity saw a reduction in budget: for years 2015 and 2016, it had been set at £90m, £30m for transmission and £60m for distribution; this amount was reduced to £70m, by lowering to £40m the budget for electricity distribution projects. Following an independent evaluation, which found that network companies reap 40% of the benefits of innovation projects, a decision was taken to remove the successfully delivery reward from the NIC. This way, licensees are forced to shoulder at least 10% of the project cost. Similarly, the possibility to recover the cost for the NIC bid preparation was removed.

3.3.3 The innovation projects under RIIO

A key challenge faced by the regulator when devising the innovation mechanisms has been finding a way to spread the knowledge collected through projects funded by it. To help with this task, a website was created to collect relevant project data: Smarter Networks Portal, managed by the Energy Network Association.[12] All figures regarding the innovation projects financed under RIIO come from an elaboration of the Smarter Networks Portal dataset. As of September 2018, Smarter Networks Portal database contains data about 906 NIA and NIC projects.

Figure 13 shows their number and total budget under the following grouping:

1. Very small projects, with a budget below £1m;
2. Small projects, with a budget between £1m and £5m;
3. Medium projects, with a budget between £5m and £10m;
4. Large projects, with a budget over £10m.

[12] www.smarternetworks.org

We can see how the majority of projects belong to the very small category. Nevertheless, the budget is divided more evenly between the different categories, with large projects taking the largest share despite their small number.

Figure 13: Number of projects by project size (a), Cumulative budget by project type (b)

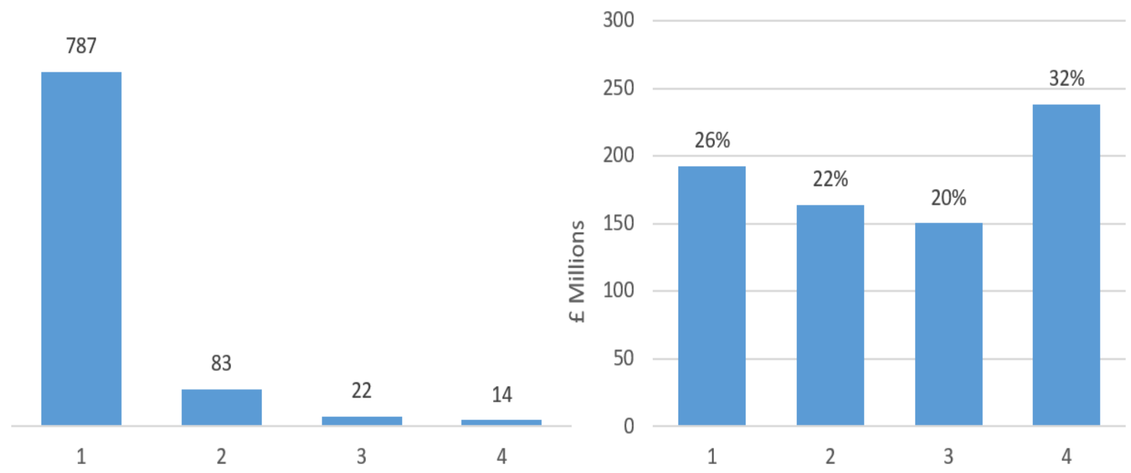
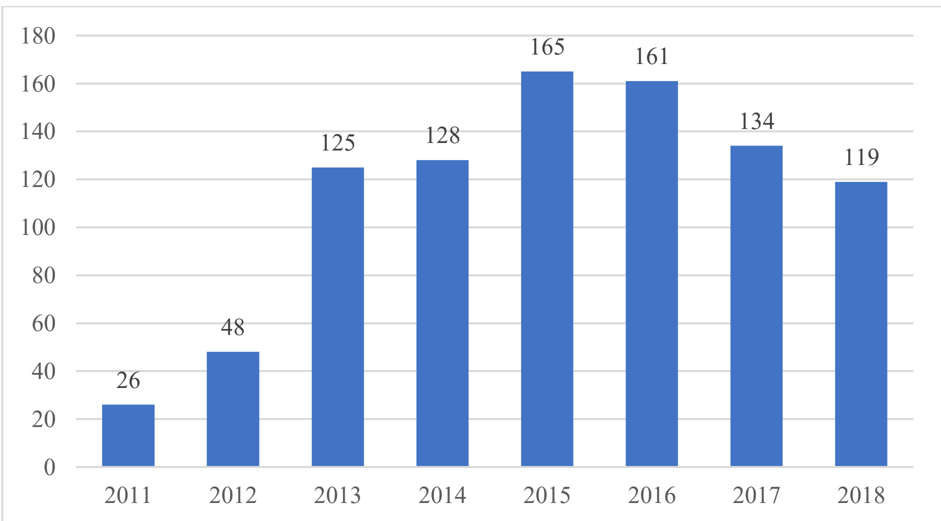


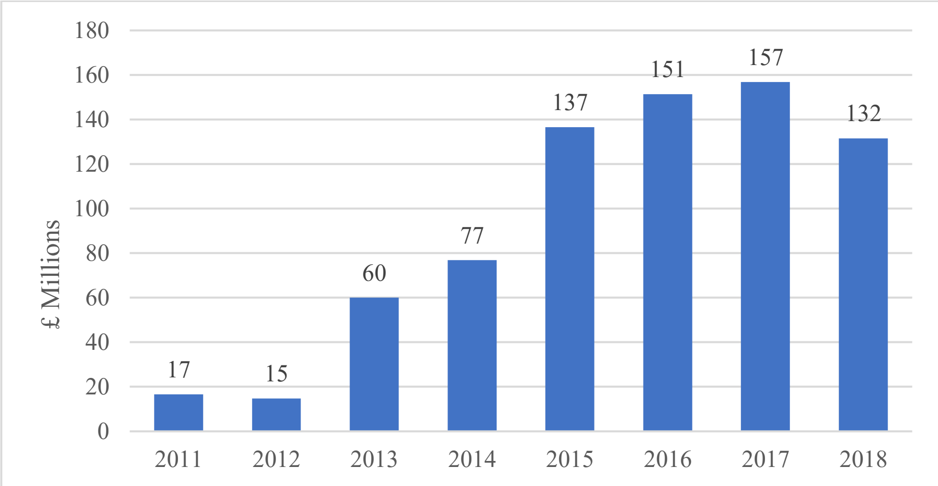
Figure 14 shows the number of projects funded under RIIO according to their start year. Although the current innovation schemes were introduced in 2013, the graph shows also the projects which started in 2011 and 2012 under the IFI which were later granted NIA funding. The amount of financed projects is overall stable (these two years excluded, for obvious reasons). We can see an increase in their number in 2015 which can be explained due to the introduction of the NIA and NIC even for the electricity distribution sector.

Figure 14: Number of projects by project start year



The decrease since 2017 can probably be ascribed to the greater scrutiny in projects approval that followed the network innovation review. It should also be noted that data regarding year 2018 is limited the first 9 months, so that the lower number depends on its partial nature.

Figure 15: Cumulative budget by year



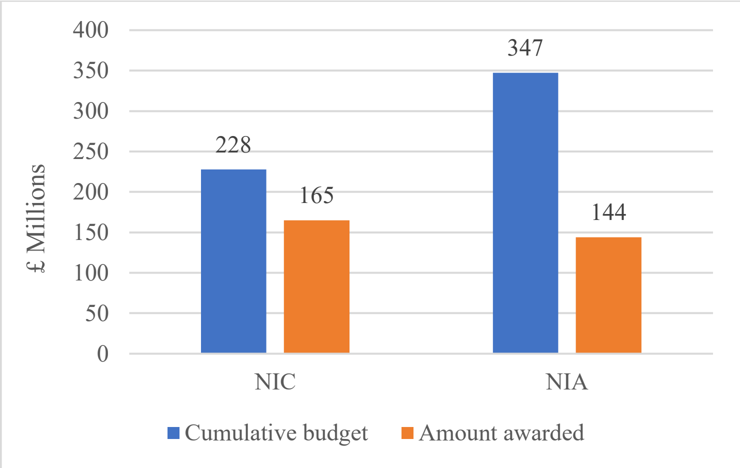
The contrast with the period previous to the introduction of the innovation scheme to the electricity distribution sector is even more stark when looking at cumulative budget. Figure 15 shows a sharp increase in 2015, with a positive trend even in the following years. Comparing the two graphs, we can see how the average project budget actually increased in the last years, since the number of projects decreased but the overall budget registered a slight increase.

Since RIIO was introduced in 2013, 874 projects where awarded NIA funding, while 32 of them were granted NIC funding. This difference derives from the scopes of the two schemes, as they are aimed at financing projects of different sizes. The average budget of a NIA project is £508K, while for NIC projects it is £9.4m.

Figure 16 shows the cumulative budgets of the projects funded under the two schemes and the total incentives awarded for each incentive mechanism up to price control year 2016-2017.[13] We can notice the difference between cumulative budgets, which are considerably higher in the case of the NIA, and incentives granted, which instead are slightly higher for the NIC.

[13] Data relative to following price control years for NIA is not yet available in a consolidated form, so that we chose to limit the time frame to have more reliable results.

Figure 16: A comparison between NIA and NIC projects cumulative budget with amount awarded (first 4 years of price control)



The two measures, cumulative budget and amount awarded, give us an insight into the source of financing for projects under the two schemes. In the case of the NIC, for each pound of incentive, network operators and other partners added £0.38, which means that they shouldered 28% of project costs. In the case of the NIA, these amounts reach £1.41 and 59% respectively.

Figure 17: Total budget by sector

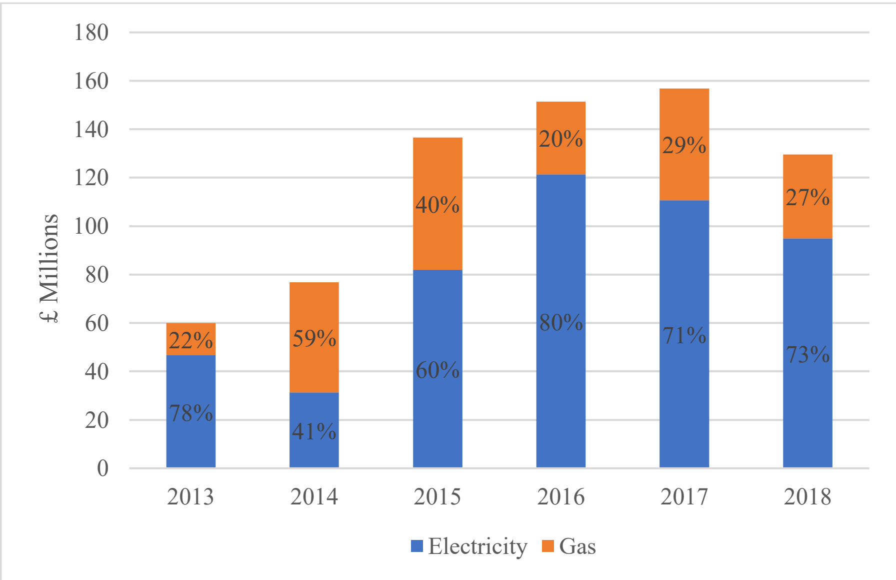


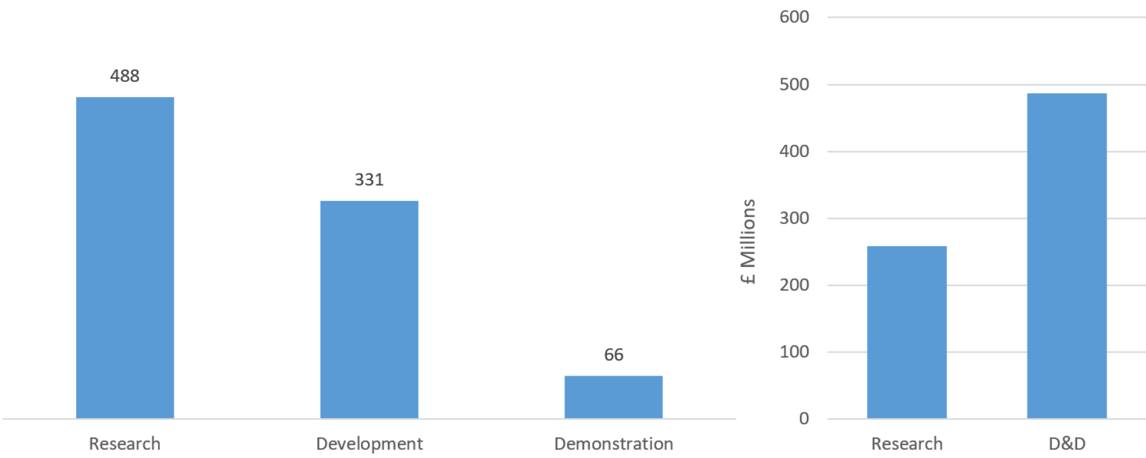
Figure 17 shows how much has been invested by year in the electricity and gas sectors. Since 2013, 69% of investments in innovative projects financed under NIA or NIC have been generated by the electricity sector. The strange distribution in year 2014 depends on how each project is assigned to a year on the graph: as before, the criterion has been the project start year, which does not necessarily coincide with the year the project was financed.[14]

The projects have been divided according to the stage of the innovation cycle they belong to, following Ofgem's definitions:

- Research: pure and applied research;
- Development: "activities with a more commercial application including technology validation and or demonstration in a working environment";
- Demonstration: "full scale demonstration in a working environment".

For 21 NIC projects, due to lack of data, we were not able to distinguish between development and demonstration stages. Since the number of uncategorized projects was not high but the cumulative budget of those projects was relevant, in Figure 18 (a) we kept the stages separated, while we grouped together development and demonstration in Figure 18 (b). The graph shows how many projects belong to each stage of the innovation cycle, and how much it has been invested in each stage overall.

Figure 18: Number of projects by innovation stage (a), Cumulative budget by innovation stage (b)



The projects with a budget above £1 million have been categorized according to the technological domain and reported in Table 6. The 118 selected projects make up for almost 75% of the overall NIA and NIC projects budget. Seven categories have been used, with

[14] This data is available for NIC projects, but not as easily available for NIA projects. Also, price control years begin on April of a given year and end on March of the following year.

each project being assigned to a single category – the most relevant one – even in the case in which its scope would encompass more than one. The aim was to understand if and how much have been invested in energy networks integration, rather than exhaustively categorize them.

Table 6: Classification of largest projects (above £1 million) by investment category

Category	No. Projects	Budget (£m)	Avg. Budget (£m)
Network Management[15]	62	325.4	5.2
Low carbon technologies and energy efficiency	7	56.1	8.0
EV and hydrogen vehicles	5	11.0	2.2
Smart Grid technologies	13	65.5	5.0
Storage systems	2	2.9	1.4
Energy networks integration	1	5.2	5.2
Others	28	85.9	3.1
Total	**118**	**552.1**	**4.7**

Unsurprisingly, most of the projects fall under the *Network Management* category, as its scope is very broad and includes a variety of network interventions. All projects that could not be placed into the defined categories were assigned to *Others*. In the context of energy networks integration, the most relevant categories are *Smart Grid technologies*, which includes demand-side response, ICT solutions to manage bidirectional energy flows, and integration of DG; *Storage systems*; and *Energy networks integration*. Out of the 118 projects, just 16 of them fall under these categories, for a total budget of £73.6 million. This shows how, although much has been invested through the NIC and NIA, few projects and just 13% percent of aforementioned budget has been destined to these areas. In particular, only one project (nearly 1% of the budget) deals directly with networks integration. A description of the most interesting projects of the three relevant categories is reported in the Appendix, highlighting what has been done and the way projects have been funded.

[15] This category includes substitution or technological improvement of the current infrastructure aimed at improving network reliability, control, safety, and service quality.

3.3.3.1 Energy networks integration: the FREEDOM project

FREEDOM (Flexible Residential Energy Efficiency Demand Optimisation and Management) is a £5.2 million development and demonstration project, started by the DNO *SP Distribution* in October 2016 and that will last until January 2019. The objective of the project is to convert households' home electric heating into a hybrid heating system that combines domestic gas boiler and air-sourced heat pump heating. Using predictive control algorithms, the technology manages the heating load and fuel type to minimize carbon emissions and allows efficient system costs based on real-time energy market prices. The project intends to find out whether the hybrid heating system is a technically capable, affordable and convenient solution, in order to:

- provide fuel arbitrage and highly flexible demand response services by switching between gas and electric load;
- gain information on how to balance the interests of different stakeholders (consumers, suppliers, DNOs and TNOs) when seeking to use demand flexibility to extract value;
- find out the benefits for the consumer, the network and the energy system as a whole of deploying a hybrid heating system with an aggregated demand response control system.

In the first six months, design and foundation development activities were performed. Then, pilot installations were undertaken in Bridgend (Wales) in four households' homes. A roll-out phase follows, with the installation being undertaken in the rest of the trial buildings. Over the following year, the households will be monitored and experimentation will be performed to refine the heating and load management processes and the consumer interface and information provision. The project investment was financed under NIA with £4.5 million.

3.3.4 The Network Operators

There are 14 electricity DNOs in Great Britain, one for each regional distribution service area, clustered into 6 major groups. Since price control year 2015-2016, the first one under RIIO for electricity distribution, they have run 186 projects financed under NIC and NIA, for a total investment of £151.25m. The gas DNOs are eight, each one covering a different geographical region. Within each area, Ofgem allows also the presence of small, local networks owned by Independent Gas Transporters (IGTs), in order to promote competition where it may be beneficial to customers. Since price control year 2013-2014, gas DNOs have invested £174.27m in 327 NIC and NIA projects. There are three licensed electricity transmission network operators (TNOs), which are responsible for the management and operation of the electricity transmission network in England and Wales, Southern Scotland, and Northern Scotland, respectively. Among them, *National Grid Electricity Transmission* (NGET) is also the System Operator (SO), which operates the whole transmission system. Under RIIO innovation schemes, electricity TNOs have carried out 257 projects and invested £309.66m. The National Transmission System (NTS) is Great Britain's high-pressure gas network which transports gas from generation facilities to gas distribution networks, or directly to industrial users. The gas transmission network is owned and operated by *National Grid Gas plc* (NGG). Under RIIO innovation schemes, it has carried out 119 innovative projects, with a total expenditure of £38.22m.

Figure 19: Investments by network operator

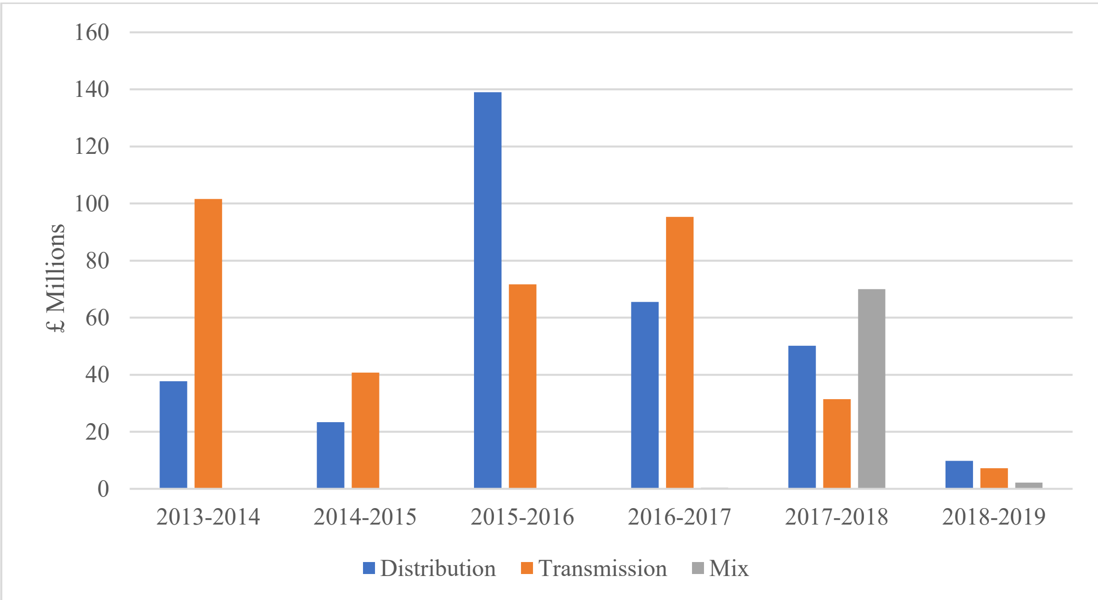
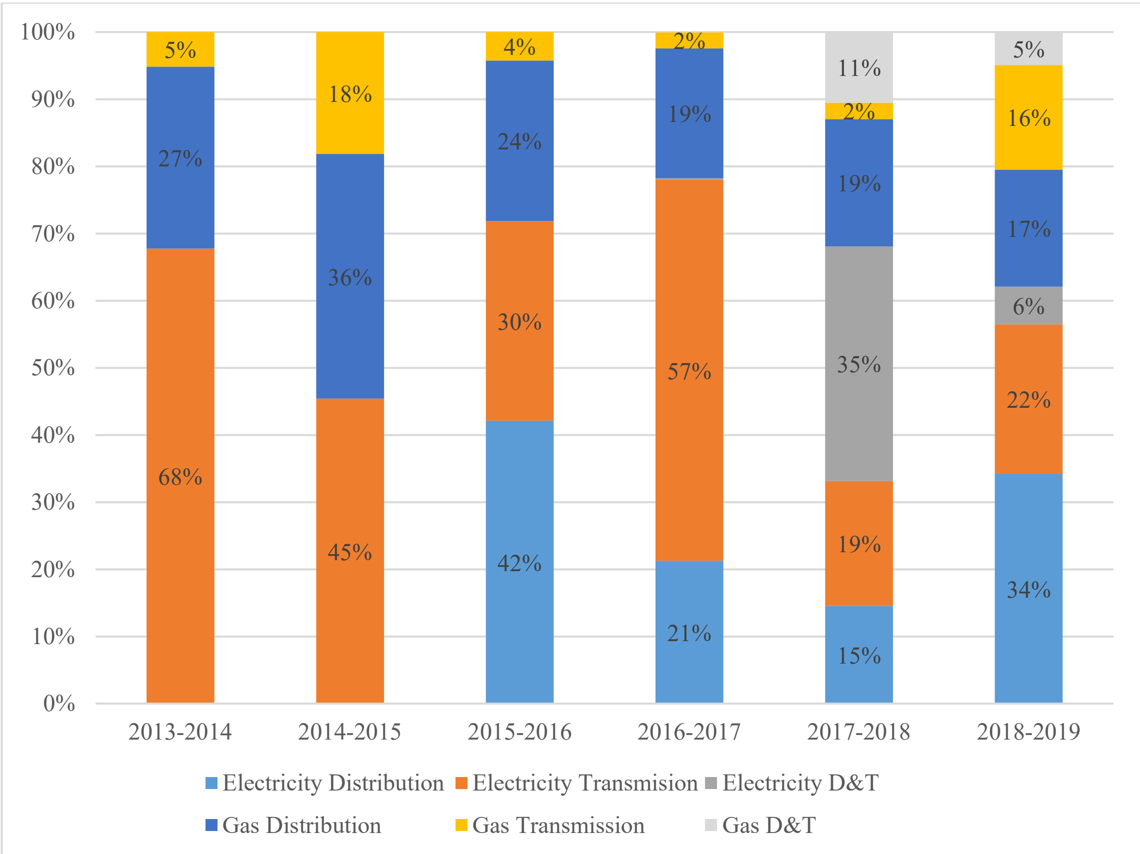


Figure 19 shows how much was invested by distribution and transmission operators for each price control year. The great increase in investments by DNOs in 2015-2016 depends on the one hand on the beginning of the price control for electricity distribution, on the other hand by the conversion of previous IFI projects to NIA funding. The lack of a clear trend in the graph can also be attributed to the nature of the NIC, which makes DNOs and TNOs of the same sector compete against one another for funding. The result can greatly influence the

distribution of investments for that given price control year. It is interesting to notice how, in price control year 2017-2018, the majority of investments can be attributed to projects which saw mixed participation of DNOs and TNOs. Lack of data for the following price control year does not allow us to make any hypothesis with regard to whether this change is going to be the norm in the coming years, but it could stem from the need of greater cooperation between network operators to face the challenges faced by the sector.
Figure 20 gives us a more detail overlook by showing the share of investments generated by DNOs and TNOs according to their energy sector in each price control year.

Figure 20: Share of investment by network operator for each sector per price control year



3.3.5 RIIO-2

In July 2018, after 5 years from RIIO's first price control, Ofgem published a "RIIO-2 Decision Framework": a resolution on the changes to be made to the regulatory framework for the second price control beginning in 2021. These decisions originate from a review of RIIO's performance and from a consultation in which industry stakeholders were called to voice their opinions. A second consultation on sector specific methodologies will be held in December 2018, therefore this resolution is not to be considered exhaustive nor definitive. The Authority's decisions were influenced by what it deemed a good performance of the RIIO model, with an increase in customer satisfaction and in innovation spending, but also characterized by higher returns than originally foreseen across network companies. The main changes to the model are:

- A reduction in price control length from 8 to 5 years. The high uncertainty in the energy sector generates unreliable assumptions and forecasts, which led to allowances being set too high and performance targets too low in the current price control. This is especially problematic in the absence of a broad scope mid period review. Ofgem retains the option to decide on a per case basis whether to set allowances for specific activities for a longer term.
- The introduction of a price control for the electricity Transmission System Operator (TSO) separate from the Transmission Owner's (no separate price control was deemed necessary for the gas TSO at this stage).
- To increase stakeholder engagement by introducing independently chaired groups through which stakeholders can voice their opinions on network companies' business plans.
- To increase innovation delivered through business as usual, but to also keep the innovation stimulus package for innovation projects that would not otherwise be undertaken under the RIIO-2 framework. While the NIA was generally considered useful as it harboured collaboration between network operators, some stakeholders pointed out a diminishing interest with regard to NIC. The roll-out mechanism is also being scrutinized, because with a shorter price control period its usefulness would be reduced.
- To give more emphasis to competition for the market, drawing from what has been done for electricity transmission and applying it to the other sectors: allowing late models of competition to be applied to projects which are new, separable and high value. The intention is to move towards early models of competition later on in the price control.
- An overall simplification of the price control, especially with regard to how outputs and costs are set. A reduction in the use of forecasts when deemed too unreliable, in

favour of indices. The elimination of the information revealing devices (i.e. IQI and fast tracking).

- Some changes to the financeability principles.

Ofgem has decided to undertake further examination of these areas:

- Innovation, to increase alignment of innovation funds with the challenges arising from the evolution of the energy sector; to coordinate with other public funds for innovation; to increase third party engagement (e.g. by allowing direct access to available funding).
- Energy efficiency, to consider whether network companies should take a more active role in granting it, by carefully considering demand and supply side solutions to network constraints.
- Investments, to make sure that future investments are assessed more carefully, especially against the options of demand-side measures and storage, to limit the risk of assets underutilization.

3.4 Italy

The liberalization process of the Italian electricity and gas markets started in 1999 and 2000, respectively. In these occasions, the Regulatory Authority for Electricity Gas and Water (AEEGSI)[16] established the unbundling of network services – which are de facto natural monopolies – and it granted free third-party access. Although today the electricity and gas markets are liberalized, they are still subject to regulation, in line with EU directives aimed at creating an integrated market and at ensuring security of energy supply. District heating networks on the other hand are not regulated.

3.4.1 The regulatory framework

In regulating the electricity and gas networks the Italian Authority was traditionally concerned with productive efficiency, that is, it focused on providing incentives for cost savings. In 2000, a price-cap mechanism was introduced, with price controls of four years. This mechanism has evolved from year 2000 to 2015 to a "hybrid" approach, with an incentive-based (price-cap) scheme applying to operating expenditures (OPEX), and a cost-of-service mechanism applying to capital expenditure (CAPEX).
Since 2016, ARERA has established a new incentive mechanism for the fifth electricity transmission and distribution price control review, as well as the introduction of output-based regulation aimed at ensuring adequate quality of service related to continuity of supply (i.e. the duration and frequency of interruptions). In order to provide greater stability and to reduce the risks related to structural network investments for network operators, the Authority has also extended the electricity regulatory period from four to eight years (2016-2023). The main risk associated with such hybrid approach is that it may direct network operators towards inefficient infrastructure investments and distort their "make or buy" decisions by making them favour CAPEX to then enjoy a higher capital remuneration, in turn potentially increasing costs for costumers. For this reason, from 2020 a new TOTEX approach will be applied for the second half of the current regulatory period, so as to make operators assess the value of network investments based on delivered outputs and long-term value for money. For the fifth gas regulatory period (2020-2023), the Authority has decided to apply the TOTEX approach but to keep the four-year period length.

[16] In December 2017 AEEGSI was replaced by ARERA (Regulatory Authority for Energy, Networks and Environment). Hence, from this point on, the text will refer to ARERA as the Italian regulatory authority.

Table 7: Summary of electricity transmission regulation per regulatory period

	2004-2007	2008-2011	2012-2015
OPEX	X efficiency (2.5%)	X efficiency (2.3%)	X efficiency (3%)
CAPEX	WACC (6.7%)	WACC (6.9%)	WACC (7.4%)
Quality of service		Output-based incentives (ENS)	Output-based incentives (ENS)
Security of supply		Input-based incentives: +2-3% WACC for 12 years on investments for the development of the RTN aimed at reducing grid congestions and improving grid interconnections.	Input-based incentives: • +1.5% WACC for 12 years on investments for the development of transport capacity; • +2% WACC for 12 years on investments for the development of transport capacity related to strategic projects aimed at reducing congestion between market areas, or at increasing Net Transfer Capacity (NTC) on electricity borders.
Storage systems			Input-based incentives: +2% WACC for 12 years on energy storage pilot projects.

Source: Lo Schiavo et al. 2013. ARERA website.

Table 8: Summary of electricity distribution regulation per regulatory period

	2004-2007	2008-2011	2012-2015
OPEX	X efficiency (3.5%)	X efficiency (1.9%)	X efficiency (2.8%)
CAPEX	WACC (6.8%)	WACC (7%)	WACC (7.6%)
Quality of service	Output-based incentives (SAIDI)	Output-based incentives (SAIDI, SAIFI, MAIFI). Input-based incentives: +2% WACC for 8–12 years on investments for the expansion of high-to-medium voltage transformation capacity in critical areas.	Output-based incentives (SAIDI, SAIFI, MAIFI). Input-based incentives: +1.5% WACC for 8-12 years on investments for the expansion of high-to-medium voltage transformation capacity in critical areas.
Network Losses		Input-based incentives: +2% WACC for 8 years on investments for the substitution of conventional medium-low voltage transformers with low-losses transformers.	Input-based incentives: +1.5% WACC for 8 years on investments for the substitution of conventional medium-low voltage transformers with low-losses transformers.
Smart Grid – integration of DG, Storage systems		Input-based incentives: +2% WACC for 12 years on smart grid pilot projects selected by a special commission appointed by ARERA in relation to their potential for the development of DG.	Output-based incentives (consultation open). Input-based incentives: +2% WACC for 12 years on smart grid pilot projects selected by a special commission appointed by ARERA in relation to their potential for the development of DG.

Source: Lo Schiavo et al. 2013. ARERA website.

Table 9: Summary of gas transmission regulation per regulatory period

	2010-2013	2014-2017	2018-2019
OPEX	X efficiency (2.1%)	X efficiency (2.4%)	X efficiency (1.3%)
CAPEX	WACC (6.4%)	WACC (6.3%)	WACC (5.4%)
Transport capacity	Input-based incentives: • +2% WACC for 7 years on investments for the development of new regional network transport capacity; • +2% WACC for 10 years on investments for the generation of new national network transport capacity; • +3% WACC for 10-15 years on investments in cross-border capacity.	Input-based incentives: • +1% WACC for 7 years on investments for the development of new regional network transport capacity; • +1% WACC for 10 years on investments for the generation of new national network transport capacity; • +2% WACC for 10 years on investments in cross-border capacity.	Input-based incentives: +1% WACC for 12 years on investments in new transport capacity (investments initiated after 1.1.2018 must show a benefit/cost ratio to the whole gas system greater than 1.5).
Security of supply		Input-based incentives: +1% WACC for 5 years on investments for safety, gas quality and support to the market that do not involve the realization of new transport capacity.	Input-based incentives: +1% WACC for 5 years on investments for safety, gas quality and support to the market that do not involve the realization of new transport capacity.

Source: SNAM website.

Table 7 and Table 8 display a synthesis of the regulatory measures adopted for the electricity TSO and DNOs in the past regulatory periods. The tables report the value of X efficiency and the remuneration of invested capital (WACC), and show the incentives provided per category of investment. In the case of both transmission and distribution network, incentives have been provided for storage systems and for the improvement of service quality (through the use of indicators of continuity of supply). In addition, for the case of transmission, incentives for security of supply have been provided in the form of an extra return on investments to ensure sufficient capacity needed to prevent and tackle emergency situations (e.g. a blackout). Similar input-based incentives are provided to electricity distribution operators to minimize network losses and invest in smart grids to promote the integration of distributed generation.

Table 10: Summary of gas distribution regulation per regulatory period

	2009-2012	**2013**	**2014-2017**
OPEX	X efficiency (3.2%)	X efficiency (3.2%)	X efficiency (1.7%)
CAPEX	WACC (7.6%)	WACC (7.7%)	WACC (6.9%)
Other incentives	Input-based incentives: +2% WACC for 8 years on investments in distribution network renovation.	Input-based incentives: +2% WACC for 8 years on investments in distribution network renovation.	Output-based incentives to quality of service.

Source: SNAM website.

Table 9 and Table 10 display a synthesis of the regulatory measures adopted for the gas TSO and DNOs in the past regulatory periods. The difference in length between the regulatory periods reported in the tables depends on the presence of transition periods of one to two years. The WACC values are averages as the Authority performs a review in between the regulatory period.

3.4.2 The Network Operators

Electricity distribution in Italy is provided by DNOs that operate under concessions and maintain low-voltage distribution grids at the local level. *e-Distribuzione* is the largest distribution company in Italy, with a market share of 85%. In 2015, eleven electricity TNOs operated the high-voltage transmission network in Italy under a concession regime. The transmission system operator is *Terna SpA*, which owns and manages 98.3% transmission assets. As for the gas market, there are six large gas DNOs which represent 70% of the market, while the remaining 30% is split among more than 200 players, which manage the distribution service in over 7,400 locations. To reduce such market fragmentation, in 2011 a ministerial decree divided the country into 175 "minimum concession areas" called ATEMs. Gas DNOs are awarded concessions through public tenders carried out in each ATEM, that allow them to operate for a maximum period of 12 years. In contrast, the gas transmission network is operated by few companies. *Snam Rete Gas Spa* is the transmission system operator and owns almost all the gas transmission infrastructure in Italy.

3.4.3 Input-based incentives

Since the third electricity price control (2008-2011), ARERA has introduced a WACC mark-up incentive mechanism, which grants an extra-WACC on top of the ordinary rate of return, that varies in duration and entity according to the type of intervention. For electricity transmission, it covers traditional network investments aimed at the enhancement of the transport capacity of the national transmission grid (RTN), congestion management and improvement of network interconnections, as well as investment in storage systems connected to the RTN (see Table 7). For electricity distribution, it covers investments relative to pilot projects on Smart Grids that support the integration of DG and include the use of battery storage systems (see Table 8). Financial data on pilot projects will be presented in detail in 3.4.3.1.
Since 2010, the same incentive mechanism applies also to investments in the development of new gas transport capacity of the grid.

3.4.3.1 Smart Grid projects in Italy

In 2010, ARERA started a selection process for Smart Grid pilot projects, defining an innovative incentive scheme for the implementation of smart technologies on active MV distribution networks. The objective was to foster an efficient use of resources, introduce new services and improve the flexibility of network management, especially in relation to the problem of intermittence of RES. The pilot projects were selected on the basis of a priority indicator (IP), which accounts for the effectiveness of the measures taken by network operators with respect to four assessment fields: network innovation, continuity of supply, new grid services and user participation. For the *i-th* project, an indicator of benefits IB_i is calculated as the sum of the scores A_j relative to the *j-th* assessment field, normalized by a coefficient α_i which considers differences in project size as well as the difference in energy injection before and after the project activities (*P-smart* indicator):

$$IB_i = \alpha_i \sum_{j=1}^{4} A_{i,j}$$

Finally, the indicator IP_i is computed as the ratio between IB_i and the cost of investment C_i associated to the *i-th* project:

$$IP_i = IB_i / C_i$$

Table 11 shows data relative to the seven projects which were approved in 2011, comparing the maximum estimated budget eligible for incentive with the actual TOTEX reported by the DNOs at the project end date (December 2014). Projects are ranked based on their IP score. The selected Smart Grid projects were allowed an extra remuneration of 2% on top of the ordinary WACC for a period of 12 years. This extra remuneration is recovered through network tariffs.

Table 11: Total cost and funding approved for smart grid pilot projects

Pilot Project	**DNO**	**Max investment eligible for extra-WACC (k€)**	**Project cost (k€)**	**IP**
A2A - CP Lambrate	A2A Reti Elettriche S.p.A.	1,150	1,165	3005
ASM Terni	ASM Terni S.p.A.	800	797.9	1375
A.S.SE.M. – CP San Severino Marche	A.S.SE.M. S.p.A.	1,193	1,265	980
A2A - CP Gavardo	A2A Reti Elettriche S.p.A.	756	326.2	663
Acea Distr.	Acea Distribuzione S.p.A.	4,970	5,403	660
ENEL Distr. - CP Carpinone	ENEL Distribuzione S.p.A.	6,740	7,389	527
Deval - CP Villeneuve	Deval S.p.A.	2,194	2,205	401

Source: ARERA, 2015.

Based on the results achieved by the smart-grid pilot projects, in 2016 ARERA drew a new output-based incentive mechanism for large-scale innovation investments for the electricity distribution system. The objective is to convert the current electricity distribution grids into an integrated "smart distribution system", so as to measure the benefits that each investment may bring at the system level.

3.4.3.2 Energy storage projects in Italy

By 2019, the TSO *Terna S.p.A.* has planned to install a 75 MW storage system in the national grid. As part of the National Electricity System Defence Plan for 2012-2015, *Terna S.p.A.* has invested €93 million for the installation of 40 MW of new lithium-based and ZEBRA (molten-salt) battery storage technologies connected to the electricity national transmission network (RTN). The aim is to maximize the injection of electricity produced by RES into the grid and increasing the security of the electricity grid. To this end, it ran a first experimentation phase called Storage Lab, consisting of two "power intensive" pilot projects – which provide for the overall installation of about 16 MW of storage capacity – necessary to test and validate the use of electrochemical storage on a large-scale. At a second stage, the results achieved have allowed the selection of the most promising technologies for the installation of the remaining 24 MW as envisaged by the Defence Plan.

Further, *Terna S.p.A.* has invested €160 million in the 35MW Large Scale Energy Storage programme (2011), consisting of six pilot projects focused on three area of Southern Italy's grid which are critical due to the high number of grid congestions deriving from excessive penetration of RES. The projects are based on the use of so-called "energy intensive" storage technologies (sodium-sulphur batteries) characterized by high accumulation capacity compared to the power rating of the plants.

The storage system pilot projects were evaluated by ARERA through an indicator primarily based on the benefit/cost ratio of the investment, calculated with reference to the conventional duration of storage systems (equal to 12 years). The benefit/cost ratio is given by the ratio between:

- benefits deriving from the reduction of the renewable energy curtailment obtained as a result of the pilot project and calculated as the product of the following factors: (a) estimated curtailment reduction, compared to the level of curtailment in the absence of the pilot project; (b) efficiency of the charge/discharge cycle of the storage systems employed; (c) current energy price, determined on the basis of the last year's electricity sales price;

- the discounted cost of the pilot project, including both capital expenditures and operating expenditures.

Both “power intensive” and “energy intensive” pilot projects were granted a 2% extra WACC for 12 years, subject to the achievement of at least 50% of the target increase in production from RES during the first two years of the storage system’s operation.

3.4.4 Output-based incentives

3.4.4.1 Incentive for quality of service

The current mechanism to ensure the continuity of transmission and distribution services entails an output-incentive regulation focusing on the improvement of continuity of supply (i.e. the occurrence of service interruptions) as well as the reduction of the observed differences in continuity levels across different territorial regions.

As for transmission, since 2004 quality of service regulation was introduced as a system of premiums and penalties based on the performance of the national transmission system operator (*Terna S.p.A.*), which is assessed in relation to objectives defined ex-ante by the Authority and related to the allowed power outages per user directly connected to the RTN. In particular, premiums and penalties are applied to two indicators: the energy not supplied (ENS) to customers due to incidents in the transmission network, and the average number of service interruptions. To reduce risks, the maximum amount of annual premiums (penalties) is equal to 2% (1.5%) of the annual revenues recognized to the system operator for the transmission service.

As for distribution services, a premium/penalty system is applied to indicators of the duration of long service interruptions (SAIDI, System Average Interruption Duration Index) per customer, as well as of the number of long and short interruptions, given by the sum of SAIFI (System Average Interruption Frequency Index) and MAIFI (Momentary Average Interruption Frequency Index) indices. Annual reward or penalties are proportional to the difference between the actual values measured by the DNOs and the target set by the regulator. At the end of the year, if there is a surplus (deficit), this is passed through to consumers by a decrease (increase) in the distribution tariff. This way, costs for higher levels of quality are equally distributed among consumers, while quality-of-service incentives to DNOs are specific to each territorial district.

3.4.4.2 Incentives for DG based on network performance indicators

Italian regulation mirrors the European directives aimed at increasing energy efficiency and generation from RES. In recent years, ARERA had to consider the most recent trends towards distributed generation and new innovative energy uses (e.g. EVs), and to acknowledge the limited experience matured in Italy in developing innovative solutions. To bridge this gap, the Authority wants to define an output-based incentive scheme which relies on network performance indicators. The main challenge is to design an indicator that is able to measure the benefits delivered by the single investment to the whole system in a precise and objective way. In order to do so, it introduced a three-phase approach that consists of research, pilot programs and final roll-out of innovative technologies.

The research was commissioned to the Politecnico di Milano in 2009, with the aim of estimating the hosting capacity of MV distribution networks and of assessing the amount of DG above which network performance becomes too deteriorated. The result was the design of the *Reverse Power- flow Time (RPT)* indicator, i.e. "*the amount of time the power flows from the distribution network to the transport grid when DG injection exceeds actual local demand in a given time interval*" (Crispim et al. 2014)**.** This indicator can be used for SG project selection by setting a threshold for the minimum level of DG for medium-voltage distribution networks. Moreover, it can be used to selectively steer the development of innovative solutions towards critical areas characterized by high RES penetration. Another output metric is the *P-smart* indicator, which can be used to assess the benefit of a Smart Grid upgrade when evaluating investment proposals. The indicator accounts for the amount of DG energy equivalent that can further be injected into the grid in safe conditions (voltage, current, frequency) following the intervention and that would allow for efficient network usage. Finally, pilot programs can perform a comprehensive test of such indicators to support the roll-out phase. As a result, an output-based incentive scheme for the future roll-out phase can be envisioned, which includes:

- an incentive determined proportionally to the *P-smart* and to the number of DG plants actually controlled;
- an *RPT* threshold for MV networks, whose reverse flow rate at the high/medium voltage node must be above a certain value;

- a set of minimum requirements for smart grid pilot projects defined by the Authority.

This incentive scheme may be further improved in the light of the results of experimentation of new innovative functions possible thanks to the smart grid investments, such as network integration with EV charging stations, demand response programmes and storage systems.

3.4.5 Other projects

In 2015, the European Commission approved the National Operational Program (PON) *Imprese e Competitività 2014-2020* launched by the Ministry of Economic Development and aimed at supporting investments for the construction of intelligent electricity distribution networks. The programme allocates a total budget of €2.3 billion, of which €1.67 billion provided by the EU and €640.5 million by national co-financing. The program aims at fostering investments in the less developed regions of Italy, with the following objectives:

- to strengthen research, technological development and innovation;
- to improve access to, use of and quality of ICT;
- to promote competitiveness of small and medium-sized enterprises;
- to support the transition to a low-carbon economy in all sectors.

The projects eligible for funding are those focusing on the implementation of measures to increase the share of electricity demand covered by distributed generation from RES. The incentives are granted in the form of a grant and cover up to 100% of the allowed costs. The public tender presented in the Ministerial Decree of 20 March 2017 allocated €80 million to finance network innovation projects. In March 2018, *e-Distribuzione* was awarded the whole amount to finance 21 smart-grid projects in the southern regions of Italy.

Since 2007, the Authority has ordered the mandatory roll-out of smart metering and has provided specific incentives to both capital and operating expenditures, including:

- allowed cost recovery within the dedicated metering tariff;
- standards or minimum requirements for smart meter design and operations.

More recently, DNOs have invested in the deployment and installation of second-generation or 2G smart meters, which allow monitoring of electricity consumption in real time, thus permitting dynamic pricing.

At the end of 2016, *e-Distribuzione* presented the Open Meter project for the roll-out of second-generation meters in Italy. The project consists of a 15-year plan (2017-2031) for the installation of 41 million 2G meters, of which around 32 million will replace the current first-generation meters. The overall investment amounts to approximately €4.3 billion, of which €1.3 billion will be spent by 2019 for the installation of the first 13 million meters. The investment will be accounted for in the metering tariff (which is separated from the distribution tariff) set by the regulator.

3.4.6 Projects overview

Table 12: Overview of investments by project category

Project category	Project	Incentive mechanism	Source of funding	Total budget
Traditional network investments (transport capacity, security of supply, energy losses, quality of service)	-	Extra WACC on specific investments.	Increase in network tariffs.	-
Smart Grids - Integration of DG	SG pilot projects.	+2% WACC for 12 years.	Increase in network tariffs.	€17.4 million
	e-Distribuzione - SG projects.	Grants.	National Operational Program (PON): EU + national funds.	€80 million
2G smart meters	*e-Distribuzione* - Open Meter project.	No incentive (mandatory).	Increase in metering tariffs.	€4.3 billion
Conversion and storage systems	*Terna S.p.A.* - Project Lab and Large Scale Energy Storage pilot projects.	+2% WACC for 12 years.	Increase in network tariffs.	€253 million

Table 12 presents a schematic view of previously described projects ordered by area of investment, showing their budget and how they have been incentivized and financed. The table reveals that investments in innovation have been undertaken both through specific incentive mechanisms and under business as usual, as in the case of the mandatory smart meter roll-out. Most of these projects have been financed through network tariffs, and therefore through an increase in energy prices for customers. However, there are projects which have been financed through the use of EU funds and national sources, as is the case with the PON *Imprese e Competitività*. The investment incentives mostly take the form of an extra-WACC, although grants have been used for projects falling outside of the Authority funding scheme.

Overall, Italy has invested in smart grids, smart meters, and storage and conversion technologies, which are necessary in determining the transformation and evolution of the current grid and are therefore enablers of the integration of energy carriers. Nevertheless, until now no project has dealt specifically with energy networks integration.

3.5 Germany

Up until 1998, the German energy industry was characterized by vertically integrated utilities being granted regional monopolies by the state. Following EU directives on the unbundling of energy services, the electricity and gas markets were liberalized respectively in 1998 and in 2003. Although reaching EU's 2020 target for CO2 emissions is unlikely, in recent years the country has invested massively in energy generation from RES, with the aim of reaching up to 80% of production by 2050. In addition, the government has made a commitment to shut down all nuclear power plants by 2022.

While district heating networks are not regulated, the task of regulating electricity and gas networks in Germany is performed by a variety of actors, the main responsibility lying on an independent federal authority: the Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railway (BNetzA), under the jurisdiction of the Federal Ministry for Economic Affairs and Energy (BMWi). BNetzA is responsible, among other things, for establishing the regulation scheme, approving network access charges and setting access conditions, and taking measures in case of abuse of market power by network operators. The federal authority is flanked by 10 State regulatory authorities (6 out of the 16 German states delegate their function to BNetzA). The state authorities are responsible for the regulation of local network operators with a customer base below 100,000, including the assignment of licenses and the setting of individual revenue caps. Larger and cross-border network operators are regulated directly by BNetzA. In 2005, through the Energy Act (EnWG), cost-plus was replaced by incentive regulation in the form of a revenue cap scheme. The first regulatory period started on 1st January 2009, with a price control period of five years, although a misalignment of one year was introduced by shortening the first gas regulatory period. The legislative framework of the regulatory scheme is provided by the Incentive Regulation Ordinance (ARegV), introduced in 2007 and amended in 2016.

3.5.1 The regulatory framework

Two years prior to the start of the regulatory period, the regulator undertakes a price control review. In order to determine the base revenues, the regulator performs an examination of total costs based on the operators' annual financial statements of the previous year, referred to as the base year. The regulator makes use of a TOTEX approach, where network operators' total costs are divided into two components:

1) Non-controllable costs, which are the costs that the firm has no possibility of influencing, as listed by the regulator in the ARegV (e.g. expansion projects for TNOs, transmission charges for DNOs, mandatory smart meter installation);
2) Controllable costs, which are the costs that the firm can influence. Through the use of benchmarking techniques, [17] these costs are further split into:
   a) efficient costs, meaning the costs which that specific firm needs to sustain in order to provide the service, and which vary according to firm to take into account firm heterogeneity;
   b) inefficient costs, which network operators are obliged to uniformly cut over the regulatory period. These costs have to reach zero by the end of the second regulatory period.

The yearly revenue allowance is thus based on these elements:

- non-controllable costs, which are adjusted yearly based on costs actually sustained;
- efficient and inefficient costs incurred by the firm in the base year to provide network services, where the inefficient component is scaled annually. These costs are adjusted annually to take into account the inflation rate, a sector efficiency factor and a network expansion factor;
- rewards or penalties dependent on compliance with quality targets related to network reliability and performance.

$$R_t = NC_t + \left[C_{E,0} + (1 - V_t)C_{I,0}\right]\left(\frac{CPI_t}{CPI_0} - XF_t\right)EF_t + Q_t$$

Where:

R_t = allowed revenues for year t.

NC_t = non-controllable costs in the year t.

$C_{E,0}$ = controllable efficient costs in the base year.

$C_{I,0}$ = controllable inefficient costs in the base year.

V_t = percentage of inefficiency that has to be reduced by the end of year t.

[17] Stochastic Frontier Analysis (SFA) and Data Envelopment Analysis (DEA) are used as benchmarking tools.

$$V_t = \begin{cases} t/10 \text{ for the 1st regulatory period} \\ (5+t)/10 \text{ for the 2nd regulatory period} \end{cases}$$

CPI_t = consumer price index in the year t.

XF_t = sector-level X factor for the year t.

$$XF_t = (1 + XF_1)^t - 1 \quad \text{with } XF_1 = \begin{cases} 1.25\% \text{ for the 1st regulatory period} \\ 1.50\% \text{ for the 2nd regulatory period} \end{cases}$$

EF_t = expansion factor in the year t. This factor applies only for distribution, and it depends on the number of connections to the grid (50%) and on the size of the service area (50%).

Q_t = reward or penalty for quality targets in the year t.

$t = 1, \ldots, 5$

3.5.2 Incentive schemes

3.5.2.1 Expansion projects

In line with the German strategic plan to greatly expand the electricity and gas networks, infrastructure investments not included in the initial revenue allowance can be recovered by network operators by requesting the approval of the federal authority. To be approved for revenue allowance adjustment, the investment has to deal with the stability or with the expansion of the transmission networks. This incentive mainly applies to TNOs, as for DNOs network expansion is accounted for in their revenue allowance through the expansion factor. DNOs can take advantage of this incentive when the investment deals with the integration of RES or CHP facilities into the network. Annual expenses of approved projects are treated as uncontrollable costs and can be recovered by increasing the revenue allowance for that year.

3.5.2.2 Research and development projects

Every year, network operators can ask the regulator for a revenue allowance adjustment that partially covers R&D project expenses actually undertaken in that year as reported in the financial statements. The increase in revenue allowance equals 50% of the total expenses not covered by public funding. For a project to be eligible, it has to be included in a research funding program approved by a regulatory authority or governmental body, e.g. the BMWi. R&D costs already included in the initial revenue caps are not eligible for adjustment.

Table 13 summarizes the main elements that characterise the German regulatory framework analysed in this chapter.

Table 13: Framework overview

Regulator	Large utilities: BNetzA. Smaller utilities: State regulators.
Type of regulation	Incentive based: revenue cap with a price control of 5 years.
Regulatory period	2009-2013, 2014-2018.
Regulatory asset base (RAB)	N/A
Allowed return on equity	7.39% after corporate taxes. 9.05% before corporate taxes.
Efficiency factor	1.25% base value for the 1st regulatory period. 1.50% base value for the 2nd regulatory period.
Allowed depreciation	Based on accounting depreciation.
Allowed inflation	CPI – Sector-level X factor efficiency factor.
Exposure to volume risk	No, expansions in volume are covered by an expansion factor.
Investments incentive	Expansion projects.
Other incentive mechanism	Research and development.

Source: Ernst & Young. 2013. “Mapping power and utilities regulation in Europe”.

3.5.3 Network innovation

Incentives to research and development and investments in new technologies in Germany are mainly undertaken under large funding programmes financed by the Federal Government to reflect the national energy policy.

Under the 6th Energy Research Programme, the Federal Government allocated approximately €3.5 billion over the period 2011-2014 to fund research and development activities on innovative technologies able to address the energy transition (*Energiewiende*) as required by German policy. The programme mainly focuses on energy efficiency and integration of RES, and particularly on electricity generation from PV and wind, heat generation from renewables, energy storage and networks integration. It has been partially financed by the Energy and Climate Fund, which channels all the emissions revenues coming from certificate auctions carried within the EU emission trading system, while the rest comes from federal budget.

The Federal Government is already discussing the 7th Energy Research Programme which is scheduled to be adopted by the end of 2018.

3.5.3.1 Storage

Under the *6th Energy Research Programme*, in 2012 the Federal Government launched the *Energy Storage Funding Initiative* to provide funding for the research, development and demonstration of energy storage systems.[18] Up until 2018, around 250 projects have been granted a total financing of €200 million. Funds are provided for 3 to 5 years in the form of investment grants and privately matched funds. The projects covered by the funding initiative range from household batteries to large-scale distributed storage systems and projects for the long-term storage of electricity from RES. Some of the areas covered are wind-hydrogen (P2G) conversion systems, batteries in distribution grids and thermal storage systems, e.g. integration in heating networks.

Through the KfW, a government-owned development bank, up to 2016 the Federal Government has provided €60 million of funding in the form of form of low-interest loans for battery storage units that are installed alongside PV systems and connected to the grid, triggering investment of around €450 million euros. Since March 2016, a new funding programme running until 2018 will provide €30 million more.

Table 14 shows a comprehensive overview of the measures undertaken by the government and the regulator to support energy storage. From this overview it emerges how public funding for energy storage has been low if compared to the overall budget allocated to the *6th Energy Research Programme*.

Table 14: Summary of storage support programmes

Entity	Description	Funding mechanism	Amount
BMWi, Federal Ministry for the Environment (BMU), Federal Ministry of Education and Research (BMBF).	*Energy Storage Funding Initiative* - R&D and demonstration of storage technologies.	Grants and privately matched funds.	€200 million through 2018.
KfW Bank	Incentives for battery storage connected to PV.	Low-interest loans and investment grants.	€60 million 2013-2015, €30 million 2016-2018.

[18] The initiative was launched jointly by the BMWi and the Federal Ministry of Education and Research.

BNetzA	Electricity storage facilities can benefit from exemption from: network tariffs, Renewable Energy Sources Act (EEG) levies, and electricity taxes in the case of pumped hydro storage.	Fees exemption.	N/A
BAFA, CHP Act (KWKG 2016).	Heat and cold storage facilities of CHP plants with at least 1 m^3 water volume equivalent or at least 0.3 m^3 per KW installed electric power receive a grant.	Investment grants.	€250 per cubic meter of storage capacity, capped to 30% of the total investment for large storage systems.
States, BMU and other ministries, universities and research institutions.	Basic research and demonstration for storage projects.	Own budget.	€22 million in BMU projects. Yearly budget of over €68 million and €65 million from universities and other research institutions respectively.[19]
BMU, Federal Office of Economics and Export Control (BAFA), KfW Bank.	*Renewable Energies Programme* – Integration of RES and storage technologies in the heat market.	Low-interest loans and repayment bonuses.[20]	N/A

Source: Borden and Schill. 2013. "Policy Efforts for the Development of Storage Technologies in the U.S. and Germany".

3.5.3.2 Smart Grids

In 2016, the German government designed the *Smart Energy Showcases - Digital Agenda for the Energy Transition* (SINTEG) funding programme to finance five large development and demonstration projects aimed at integrating RES and smart technologies into the grid, enhancing network security and energy efficiency. SINTEG covers a five-year (2016-2020) period and was allocated a total of €700 million, of which more than €200 million provided as grants by the BMWi while the remaining €500 million consist of private investments made by participating companies. The five projects were selected though a competitive

[19] Data relative to 2013.
[20] Reductions on the sum to be repaid at timely investment completion.

tender and were initiated between 2016 and 2017. In Table 15 the projects are reported with the funding amount and a brief description.

Table 15: SINTEG projects

Project name	Granted sum (€m)	Description
C/sells: large-scale showcase in the 'solar arch' in southern Germany	43.5	The project focuses on the integration of solar energy into the grid through the demonstration of a national cellular network that interconnects regional energy systems and balances the energy generated by each of them to optimize the overall energy system.
Designnetz: a modular concept for the energy transition – from isolated solutions to an efficient energy system of the future	29.2	Development of innovative solutions to supply decentralized solar and wind energy to urban and industrial load centres in a safe and efficient manner.
enera: the next big step in the energy transition	51.4	enera intends to improve stability and security of energy supply by using intelligent measuring systems and ICT to integrate regional energy systems into an overall system, and by setting up a Smart Data and Service Platform for data analysis. In addition, enera demonstrates how market-contracted network management and digitization can significantly reduce network expansion costs and create opportunities for innovative business models.
NEW 4.0: the energy transition in the north of Germany	41.5	The project aims at maximizing efficiency in the use of regional electricity overproduction from wind by flexible load management through demand side response and storage, and by improving the supply of electricity from one region to the other.
WindNODE: showcase for smart energy from the north-east of Germany	36.5	The focus of the project is the efficient integration of electricity, heat and mobility to accommodate fluctuations in regional wind power in a flexible way. To this aim, WindNODE intends to develop innovative products and services that complement the traditional volume-based energy sales business, and to define data security standards to ensure consumer protection within the digitalized network.

3.5.3.3 CHP

In 2016, the new CHP Act (KWKG 2016) was issued to promote the construction and modernisation of efficient CHP power plants in Germany and to foster the development of district heating and cooling networks by:

- Increasing the maximum annual fund from €750 million to €1.5 billion;
- Granting financial support to existing installations and new systems;
- Reducing the CHP expansion target to 110 TWh per year by 2020 and to 120 TWh per year by 2025 with respect to the previous 145-150 TWh targets;
- Granting a surcharge to electricity from CHP only when it is fed into a public supply grid. Special arrangements apply for self-produced electricity from cogeneration in electricity-intensive industries;
- Excluding from the incentives new plants that use coal as fuel.

The CHP Act provides significant incentives to further increase the percentage of electricity produced from cogeneration in Germany, as it entitles operators that own newly constructed or recently modernised cogeneration plants to obtain surcharges on the electricity market price for CHP-generated electricity. Following the amendment to the CHP Act in 2016, the amount of CHP surcharge on the electricity market price is not set by the state but is based on a competitive auction process managed by BNetzA. The first auction was held in October 2017 in order to select projects for the installation of up to 100MW capacity in existing or new CHP plants. Among the 20 tender projects presented, only seven projects - three modernisation projects and four new construction projects - corresponding to a total volume of just 82MW installed capacity were awarded contracts.

The surcharges are financed through a levy on electricity consumption that consists of a supplement to network charges. The CHP-surcharge is passed through to consumers and is determined each year by transmission system operators as a rate per kWh consumed, resulting in an increase in the electricity price dependent on consumer category. For households, in 2016 this increase amounted to 0.445 € cent/kWh, corresponding to 1.5% of the average household electricity price (29.73 € cent/kWh). A reduced rate is established by the CHP Act for special categories of consumers (with a yearly consumption > 1GWh).

3.5.4 Energy networks integration: the WindNODE project

The WindNODE project takes place in Northeastern Germany, where a high percentage of electricity is generated from RES and especially wind. However, due to weather conditions, this percentage fluctuates, occasionally causing a surplus production of more than three times the electricity needed, while other times it is not sufficient to cover energy demand. The WindNODE project intends to develop an intelligent energy grid able to balance energy production and consumption. To do so, the project engages electricity consumers from the industry, the retail sector and residential areas who want to flexibly align their energy consumption with the expected electricity production. As part of the project, WindNODE intends also to enhance grid flexibility by testing the integration of district heating (DH) and the electricity network. To do so, it will be researched and tested whether and to what extent a 120 MW power-to-heat (P2H) plant would be able to supply up to 30,000 households in winter and up to 300,000 in summer with the electricity surpluses generated by wind and PV in the surrounding area. The construction of the facility would require an investment of nearly €100 million over two years, and it would be the biggest German heating plant powered with electricity. Prior to this, initial development and testing activities on trial equipment are carried out, covered by a €2.24 million grant from the BMWi. Initial development and testing activities are divided into three stages:

1. In 2017, an ICT platform was tested and developed at the Berlin's central heating plant for the communication and control of the integrated system;
2. In 2018, a small-scale test and control of power-to-district heating has been performed on a 7.5 MW power-to-heat plant in Berlin-Buch;
3. In 2019, the large-scale use of power-to-district heating will be tested through a 100MW facility at the Reuter West site.

The aim is to evaluate the coordinated management of bottlenecks within the new integrated network over the long-term, under the limitations posed by both DH system and electricity network. The new integrated system will require joint technology and process development and close coordination between electricity network and DH system operators, that are not allowed by the currently implemented ICT solutions.

3.6 France

In France, the liberalization of gas and electricity markets started in 1996 and 1998, respectively, when France had to implement into its national law two directives issued by the European Commission to promote an effective and efficient internal energy market open to competition, and the unbundling of transmission and distribution services. In 2000, the Commission for Energy Regulation (Commission de Régulation de l'Énergie, CRE) was established, which regulates the French gas and electricity markets and ensures third-party access to transmission and distribution networks. In compliance with the French Energy Code, the CRE sets network tariffs for electricity and gas transmission and distribution based on projected network expenditure over the regulatory period. In France, the Authority introduced incentive regulation in 2008 for gas distribution[21] and in 2009 for gas and electricity transmission and electricity distribution. Since its introduction, incentive regulation has significantly improved the efficiency of operators in terms of operating expenses and quality of service (through premium/penalty mechanisms), but has so far had limited impact on improving the efficiency of network investments.

The heat network in France is not regulated, but it is subject to the national legislative framework. The government supports district heating expansion through a variety of measures, mainly related to the use of RES for heat generation, ranging from grants to VAT reductions. In addition, since 2012 obligations for customers to connect to DH in specific areas can been introduced by local authorities.

3.6.1 The regulatory framework

France adopts a revenue cap mechanism with a regulatory period which lasts 4 years. The framework is identical for transmission and distribution of both electricity and gas. Revenue allowances are set at the beginning of the regulatory period following a building block approach:

$$R_t = OPEX_{F,t} + D_{F,t} + WACC * RAB_{F,t} + CRCP_{t-1} + I_{t-1}$$

Where:

$OPEX_{F,t}$ = forecast OPEX for year t.

[21] In 2008, incentive regulation applied only to GRDF, the main gas DNO. From 2009, to all gas DNOs.

$D_{F,t}$ = forecast assets depreciation for year t.

$RAB_{F,t}$ = forecast regulatory asset base for year t.

$CRCP_{t-1}$ = regulatory account balance at the end of the previous year.

I_{t-1} = financial incentives from the previous year.

$t = 1, \dots, 4$

The regulatory framework does not make use of a TOTEX approach, instead OPEX and CAPEX are treated separately. OPEX are estimated for each year of the regulatory period by auditing each firm's business plan, in order to define a forecast cost trajectory approved by the regulator. In setting this trajectory, the Authority takes into account the efficiency gains the firm is expected to reach.[22] The revenue allowance does not get adjusted to reflect a difference in actual OPEX from what was predicted, instead a 100% sharing factor is used: if OPEX are lower than the forecast defined ex-ante, the firm keeps 100% of the additional productivity gains, but if OPEX are higher, the firm bears 100% of productivity losses.

On the other hand, the actual value of sustained CAPEX is added to the RAB. The revenue allowance for a given year reflects the forecast value of depreciation and the return on regulated assets, but a regulatory account is also included to track differences between forecasts and actual expenses. The "Compte de Régularisation des Charges et des Produits" (CRCP) account registers all differences between the forecast capital expenditure trajectory and the actual one. The differences are fully offset by annual tariff changes through the clearance of the CRCP.

This different way in which OPEX and CAPEX are treated – where all the risk is shouldered by the firm in the former, while in the latter the consumer bears the whole risk – can push firms toward overinvesting in capital as all these expenses are passed through to customers and they generate a return on capital that increases the revenue allowance. As a result, this approach provides limited incentive to cost reduction and thus strongly limits efficiency of operators' investments. CRE recognized this problem and, starting from 2016, it introduced a differentiation to the way grid and off-grid CAPEX are treated. Off-grid expenditures (e.g. real estate, vehicles, information systems) are deemed by the Authority to be the type of expenditures where a higher degree of substitutability between CAPEX and OPEX exists, and therefore offer a greater incentive to the regulated firm to overinvest in capital to see its

[22] No information is made public about the techniques used in the auditing process nor about each firm's efficiency target.

RAB increased. To offset this risk, the regulator started treating off-grid CAPEX in a similar way it treats OPEX. Off-grid CAPEX are still added to the RAB with their actual value, but a 100% sharing factor is introduced for any difference with respect to the forecast value. However, it should be noted that this efficiency incentive is limited only to the regulatory period in which such expenditures are incurred: from the following regulatory period, cost savings or overruns are shared with customers through tariff changes. Innovative projects are excluded from this treatment, and are fully recovered through the CRCP. As for grid CAPEX, the way they are treated depends on whether the firm belongs to the transmission or the distribution sector. For distribution, a sharing factor of 20% has been put into place, but potential gains or losses are capped at a low value (roughly 2% of annual grid CAPEX investments). For transmission, grid CAPEX are still completely passed through to customers via the CRCP.[23]

Tariffs are adjusted every year to account for inflation (CPI) and the discrepancy reported by the CRCP balance. The regulator allows a change in tariffs of maximum ±2% to reflect the clearance of the CRCP balance (therefore the annual change is in the range of CPI ±2%). Where this is not enough to cover the CRCP balance, the remaining amount is compounded by applying a risk-free interest rate, and is then recovered over the following years.

3.6.2 Incentive schemes

3.6.2.1 Efficiency incentives

Large investments for network development (excluding the development of network interconnections) made by gas and electricity transmission system operators are subject to an annual premium/penalty on the allowed revenue, when they exceed a budget threshold fixed at €30 million for the electricity TSO (*RTE*) and €20 million for the gas TSO (*GRTgaz*).[24] The incentive scheme is based on an audit of the project budget presented by the operators and the estimation of a target budget by the regulator. If the actual capital expenditure is less than 90% (greater than 110%) of the target budget, the TSO is awarded

[23] This difference comes from the fact that, for gas and electricity transmission, the technical characteristics of network development works (e.g. geographical characteristics of the areas crossed) are such that their cost of implementation is very variable, and the small number of projects run each year does not allow for their forecast errors to average out.
[24] For gas transmission, the mechanism applies also to projects with a budget representing at least 20% of the TSO's average annual investment for the current regulatory period.

a premium (penalty) equal to 20% of the difference between 90% (110%) of the target budget and the actual capital expenditure. If the capital expenditure incurred is between 90% and 110% of the target budget, no premium or penalty is awarded.
In the case of electricity and gas distribution, as previously mentioned, the premium/penalty on the allowed revenue is used to incentivize a better control of grid CAPEX. In particular, for each year of the regulatory period, the difference between forecast and actual capital expenditures for network development is registered in the CRCP balance. This difference, positive or negative, reflects the efficiency of the operator, and it is shared between the operator and the network users through a 20% sharing factor. This annual incentive is capped at ± €30 million for the main electricity DNO (*Enedis*) and ± €9 million for the main gas DNO (*GRDF*).

3.6.2.2 Incentives to the development of cross-border interconnections

The strengthening of cross-border trading capacity with neighbouring countries is one of the conditions for the emergence of an integrated European electricity market and a key concern for France, which is the leading exporter of electricity in Europe. Cross-border interconnections enable the optimization of resources usage in a context of increasing electricity production from RES and contribute to enhance the security of supply. For this reason, since 2013 the French regulator provides financial incentives to the electricity TSO and the two major gas TNOs (*GRTgaz* and *TIGF*) for the development of cross-border interconnections. The mechanism is based on three distinct incentives:

- a premium fixed at the time the project is commissioned, defined by the regulator as a share of the value of the interconnection for the European system, assessed taking into account the additional trade flows generated and a forecast of market prices and investment cost. This premium is awarded at the time the infrastructure is ready for use as an incentive for quick delivery;
- a premium/penalty, which is added to the fixed premium as an incentive to minimize cost. It is set according to the difference between the target cost of the project as forecast by the CRE and the cost actually incurred by the operator. In the event that the actual cost exceeds the target cost, the amount of penalty on the TSO's overall remuneration for interconnection projects will be limited so that the overall penalties cannot lead to a decrease in WACC greater than 1%;

- a premium/penalty calculated each year based on the actual use of the infrastructure, i.e. the extent to which trade flows exceed the flows initially forecast by the operator. In case of a penalty, its value cannot exceed the value of the fraction of the premium established at the moment the project is commissioned relative to that year. This premium/penalty is awarded during the first 10 years of operation of the infrastructure.

3.6.2.3 Incentives to quality of service

The regulator defines quality of service indicators to be used by the two main gas and electricity DNOs and the two main gas TNOs for monitoring their performance. Each indicator is subject to a financial incentive fixed for the entire regulatory period that is related to the accomplishment of a target level fixed by the Authority. Every year, the operator is awarded (pays) a bonus (penalty) through an adjustment of the revenue allowance if the value of the indicator falls above (below) the target level. The amount of the financial incentive for each indicator is subject to a threshold set by the regulator in line with the historical values of the indicator. For example, for gas transmission the incentive ceiling for each indicator is set at ±600k € for *GRTgaz* and ±300k € for *TIGF*. Finally, for electricity transmission, quality of service indicators are used only for monitoring purposes by the TSO.

3.6.2.4 Incentives to R&D and innovation

R&D and innovation expenditures are treated differently from other expenditures by the regulator. For the whole regulatory period, each operator proposes a yearly R&D budget that is subject to the approval of the regulator. Any amount received by external sources of financing (e.g. national or European funds) are excluded from the estimated budget. Again, OPEX and CAPEX are treated differently. As for OPEX, if at the end of each year the amount spent is lower than it was planned, the difference is entirely passed through to network users through the CRCP account, which translates into lower charges. If actual expenses are greater than it was planned, this cost overrun is shouldered by the firm. As for CAPEX, the difference (positive or negative) is fully offset by the CRCP account. However, each year the network operator has to submit a report, which can be audited by the regulator, that justifies any discrepancy with respect to the planned budget.

Due to the different scheme applied to OPEX and CAPEX, the regulator has observed that investments that produce a reduction in CAPEX (e.g. demand-side management, storage) and a less than proportional increase in OPEX may be penalized. This is especially true for Smart Grid investments, that for this reason are further incentivized. In fact, the regulator allows Smart Grid projects with OPEX higher than €3 million to recover justified cost overruns through the CRCP account.

3.6.3 Network innovation

Up to 2015, France has invested €680 million in Smart Grids, of which nearly 63% came from firms' private investments (JRC, 2017). This is not surprising, as network operators bear very low investment risk as a result of the established regulatory framework, which allows the allocation of significant resources for R&D projects and covers cost overruns through adjustments in network tariffs. Aside from private financing, the other main sources of funding are the French state and the European Union.

National funds mainly come from the *Programme for Investment in the Future* ("*Programme d'investissements d'avenir"*, PIA), that is the major initiative launched by the French government to finance demonstration projects for renewable and low-carbon energy, Smart Grids and to accelerate technological innovation for energy efficiency over a period of ten years (2010-2020). It provides funds through a combination of grants and other financial tools, such as repayable advance loans or investments in equity. The programme is supported by many organizations, including the Environment and Energy Management Agency (ADEME), the main public body responsible for innovation and concerned with sustainability, Smart Grids, electricity storage and e-mobility. Since 2015, under the PIA framework, ADEME has allocated €1.7 billion to finance demonstration projects in these areas; in addition, €1.1 billion have been dedicated to the roll-out of charging points for electric vehicles.[25]

3.6.3.1 Smart Grid projects[26]

Since 2010, the main electricity DNO *Enedis* and the TSO *RTE* have been involved in more than 20 Smart Grid demonstration projects in France and Europe in collaboration with many partners (network operators, suppliers, innovative start-ups, etc.). Table 16 reports a non-exhaustive list of the most relevant Smart Grid projects undertaken in France, specifying the

[25] Data source: *Energy Policies of IEA Countries: France*, IEA, 2016.
[26] Detailed information on each Smart Grid project can be found at http://www.smartgrids-cre.fr/.

amount of private funds provided by *Enedis*, *RTE* and other partners, apart from the PIA national funds.

Table 16: Most relevant Smart Grid demonstration projects in France

Project	Total Budget (€m)	Private funds (€m)	Description
Smart Electric Lyon (2012-2016)	71	61.3	Exploitation of data collected from smart meters for the development of interactive technical solutions (energy management systems, information services, web interfaces and mobile applications). The proposed solutions should help to reduce consumptions and ensure peak load-shifting. The project will assess the energy savings and ease the integration of active management for grid optimisation.
Poste intelligent (2012-2016)	32	22.3	Optimization of the capacity and operational performance of electrical substation facilities (that allow the interaction between the TSO and the DSO) both in terms of energy flows and the exchange of information through digital and optical technologies, in order to compensate for the intermittency of RES. Equipped with a weather station, the smart station will adapt to climatic conditions, but will also be able, in case of incident on a line, to analyse it and to restore the current automatically and very quickly.
Smart Grid Vendée (2014-2018)	27.7	18.2	Optimization of the local distribution network in Vendée (department in the Pays-de-la-Loire region), through the management of local constraints (stability of the electrical voltage) and a control system which facilitates the consumption of locally generated electricity. The project developed simulation and forecast information system tools to monitor the electrical state of the grid, the electricity consumption and production.
SOGRID (2012-2016)	27	14.7	Trial of a new-generation communication infrastructure using PLC (powerline communication) technology to enable the transmission of digital information from smart meters connected to the distribution grid to the source substation.
VENTEEA (2012-2016)	23.8	16.4	Test of new functions to adapt the distribution network to the generation of energy from wind in rural areas. The project will explore how the use of storage close to decentralised production resources can offer ancillary services to the grid (grid stabilisation, voltage control, losses reduction, controllability of wind farm output).
BienVEnu (2015-2018)	10	6	Test of new solutions for connecting EV charging stations in residential housing. Charging points are installed in 10 pilot buildings connecting about 10 EVs each. The project relies on an innovative solution based on modular equipment that can be adapted to easily integrate new users.

Source: ADEME, 2015.

In 2016, following a national call for projects launched as part of the governmental plan *New Indsutrial France* (“*Nouvelle France Industrielle”*, NFI) for the deployment of smart electricity networks, the Ministries of Industry and Energy selected three programmes, two of which aimed at a first large-scale deployment of smart technologies (see Table 17).

Apart from national and European funds, the operators *RTE* and *Enedis* have planned to invest significantly in the SMILE and FlexGrid programmes over the period 2017-2020, and their provisional budget has been approved by the regulator.

Table 17: The SMILE and FlexGrid programmes under NFI

Programme	Description	Budget
SMILE (Smart Ideas to Link Energies)	Support the deployment of a series of regional projects in Bretagne and Pays de la Loire regions. Activities include: • Deployment of four “new generation” electrical substations, with high voltage equipment fitted with optic fibres and sensors to measure the flow in the electrical system in real time and gather data to optimise the network; • Modernisation of network infrastructures through the digitisation of 34 source stations (to switch to dynamic management of the electric network); • Implementation of a web portal (*Open Data*) and an application (*Eco2mix*): two digital tools designed to provide users with useful information (recommendations, tables, graphics, etc.) to improve energy management; • Integration of EVs through a network of 1000 smart charging stations using energy generated from RES.	€300m including: • €28m from *RTE*. • €21m from *Enedis*.
FlexGrid	The programme counts about 40 regional projects in the region Provence-Alpes-Côte d’Azur deploying electrical systems using electricity generated from RES, storage systems and charging stations for EVs. These technologies will allow to intelligently manage the production and distribution of electricity. Among other infrastructures, smart and communicating meters (Enedis' *Linky* meters) will be installed, to allow power grid operators to know in real time the energy consumption of households.	€340m including: • €12m from *RTE*. • €20m from *Enedis*.

Source: Programmes’ websites.[27]

[27] Websites can be reached at https://smile-smartgrids.fr/ and http://www.flexgrid.fr/le-programme-flexgrid/.

3.6.3.2 Electrical storage and Power-to-Gas (P2G) projects

As observed by the Authority itself, current regulation does not include any provision that supports the effective development of electrical storage. For this reason, few electrical storage facilities are connected to the distribution network so far, mostly consisting of experiments. Table 18 summarizes the storage and P2G projects discussed below.

Table 18: Summary of storage and P2G projects

Category	Project(s)	Operator	Budget (€m)
Storage	11 pilot projects in isolated networks (islands and overseas territories).	Local distribution network operators.	N/A
	The RINGO project.	*RTE*	80
P2G	The Jupiter 1000 project.	*GRTgaz*	30

Storage in isolated networks

In the short-medium term, storage installations do not have any solid economic justification, apart from specific cases like isolated networks (islands such as Corsica and overseas territories). The implementation of centralized storage systems is particularly meaningful in these territories, as they are characterized by high electricity production costs and weather conditions favourable to the integration of RES. In 2017, the regulator has selected through a tender 11 pilot projects to be run by local network operators in these geographical areas, [28] with a cumulative power of 50MW and a storage capacity of 56.8 MWh. These projects will have a cumulative cost of €80 million, and the regulator has estimated that they will generate, over 25 years, a saving in electricity charges of around €370 million.

Battery storage: the RINGO project

In 2017, the electricity TSO *RTE* announced a demonstration project for electricity storage, called RINGO, with a budget of €80 million. The project intends to install a battery storage system to be used to avoid congestions at critical nodes on the transmission network. Batteries will be placed where the lines are congested and absorb large amounts of fluctuating energy from RES. Each site's capacity will be of 12 MW / 24 MWh. If too much electricity is being generated in a region, *RTE* will be able to store this surplus while

[28] Network operators in these areas are usually vertical integrated, acting also as generators.

simultaneously injecting the same amount of electricity into another region. The storage systems will be put into service in 2020, for a test period of three years.

P2G: the Jupiter 1000 project

In 2014, the French gas TSO *GRTgaz* launched, together with seven industrial partners, the first P2G project linked to the French gas transmission network, called Jupiter 1000. The project aims at recovering surplus electricity from renewable sources (wind and solar) and recycle CO2 produced by industrial smoke. It intends to build a demonstration P2G plant with a power rating of 1 MWe (i.e. a production level equivalent to the annual electricity consumption of about 150 families), which is planned to come into service in 2018. The Jupiter 1000 plant will produce hydrogen entirely from renewable energy by means of two electrolysers. By a methanation process, hydrogen is combined with the CO2 captured from a nearby industrial site to obtain synthetized methane, that can then be injected into the gas transmission network.

According to the performance levels shown by the demonstrator, *GRTgaz* and its partners will define the future technical and economic standards of a full-sized installation of this type. In fact, *GRTgaz* estimates that more than 15 TWh of renewable gas per year could be produced using the P2G conversion technology by 2050.

The project has a budget of €30 million, of which €20 million are shouldered by the industrial partners and €10 million are given as grants by the European Union (through the European Regional Development Fund, ERDF) and the French government.

3.6.4 Energy networks integration

In a resolution of 2015, the regulator asked electricity and gas DNOs (serving more than 100,000 customers) to specify how the local energy systems may be optimized in order to bring greater coordination between energy networks, and to assess the impact this would have on the overall management of the energy systems. In response to this request, DNOs have launched pilot projects aimed at testing synergies between electricity, gas and heat distribution networks which integrate RES. In particular, the regulator mentions three projects that were run by the DNOs *Enedis* (electricity) and *GRDF* (gas) in collaboration with other partners for the optimization of local networks (see Table 19), that represent the first attempt of integration of energy networks in France.

Table 19: Three networks integration demonstrators for the optimization of local networks in France

Project	Start date	Budget (€m)	Description
SunRise (Smart Urban Networks for Resilient Infrastructures and Sustainable Ecosystems)	2010	12	Large-scale demonstration of the interdependent management of water, electricity, gas and heating networks at the Campus of the University of Lille, which has the size of a small town (140 buildings, 25,000 users, 70km of urban network).
Brest Rive Droite	2012	N/A	The project seeks solutions to compensate for the new electrical needs linked to densification and urban development in Brest Métropole Océane, alternative to the reinforcement of the electricity network. The guiding principle is to work on the integration of the different energy networks (electricity, gas and heat networks).
GRHYD (Gestion des Réseaux par l'injection d'Hydrogène pour Décarboner les énergies)	2014	15	The project aims to convert surplus energy generated from renewable sources into hydrogen, which will then be blended with natural gas for a broad range of applications, including space heating, water heating and fuelling of hydrogen-powered vehicles.

4 Conclusions

In this work we performed a detailed comparative analysis of the regulatory frameworks of four reference countries (the UK, Italy, Germany and France), especially focusing on the role played by the national regulatory authorities in providing financial incentives for innovation to network operators. To do so, we examined resolutions and reports released by the Authorities themselves, and the websites of the main network companies operating in the electricity and gas markets. In the special case of the UK, our analysis included the elaboration of data provided by the "Smarter Networks" portal, which contains a comprehensive database of network innovation projects (network management, smart grids, storage, EVs and networks integration) financed through the incentive schemes designed under the RIIO framework.

The four countries follow different approaches to the way they foster network innovation: at one end, in the UK investments are almost entirely performed under the incentive schemes provided by the regulatory framework, financed by increases in network charges ultimately shouldered by consumers; at the opposite end, in Germany innovation is financed mainly through large funding programmes run by the Federal Government; Italy and France are placed in the middle, with incentives playing a pivotal role although an important contribution is also provided by national and European funds.

Although a softer incentive regulation, such as the RIIO framework, has proved to positively influence innovation and to improve the operational performance of regulated firms, it also allows excessive profit margins for network operators in return for their investments. These costs are then passed onto consumers, leading to a significant increase in energy bills. By contrast, a tighter regulation may negatively affect innovation, as it allows lower returns on investments and puts great risk on network operators, especially in the case of radical innovations such as the integration of energy networks. A trade-off needs to be found in order to balance the investment risk borne by customers and operators, and to avoid unjustified increase in energy prices.

With the aim of making operators properly assess the value of network investments on the basis of delivered outputs and avoid increased costs for final customers, a TOTEX approach is being used in the UK and Germany and is planned to be adopted also in Italy from 2020. In France, capital and operating expenditures are instead subject to different incentive mechanisms, and such approach has proved to be less effective in supporting efficient investments in innovation.

Our analysis does not provide an exhaustive overview of all innovation projects run in the four countries, as the main focus was on the investments financed through each state's regulatory incentives. Nevertheless, a wide range of projects were analysed. On the basis of our findings, no country is significantly investing in networks integration. Although the UK is the leader in terms of overall network innovation, we found limited evidence of operators' investments for the integration of energy networks financed under the RIIO framework. In Italy no project has been run until now in this technological field. Nevertheless, both the UK and Italy have invested in smart grids, storage and conversion technologies, which are enablers of the integration of energy carriers. In Germany, the only project found tests the integration of the electricity network and district heating at a small scale to accommodate fluctuations in wind power. France is the country which has invested the most in networks integration, having run three pilot projects experimenting with the integration of electricity, gas and heat networks, and with P2G technology connecting hydrogen-powered vehicles to the grid.

The main difficulties encountered in our work were related to the acquisition of data regarding the innovation effort in each State – both due to the lack of such data and to their availability only in foreign languages – and the absence of a database which collects all innovation projects run across Europe. Due to these circumstances such an overview can only be partial, but we believe it can still be useful in providing insight on what has been done up until now and what can be learned from the current regulatory efforts to be used as a guidance for tackling the challenges arising from the integration of energy networks and the consolidation of a sustainable European energy market.

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Appendix

Storage systems

Project Summary			
Project Name	Solar Storage		
Funding Licensee	Western Power Distribution (WPD)		
Lead Sector	Electricity Distribution		
Start Date	01/04/2015	**End Date**	01/04/2018
Project Type	Demonstration Project		
Project Objectives	The project intended to demonstrate the potential value of integrating utility-scale storage systems with distributed generation of electricity from renewables in order to address the problems of peak local demand, RES unpredictability and to limit the negative impact of the use of multiple active storage or quality management devices on power quality.		
Project Description	The project designed a battery storage and control system and tested its integration with a 1.3MW photovoltaic system connected to the WPD South West's 11kV network. The project demonstrated safe, reliable operation of the battery under operational conditions. In addition, the storage and control system has proved to allow: • better matching of electricity supply and demand; • the possibility to import electricity from the grid in periods in which demand is low; • improved voltage management; • reduced capacity requirement per MW peak of PV generation; • smart coordination of multiple storage devices.		
Project Funding			
Incentive Mechanism	NIA: increase in the yearly revenue allowance.		
Source of funding	Increase in the licensee's network charges.		
Total Budget (£m)	1.8	**Funding Awarded (£m)**	1.5

<table>
<tr><td colspan="4">Project Summary</td></tr>
<tr><td>Project Name</td><td colspan="3">Industrial & Commercial Storage</td></tr>
<tr><td>Funding Licensee</td><td colspan="3">Western Power Distribution (WPD)</td></tr>
<tr><td>Lead Sector</td><td colspan="3">Electricity Distribution</td></tr>
<tr><td>Start Date</td><td>01/08/2016</td><td>End Date</td><td>01/04/2019</td></tr>
<tr><td>Project Type</td><td colspan="3">Demonstration Project</td></tr>
<tr><td>Project Objectives</td><td colspan="3">The project aims at examining the use of storage for WPD’s industrial and commercial (I&C) network customers in order to:
• enhance local energy management;
• defer expensive and time-consuming network reinforcements necessary for the connection of low-carbon technologies (e.g. such as wind and PV) to the low-voltage network;
• maximise the consumption of electricity produced on-site;
• improve grid balancing and strengthen the flexibility and reliability of the grid;
• reduce the overall power consumption of I&C customers and distribution network charges thanks to the reduced reinforcement requirements;</td></tr>
<tr><td>Project Description</td><td colspan="3">The project started with a comprehensive review of different battery storage technologies and their application. Then, detailed design and modelling of storage solutions was performed, in order to test their potential installation in the WPD’s network. Trial and experiments were conducted in four sites to understand the benefits of installing storage facilities in industrial and commercial areas. The acquired knowledge will be used to provide recommendations on safety, operation and maintenance of storage devices.</td></tr>
<tr><td colspan="4">Project Funding</td></tr>
<tr><td>Incentive Mechanism</td><td colspan="3">NIA: increase in the yearly revenue allowance.</td></tr>
<tr><td>Source of funding</td><td colspan="3">Increase in the licensee’s network charges.</td></tr>
<tr><td>Total Budget (£m)</td><td>1.1</td><td>Funding Awarded (£m)</td><td>1.0</td></tr>
</table>

Smart Grid technologies

Project Summary			
Project Name	Enhanced Frequency Control Capability (EFCC)		
Funding Licensee	National Grid Electricity Transmission (NGET)		
Lead Sector	Electricity Transmission		
Start Date	01/01/2015	**End Date**	01/03/2018
Project Type	Development and demonstration project		
Project Objectives	The objective of this project is to develop an innovative monitoring and control system which will obtain accurate electricity frequency data at the regional level and enable the required rate and volume of demand response. The new system is used to demonstrate the frequency response capability and coordination in order to develop an optimised and coordinated model which ensures the utilisation of an appropriate mix of response.		
Project Description	Development of a monitoring and control system which uses local frequency to trigger a response as fast as possible after an event caused by a disturbance source in such a way as to limit the response to the region close to it. The developed system will then be used to record data from selected response providers connected to distribution and transmission networks in order to investigate the characteristics of different forms of response and the capability of providers. Finally, it will be demonstrated a way to coordinate them in order to provide an optimal response to system events as well as the most efficient frequency response under different system conditions.		
Project Funding			
Incentive Mechanism	NIC: equal monthly transfers over one year from the SO to the funding licensee		
Source of funding	Increase in the SO's network charges.		
Total Budget (£m)	9.3	**Funding Awarded (£m)**	6.9

Project Summary			
Project Name	Real-Time Networks		
Funding Licensee	Scotland Gas Networks and Southern Gas Networks		
Lead Sector	Gas Distribution		
Start Date	01/04/2016	**End Date**	01/04/2019
Project Type	Demonstration project		
Project Objectives	This project aims to develop, install and demonstrate a flexible real-time platform that will enable to understand of GB's gas network operation and to meet evolving needs deriving from new gas sources and downstream renewables.		
Project Description	The project will install innovative sensing technologies that will support the revision of network modelling and data management methods for the development of a real-time network model. Real-time modelling and advanced forecasting will be possible thanks to a new cloud-based system and custom-made software. Then, it will be analysed the impact of downstream renewable technologies on the network capacity and system management. Finally, the simulation of new distributed and non-conventional gas sources may also allow to demonstrate the ability of the network to effectively accept and manage variations in gas quality in order to reduce processing and capital costs.		
Project Funding			
Incentive Mechanism	NIC: equal monthly transfers over one year from the SO to the funding licensee		
Source of funding	Increase in the SO's network charges.		
Total Budget (£m)	8	**Funding Awarded (£m)**	7.1

Project Summary			
Project Name	Open LV		
Funding Licensee	Western Power Distribution (WPD)		
Lead Sector	Electricity Distribution		
Start Date	01/01/2017	**End Date**	01/04/2020
Project Type	Demonstration project		
Project Objectives	The project intends to demonstrate the benefits provided to network operators and customers by an open platform for an electricity substation, as opposite to proprietary platforms being deployed in GB that risk to compete with each other in addressing the highly specific needs of single substations.		
Project Description	The Open LV is a software platform operating on off-the-shelf commodity hardware. It represents an interface between the HV/LV substation assets and the customers it serves. Similar to a smartphone, the software architecture has been built to allow different “apps” that allow multiple functions, including real-time thermal rating, automated voltage management, demand-side response to manage EV charging, control of DG, automated energy storage, etc. First, the project will demonstrate the capability of the platform to perform measurements and network control effectively and securely from a HV/LV substation and through a highly decentralized architecture. Secondly, through community engagement it will be created an ecosystem to test the value of providing customers with the access to LV network data and involve them in a smarter grid through an open platform. Finally, app developers will be involved to improve network performance, support the deployment of LCTs and allow non-traditional business models.		
Project Funding			
Incentive Mechanism	NIC: equal monthly transfers over one year from the SO to the funding licensee		
Source of funding	Increase in the SO’s network charges.		
Total Budget (£m)	5.9	**Funding Awarded (£m)**	4.9

Energy networks integration

<table>
<tr><td colspan="4">Project Summary</td></tr>
<tr><td>Project Name</td><td colspan="3">FREEDOM - Flexible Residential Energy Efficiency Demand Optimisation and Management</td></tr>
<tr><td>Funding Licensee(s)</td><td colspan="3">SP Distribution</td></tr>
<tr><td>Lead Sector</td><td colspan="3">Electricity Distribution</td></tr>
<tr><td>Start Date</td><td>01/10/2016</td><td>End Date</td><td>01/01/2019</td></tr>
<tr><td>Project Type</td><td colspan="3">Development and Demonstration Project</td></tr>
<tr><td>Project Objectives</td><td colspan="3">The project objective is to convert households' home electric heating into a hybrid heating system that combines domestic gas boiler and air-sourced heat pump heating. Using predictive control algorithms, the technology manages the heating load and fuel type to minimize carbon emissions and allows efficient system costs based on real-time energy market prices. The project intends to find out whether the hybrid heating system is a technically capable, affordable and convenient solution, in order to:
provide fuel arbitrage and highly flexible demand response services by switching between gas and electric load;
gain information on how to balance the interests of different stakeholders (consumers, suppliers, DNOs and TNOs) when seeking to use demand flexibility to extract value;
find out the benefits for the consumer, the network and the energy system as a whole of deploying a hybrid heating system with an aggregated demand response control system.</td></tr>
<tr><td>Project Description</td><td colspan="3">In the first six months, design and foundation development activities will be performed. Then, pilot installations will be undertaken in Bridgend (Wales) in four households' homes. A roll-out phase will follow, with the installation being undertaken in the rest of the trial buildings. Over the following year, the households will be monitored and experimentation will be performed to refine the heating and load management processes and the consumer interface and information provision.</td></tr>
<tr><td colspan="4">Project Funding</td></tr>
<tr><td>Incentive Mechanism</td><td colspan="3">NIA: increase in the yearly revenue allowance.</td></tr>
<tr><td>Source of funding</td><td colspan="3">Increase in the licensee's network charges.</td></tr>
<tr><td>Total Budget (£m)</td><td>5.2</td><td>Funding Awarded (£m)</td><td>4.5</td></tr>
</table>