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Διπλωματική εργασία με θέμα:

Financial analysis of energy companies in the European energy market

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ΔΗΛΩΣΗ ΓΡΑΦΟΝΤΑ

Ο υπογράφων Λεβεντάκος Κωνσταντίνος βεβαιώνω ότι το έργο που εκπονήθηκε και παρουσιάζεται στην υποβαλλόμενη διπλωματική εργασία είναι αποκλειστικά ατομικό δικό μου. Όποιες πληροφορίες και υλικό που περιέχονται έχουν αντληθεί από άλλες πηγές, έχουν καταλλήλως αναφερθεί στην παρούσα διπλωματική εργασία. Επιπλέον, τελώ εν γνώσει ότι σε περίπτωση διαπίστωσης ότι δεν συντρέχουν όσα βεβαιώνονται από μέρους μου, μου αφαιρείται ανά πάσα στιγμή αμέσως ο τίτλος.

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FOREWORD

Before presenting the results of this master thesis, I feel obliged to thank some people who have played a very important role in its implementation.

First of all, I want to thank the supervising professor of this paper, Dr. Athanasios Dagoumas, for the assignment of the specific subject, for his confidence and appreciation, his immediate response to all my concerns and his valuable guidance throughout our cooperation.

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1. ABSTRACT – MASTER THESIS STRUCTURE

The aim of this paper is the evaluation of the profitability, financial and liquidity performances subsequent to the reactions of the energy company management, following the market opening. This analysis is carried out taking into account the geographical position of the companies that significantly influence the strategic reactions of firms.

Europe, which is heavily dependent on oil and gas from external sources, has been engaged in a debate on building an integrated and competitive energy market since the early 1990s. Leaving aside the previous national energy models, the EU has instituted to share the responsibility to develop a strategic policy to change current trends. A truly competitive, single European electricity and gas market is expected to be a free market and open to competition of Europe-wide companies rather than being restricted to only dominant national actors. The new energy market will improve security supply and boost efficiency and competitiveness. According to a Green Paper, the energy strategy of the EU has three pillars which balance fundamental needs of the Union; securing an expanding supply of energy from both domestic and foreign sources, developing a more competitive internal energy market, and encouraging and supporting environmental protection and development of clean and renewable energy sources.

The market reform in Europe has started with the British experience and the developments in British markets inspired the EU energy strategy and became the main driver for further developments. Over recent years, a number of changes have occurred in the European energy sector, but 10 years after the Lisbon Treaty the energy markets of Europe still are significantly far from the unique energy market goal.[1] The theoretical framework of the European energy policy seems to be suitably designed, but its application is posing considerable problems.

[1] Neelie Kroes, *Improving Competition in European Energy Markets Through Effective Unbundling*, 31 Fordham Int'l L.J. 1387 (2007).

European energy policy- making has always been a balancing act between European and national competences; between government involvement and free markets; and between the public interests of security of supply, the environment and relatively low prices (recently translated into competitiveness). The implementation of policy measures that change the market structure is a delicate undertaking because each member state's energy market is structured differently in terms of energy mix, import dependency and organization. Market saturation, resource nationalism and security of demand (security of investment) often mean that measures that are optimal according to textbook economics play out differently in the dynamic reality of market developments. The actual impact of policy measures on the strategic behavior of companies is often ignored, and policy outcomes are not as clear cut as theory suggests. The main competence of the EU is in the area of competition in the internal (European) market, leaving sufficient room for national interpretations regarding the structure of domestic markets. This room for interpretation is amplified by the national competence over security of supply issues, showing definite but distinctly different preferences among member states.

Moreover, EU environmental policies provide member states with tools to engineer national strategic environments for their companies that help −or hinder− them in their strategic approaches to the EU market. Companies are thus facing a complexity of national and EU market designs in which they must shape their strategies for certain member state markets and decide on their overall EU approach. Thus, both historical and regulatory differences among member states provide energy companies with different strategic toolsets with which to develop their EU strategies. Companies are not mere followers of the national and EU market design but are active participants in shaping this process. Generally, companies adapt their strategies to a changing environment, a process that often moves faster than the implementation of new policy measures. These strategic reactions are often taken to mitigate risks and to secure a strong position in an increasingly competitive market. Such responses interact with the main policy priorities. It is therefore interesting to understand the interaction between company strategies and policy priorities and to assess whether synergies can be found and whether strategies and policy objectives can be aligned.

The structure of the paper is as follows. Chapter 2 introduces the major changes that have taken place and that have formed the basis of the EU's Energy Market. Chapter 3 presents the key changes that happened in Europe's energy mix in 2017. Chapter 4 discusses the alignment of company strategies and policy objectives and presents a number of recommendations to make use of the companies for reaching policy and financial targets. Chapter 5 presents the chosen figures to be calculated, the method of calculation and the results of each indicator for the sample of the energy companies. The tables on which the calculation of the ratios and the tables were based, in the results of which the charts were based, are also presented in the fifth chapter. The final chapter provides the conclusion.

2. ENERGY MARKET IN THE EUROPE

Energy is an indispensable aspect of our daily lives. We need it for heating, cooling, lighting and moving around; it is essential for the functioning of our homes, offices, work places and the entire economy. Its importance makes its accessibility a politically sensitive topic. This is one of the reasons why the Commission has proposed its Energy Union Strategy. The price of energy is also sensitive. On the one hand, low prices can be beneficial as they raise our purchasing power and standard of living and they reduce costs for our businesses and so increase their competitiveness. At the same time, since energy is delivered through markets, energy suppliers need prices to cover their costs and to finance investment to ensure the future delivery of energy. High prices send signals to reduce the use of high-carbon energy or to encourage energy efficiency and the use of innovative eco-designed products and clean technologies.

The history of energy prices and costs shows major changes and major impacts. In the 1970s and 1980s, restrictions by oil suppliers drove up prices and triggered economic shocks. More recently, new energy supplies and growing use of alternative energy sources have boosted supply, while energy efficiency measures and weak growth have reduced demand and brought wholesale prices down. The EU has found that the more competitive and liquid the energy market is, the more diverse and numerous our energy supplies and suppliers are, the less exposed we are to such volatility.

The European Commission produced a first report on energy prices and costs in 2014[2]. This showed a picture of high global energy prices, with prices diverging considerably across EU

[2] COM(2014) 21 /2

Member States, and significantly higher for Europe than for its international trading partners, particularly the United States. Retail prices had risen more than wholesale prices because of increases in network price component and taxes and levies. Data weaknesses led to the recommendation to improve the detail, transparency and consistency of energy price data collection[3]. The report's policy conclusions found that the data and evidence presented showed the partial development of the internal market for energy and a need for further measures to improve Europe's energy efficiency and security and diversity of low-carbon energy supplies. The energy union framework strategy and its roadmap set the framework for taking this work forward every two years, starting in 2016[4].

The last two decades have seen a number of significant changes in EU energy policy, designed to tackle the fundamental challenge of sustaining economic competitiveness, rising global competition for scarce natural resources and the risks associated with climate change[5]. Several major EU policy initiatives in the areas of market opening and integration, renewables policy and climate change mitigation have contributed to reshaping energy markets.

Since 1996, the EU has engaged in a process of market opening in network industries, including in the energy markets. In 2009, the process made a huge leap forward with the adoption of the Third Energy Package, which aims to create a single electricity and gas market. In parallel, the Climate and Energy package adopted in 2009 has introduced a policy framework to reach the three "20" targets: achieving a 20% reduction in EU- wide greenhouse gas emissions, a 20 % share of energy from renewable sources in overall EU energy consumption and a 20% decrease in primary energy use by 2020 compared to a pre- defined baseline.

While these measures may be aimed primarily at fulfilling the competitiveness, security of supply, and sustainability objectives of EU energy policy, what ultimately matters for consumers is the retail price they will have to pay for their gas and electricity. These consumers are not only limited to households; they are also industries including small and medium sized enterprises (SME's). Thus, any increase in retail prices has an impact both on welfare of households and on the competitiveness of the European economy. In particular, between 2004

[3] This led to the Commission's proposal and the adoption of Regulation of the European Parliament and of the Council on European statistics on natural gas and electricity prices, Regulation (EU) 2016/1952, 26 October 2016.
[4] See references in the Action Point 8 the Energy Union Framework Strategy (February 2015) and the updated roadmap for the Energy Union (November 2015).
[5] Delgado et al. (2007); European Commission (2007).

and 2015, retail electricity and gas prices have increased considerably by 65% and 42% respectively compared to 18% for inflation over the same period[6].

The new energy market of the EU is expected to encourage diversification and flexibility to react to market conditions across the countries. It also provides a more powerful bargaining position for European energy companies when sourcing energy in global markets, since there is a larger range of options available with regard to supply routes and there is better access to customers. However, the short experience of the EU revealed that, due to political and economic barriers, the EU would not be able to reach her goals in the near future. These barriers caused significant development differences among the regions, which have different, trading arrangements.

After the adoption of the second energy package in June 2003, the EU's approach to the single market goal in energy markets became much more crystalized and the third package emphasized and routed this objective by the detailed sanctions. In this direction, the EU followed the idea that the final aim of a single electricity market could be achieved by the creation of regional markets as an intermediate step. Currently, European electricity and gas markets are separated into seven and three different regional initiatives respectively, as can be seen in Table 1. So, the energy markets have been moving to a regional segmentation. Currently, the regional nature of the energy market is motivated by EU policy makers hoping to manage them more easily in the future than many small markets.

Table 1: Electricity and gas regional initiatives of EU	
Electricity Regional Initiative (ERI)	
Regions	**Countries**
Central-West	Belgium, France, Germany, Luxembourg and the Netherlands
Central-East	Austria, Czech Republic, Germany, Hungary, Poland, Slovakia and Slovenia
Central-South	Italy, Austria, France, Germany, Greece, and Slovenia
Northern	Denmark, Finland, Germany, Norway, Poland and Sweden

[6] HICP, Eurostat.

South-West	Spain, France and Portugal
Baltic	Latvia, Estonia and Lithuania
France-UK- Ireland	France, Ireland and the United Kingdom
Gas Regional Initiative (GRI)	
North-West South	The Netherlands, Belgium, Denmark, France, Germany, Ireland, Sweden and the United Kingdom
South-South East	Romania, Slovakia and Slovenia
South	Spain, France and Portugal

Source: European Commission (2010b) From regional markets to a single European market, prepared by Everis and Mercados EMI

The main advantage of this bottom-up regional approach is that it enables the involvement of the relevant stakeholders more than it is usually possible on a European level. In addition, the regional approach can also better take account of regional specificities, where divergences from the European standards are needed on an exceptional basis. At the same time, the regional approach enables a step-by-step development towards an integrated European energy market. However, it should be noted that, in contrast with the original regional strategy, the regions are different and overlapping. In practice, countries involved in more than one region can of course not be equally committed to every region at the same time.

As the spot markets develop, a similar trend in financial markets on energy is being observed with the growth of a variety of derivative instruments. Currently the structure of Europe's power markets seems considerably complex. There are more than half a dozen exchanges, most of which offer trading in both spot and futures contracts. Some of them started to broaden their activities beyond the national borders.

2.1. ELECTRICITY MARKET

The electricity market is the leading market of the EU energy sector even though it has some important problems with competition among member countries and its effectiveness. Although the EU has recognized seven regional electricity initiatives, specifically the European electricity market can be observed in three regional groups: the United Kingdom, the Nordic Countries and Continental Europe. The markets differ in not only their historical experience, but also as to their regional characteristics. A recent research indicates that the UK's energy

market remains the most competitive in the EU and G7, since it moved from pure monopolies to a market economy.[7] The level of consumer participation in UK energy supply
markets is among the highest of any retail energy market throughout the world. The annual switching rate of 18% also compares well with other retail services in the UK, such as fixed and mobile telecommunication, insurance products, mortgages, and personal current accounts. Almost all consumers (96%) know that they can change energy suppliers and most (70%) feel confident that they know how to do this.[8]

The Nordic energy market, which is established by integration of the markets of Denmark, Finland, Norway, and Sweden, is the most harmonized cross-border electricity market in the world since the mid 1990s. Nordpool is established by Norway and Sweden as the first international power exchange and next Finland (1998) and Denmark (1999–2000) joined the Nordic spot market. A few major power producers have a dominating position in their markets, but none of them has a big share (more than 20%) of the Nordic market. It indicates that the degree of integration increases the level of competition among the market players. Public ownership is still dominating the region. The level of consumer participation in Nordic energy supply markets is relatively high given that customers can easily change their suppliers and tariffs. Since the main feature of Nordic countries is the relatively higher level of annual electricity consumption than in other European countries, this provides an incentive for customers to take an active interest in the market.[9] The Nordic market has properties that distinguish it from the rest of Europe. The adoption of the Nordic experience in other countries is not easy, as the success of the Nordic model depends on area-specific factors, such as ample supply of hydropower and significant inter-connector capacities.[10] In particular, the Nordic experiences suggest that a "deregulated" market for electricity works well if there are no price regulations and constraints on the development of financial markets and there is continued political support for a market-based electricity supply system also when electricity is scarce and prices are high.

The energy market reform process in most Continental European countries has been driven by the initiation of Germany in the late 1990s, a decade after the advances made in the UK and Norway with the Directives of the EC. The German electricity market is the biggest in

[7] OXERA (2007) Energy market competition in EU and G7: forward projections, 2007–11. Prepared for Department for Business, Enterprise and Regulatory Reform.

[8] OFGEM (2009) Energy protecting consumer interests: now and for the future. Annual report 2008–2009, 82/09

[9] Littlechild S (2006) Competition and contracts in the Nordic residential electricity markets. Utilities Policy 14(3):135–147

[10] Amundsen ES, Bergman L (2006) Why has the Nordic electricity market worked so well? Utilities Policy 14(3):148–157

continental Europe by number of players and generation capacity. It is also the fastest to open up, with immediate 100% full customer choice without any restructuring of the industry. France has a mass market with more than 3.5 million eligible customers, which makes it third in size among all open markets within the EU.[11] The French government postponed liberalization at the beginning, then after 2004, the status of public company EDF has been changed and the market is opened to liberalization. Austria's electricity market was partly opened to liberalization in 1999, then the whole market was liberalized during the early 2000s and a voluntary energy spot 16 M.B. Karan and H. Kazdagli market of Austria – EXAA – was established. Four regional companies (EPZ, EPON, UNA and EZH) were dominating the generation in the Netherlands until1998. Although the Dutch government had planned to organize a "national champion" by merging the four companies into SEP that would have competitive power in the EU market, the merger failed and the major restructuring feature was a selloutto big companies of Europe (Electrabel, Reliant E.ON).[12] In Belgium, the process has been dominated by Electrabel, which is controlled by the French Suez Group through the intermediate engineering contractor Tractebel. Electrabel and Tractebel were merged in 2005 to be an important player in EU and the world market.[13]

According to the report of the International Energy Agency, Spain has made substantial progress in its energy policy, over the last 4 years. Together with Portugal, it has set up the common Iberian electricity market, MIBEL, and has strong ambitions in developing it further. Spain is determined and successful in promoting renewable energy and puts increasing emphasis on improving energy efficiency. Furthermore, all South East European countries agreed to adopt the EU legislation.

Central European countries are physically integrated within the western European grid, and have taken the first steps towards adopting the EU Western Europe model with regulated third party access for larger customers. Poland and Hungary were the forerunners of energy reform. The central European electricity market is the largest regional market in Europe and it is obvious that further progress towards an integrated electricity market in Europe will depend strongly on the development of this market.[14] However, the last 10 years of experience indicates that the generation capacity of Central Europe is not diversified well and the number

[11] Barthe F (2005) Deregulation and opening of the electricity market in France. In: 18th international conference on electric distribution, Turin, June 6–9

[12] Van Damme E (2005) Liberalizing the Dutch Electricity Market: 1998–2004. TILEC Discussing Paper, DP 009

[13] Haase N (2008) European gas market liberalization: are regulatory regimes moving towards convergence? Oxford Institute for Energy Studies, NG 24

[14] Jamasb T, Pollitt M (2005) Electricity market reform in the EU: review of progress toward liberalization & integration. Energy, 11–42

of competitors in the market has not increased sufficiently. Therefore, contrary to expectations in the late 1990s, the wholesale and retail markets lagged behind the objectives of the EU. Recent research indicates that there is a very strong market correlation between Scandinavian and continental electricity markets (Germany, Holland, France, Austria and Spain) yet Italian and Polish markets are poorly correlated to all other markets.[15]

2.2. GAS MARKET

European gas markets have gone through a profound restructuring process since 1998, but the decline of indigenous resources and a growing dependence on large share gas supplies are still the main obstacles of market liberalization and integration. Natural gas accounts for 25% of primary energy use in the EU and nearly 60% of consumed gas is imported.[16] Since 1998, following the gas directives, EU markets attempted to integrate and harmonize gas markets while asking for country-specific solutions to take into account different national characteristics.

As the gas market of Europe is liberalized, the gas market centers and hubs are developed. Particularly the Bunde-Qude, Zeebrugge, and Baumgarten hubs are the main hubs that are dealing with the largest volumes of gas in Europe. Currently, Germany has the most structured market within the EU and it not only consumes natural gas, but also provides a fair amount of gas storage and serves as a transit country for gas, e.g., to France, via Switzerland to Italy or via Belgium to the U.K.

[15] Majstrovic G, Bajs D, Sutlovic E (2008) Correlation and regression of wholesale electricity market daily prices in Europe. 3(4):699–708

[16] Rademaekers K, Slingenberg A, Morsy S (2008) Review and analysis of EU wholesale energy markets. ECORYS Netherlands, EU DG TREN Final Report

At the beginning of 2000, EU was expected to reach full liberalization before the mid-decade, but European gas markets still lacked competition, cross-border integration, and harmonization. Due to the discretion of the European framework regulation, member states can choose to a large extent which regulatory instruments to apply. Although most consumers in Europe can now choose their gas supplier and a significant progress has been achieved towards the harmonization of national legislation as a result of the EU energy policy, obstacles to competition that are related with the market structures or national attitudes of the countries still remain. Although the former monopoly gas companies are still very powerful in many countries, their market shares have been reduced ever since the competition was introduced. Many European energy companies have moved defensively and tended to resist a change to their traditional business model. To compensate for this, many companies invested particularly in Central and Eastern European countries. Many gas companies have also diversified into the sale of electricity and other utility products such as water and telecoms (Harris and Jackson 2005). It should be underlined that currently power companies play an important role in the European gas market, particularly in Italy, Spain, and the U.K. A recent research indicates that the reform brought about a divergent convergence of regulatory regimes that now functions as a framework for natural gas market organization in the EU.[17]

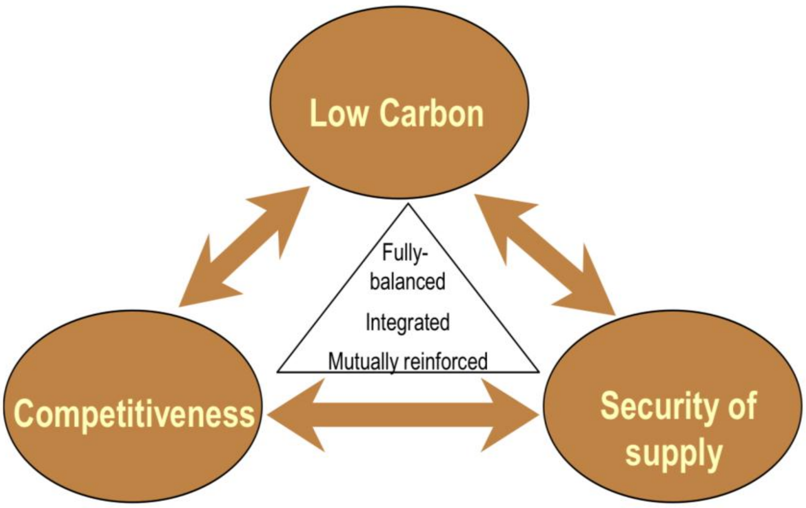
The sectoral inquiry launched by the EC (2007a, b) reveals serious failures in a competitive gas market in the EU. The report points out five important distortions; the first one is the high level of market concentration in the gas market due to insufficient unbundling and the dismantlement of vertically integrated large incumbents. The second defect is the existence of illiquid gas markets and a lack of infrastructure limiting the access of new entrants. The insufficient cross-border competition, lack of reliable information and transparency of gas markets are the other three distortions. On the other hand, International Energy Agency (2008) underlines that after the 2005–2006 supply crises; energy policy has progressively focused on security of supply issues, instead of on market competitiveness.

[17] Haase N (2008) European gas market liberalization: are regulatory regimes moving towards convergence? Oxford Institute for Energy Studies, NG 24

2.3. EUROPE'S NEW ENERGY POLICY PACKAGES

In January 2007 the European Commission proposed an integrated energy policy for Europe re-emphasizing the three major energy policy priorities of clean, competitive and secure energy. In the course of 2007 and 2008, this proposal was translated into several directives and policy briefs, i.e., the "Third Package", covering the market structure and competitiveness, the "Climate and Energy" package, dealing with CO_2 reduction and renewables, and the second Strategic Energy Review, containing various concrete actions and the announcement of a security of supply directive to be presented in 2010. Three policy priorities will be briefly discussed below.

Figure 1. Europe's integrated energy policy



Competitiveness

Some of the main goals of the European internal energy market policy are to create a complete internal energy market, with real choices for EU energy users, households and businesses; and to provide incentives for the sector to realise the projected huge investment needs. This implies further reducing inefficiencies produced by remaining national barriers, the grids and production capacity. It is argued that the realisation of the internal market is not only beneficial to competitiveness, but also to sustainability and supply security. According to the Commission's analysis, the realization of the policy goals requires a clearer separation of energy production and supply from energy transmission.[18]

The policy proposals in the Third Package intend to strengthen the regulatory instruments and devices, and also to promote the far- reaching step of ownership unbundling, requiring a full divestment of the transmission networks from the vertically integrated gas and electricity companies.[19] After a period of lengthy discussions, the energy Council accepted most of the proposals in the Third Package. With regard to the unbundling discussion, member states can choose between ownership unbundling and the ITO (independent transmission operator) model.

Climate and energy

The climate and energy package has been approved by the member states of the European Union. They agreed to legally binding targets to cut greenhouse gas emissions by 20%, to achieve a 20% share in the energy mix for renewable energy and to improve energy efficiency by 20%, all by 2020. Agreement was reached to revise the emissions trading system, on the distribution of the reduction effort outside of the emissions trading system and on a legal framework for carbon capture and storage (CCS). Furthermore, the level of emissions from small sources should be 10% lower in 2020 than in 2005. Europe is the first region in the world to commit to such far-reaching and legally binding emission reductions. It therefore regards itself as the leader in the fight against climate change. If an international climate agreement is reached in Copenhagen in 2009, Europe will commit itself to a further reduction of CO2 emissions, to 30% by 2020, provided that other developed countries take on similar commitments.

Toward security of supply and low- carbon energy

[18] See for instance the Commission's Impact Assessment on the 3rd package, http://ec.europa.eu/energy/electricity/package_2007/doc/2007_09_19_impact_assessment_en.pdf .
[19] De Jong, J.J. *The Third EU Energy Market Package. Are we Singing the Right Song.* CIEP Briefing Paper. The Hague, Clingendael Institute, February 2008.

The European Union does not have a common security of supply policy but is increasingly aware of the issues at stake. Due to decreasing domestic production and growing energy demand, import dependence is bound to increase. Moreover, the 2004 enlargement increased the asymmetric exposure to security of supply risks. The internal market increasingly necessitates cross-border solutions and coordinated crisis mechanisms. Speaking with one voice, coordinating infrastructure improvements and deepening relationships with key supplying countries, transit countries and other consumers are the key elements of Europe's approach. Very often however, the differences of opinion in foreign policy stand in the way of making progress in formulating an external energy policy. In its second Strategic Energy Review, the Commission proposed a fivepoint action plan, called the "EU Energy Security and Solidarity Action Plan".[20] The plan focuses on: infrastructure needs and the diversification of energy suppliers; external energy relations; oil and gas strategic reserves and crisis response mechanisms; energy efficiency; and making the best use of the EU's indigenous energy resources. This plan will amongst others lead to a new EU regulation on security of supply that obliges all member states to make their own preventive action plan and emergency plan.

When energy prices began to increase in the mid 2000s and markets became tighter, the policy agenda was no longer dominated by the drive to make the energy sector more efficient and to reduce government involvement. Energy was elevated on the political agenda due to increased international competition for energy resources, in part caused by the rapid development of large countries such as China and India, a growing awareness of the dependency on a small number of suppliers and the changing security of supply outlook due to the 2004 EU enlargement. This coincided with a renewed emphasis on national interests by the governments of energy-producing countries (resource nationalism) and further limited access to resources for Western companies.

In the 1990s, market liberalization and the environment received a major boost from the large volumes of gas that became available to the EU markets as a result of the economic contraction in Eastern Europe and the former Soviet Union and the expansion of North Sea gas production. Under these beneficial market circumstances, companies began to replace coal-fired electricity plants with gas-fired plants, in the process reducing the grip of the coal sector on their portfolio choices. In the 1990s, the hope of accessing the vast resources of Russia with direct foreign

[20] European Commission. *Second Strategic Energy Review. An EU energy security and solidarity action plan.* SEC(2008) 2794/5. Brussels, 2008.

investments had not yet been dashed, and the Caspian resources were included in the assessment that the EU was in the fortunate position of having economic access to vast oil and gas resources. The market model confirmed the view that suppliers would have to compete for consumers, such as the EU.

Certain developments prevented this view from being realized in international markets. First, the cost reductions in LNG gave the new suppliers in the Middle East an alternative option to develop their resources. The successes of Qatar in developing LNG trains for international markets inspired other producers, such as Russia, to contemplate alternative markets for their gas. Second, the rapid urbanization in China increased the Chinese appetite for gas to reduce smog. China's interest in oil imports from the Caspian Sea region was broadened to include gas, and pipeline infrastructures were developed that freed the region from becoming a captive producer for Russia and the EU. Third, the expected privatization and liberalization of the Russian energy sector did not materialize. Rather, President Putin intervened and partially renationalized oil and gas resources to develop a predominantly Russian-based industry. In gas, Gazprom was awarded an export monopoly, thwarting a deal with independent producers. Russia became more active in managing the gas flows from the Caspian region to close its output gap between the maturation of the fields in Siberia and the opening up of new fields in Yamal and the Barentz Sea. Fourth, the initial optimism about LNG being able to provide the EU with ample diversification opportunities was tempered by the competition for new LNG flows with other consuming countries, including the US, and the rapid demand for energy in general in the period of 2004-2008.

The EU view of gas changed from a vehicle that introduced more competition and a cleaner environment to a fuel with its own security of supply difficulties. Before 2004, the import dependency on Norway, Algeria and Russia was not a major issue. Relationships between these three traditional EU market suppliers were longstanding and mainly organized though long-term contracts. The EU emphasis on reducing the length of the supply contracts and the abolishment of the destination clause had soured relations to some extent. Perhaps it had inspired a somewhat stronger hold by producers on their gas sectors, but this problem was deemed manageable due to interdependency. In 2004, the Eastern European countries joined the EU and introduced their own view on a structural import dependency on gas supplies that primarily originated in Russia. In 2006, when the dispute erupted between Russia and Ukraine over gas price contracts and transition fees, the energy relationships became politicized. In the aftermath of the conflict there was little sympathy for the Russian struggle to normalize economic relations with the former Soviet Union states. EU policy-makers responded to the conflict by re-emphasizing the importance of security of supply policies. Only in 2009, with the outbreak of yet another conflict, did the EU begin to acknowledge the complexity of the Russia-Ukraine relationship and the role of Ukraine itself. Earlier attempts of individual member states to reduce the Ukrainian near- monopoly over gas transit from Russia to the EU market were seen in a slightly different light but have yet to lead to less politicized relationships regarding gas.

Concerns about global climate change had already been on the radar screen of European policy makers for several years. European member states had already adopted the Kyoto targets, had implemented a directive that included (non-binding) targets of 12% of gross inland energy production from renewable energy in 2010[21] and had introduced the emission trading scheme (ETS). It took, however, until 2007 for more ambitious and longer-term targets to be proposed, which would require a much more fundamental change in Europe's energy system. In the past couple of years, the drivers behind the tighter environmental requirements on the energy sector and energy efficiency goals have no longer been inspired by climate change concerns alone. More and more, energy security goals are being integrated into the low-carbon economic strategy. The reduction of import dependency through the promotion of alternative energy resources such as sun and wind, and diversification to, for instance, biofuels, are part and parcel of the new energy strategy. Yet in the short run, a shift towards more renewable energy could deteriorate energy security, because it can cause instability in the electricity grid, requiring major adaptations to the energy infrastructure which will take a long time to realize. Such a shift towards a low-carbon economy could also hold back investments in new fossil fuel production capacity, needed to satisfy short- and medium-term demand, due to concerns about the long-term security of demand.

2.4. FINANCIAL ASPECTS OF ENERGY TRADING IN EUROPE

During ongoing liberalization of the energy sector in Europe and many other parts of the world, electricity and gas trading has dramatically increased in many countries and numerous over-the-counter markets (OTC) and energy exchanges have emerged. Despite the multiple

[21] European Commission. *Directive 2001/77/EC on the promotion of electricity produced from renewable sources in the internal energy market.* September 2001.

obstructions, the number of financial institutions participating in these markets is continuously increasing. Thus, trading in these exchanges became a basic indicator of market liberalization, but also one of the key drivers of the liberalization.

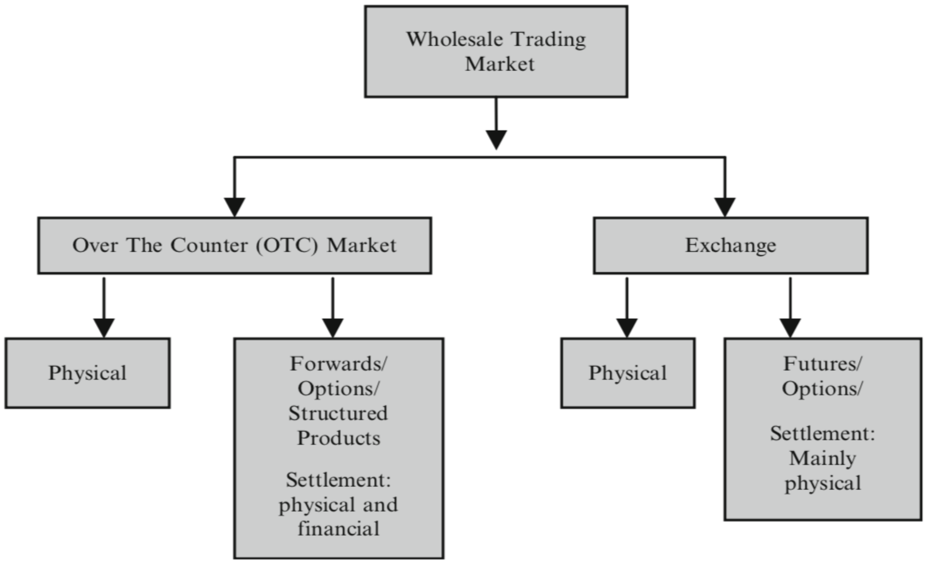


Figure 2. The structure of power trading in Europe
Source: Rademaekers et al. (2008)

Wholesale power trading in Europe is handled in exchanges and OTC, but these are not equally divided in terms of volumes. The general structure of European power trading is given in Fig. 2. While OTCs are the main power of power trading, the importance of energy products and derivatives trading are increasing due to the substantial price and volume risks that the markets can exhibit. Energy trading offers the standardized products in Europe to manage the more volatile market conditions and contributes to lower prices for customers. At the same time, promoted market information supports competition and reinforces market efficiency. Liquid day-ahead and forward markets, together with open intra-day and balancing markets are instrumental to integrating markets.

3. ENERGY MIX

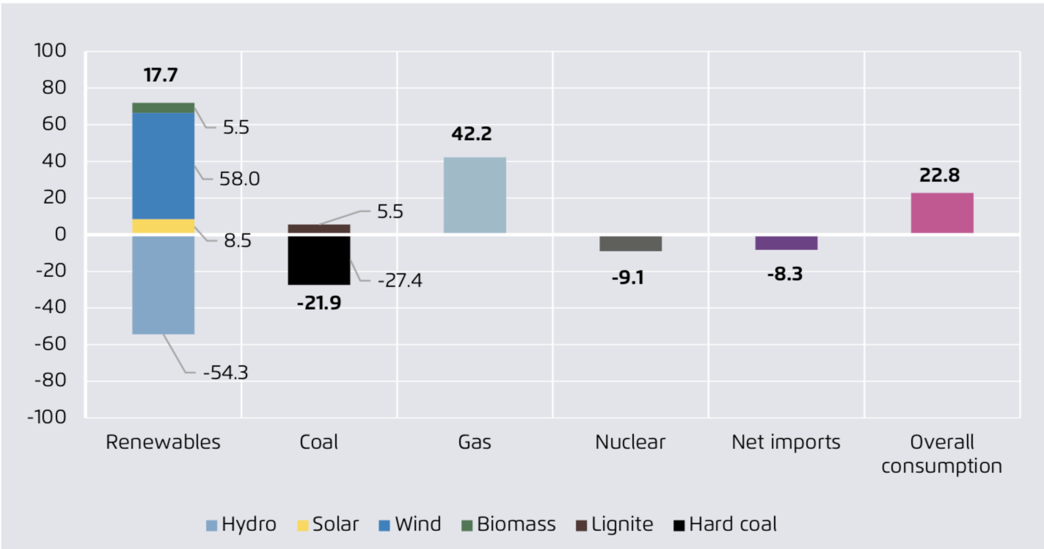
3.1. KEY CHANGES TO THE ELECTRICITY MIX IN 2017

Figures 1, 2 and 3 below show the changes to the European fuel mix in 2017. Here, we briefly list a number of key changes that happened in Europe's electricity mix in 2017. All of these themes are explored in much more detail in the following chapters.

- Electricity consumption rose by 0.7% (+23 Tera- watt hours), the third consecutive year of increases, raising questions over progress in energy efficiency.
- Net electricity imports into the EU fell slightly by 8 Terawatt hours, as Serbia, Bosnia, Macedonia and Albania all exported less electricity to EU countries.
- Wind generation increased by a massive 19% (+58 Terawatt hours). Two-thirds of this was in Germany and the UK.
- Solar generation rose by 8% (+9 Terawatt hours), which was only 1/6th of the rise in wind genera- tion, despite huge recent price falls.

- Biomass generation rose only 3% (+5 Terawatt hours), providing some reassurance that biomass growth is in check.
- Hydro generation fell by 16% (-54 Terawatt hours) to the lowest level this century. All hydro regions in Europe experienced very low rainfall in various months throughout 2017.
- Nuclear generation fell 1% (-9 Terawatt hours), as safety authorities shut down several power plants in Germany and France. France had the lowest nuclear power production this century.
- Gas generation rose by 7% (+42 Terawatt hours), mostly due to the temporary need to fill the hydro deficit in Spain, Portugal, Italy and France.
- Hard coal generation fell 7% (-27 Terawatt hours), mostly displaced by more wind, especially in Germany and the UK.
- Lignite generation, however, actually increased by 2% (6 Terawatt hours), especially in South-East Europe.
- Overall fossil generation rose by 1.6% (+23 Tera- watt hours), as gas generation rose faster than coal fell.
- CO_2 emissions for the EU power sector, we forecast, will be exactly unchanged at 1019 million tones, but overall EU ETS emissions are estimated to rise slightly.[22]

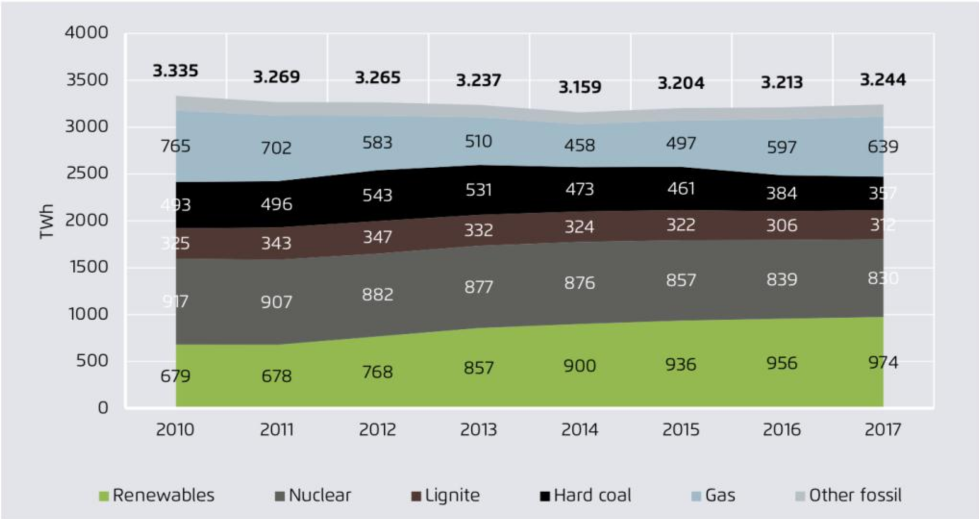
Changes in electricity production and consumption, from 2016 to 2017 Figure 3



Source: Eurostat – Entso-E

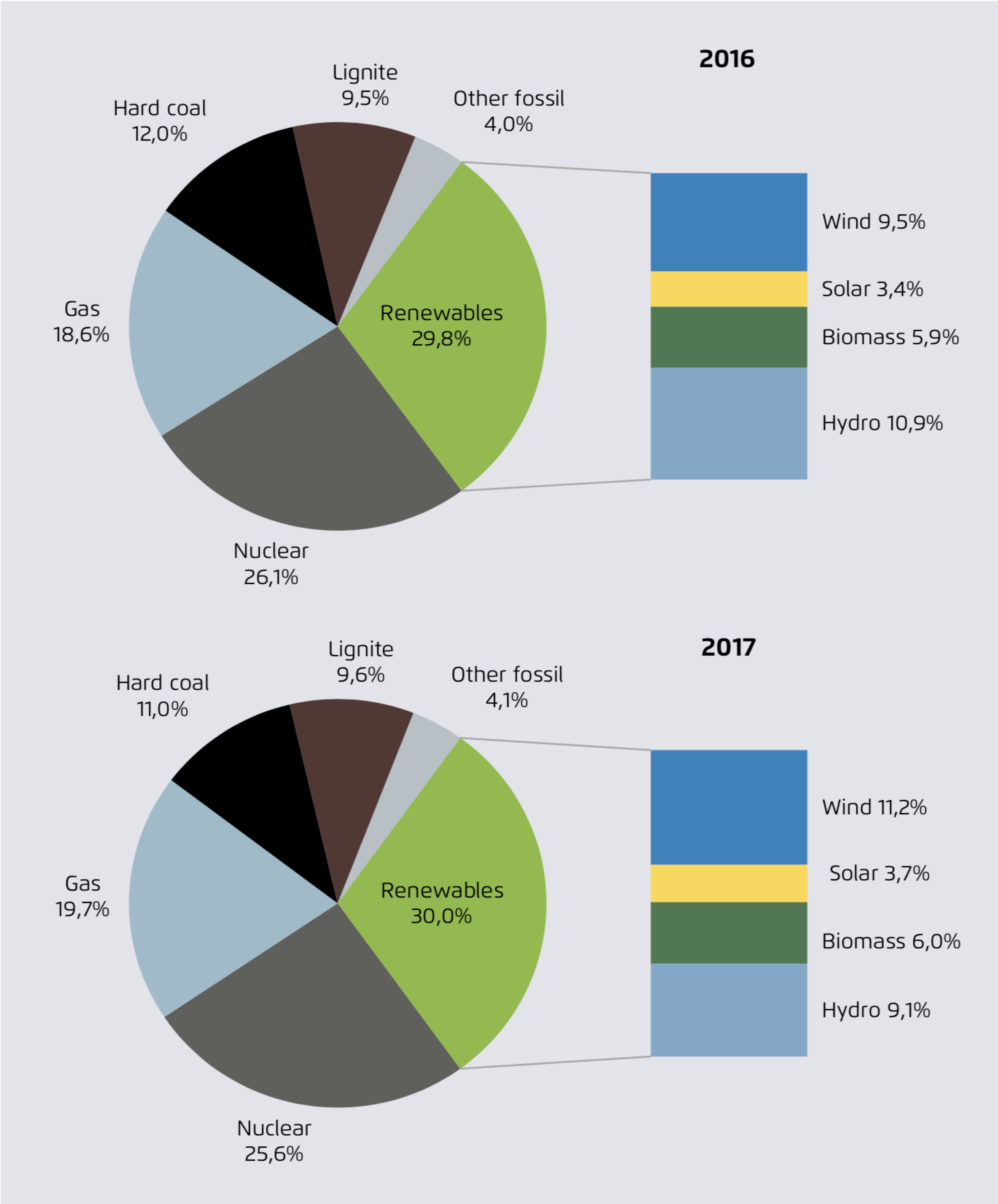
[22] Data for years 2000 to 2015 are aggregated from EUROSTAT. Data for 2016 and 2017 are estimated by us from a combination of sources, including ENTSO-E monthly data, ENTSO-E hourly data, and transmission system operator (TSO) data.

EU electricity generation, by fuel type	Figure 4



Source: Eurostat – Entso-E

Generation mix in 2016 and 2017	Figure 5

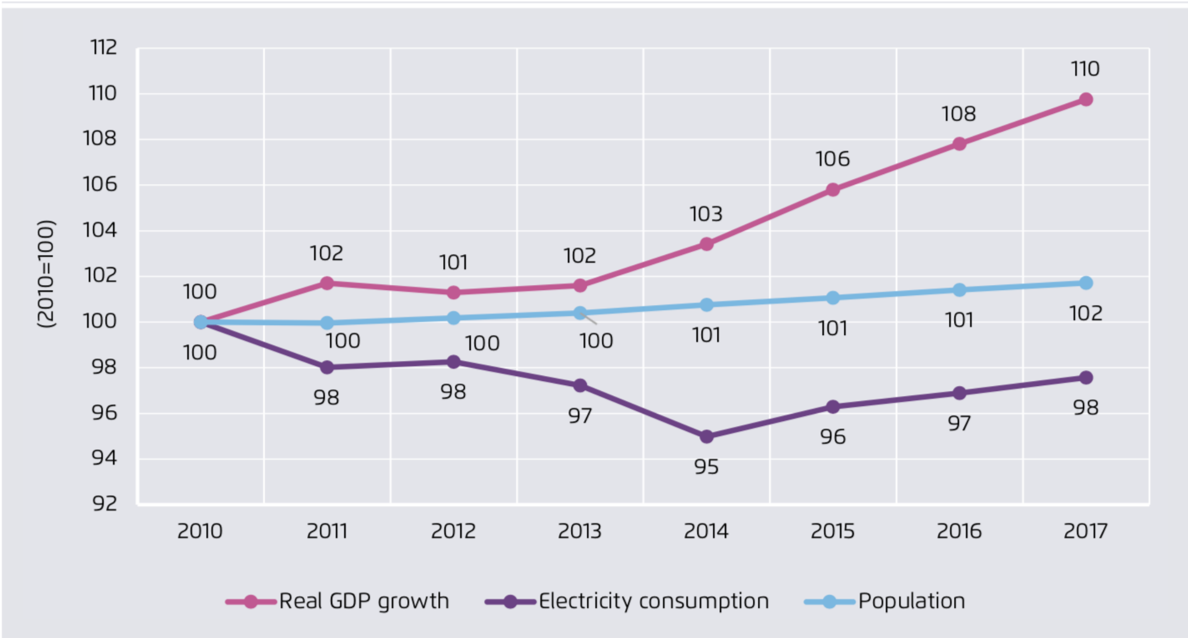


Source: Eurostat – Entso-E

3.2. ELECTRICITY CONSUMPTION

Electricity consumption increased by 0.7% (23 Tera watt hours) in 2017, the third year in a row that overall European electricity consumption has increased. Electricity consumption rose in every country in 2017, except in the UK. While from 2010-2014 there was a downward trend in power consumption, it is now almost back to 2010 levels. In the same time period, Europe's GDP rose and is now 10% above 2010 levels (see figure 4).

EU electricity consumption (indexed) Figure 6



Source: Eurostat – Entso-E

There are four reasons to explain rising electricity consumption:

First, and most importantly, progress in energy efficiency seems to be insufficient to keep track with Europe's economy recovering. Europe's GDP is growing at about 2% per year in the past three years and power demand at about 1% per year. With GDP growth being about double the size of power demand growth, this suggests that energy efficiency is rising, but not enough to meet the European Union's overall efficiency targets.

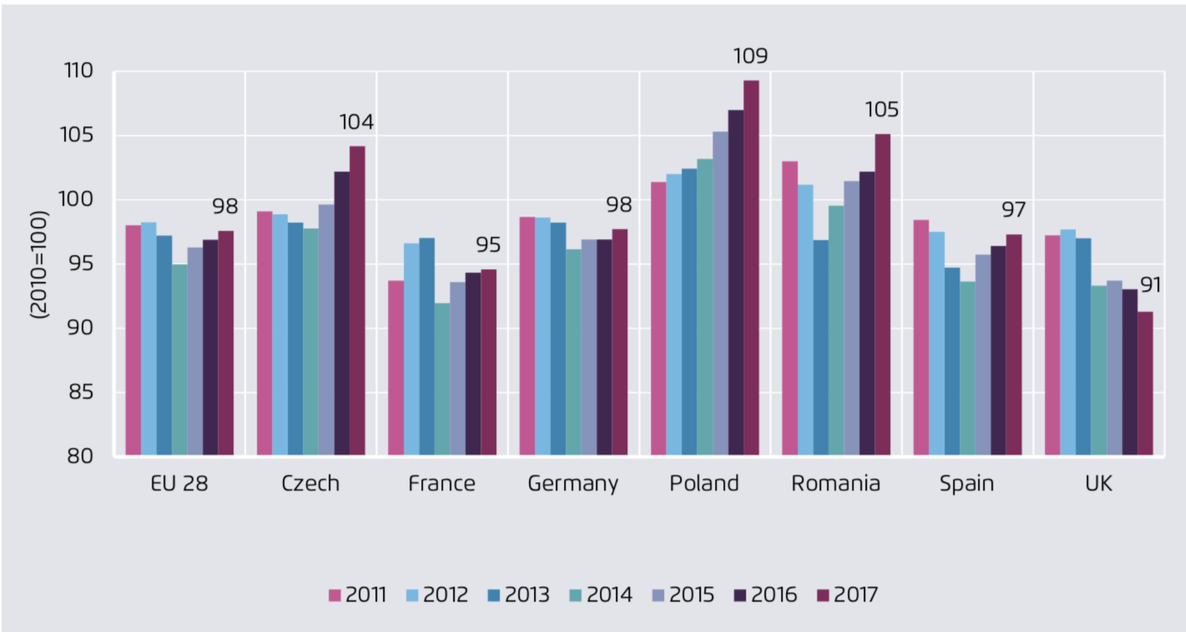
Second, industrial production rose faster than GDP, meaning economic growth was more energy-intensive than normal. The EUROSTAT industrial production index for November 2017 is 4% higher than for November 2016. Especially industrial production in the struggling South Eastern European economies is regaining its pre-crisis level of output. EU steel production rose by a hefty 5% from Jan–Nov 2017, mostly in Germany, Italy and the Czech Republic.

Third, the population of Europe is rising, not least due to increased immigration in 2016 and 2017. The EUpopulation has increased by more than 3 million people over the last two years. Although many of the EU's new inhabitants are unlikely to be large users of electricity, they of course also use electricity directly and indirectly.

And fourth, while still minimal at this stage, we are seeing the beginning of additional power demand from new sectors. The digital revolution means using more electricity, for example through the meteoric growth of video streaming and the increase in Bitcoin mining, as more and bigger server farms are com- missioned. Additionally, the electric vehicle market is now kicking off, with electric and plug-in vehicles amounting to some 800,000 vehicles by the end of 2017. All of this does not add much to power demand in 2017 but could indicate the beginning of some- thing big taking off.

Figure 5 shows the development of electricity consumption since 2010 of countries which showed the biggest changes. The differences over 7 years are big, but not great. The country with the biggest fall is the UK, with a 9% fall over 7 years. The country with the biggest rise is Poland, with a 9% rise over 7 years.

Electricity consumption by country (indexed) Figure 7



Source: Eurostat – Entso-E

3.3. RENEWABLES

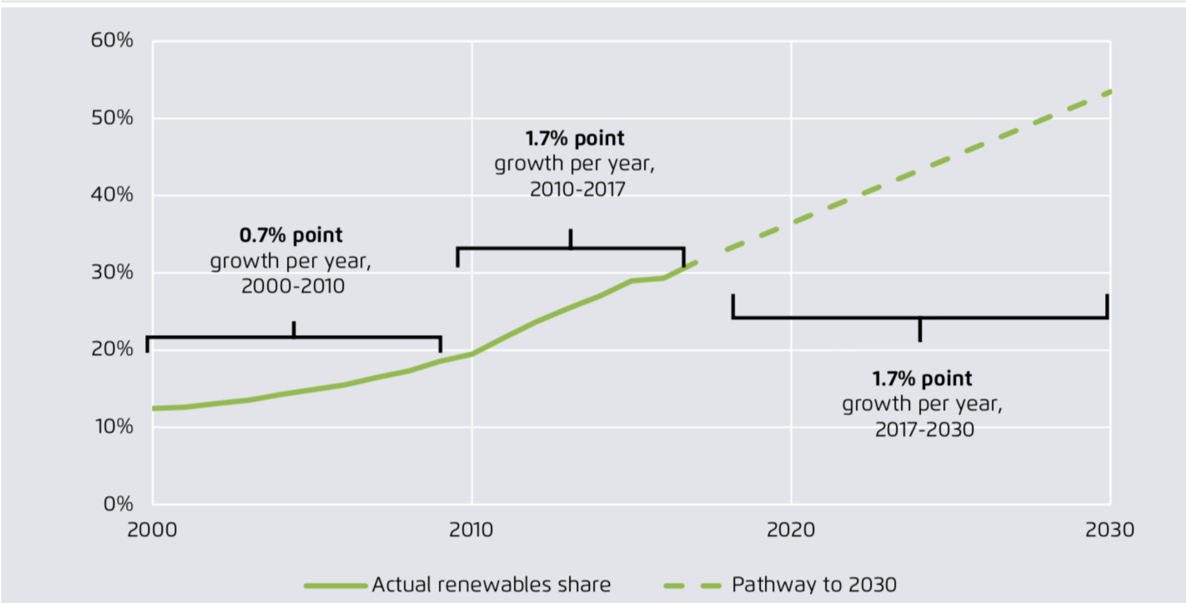
In 2017, renewables generated 30% of Europe's electricity for the first time. It was a rise of only 0.2% points - from 29.8% in 2016 to 30.0% in 2017 of electricity production (see figure 6). This was because the huge growth in wind generation was almost completely offset by the lowest hydro electricity generation in a decade (see chapter 3.5).

Renewables share as percentage of gross electricity production Figure 8

Source: Eurostat – Entso-E

Wind, solar and biomass grew to 20.9% of the EU electricity mix. This is up from just 9.7% in 2010 and represents an average growth of 1.7 percentage points per year. If this rate continued, then it is just sufficient for total renewables to hit 50% of the EU electricity mix by 2030 (see figure 7). This is considered what is needed to hit the EU's current 2030 renewable target of a 27% share in final energy demand.

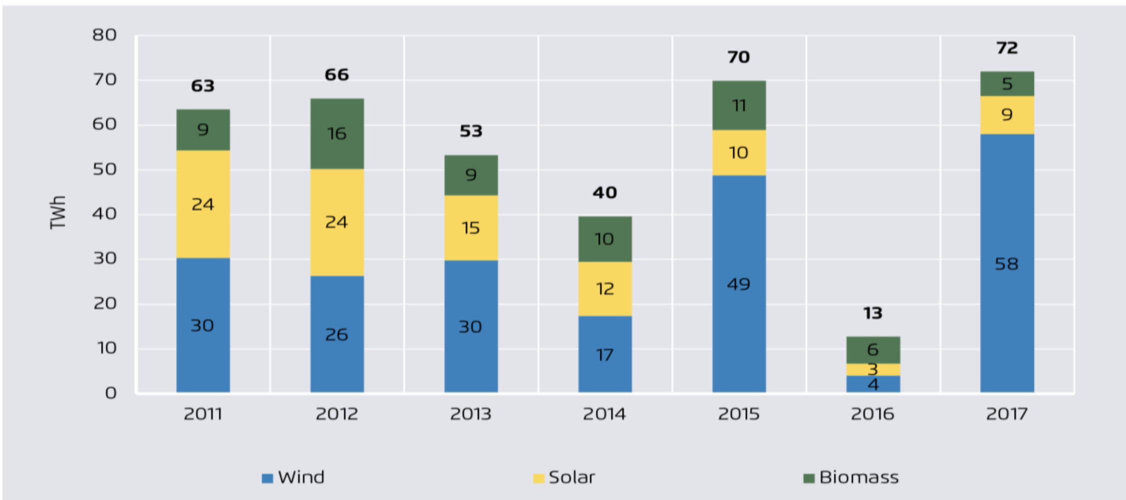
Renewables share as percentage of gross electricity production: the trend to 2050 Figure 9



Source: Eurostat – Entso-E

Given this, it is easy to envisage how the renewables deployment could be sped up to achieve the 35% renewable target that is currently under negotiation. 2017 saw a massive growth in wind power generation (see figure 8), driven by onshore and offshore capacity additions, and an above average wind yield in the fourth quarter in 2017. Wind generation grew by a massive 58-Terawatt hours, solar grew by 9 Terawatt hours and biomass grew by only 5 Terawatt hours.

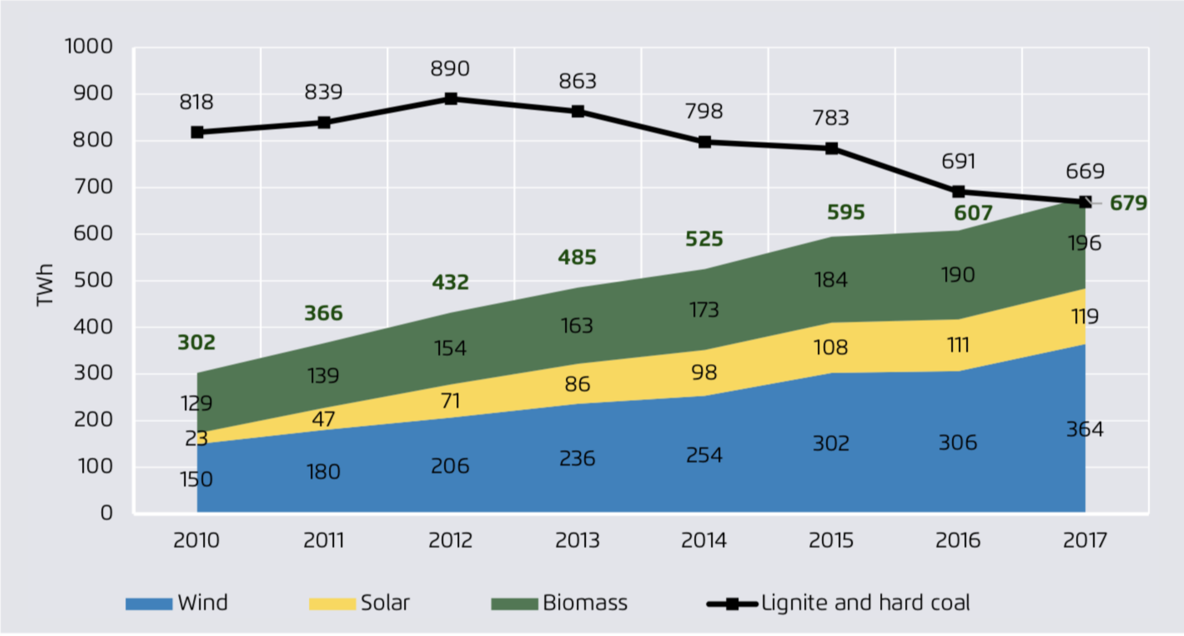
Changes in renewable electricity generation Figure 10



Source: Eurostat – Entso-E

That led to wind, solar and biomass generation sur passing coal generation for the first time (see figure 9). This is incredible progress, considering just five years ago, coal generation was more than twice that of wind, solar and biomass.

Renewables versus coal electricity generation Figure 11

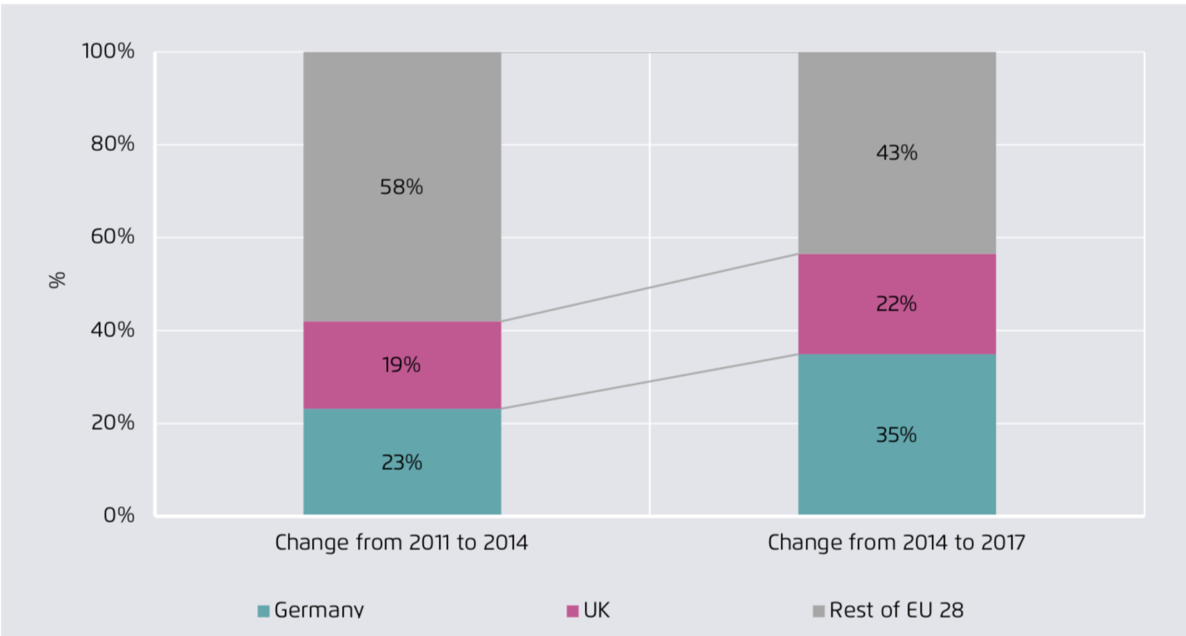


Source: Eurostat – Entso-E

The increase in renewables has been approximately steady – with almost exactly the same growth from 2011 to 2014 (159 Terawatt hours), as from 2014 to 2017 (155 Terawatt hours). However, renewables growth has become more concentrated geographically and by technology. Geographically, the majority of that growth was in Germany and the UK alone (see figure 10). The remaining 26 EU countries had 58% of the renewables growth from 2011 to 2014, but only 43% of the growth from 2014 to 2017. To some extent this may reflect the fact that some Member States have already reached their national 2020 targets under the EU Renewable Energy Directive (BG, CZ, DK, EE, FI, HR, IT, LT, SE, RO).[23] It is, however, also a reflection of unnecessarily high financing costs, particularly in Central and South-Eastern Europe, standing in the way of translating the dramatic decline in renewable energy technology costs into truly low cost renewable energy projects.

[23] EU Commission RES Progress Report 2017

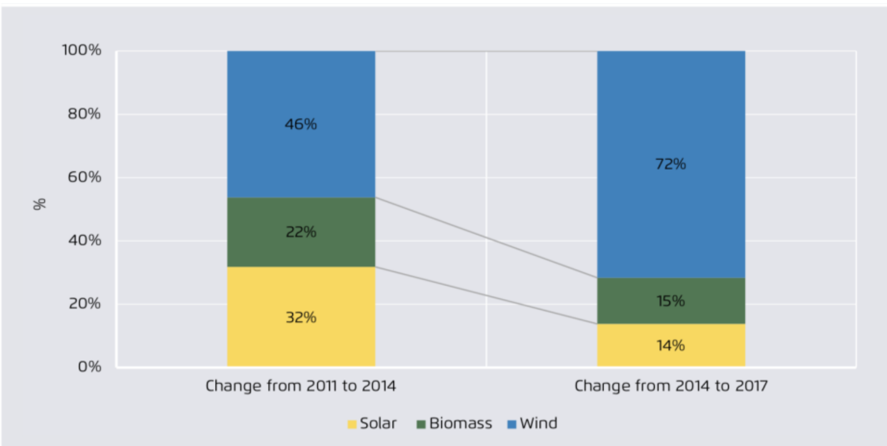
Changes in non-hydro renewables generation by country Figure 12



Source: Eurostat – Entso-E

Technologically, the growth has gotten much more concentrated towards wind (see figure 11). Wind had 46% of the EU renewables growth from 2011 to 2014, but this increased to 72% of the growth from 2014 to 2017. Given the sustainability problems, it is welcome that the biomass boom is over in Europe, with just 15% of additional renewable electricity generation coming from biomass since 2014. However, it is disappointing that solar generation is still lagging so substantially.

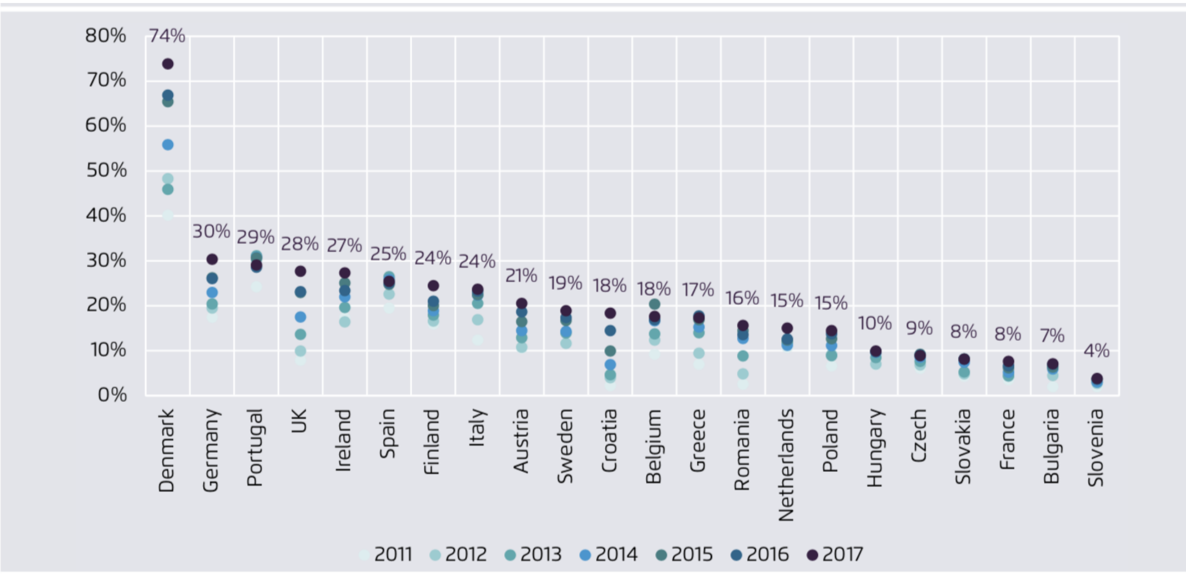
Changes in non-hydro renewables generation by type Figure 13



Source: Eurostat – Entso-E

Figure 12 shows how wind, solar and biomass has increased in every EU country in the last 7 years. In 2017, Denmark is the leader with the biggest rise and the highest penetration: wind+solar+biomass rose 7 percentage points from 67% to an incredible 74% of total electricity production. Of Denmark's 2017 rise, three quarters was from wind. In the last 7 years, wind+solar+biomass increased its share of electric- ity production in every country, but at very different rates. Since 2010, the countries with the biggest increase in penetration were Denmark (up 42 percentage points, to 74% in 2017), the UK (+22 to 28%), then Germany (+17 to 30%).

Wind, solar and biomass as percentage of national electricity production Figure 14



Source: Eurostat – Entso-E

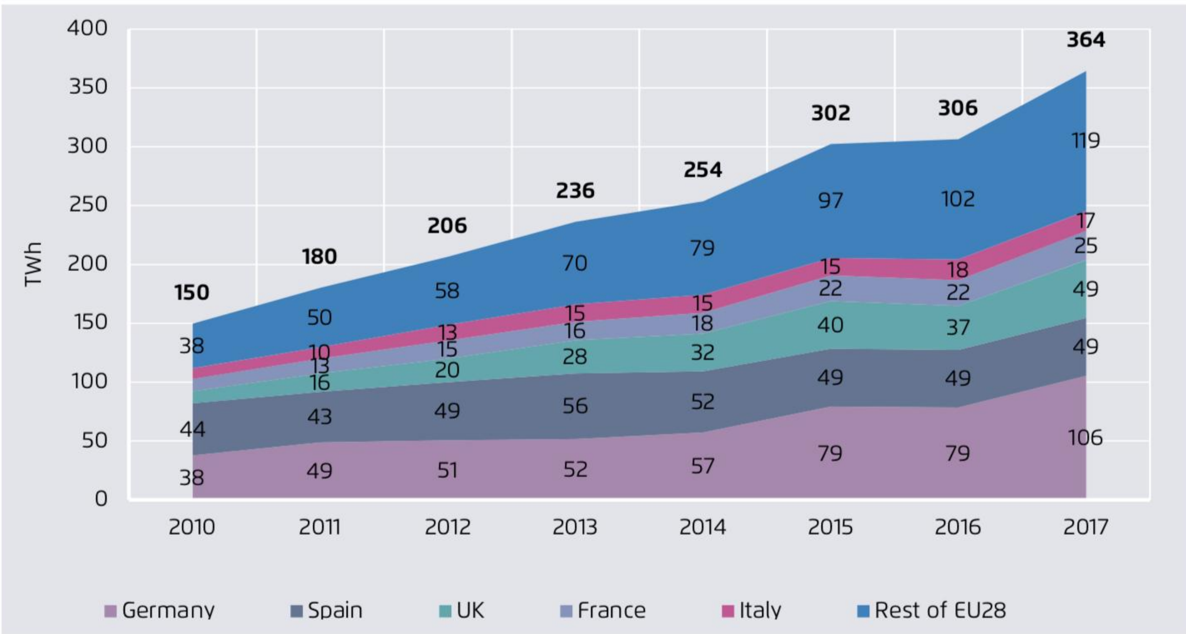
However, many countries did very little. Many countries had anemic renewables growth throughout this decade like Slovenia, Bulgaria, France, Slovakia, the Czech Republic and Hungary; other countries had good growth at the start of the decade, but then gave up on renewables with almost no growth in the last three years, like Spain, Italy, Portugal, Belgium and Greece. There are six countries that still have <10% of their electricity production from wind+solar+biomass in 2017: these were Slovenia (4%), Bulgaria (7%), France (8%), Slovakia (8%), Czech Republic (8%) and Hungary (10%).

According to BNEF, fewer Euros were invested in renewables in 2017 - mostly caused by the fall in the cost of renewables, rather than the speed of deployment. Europe as a whole invested 57.4 billion dollars in clean energy technologies, which amounts to a 26%-decrease compared with 2016. While UK and German investments declined, Spain, Sweden, and the Netherlands realized the highest increases. Mean- while, clean energy investment activity intensified in China (up 24%), the U.S (up 1%), Australia (up 150% due to large wind and solar projects), and Mexico (up 516%).

A favorable year for wind

Wind generation overtakes hard coal generation for the first time. Wind generation increased by a massive 19% from 306 to 364 Terawatt hours in 2017 (see figure 13). This followed a poor wind year in 2016 and huge investments into onshore and offshore wind plants in 2017. In countries with the highest increases in wind electricity generation, namely Germany, the UK and the Netherlands, hard coal-based generation simultaneously fell, leading to falls in CO_2 emissions.

Wind electricity generation (including split of top 5 countries) Figure 15



Source: Eurostat – Entso-E

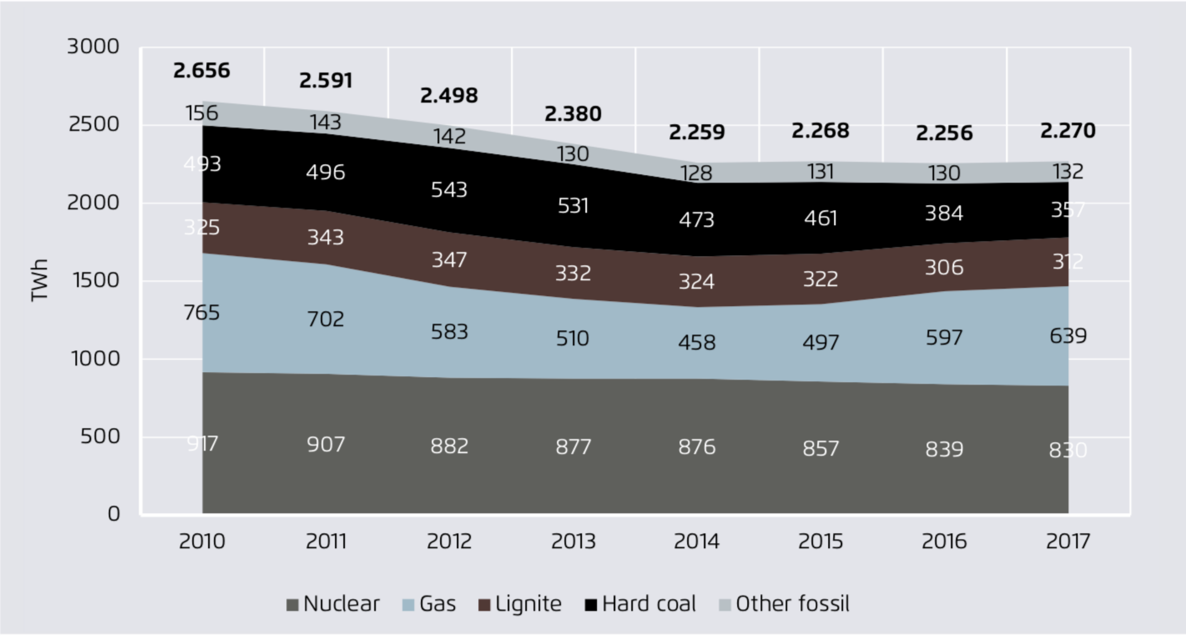
Installation rate: WindEurope estimated that 14 Gigawatt would be installed in 2017 (see figure 14) resulting in roughly 168 Gigawatt of cumulative capacity in Europe. If their estimate is true, it would set a record not only for off- shore wind deployment, but surprisingly also for onshore wind deployment. As mentioned above, this growth is very skewed towards Germany and the UK. New capacity will be scaled up in France, Spain and the Netherlands, which is good news, but far from an even transition. For instance, Germany added more than one Gigawatt offshore and more than 5 Gigawatt onshore capacity. As Wind Europe reported, 15 countries in the European Union experienced no capacity additions in the first half of 2017, while only 5 countries surpassed the mark of 100 MW. [24]

3.4 CONVENTIONAL GENERATION

Overall developments in conventional power production

In 2017, overall conventional generation rose again slightly and is now back at 2015 levels (see figure 20). The increase in power demand and one-off decline in hydro were the main reasons that overall conventional power production rose again.

Conventional electricity generation Figure 16



More importantly, 2017 saw rising fossil fuel power production (hard coal, lignite, gas, oil) for the third year in a row. Hence, Europe might enter a structural problem: If there is a structural rise in electricity consumption and renewables growth stays at cur- rent levels, then the future decline in fossil generation will be slower than expected. Therefore, CO_2 emissions might not fall as needed.

[24] Wind in Power (2017)

Phasing out hard coal made progress

Hard coal generation fell by 7% (27 Terawatt hours) in 2017. This follows on a 17% fall in 2016 and means hard coal generation is now 34% lower than high levels back in 2012 (see figure 21). The 2017 fall was due to a surge in wind generation: Germany, the UK, and Netherlands saw their coal generation fall by 29-Terawatt hours, while their wind generation increased by a massive 41-Terawatt hours. At the same time, the poor hydro generation led to higher coal generation in both Spain and Portugal.

The big news in 2017, however, related to national coal phaseout plans. Several countries have now com- mitted to phase-out coal generation by 2030 or before (see figure 22). In 2017, the Netherlands committed to retiring all its coal plants by 2030 and to replace them with renewable electricity, despite most of the coal plants currently being only two to three years old. Also in 2017, Italy committed to close its coal plants by 2025; it is however currently unclear if this is a complete move to renewables, or whether it might lead to an increased role for gas. Portugal confirmed it would ensure there is no coal generation by 2030.

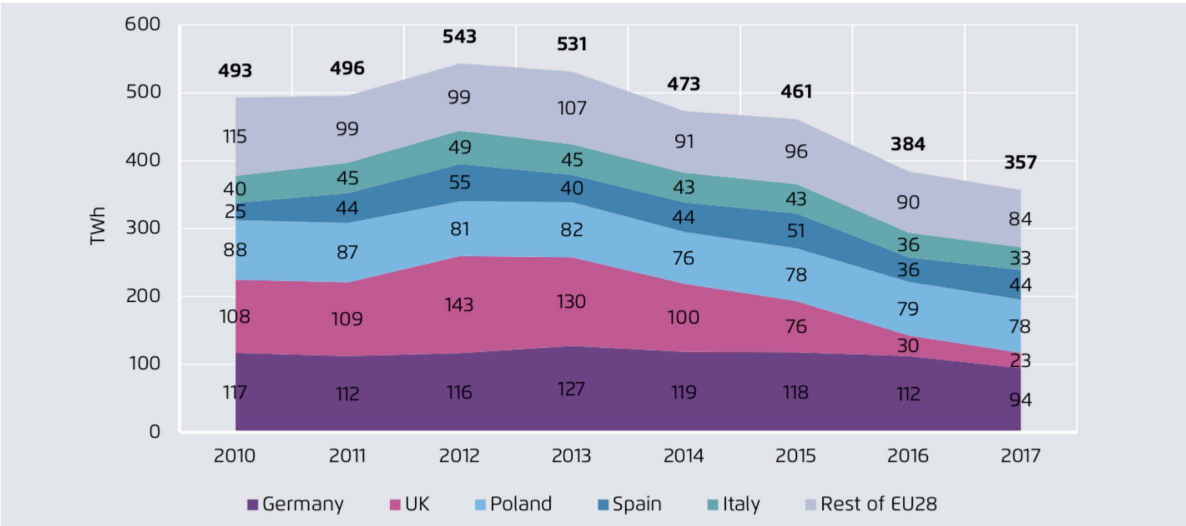
In Germany, the market-based shut down of hard coal generation capacities in 2017 continued. Due to low power market prices and the shrinking profitability of hard coal assets, about three gigawatts of capacity were taken out of the market in 2017. Additionally, several municipal utilities announced to end the coal generation for district heating purposes. The people of Munich voted for a local coal phase out by 2022, Berlin will shut down its last coal plants until 2030. Datteln power plant will be last hard coal plant to get connected to the grid in 2018 (1.1 gigawatts).

About 14 Gigawatt of EU coal plants have closed in 2016 or 2017 (see figure 23 and table 2). However, the future remains uncertain: there are only 7 Gigawatt of coal plants that have announced their intention to retire out of the 157 Gigawatt of remaining operational coal plants.

Figure 24 shows how the coal mix has evolved in every EU country - important given that 66% of CO_2 emissions from the power sector in 2017 are from hard coal or lignite. The biggest fall in 2017 was perhaps unsurprisingly the country with the biggest rise in renewables: Denmark. Its coal generation fell from 28% in 2016 to 21% in 2017; only back in 2010, it was 44% of electricity production. The two countries that have seen coal penetration fall the most since

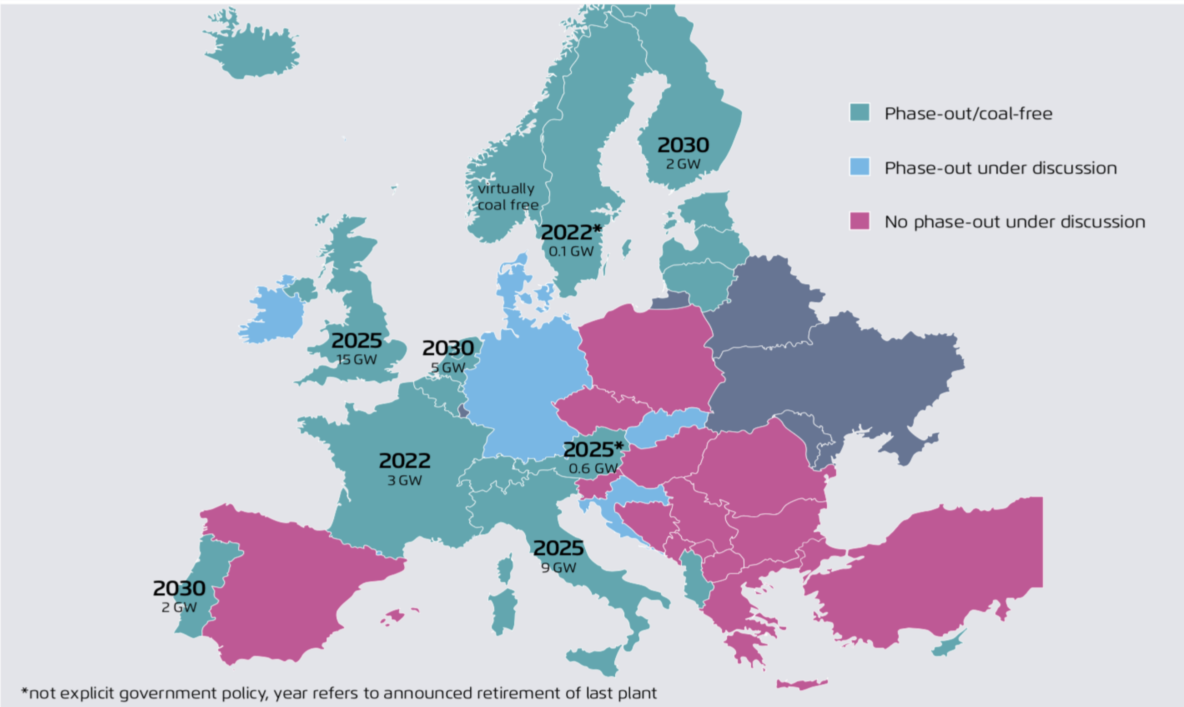
2010, besides Denmark, are the UK (from 28% to 7%) and Greece (from 54% to 34%). Germany fell only 5 percentage points - from 42% in 2010 to 37% in 2017, leaving it still with the fourth most coal-intensive electricity production. Germany's coal-intensity is only eclipsed by Poland (77%), the Czech Republic (49%) and Bulgaria (46%).

Hard coal electricity generation (including split of top 5 countries) Figure 17



Source: Eurostat – Entso-E

Coal phase-out years and operational capacity Figure 18



Source: Eurostat – Entso-E

Retired coal plants in 2017 Figure 19

Country	Plant name	Coal type	Owner	Year opened	MW (gross)
Croatia	Plomin 1	Hard coal	HEP	1969	125
Finland	Kristiina 2	Hard coal	PVO	1983	242
Finland	Tahkoluoto	Hard coal	PVO	1976	225
Germany	Berlin-Klingenberg	Lignite	Vattenfall	1986	164
Germany	Ensdorf	Hard coal	RWE	1963	430
Germany	Herne 3, Marl II	Hard coal	STEAG	1966	378
Germany	Voerde	Hard coal	STEAG	1982	1522
Germany	Voerde West	Hard coal	STEAG	1971	712
Italy	Genova	Hard coal	Enel	1952	155
Netherlands	Maasvlakte	Hard coal	Uniper	1987	1207
Poland	Adamow B	Lignite	Zepak	1964	600

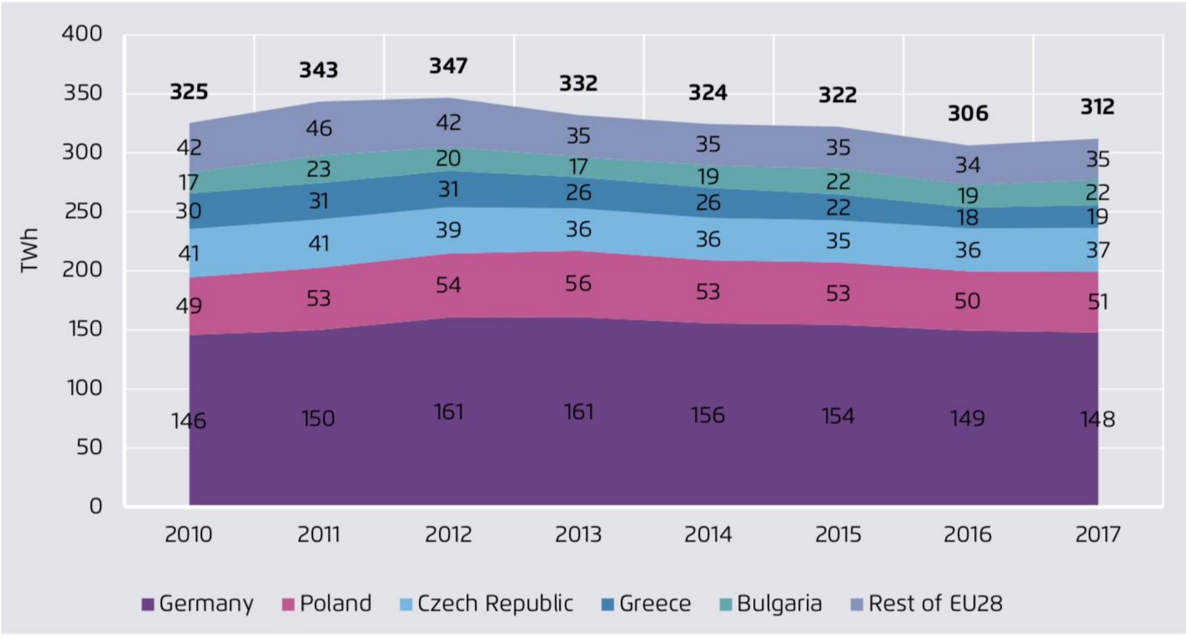
Source: Eurostat – Entso-E

Lignite stays constant

Power production by lignite, the most CO_2-intensive fossil fuel, rose slightly by 6 Terawatt hours (2%) in 2017. German lignite generation fell by 1%, and there were small increases recorded in Greece, Bulgaria, Czech Republic and Romania (see figure 25). Since the marginal costs of the lignite generation are not exposed to price changes on international energy markets, impulses for the reduction of lignite use can only come from the European emission trading scheme or national initiatives. The current reform of the European emission trading scheme is not expected to cause significantly increasing CO_2 prices in the near future. If a European carbon floor price remains unlikely, national initiatives are the only way forward to limit the use of lignite.

There was also little momentum on lignite units closing, other than Poland's Adamow (600MW) closed at the end of 2017. Two retirements in Germany were already known: Vattenfall's Berlin Klingenberg (188MW) retired, and Frimmersdorf P & Q units (635MW) entered into the lignite reserve. Hence, in 2018 a slight reduction in lignite power production might occur.

Lignite electricity generation (including split of top 5 countries) Figure 20



Source: Eurostat – Entso-E

Overall, the situation of the lignite sector at the end of 2017 can be characterized as follows:

→ Despite being the dirtiest fuel, the lignite sector seems so far to be unaffected by Europe's climate policy. The national coal phase-out plans mentioned above all relate to countries with hard coal, so do not touch lignite. And in 2017, the profitability of lignite power plants improved as higher hard coal and gas prices pushed up power prices, whilst CO_2 prices stayed low.

→ The EU debate on phasing out lignite began in 2017. In December 2017, the European Commission set up a platform to work out how to transition mainly lignite-intensive regions. And in Germany, the question of a lignite phase out played an important role in the coalition treaty discussions at the end of 2017 and beginning of 2018. The current state of play is that by the end of 2018 a government commission shall propose a phase-out plan which should then be signed into law and implemented as of 2019.

→ Tighter coal plant limits agreed in 2017. Tighter air pollution limits for NO_X, SO_2 and mercury were agreed for all power plants, coming into force in 2021. This implies that older coal and lignite power plants might need to invest in scrubber technologies. It's not yet clear how many lignite plants would close as a result.

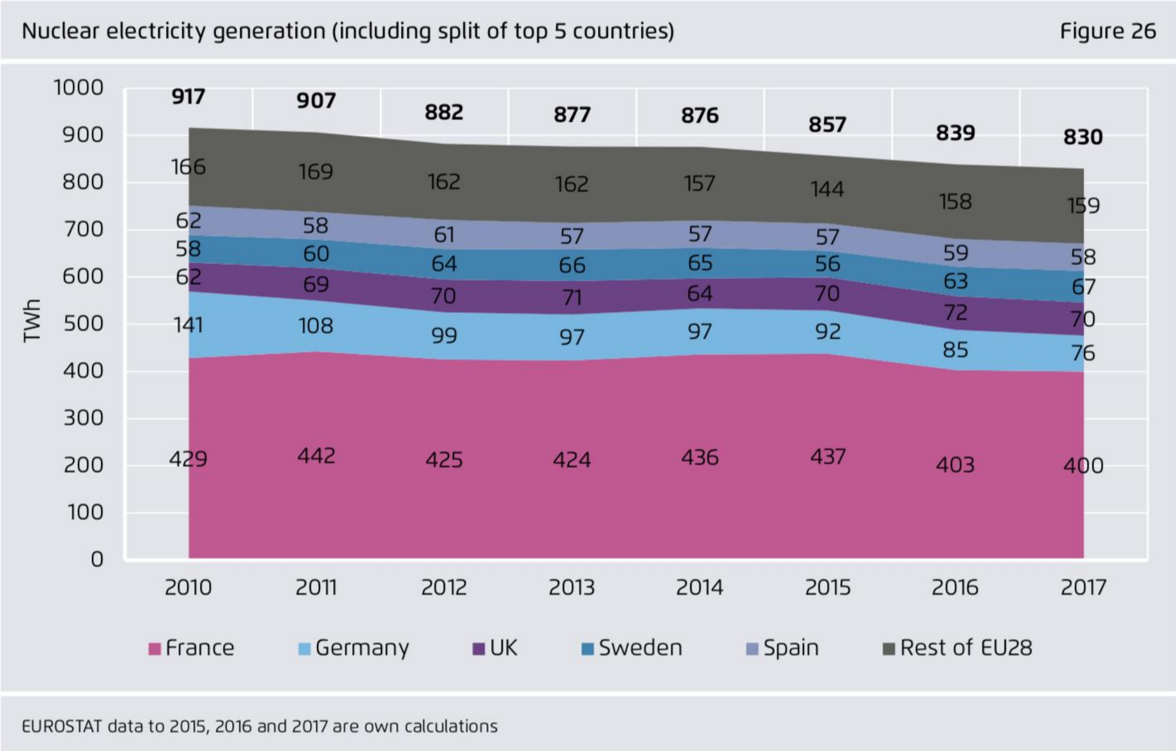
Nuclear availability continues to struggle

Nuclear generation fell again by 1% (9 Terawatt hours) in 2017. The biggest drops occured in Germany and in France, where nuclear authorities closed down several power plants in the first half of 2017 for safety reasons (see figure 26). France saw its lowest nuclear generation this century. Sweden and Czech Republic saw small increases in 2017.

Nuclear power production fell again as in previous years, leading to its lowest level in Europe since 2010. Since no nuclear power plant was closed in 2017, other reasons are responsible for the fall in power production. It seems that as nuclear power plants in Europe get older, more outages occur. Also, the increase of renewable generation is causing nuclear plants to operate more flexibly, reducing their operating hours.

In 2018, Germany will experience another drop in nuclear generation. As part of Germany's nuclear phase-out, the Gundremmingen B reactor (1,284 megawatts) was shut down on 31 December 2017, after 33 years of operation.

Nuclear electricity generation (including split of top 5 countries) Figure 21



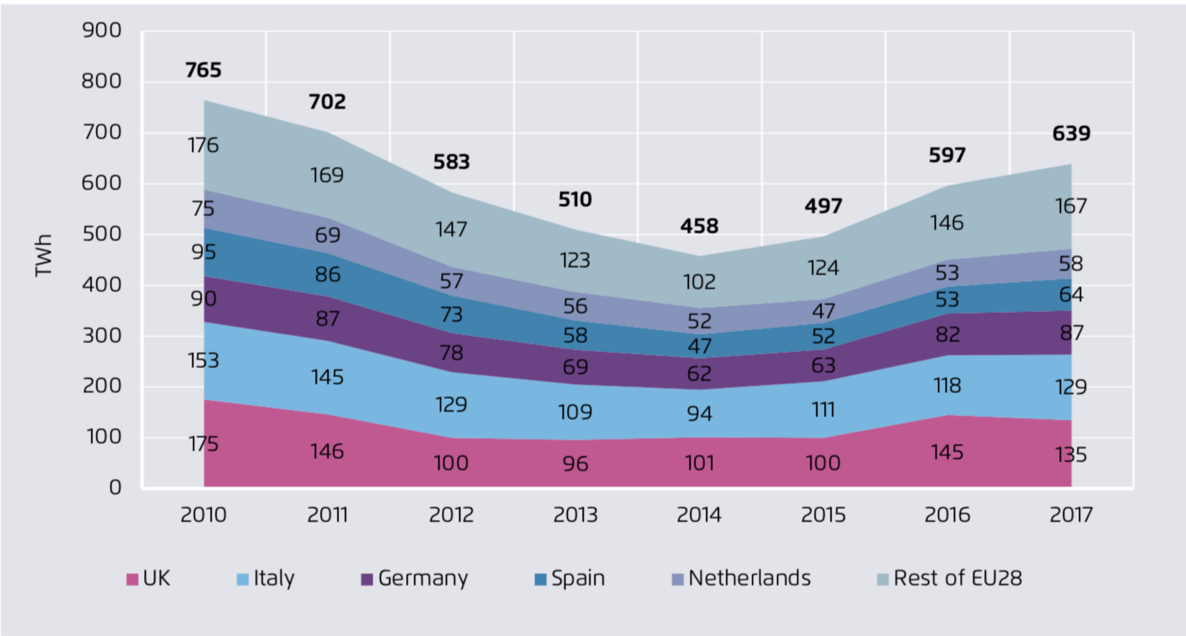
Source: Eurostat – Entso-E

Gas fills in gaps

Gas generation rose by 7% (42 Terawatt hours) in 2017. This was mostly temporary, to make up for the very low hydro generation levels in Spain, Portugal, Italy, Austria and France. These five countries had 35 Tera- watt hours of higher gas generation in 2017, compared to 45 Terawatt hours lower hydro generation. 2017 was the third year of rising gas generation, following on from a 20% rise last year. France has seen the largest increase in recent years, increasing its share of gas in the electricity mix from 4% to 7% in 2017. However, Europe's gas generation is still 20% below its peak in 2008 (see figure 27). Throughout 2017, there was broadly the same level of coal-gas switching as in 2016 (see figure 28). Coal was broadly cheaper than gas, although the newest gas plants were cheaper to run than the oldest coal plants.

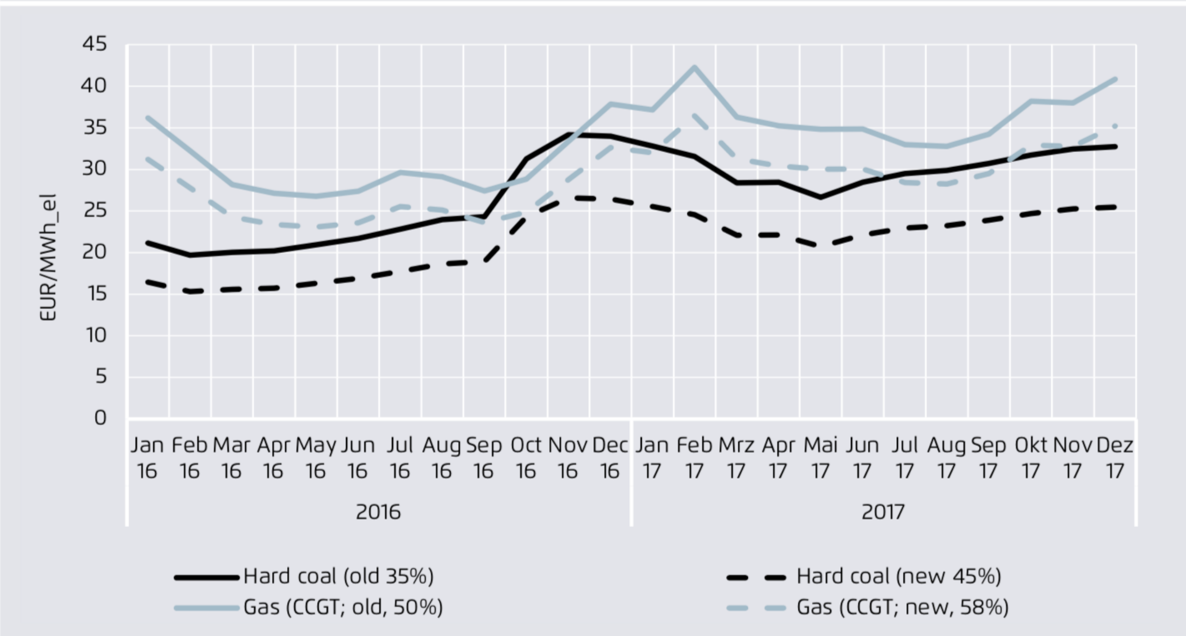
Because of the low 8 Euros/tonne carbon price, this general situation is true for every European country – with one exception: the UK, which has a domestic carbon price on top of the EU ETS, resulting in a total carbon price of around 30 Euros/tonne. Here, lower- carbon gas power production was cheaper than high-carbon coal power production.

Gas electricity generation (including split of top 5 countries) Figure 22



Source: Eurostat – Entso-E

Marginal cost of standard-type power plants 2016–2017 Figure 23



Source: Eurostat – Entso-E

4. Energy Service Companies in Europe

Improving energy efficiency is one of the most important pillars of a sustainable energy policy and a key component of climate change mitigation strategies. The private sector, including energy service companies (ESCOs) can play a critical role in improving energy efficiency at the market level. ESCOs have the necessary know-how to provide turnkey services and solutions achieving significant energy cost reductions while addressing various market related barriers on the ground. ESCOs can handle projects, manage or mobilize financial resources, undertake installation and maintenance work as well as collaborate with other market players. When providing Energy Performance Contracting (EPC), ESCOs share the unique characteristic to assume performance risks by linking their compensation to the performance of their implemented projects, thus incentivizing themselves to deliver savings-oriented solutions.

Their value of ESCOs in unlocking the energy saving potential in the market is recognized by various EU directives and initiatives in the European context, such as the Energy Efficiency Directive (2012/27/EU; EED), which sets explicit requirements to promote the market of energy services through its Article 18. The EED provides definitions for energy performance contracting, energy services and energy service providers and calls for Member States to take actions to strengthen the energy services market. The key role of Energy Performance Contracting (EPC) in driving energy efficiency investments is also highlighted in the "Clean Energy for All Europeans" communication[25]. According to this communication, the role of EPC must increase, in particular in the public sector, as they offer a holistic approach to renovations, including financing, carrying out the works and energy management.

Building on its previous reports, investigating the status of the ESCO market in the EU, the Joint Research Centre (JRC) reviewed the efforts made by Member States to stimulate the market of energy services, and in particular the market for EPC, and the size of the national markets with their main characteristics during the period 2014-2016. The findings show new developments since the last report published by the JRC in 2014 for the period 2010-2013.

The average ESCO market of the European Union has been on a steady rise for the last decades. Even if the financial crisis of 2008 caused a short backdrop, the ESCO markets were able to rather easily overcome the challenges and turn the financial restrictions into an opportunity. As of 2014-2016, in general the markets are on a growth path, although this growth is not as widespread across countries as it was in the period 2010- 2013. Traditionally, in Europe, energy services markets included a variety of contract types, many types of contractors (suppliers) and a few types of clients (mainly industry and public sector). As of 2016, there are still many types of contracts; however, energy performance contracting is more and more regarded as a distinguished contract type, and companies started to be classified based on their offerings. In parallel both ESC and EPC are by now extended to almost all types of projects (transport being an exception), including traditionally ignored ones, such as residential and SMEs.

[25] http://eur-lex.europa.eu/legalcontent/EN/TXT/?qid=1481278671064&uri=CELEX:52016DC0860

The total EU market was estimated at $2.7 billion (€2.4 billion) ESCO revenue in 2015, with a forecasted growth to $3.1 billion (€2.8 billion) in 2024 at a 1.7% compound annual growth rate (Talon and Gartner 2015).

18 of the 28 Member States reported unchanged ESCO markets, and only 7 national ESCO markets have grown during the period 2014-2016, with 3 decreasing markets (AT, HU and EE) and 1 where it was unclear (IE). This compares to 9 and 18 MSs respectively during the previous period 2010-2013. Out of those markets that were growing, none of them grew significantly, as opposed to 4 of the 18 growing markets in 2013, which experienced a boom then. It should be noted that there are MSs where increase was experienced in EPC usage.

4.1. PRIVATIZATION

The privatization stage is an initial but difficult part of the reforms. Although market structures of the countries have changed in the last decades, only a few countries have full private ownership in the electricity market. Figure 24 illustrates a strong move away from full public ownership towards more private involvement, but still the public companies are powerful in France, Portugal, Poland, and some other countries. The reason behind this picture is mostly political given that the governments are keeping their power on market competition. In many cases, governments keep considerable economic interests in energy companies, which might constrain business decisions and thus be an obstacle to the acquisition of such firms by private investors.

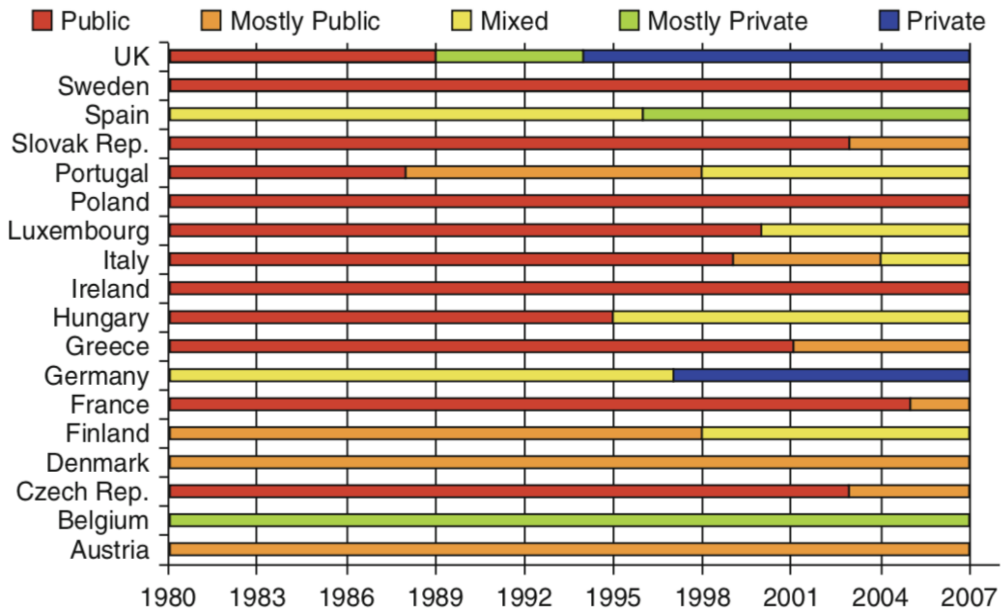


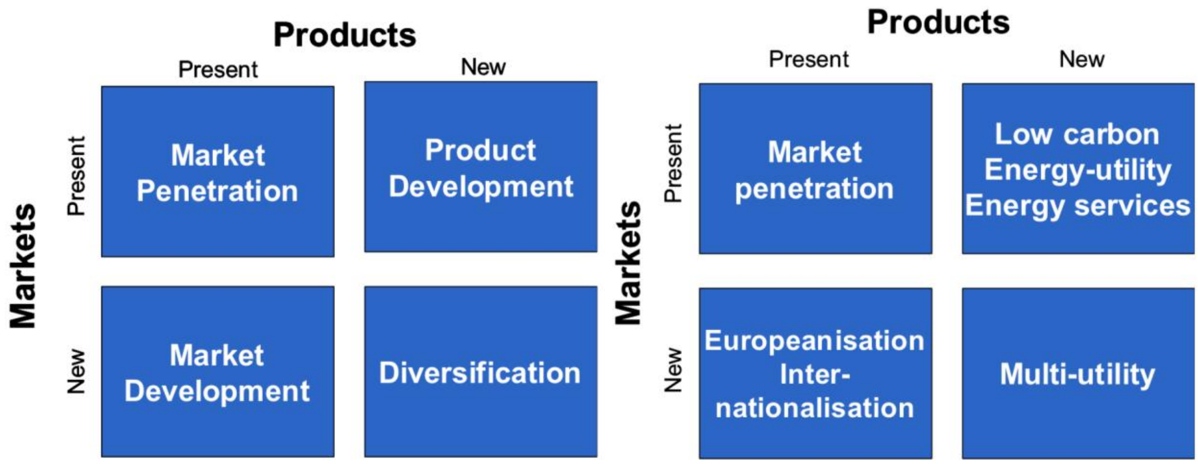
Figure 24. Electricity privatisation timeline by country
Source: OECD International Regulation Database, 2009

4.2. IMPACT OF ENERGY POLICY ON GROWTH OPPORTUNITIES OF ENERGY COMPANIES

The start of the liberalization process in continental Europe coincided with a period of lower growth rates. This meant that traditional growth opportunities for the national energy markets had become limited. At the same time, there was a growing awareness that a shift towards a lower-carbon energy system and efficient use of energy resources was vital for an economically, environmentally and socially sustainable future. Growth in the home markets was often impossible without consolidation. This was due to the fact that many companies were already dominant and protected market players. With the prospect of opening up the domestic markets and increasing competition, market share of these companies was bound to decrease. Some players were dominant because they were the traditional (regional) monopolists (like Electricité de France, Gaz de France, Eni and Enel). Others became dominant as a result of a wave of consolidation at the national market level, where many municipal energy companies were merged into larger players. As long as international oil and gas markets were buyers' markets, security of supply was not really an issue. As a matter of fact, many believed that the internal market, once complete, would automatically serve this priority of energy policy-making. Only when the buyer's market changed to a seller's market, after 2003, did security of supply consideration enter into the strategic planning of both governments and companies. Throughout the 1990s security of supply was not really an issue, and the strategic agenda of companies was mainly driven by market restructuring (liberalisation) and climate policy.

The lack of growth prospects in the home markets resulted in two main growth strategies: Europeanization (market development) and product development (see Figure 25).[26] Both can be achieved through mergers and acquisitions.

Figure 25. Product/market matrices: generic and applied to the EU energy industry



Source: CIEP Analysis, Ansoff, H.I. Strategies for Diversification. Harvard Business Review. Vol. 35. 113-124. 1957.

Mergers and acquisitions are an attractive strategy in mature market circumstances. Endogenous growth −acquiring new customers− is very time-consuming. It can also be costly when it leads to price wars with competitors or when other costly methods must be pursued to add new clients. Mergers and acquisitions are an attractive growth strategy in a mature market, as a way to spread out large amounts of cash. Companies often prefer growth over paying large dividends. One of the arguments for the latter is related to prestige but growing to a large enough size also makes acquisition by a competitor less likely. Hannan and Freeman (1989) emphasize in their work on organizational ecology that efficiency is not the absolute decisive factor in being able to survive in an industry; it is only one of the dimensions. In many cases political ties are more important. They also state that the most efficient producers are

[26] The matrix at the left is known as the product/market matrix, developed by Ansoff. The right picture is the matrix applied at the energy industry. Ansoff, H.I. Strategies for Diversification. *Harvard Business Review.* Vol. 35. 113-124. 1957.

presumably the most attractive targets for take-overs. The take-overs are done by larger firms that are less efficient but better capable of staying in business.[27] Mergers and acquisitions generally do not seem a good strategy for improvements in efficiency and cost reduction, because the expected synergistic benefits often do not materialize and economies of scale are not unlimited.[28]

The most recent examples of market development through mergers and acquisitions can be found on the Dutch energy market, where RWE (Germany) has bought Essent (€9.3 billion), and Vattenfall (Sweden) took Nuon for €8.5 billion . Other examples of large mergers and acquisitions intended to enter or develop new markets are the take-over of Endesa (Spain) by Enel (Italy) and the acquisition of Scottish Power by Iberdrola. Mergers and acquisitions are also used as a strategy to broaden the product portfolio (product development). The merger of GDF and Suez is a clear example of such a shift toward a multi-energy strategy. Until 2004, GDF could only be active in the gas business because EDF was the traditional actor on the electricity market. Suez was particularly strong in power, which led to a strong combination of power and gas activities. Another (in)famous example is the takeover of Ruhrgas by E.ON in 2002. The German competition authority had blocked the deal, but the German Counsellor Gerhard Schröder overruled the "Bundeskartellamt" for industrial and political strategic reasons.[29]

Over time, the European power and gas companies made several attempts to find new growth opportunities, such as offering related products like water, waste management, telecommunications, and even chemicals and financial services. This so-called multi- utility strategy should have resulted in cost advantages, because different types of utility services use similar assets (wires, pipelines) and similar skills (management and network maintenance), which would avoid duplication.[30] The expected cost advantages were not realized in many cases, and as a result, almost all market players ended the multi-utility strategy. Non-synergetic (non-energy) parts of the company were sold-off and invested in strengthening the energy parts

[27] Hannan, M.T., Freeman, J. *Organizational Ecology.* Harvard University Press, Cambridge Massachusetts. 1989.

[28] Marginal costs use to fall until an optimal volume, the 'most efficient scale', and then start to rise again. Mergers or acquisitions, for example, only lead to a more economical production scale when the utilization rate of plants in the new combination goes up and the requires overhead goes down. The benefit goes down again when the firm continues to grow. So, the average cost curve is U-shaped, with the most efficient scale point at the lowest part of the U-curve. (Tirole, J. *The Theory of Industrial Organization.* Fourteenth printing. p. 16-18. The MIT Press, Cambridge, Massachusetts, 2003; Schenk, H. Mergers and concentration policy. In: Bianchi, P. and Labory, S. International Handbook on Industrial Policy. Edward Elgar, Cheltenham, UK. 2006)

[29] Falck, O., Heblich, S. Do We Need National Champions? If So, Do We Need a Champions-Related Industrial Policy? An Evolutionary Perspective. *Jena Economic Research Papers.* 2007 - 088.

[30] Fraquelli, G., Piacenza, M., Vannoni, D. "Scope and Scale Economies in Multi-Utilities: Evidence from Gas, Water and Electricity Combinations" *Applied Economics.* Vol. 36. p. 2045 – 2057. 2004.

of the company (Table 2), so the combination of energy services remained primary. Table 2 shows the strategy shift in some of the major European companies from multi-utility towards multi - energy.

In the 1990s, RWE was active in chemicals, construction, telecommunications, water and waste management in addition to energy. Since the end of the 1990s, increased competition in the power and gas business required RWE to refocus, and it started to sell off non-energy activities.[31] Nevertheless, RWE acquired the UK company Thames Water in 2003, only to sell it again in 2006, as "a milestone in RWE's strategy to focus on its core strengths and focus on the converging European electricity and gas markets".[32] Enel, too, presented a new, purely energy-focused strategy in September 2002, after entering the water business in 1998. The French companies EDF and GDF were in a different position than their German counterparts. They could not diversify their portfolio and engage in a multi-utility strategy because they were constrained by regulation.[33] This situation changed when European policy no longer accepted such monopolies, the French market had to be opened for competition and they were partly privatized.

Table 2. Multi-energy and multi-utility strategy of Europe's major power and gas companies

Company	Multi-utility	Multi-energy
E.ON	Divesting non-energy assets since 2000.	In 1999 desired to become a one-stop energy shop. After acquisition of Ruhrgas in 2002, it became a multi- energy player.
RWE	Divesting non-energy assets. Also gradually withdrawing from water business.	Primary focus on energy since 2004, but some water activities remain.
Enel	Started multi-utility in 1998. Divesting non-energy assets since 2002.	Started with gas in 2000. Primary focus on energy since 2002.
Eni	Divestment of non-energy assets since early 2000s.	Since 2000 focus has been on power and gas; expanding power generation capacity.
EDF	n.a.	Until 2004 no multi-energy possible; since 2004 active in both gas and electricity.
GDF	n.a.	Until 2004 no multi-energy possible; since 2004 active in both gas and electricity.
Suez	Multi-utility focus. After merger with GDF, Suez will spin off environment business, which will end multi-utility strategy.	Multi-energy strategy after the merger with GDF and spin off of environmental business.

[31] Company website information used: www.RWE.com .

[32] Former CEO of RWE Harry Roels in: The Guardian, 17 October 2006. *Thames Water sold for £8bn to Australian bank Macquarie.*

[33] Finon, D., Midttun, A., Omland, T. *Strategic Configuration: A Casuistic Approach*. In: Finon, D. and Middtun, A. (eds.) Reshaping European Gas and Electricity Industries. Regulation, Markets and Business Strategies. Amsterdam: Elsevier. pp. 297 – 353. 2004.

Centrica	When monopoly was terminated (1998), Centrica diversified its activities, e.g. Automobile Association in 1999 (sold in 2004) and telecommunication in 2000 (sold in 2005).	Has included electricity supply in its activities since the opening of the market to competition in 1998. Since 2005 focus has been purely on energy.

Source: CIEP analysis of annual reports and corporate websites

4.3. RECENT COMPANY STRATEGIES

As already discussed, the external environment has become increasingly uncertain. It is not the aim of this paper to present a comprehensive overview of all changes that have taken place, but to relate major developments of the companies' strategic responses. Table 3 shows some major trends in the types of strategic responses.

Table 3. Strategic reactions to the trends in the external environment

Dimension	Situation	Strategic response
Supply/demand outlook	Mid- to long-term: tight supply and demand due to decreasing domestic production and continuing growth of global demand	• Upstream integration • Long-term contracts • Fuel diversification
Access to resources	Access has decreased because of increasing resource nationalism. The lower oil price in 2009 could change this. Few easy oil and gas reserves are accessible.	• Diversification of suppliers • Joint ventures and asset swaps • Upstream integration where possible
Need for investments	Very high need due to: - Required capacity replacements (in power and upstream gas & oil) - Grid improvements - Renewable capacity	• Diverse investments • Depends on oil price, CO_2 price, demand forecast and credit availability
Demand forecast northwest Europe	Mature northwest European gas and electricity markets. Growth depends on role of gas in fuel mix and whether or not Europe will move towards an all-electric society.	• New products (multi energy) • Europeanization/ • Internationalization • Made investments with energy intensive industries
Demand for renewables	High demand because of policy targets	• Acquisition of complete projects and licenses from developers

		• Investment in lowest cost renewables, e.g. biomass and hydro
Price volatility	Continues to be high. Forecasting future prices is extremely difficult.	• Gas storage • Vertical integration • Diversification in fuel mix
CO2 price	Uncertain	• Investments in expensive projects that require high CO2 prices are delayed.
Liberalisation	Increased competition	• Customer retention programs, e.g. fixed prices • Multi-energy offerings
Market integration	Opening up of new markets Focus on realizing new interconnections between markets Market coupling initiatives	• Entering new markets with acquisition or organic growth
Market structure	Consolidation	• Acquisitions to avoid being taken over • Operational excellence

Source: CIEP Analysis

4.3.1. STRATEGIES FOR SECURING SUPPLY

Long term supply contacts

The supply side risk can be managed by closing long-term supply contracts with producing countries. Several major energy companies prolonged their long-term supply contracts with the NOCs of producing countries (see Table 4). Long term contracts can be seen as a type of vertical integration. The difference with becoming active in the upsteram stages of the value chain is that the additional income related to upstream operations is not realised, but the additional risks of exploration and development of new fields are also not shared. A survey by Pricewaterhouse Coopers shows that boardroom members regard long-term contracts as the most important means for handling fuel supply challenges.[34] For ENI and GDF, long-term supply contracts account for approximately 85% of total gas deliveries.[35]

Upstream integration

Companies aiming to minimise their exposure to the supply side risks can choose upstream integration. This can be a difficult strategy to pursue and risky to fully rely on, because producing countries are increasingly reluctant to grant foreign companies access to their resources. An example of a gas company that is actively integrating in the upstream is GDF. GDF currently operates gas fields in nine countries and has the ambition to own reserves of 1,000 Mboe (160 bcm) in the medium-term, two-thirds of which is natural gas. Production from their own reserves is still limited, however, accounting in 2005 for 3% of total gas sold and far below the target of 15% set in 2000. Other examples can be found in Table 6. In general, gas companies with limited reserves of their own aim to integrate vertically in a sellers' market in order to control and benefit from the margins on production and to be less vulnerable for further price increases.

Gas storage

Investing in gas storage is one way a company can reduce its vulnerability to supply side risks. Storage can be useful to deal with short-term disruptions, price hikes and volatility of prices. The demand for gas storage has grown over the last decades and is expected to continue to do so after 2010, because gross production flexibility (indigenous production and imports) is declining.[34] Several companies are investing in new storage capacity. Storage of power is more complicated than the storage of gas. Nevertheless, power storage in the long run requires the attention of both industry and policy makers, because it might be essential to balance the intermittency of renewable energy capacity, especially wind.

Joint ventures / asset swaps

Another approach for managing supply side risks is to engage in joint ventures and asset swaps with producers, or other forms of collaboration. Joint ventures can be very effective, as they create common interests for the companies of both the producing and consuming countries. Joint ventures can consist of upstream cooperation. For example, utilities might get stakes in

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[34] Pricewaterhouse Coopers, *Energy and efficiency. The changing power climate,* Utilities global survey 2007. [33] Annual reports ENI and GDF.

[35] CIEP, *The European Market for Seasonal Storage,* The Clingendael Institute, The Hague, February 2006.

E&P projects and in return grant producers access to the downstream market, share the investment risks or guarantee long-term demand.

Diversification of suppliers

Supply can also be assured by diversifying the number of suppliers. GDF is the most obvious exponent of this strategy. It had already adopted a strategy of diversifying gas supply in the late 1970s. The new supply from Egypt and Libya, in addition to Russia, Algeria and the Netherlands, shows that GDF is still focusing on diversification of its supply. Gas from Egypt and Libya, as well as the potential production from Mauritania, will be shipped as LNG. GDF is not only expanding its LNG supplies but also its piped gas. At the end of 2006, GDF signed a 20-year agreement with Algeria for the delivery of an additional 1 bcm/a, shipped through the Medgaz pipeline between Algeria and Spain, which is scheduled to be operational in 2009. Supply contracts with Gazprom (12 bcm) have been extended until 2032. Moreover, an additional 2.5 bcm/a of Russian gas will be shipped through the Nord Stream pipeline expected to start in late 2010.

Diversification of supply routes

Diversification can also be achieved by developing new transport routes for gas. This can be done by building LNG terminals or by constructing new gas pipelines. New supply routes can secure supplies by avoiding sensitive or dominant transit countries, such as Ukraine, or by diversifying the suppliers. The latter is not always possible with pipelines, because the resource base for piped gas should be relatively near the consuming market. Throughout Europe a large number of LNG terminals are planned, under construction or recently constructed. Having an LNG terminal, however, does not in itself secure supplies to that terminal. It seems to be increasingly difficult to contract LNG supplies.[36] This leads to delayed investment decisions in regasification terminals. A new pipeline, especially one that is being built in cooperation with a producer (which is obviously not the case with the Nabucco pipeline), is a more certain option for securing supplies. Such a pipeline has two advantages. First, with a producer having a financial interest in the project, the chance that the pipeline will run dry seems very low. Second, connecting a newly built pipeline to a (new) gas field enables the pipeline to run on full capacity and increases security of demand for the producer.

[36] Petroleum Intelligence Weekly, 14 January 2008. *LNG Terminal Playing to Empty Houses,* p.1. Energy Intelligence.

Fuel choice

Finally, changing the fuel mix (both for existing plants and for newly built and proposed plants), is a kind of strategic response that can help to lower the dependence on gas imports and hence the vulnerability of supply. A generation portfolio that consists of several sources seems to be attractive because it spreads the risks and enables a switch to other sources when needed. In addition, when gas is the marginal fuel and gas prices are high, it is beneficial to have coal and nuclear power because the marginal costs of these fuels is lower than for gas. Therefore, using renewables, coal or nuclear instead of gas for power generation can be an effective response to supply insecurity.

Small players versus large players

Small players generally have fewer instruments to secure supplies than large players. From the possible strategic responses summarized in Table 4, the first three seem to be much more difficult for small players than for large players. Closing a long-term supply contract with a producer necessarily means the purchase of a significant volume of gas, which is obviously harder for a small company than for a large company. Upstream integration requires the ability to make multi-billion investments in uncertain projects, which requires a large balance sheet. In addition, upstream activities demand specific knowledge and skills that are not always available to smaller players, especially those that were previously active only in the power sector. Joint ventures in gas fields or large- scale pipeline projects that are built in conjunction with national companies from producing countries require specific capabilities (capital, skills and the ability to take large risks) that are more likely to be found with large players than with smaller ones. Table 4 summarises the different types of strategic responses and mentions various examples of this.

Table 4. Different strategic responses to supply side risks and perspectives

Type of response	Examples[37]
Long-term contracts	

[37] The examples given are not exhaustive, but are meant to give an idea of the current trends in the industry.

	• GDF extended its contract with Gazprom until 2030, and in exchange Gazprom received the right to sell 1.5 bcm/a directly to the end customers.[38] • GDF closed a 20- year contract with Sonatrach (delivery starting at the end of 2009) that will supply gas through Spain via the Medgaz pipeline. • ENEL signed an agreement with Sonatrach to supply 8bcm/a by the end of 2012 through the GALSI pipeline.
	• In 2006 Eni extended its supply contracts with Gazprom through to 2035. Gazprom supplies around one third of Italy's gas consumption. In exchange, Gazprom received the right to use Eni's pipeline network to sell directly to Italian customers. • E.ON has extended all its long-term supply contracts with Gazprom through to 2035.
Upstream integration (gas)	• E.ON wants to supply 15-20% of its gas from its own equity. It recently bought a stake in the Norwegian gas sector. In addition, E.ON has been negotiating for a long time to secure a stake in the Russian Yushno Russkoye gas field. • GDF has stakes in upstream projects in Norway, Germany, the Netherlands, the UK and increasingly in North Africa (Mauretania). • ENI is traditionally an important upstream player and owns hydrocarbon reserves throughout the world.
Gas storage	• GDF has increased gas storage and expects to have a storage capacity of 10 bcm by 2010. • OMV and Gazprom signed a co-operation agreement to jointly carry out storage projects in Austria and neighbouring countries.[39] • Expanding gas storage is one of the key elements for E.ON, and it has been expanding gas storage in Hungary and the UK.
Joint ventures/asset swaps	• Nord Stream pipeline plans to deliver 55 bcm of Russian gas to Europe and is a joint venture between Gazprom (51%), E.ON-Ruhrgas (20%), Wintershall (20%) and Gasunie (9%). • E.ON plans to build power plants with Gazprom in the UK, Germany and Hungary. This most likely has to do with negotiations about E.ON's possible stake in Yushno Russkoye.[40] • ENI and Gazprom jointly developed the South Stream and Blue Stream pipelines.

[38] International Herald Tribune, December 19, 2006. *Russian company to sell natural gas directly to French consumers.*

[39] Energy Business Review Online, 29 January 2008. OMV and Gazprom to develop gas trading hub in Austria.

[40] Financial Times, 13 November 2007. *Eon eyes Gazprom as power plant partner*

Diversification of suppliers and supply routes	• GDF historically has had a strategy of having a diverse portfolio of suppliers. • Blue Stream and Yamal diversify transit countries. • Nabucco is meant to diversify both transit countries and suppliers. • Nord Stream and South Stream are meant to diversify transit countries.
Fuel mix	• Dutch power generators (E.ON, RWE, Electrabel, Essent) are planning new coal-fired power stations.[41] • E.ON has been increasing its share of gas in power generation; in 1999 it was just over 2% and in 2006 it was 8%, which is still below the German average.

Source: CIEP Analysis

4.3.2. STRATEGIES FOR SECURING DEMAND

Mergers and acquisitions

Mergers and acquisitions are observed closely in the European energy sector. A number of recent examples will be given in Table 4. It is often stated that economies of scale are the main reason behind this type of growth, but expected synergies often do not seem to materialise. Another rationale behind all the M&As is strategic, i.e. companies want to secure their position within the consolidating and integrating European energy market and avoid becoming the subject of an acquisition by another company. M&As are often chosen as a way to grow internationally, because growing organically in the retail segment requires a large portfolio of customers, which is obviously difficult to obtain without taking over an existing firm. The threshold of profitability for supplying the residential market segment is two million customers.[42]

Internationalization; shifts to less saturated markets

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[41] For further information on coal fired power generation in the Netherlands see: Van den Heuvel, S.T.A. and De Jong, J.J. *Putting Coal to the Test: Is Coal Fired Generation Clean, Competitive and Secure?* December 2007. CIEP Briefing Paper.

[42] Finon, D. and Glachant, J.M., *Competition and Market Integration in Europe: Towards a Multienergy and Multidomestic Oligopoly.* In: Finon, D. and Middtun, A. (eds.): Reshaping European Gas and Electricity Industries. Regulation, Markets and Business Strategies. Amsterdam: Elsevier. pp. 259 – 272. 2004

Enel and E.ON seem to have a similar international growth strategy. Both companies have focused on growing in Central and Eastern Europe and Russia. These regions are attractive growth areas, because the market is large with strong demand potential, there is need for new capacity (the market is tight) and the market is in most cases privatised and/or liberalised.[43] Another example of strategic resemblance is the surprising battle for the take-over of the Spanish company Endesa by E.ON. Just when E.ON thought that the deal was secure, Enel started to build up an interest in the company and finally won the battle, thanks to the cooperation of the Spanish building company Acciona.

Multi-energy offerings

Offering multi-energy services is an attractive strategy for continued growth in a saturated market. Virtually all major European utilities offer both gas and power to their customers.

Differentiation

Differentiation with energy products is generally a difficult strategy, because the actual product leaves no room to differentiate. This, however, depends on how a company sees its role: as a supplier of a certain goods or services, or as a means to satisfy the needs that customers have. It is obvious that the latter relates to a much wider array of strategic options than the former. Companies can differentiate their offerings to a certain extent with flexible payment schemes, excellent service levels, an additional energy advisory or by building a green image.

Binding the customer

Another important strategic response is that companies try to bind the customer, e.g. by offering a fixed price for gas or power, which varies from one to ten years. The changes in the industry make the relationship with the customer more important. Companies can invest in solar panels to put on the roofs of their customers or provide other energy efficient measures to improve their customer's place. The company thus diminishes the barrier that customers face when making high initial investments for this type of product. The customer can repay the company's investment by paying a monthly fee or by using the savings to repay the energy company.

Table 5. Different strategic responses to demand side risks and perspectives.

[43] In Russia thermal power generation is privatized and liberalized

Type of response	Examples[44]
Mergers and acquisitions	• Enel took over Endesa. • Suez and Gaz de France merged into one company. • Iberdrola acquired Scottish Power. • E.ON acquired Ruhrgas.
Internationalization; shifts to less saturated markets	• E.ON, ENEL, RWE are growing in Central and Eastern Europe, as well as in Russia. • EDF hopes to benefit from the renewed interest in nuclear energy and has developed plans to build nuclear power plants in the US, the UK, China and South Africa.[45] • GDF is also expanding internationally. In 2001 only 15% of total sales came from international activities, compared to almost 40% in 2006.[46]
Multi-energy offerings	• All major European energy utility companies (ENEL, ENI, EDF, Suez- GDF, E.ON, RWE, etc.) offer both gas and power. • A number of M&As fit the multi-energy strategy very well, for example, the take-over of Ruhrgas by E.ON and the merger of Suez and GDF.
Differentiation	• In 2007 almost all companies decided to position themselves as "green" companies. For a long time RWE did not report any planned investments in renewables, but at the end of 2007 it announced a plan to invest €1 billion per year in renewables in Europe.[47] • Under a new low-budget label, e-wie-einfach, E.ON offers energy with a two year price cap. • New E.ON customers in the Netherlands receive energy saving products worth €130.
Binding the customer	• Companies offer their clients one- to ten-year fixed tariffs for gas and power. • In the Netherlands the Dutch power company Nuon gives their clients energy saving products, which they can pay with the savings they make.

Source: CIEP Analysis

4.4. INTERACTION WITH COMPANIES FROM PRODUCING COUNTRIES

National oil companies from producing countries, just like the European utilities, are very interested in vertical integration as a way to reduce exposure to shifting rents along the value chain. The difference is that NOCs look for forward integration by entering the downstream

[44] The examples given are not exhaustive, but are meant to give an idea of the current trends in the industry.

[45] Financial Times, *EDF to expand outside Europe,* 14 November 2007.

[46] Gaz de France, *Annual reports 2001 – 2006.* Paris.

[47] Die Welt, *RWE investiert Milliarden in Ökostrom,* 21 November 2007.

segments of the European market to capture more rents, rather than for backward (upstream) integration.

Gazprom, for example, aims to become *"a leading world energy company which will participate in all parts of the value chain and with a diversified portfolio of products and diversified geographical activity"*.[48] In the extension of a long-term supply contract between Gaz de France and Gazprom, it is agreed that Gazprom, in return, will be able to sell gas directly to the French customers with a total of 1.5 bcm in 2008. Gazprom made the same kind of agreement with the Italian Eni and will be supplying around 3.5 bcm directly to Italian end-customers.[49] Sonatrach has also been trying to reach the energy consumer in Spain. This met with strong opposition from Spanish politicians who, in response, started to develop a law that prevented the takeover of their national companies.

The European Commission also reacted to the trend that (semi-) state-companies are becoming active on the European market. A number of ways to protect the European market have been considered, ranging from special attention from competition authorities to defining the European energy sector as a strategic sector.

4.5. VERTICAL INTERGRATION IN THE ENERGY INDUSTRY

Stuckey and White (1993) argue that companies should not vertically integrate unless it is absolutely necessary to create or protect value.[50] Their reasoning behind this is that integration often entails high internal organizational costs and is a risky (hard to reverse) strategy. They present four situations in which vertical integration can be a good strategy:

1. The market is risky and unreliable;
2. Companies in adjacent stages of the industry chain have more market power than companies in other stage;
3. Integration would create or exploit market power by raising barriers to entry or allowing price discrimination across customer segments;

[48] Financial Times, 22 May 2007, *Gazprom to press on with EU investment.*

[49] Financial Times, 20 December 2006, *Gazprom poses challenges to EU nations.*

[50] Stuckey, J., White, D. When and when not to vertically integrate. *The McKinsey Quarterly.* No. 3. 1993.

4. The market is young, and the company must integrate forward to develop a market, or the market is declining.

These four reasons to vertically integrate can easily be applied to the energy sector and be used as a framework to compare the rationale of vertical integration on the pre- liberalized energy market compared to the current market. Table 6 shows the results.

Table 6. Comparison between reasons to vertically integrate in the pre-liberalized market and in the current market

	Pre-liberalization (1990s)	Current market
1.	• Trust in functioning of the market and economic rationality. Idea emerges that market forces will deliver better outcomes than state companies. • Supply seems to be no issue (over-supplied market/buyer's market). • Growing demand	• Increasing concerns in consuming countries about security of supply due to geopolitical uncertainties • The market is tight (seller's market) and there is uncertainty if level of investments is sufficient to meet future demand. • Increasing concern in producing countries about security of demand due to desired energy transition and climate and efficiency policy in consuming countries • Technological change towards cleaner energy is underway, but timing and degree of change remains uncertain.
2.	• Foreign direct investment was believed to gain importance and seen as an effective means to secure supply • Buyer's market, meaning that the power is with the buyers • Mid- and downstream companies were often state-owned (and/or monopolies), thus differences in power between segments of the value chain was not an issue. • In many cases companies were integrated (state) monopolies that only operated in their home markets. Barriers to entry were high and so market power could not increase. • Price discrimination and exploiting market power was hard in countries where regulated tariffs were in place.	• Seller's market, meaning that the power is with the suppliers and the buyers are forced to accept the price • Increased resource nationalism. • Liberalisation and privatisation leads to potential benefits to exert market power in certain stages of the value chain (e.g.in transport).
3.	• In many cases companies were integrated (state) monopolies that only operated in their home markets. Barriers to entry were high and so market power could not increase.	• In an open and competitive market, market power and raising barriers to entry can be very beneficial. • In a liberalised free market, companies try to maximise profits.

	• Price discrimination and exploiting market power was hard in countries where regulated tariffs were in place.	

Following the application of the later framework to the energy sector, it can be concluded from Table 7 that in the current market environment there are more strategic reasons for companies to vertically integrate than in the pre-liberalized market environment. In fact, all exemptions perfectly fit the current situation in the energy industry. The market has, in fact, become more uncertain, and upstream players have more market power than downstream players due to tight supply-demand balance. Exploiting market power has become more attractive for profit optimization, and the market is saturated, so capturing more rents from the value chain by integration can be necessary.[51] The increased incentive to vertically integrate does not seem to be perfectly in line with the view of European Commission on market reform, e.g. in relation to ownership unbundling proposals.

The impact of vertical integration on competition

In general, the impact of vertical integration on competition is less clear-cut than the impact of horizontal integration. Horizontal integration in the same market generally leads to higher market shares and hence to a less competitive market structure.[52] Vertical integration can have both a negative and a positive impact on competition.[53] A negative effect of vertical integration is the reduction of liquidity in the wholesale market, because the merged company would buy and sell more gas and/or power internally. This would make wholesale prices a less reliable indicator of supply and demand fundamentals, since the prices would be based on fewer transactions. The reduction of liquidity can make prices more volatile and hence provoke more vertical integration. This can eventually lead to a barrier to entering the market as a non-integrated company. Finally, vertical integration reduces the number of potential entrants into the market. The positive effect of vertical integration is that it can reduce the costs of supplying gas and electricity to customers, because it lowers the risks.

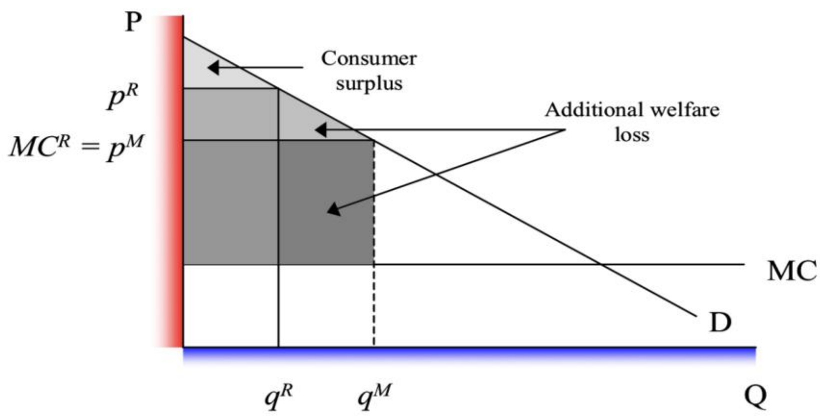
[51] H.W. De Jong (1996) explains that in a mature market, the market tends to integrate again to avoid transaction costs as profits go down.

[52] In the case that a market has one very big player and several small ones, it can be beneficial for the level of competition in the market when some of the small companies merge and can pose a more credible threat to the dominant player.

[53] Moselle, B. Newbery, D. Harris, D. *Factors affecting geographic market definition and merger control for the Dutch electricity sector.* NMa, The Hague. 2006.

Tirole shows that when considering a market in which both downstream and upstream companies can exercise market power, the consumer is worse off in the situation of a separated chain than in the situation of one integrated company.[54] This has to do with 'double marginalization'.[55] In short this means that in the situation of separate downstream and upstream players with market power, both companies can ask a price above marginal production costs (MC) (see Figure 26), i.e., exercise market power. Each player in the chain sets its price, without taking into account the price that the next company in the chain sets. This leads to a situation where companies offer an amount that is not equal to the amount where marginal costs are the same as marginal revenues, hence their profits are not maximized. So, when the companies would be integrated into one company, they would be able to increase the profit margin and at the same time offer a lower price to the customer. The lower price again leads to increasing demand and consequently to even higher profits. Double marginalization does not occur when the downstream market is perfectly competitive, because in that case the downstream companies do not have the ability to ask a premium price.

Figure 26. Double marginalization



In relation to European energy and competition policy, the concept of double marginalization shows that avoiding vertically integrated companies will only have a positive welfare effect when the policy leads to a perfectly competitive market. Such a market structure is obviously the goal of European policy but looking at the ongoing consolidation in the European industry

[54] Tirole, J. *The Theory of Industrial Organization.* Cambridge (Massachusetts). The MIT Press. Fourteenth printing. 2003.

[55] Also characterized by the following: *"What is worse than a monopoly? A chain of monopolies." Or "What is worse than a oligopoly? A chain of oligopolies."* Double marginalization refers to the case that two companies in the chain can exert market power. When e.g. three companies can do this, there is triple marginalization.

and the importance of scale it seems uncertain whether or not such a structure will emerge. In this case there is a risk that splitting the companies up may lead to higher instead of lower prices for customers.

5. FINANCIAL ANALYSIS AND RESULTS

5.1. SAMPLE

The sample comprises energy companies based in the European continent. It is should be noted that is not confined to European Union (EU) countries, albeit EU companies comprise the vast majority. The companies of the energy sector are split in three groups in an effort to capture special features. Chronologically, the research expands in the last decade, namely years 2008-2017.

Table 31 depicts the companies and their statutory base at country level. The sample is divided in three subcategories; Electric Energy, Oil and Gas and Renewable Energy.

Table 31. **Company Sample**

Electric Energy		
	Company Name	**Country**
1	RWE	Germany
2	EON	Germany
3	EnBW	Germany
4	Engie	France
5	EDF	France
6	Enel	Italy
7	Iberdrola	Spain

8	Vattenfall	Sweden
9	SSE	United Kingdom
10	National Grid	United Kingdom
Oil and Gas		
	Company Name	**Country**
1	TOTAL	France
2	ENI	Italy
3	GAZPROM	Russia
4	STATOIL	Norway
5	OMV	Austria
6	REPSOL	Spain
7	Gas Natural	Spain
8	BP	United Kingdom
9	SHELL	United Kingdom
10	LUKOIL	Russia
Renewable Energy		
	Company Name	**Country**
1	EDP Renovaveis	Spain

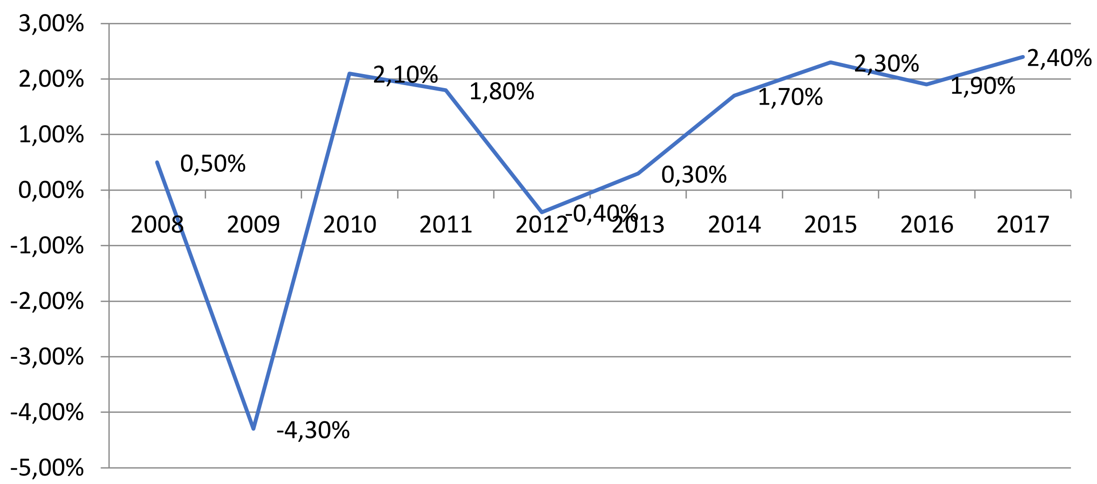
Most of the companies prepared their financial statements according to International Financial Standards (IFRS). This fact greatly facilitates comparability. The only exception is Gazprom that had adopted the national accounting standards from 2008 to 2013. Three other companies that originally belong to the third group "Renewable Energy" did not publish their annual financial data, or they utilized solely domestic language. The plea for annual reports, via email, was not satisfied. These companies are NTR plc, Reykjavik Geothermal LTD and Natur Energi. The inclusion of only one company in the latter category had as an impact to omit the sector from total averages. In the tables that are supplemented with the financial ratio analysis, the category "Total" comprises the average figures of the first two subsectors, namely Electricity and Oil and Gas.

The analysis is based on published financial data deriving from annual reports. All annual reports were downloaded from company sites. Research was also assisted by specialized reports from acknowledged institutions. Statistical data was derived from Eurostat. Microsoft Excel was the spreadsheet software applied for the ratio analysis. Historical share prices were derived from the “Yahoo Finance” platform. Share prices were adjusted for splits and dividend payments.

5.2. MACROECONOMIC ENVIRONMENT

The European energy market faced numerous challenges during the last decade. Adverse macroeconomic conditions, supported by industry specific factors, caused a "perfect storm" (McKinsey & Company, 2014). The sector was greatly influenced by the economic crisis commenced in year 2008. The spillover effect of the US financial crisis affected many European countries. Some of them, members of the European Union (EU), lost access to capital markets and were forced to implement economic adjustment programmes run by the European Commission, the European Central Bank and the International Monetary Fund. **Figure 1** presents the real GDP growth rate (in real terms) for the twenty eight European countries, members of the EU.

Figure 1. Real GDP Growth Rate % EU-28



Source: Eurostat

Energy demand was largely affected. Energy companies witnessed an annual reduction in power demand equal to 0.3% from 2008 to 2012 (McKinsey & Company, 2014). Many companies decided to downsize. Downsize policies were also induced by EU policies described in the "European Union Environmental Policy" section.

The property, plant and equipment account for the electricity companies' subset exhibited a clear downward trend, especially in the last 5 years (2013-2017). The companies that increased the property account were either less in absolute figures or the positive percentage change was inferior to the negative respective, for that period. The trend observed for the period of study, 2008-2017, is presented in **Table 32**.

Table 32 Electric Sector – Property, Plant, Equipment Account

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Negative Average	-	-7.8%	-5.2%	-2.2%	-7.8%	-7.5%	-6.6%	-14.3%	-5.1%
Negative Instances	0%	30%	20%	40%	60%	50%	50%	50%	30%
Positive Average	14.1%	10.0%	5.6%	5.6%	3.2%	5.8%	4.6%	4.2%	4.5%
Positive Instances	100%	70%	80%	60%	40%	50%	50%	50%	70%

Source: Own calculations

The oil and gas companies' subset exhibits a downward trend in absolute figures especially from 2015-2017. However positive changes surpass negative equivalents in percentage terms, as presented in **Table 33**. This sector has substantial funds committed to fixed assets and disinvestment requires much time to be delivered.

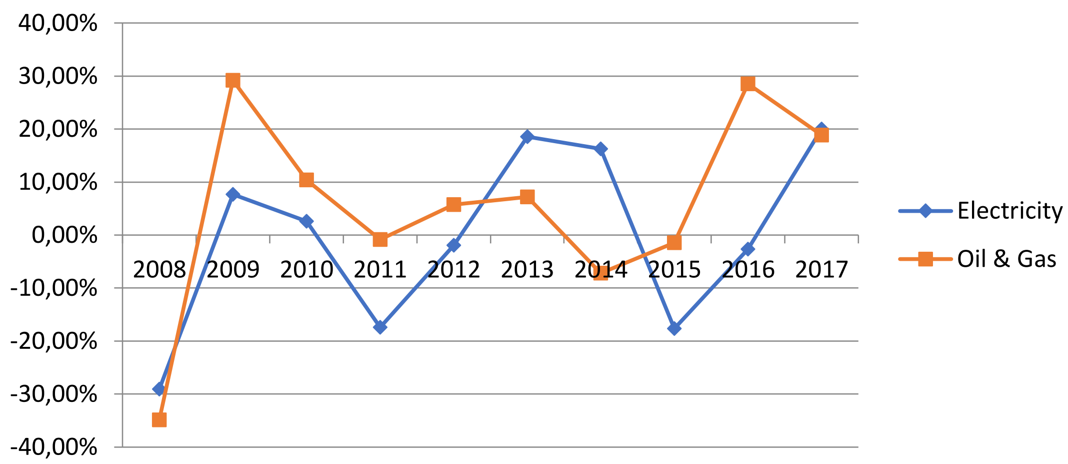
Table 33. **Oil and Gas Sector – Property, Plant, Equipment Account**

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Negative Average	-	-6.0%	-2.0%	-12.4%	-4.2%	-18.5%	-5.6%	-3.2%	-5.4%
Negative Instances	0%	10%	10%	30%	30%	20%	60%	50%	70%
Positive Average	27.2%	6.4%	11.9%	8.9%	11.3%	14.3%	21.8%	11.7%	7.1%
Positive Instances	100%	90%	90%	70%	70%	70%	40%	40%	30%

Source: Own calculations

As already pointed out, energy companies were severely affected by the financial markets' turmoil. Companies of the two subsectors, electricity and oil and gas, lost nearly 50% of their capitalization. **Figure 2** presents average share performance for 19 energy companies. Vattenfall, the Swedish energy company, is under state control and its' shares are not publicly traded. Average variability differs between the two groups. Average standard deviation of performances, for the whole period, is 15.83% for the electricity and 20.08% for the oil and gas sector. This is indicative of the challenges faced by fossil fuels companies, as renewable sources of energy gain popularity.

Figure 2. Average Share Performance 2008-2017



5.3. EUROPEAN UNION ENVIRONMENTAL POLICY

The importance of the European Union and its policies is influential for all countries comprising the continent. On November 20th, 2013 the European Parliament and the council decided on the 7th Environment Action Programme (EAP) to 2020, namely "Living well, within the limits of our planet" (Decision 1386/2013/EU). The programme includes goals relative to energy consumption and generation. The goals set, affect energy companies' strategies and are integrated in future investment decision making.

The general objectives, related either directly or indirectly to energy, are summarized below (General Union Environment Action Programme to 2020, 2014):

- The Union has set itself the objective of becoming a smart, sustainable and inclusive economy by 2020 with a set of policies and actions aimed at making it a low-carbon and resource-efficient Economy
- The 7th EAP should help to achieve the environment and climate change targets on which the Union has already agreed and to identify policy gaps where additional targets may be required.
- The Union has agreed to achieve a reduction of at least 20 % of its GreenHouse Gas (GHG) emissions by 2020 (30 %, provided that other developed countries commit themselves to comparable emissions reductions and that developing countries contribute adequately according to their responsibilities and respective capabilities); to ensure that 20 % of energy consumption comes from renewable energy by 2020; and to achieve a 20 % cut in primary energy use compared with projected levels, by improving energy efficiency.

The greenhouse gas emissions are heavily influenced by lignite and coal utilization in power generation. Many companies implemented strategies to shut down such plants that oppose to low carbon initiative. Simultaneously, alternative power resources and especially renewable ones, play a vital role in strategic planning. EU expects that European renewable sources sector will generate 400,000 new jobs by 2020 (Employment in Europe, 2009).

Nuclear power is also seriously questioned. In Germany there is a growing debate on the shutting down of nuclear plants, whereas in France nuclear power remains the most popular energy source. All these policies and initiatives have impacts on financial performance of the energy companies in the European Continent.

Table 34 presents the energy sources production mix per country, as well as at EU level, for year 2017.

Table 34. **Energy Production Source Mix – Year 2017**

Year 2017	Lignite	Hard Coal	Other fossil	Gas	Nuclear	Hydro	Solar	Wind	Biomass
EU28	**10%**	**11%**	**4%**	**20%**	**26%**	**9%**	**4%**	**11%**	**6%**
Austria	0%	4%	2%	15%	0%	58%	2%	11%	8%
Belgium	0%	0%	5%	28%	49%	0%	3%	7%	7%
Bulgaria	45%	1%	1%	7%	33%	6%	3%	3%	1%
Cyprus	0%	0%	87%	0%	0%	0%	5%	7%	1%
Czech	43%	7%	4%	4%	33%	2%	3%	1%	6%
Denmark	0%	21%	3%	2%	0%	0%	3%	50%	21%
Estonia	0%	0%	86%	0%	0%	0%	0%	5%	8%
Finland	5%	9%	2%	6%	34%	21%	0%	7%	17%
France	0%	2%	1%	7%	73%	9%	2%	5%	1%
Germany	23%	15%	4%	13%	12%	3%	6%	16%	8%
Greece	34%	0%	10%	31%	0%	8%	7%	10%	0%
Hungary	16%	-1%	1%	24%	49%	1%	0%	2%	8%
Ireland	8%	11%	2%	50%	0%	2%	0%	26%	2%
Italy	0%	12%	7%	45%	0%	13%	9%	6%	9%
Latvia	0%	0%	0%	39%	0%	49%	0%	2%	10%
Lithuania	0%	0%	0%	32%	0%	17%	3%	35%	13%
Netherlands	0%	26%	6%	49%	3%	0%	2%	9%	4%
Poland	31%	47%	3%	4%	0%	1%	0%	8%	6%
Portugal	0%	25%	3%	31%	0%	11%	2%	22%	6%
Romania	27%	-1%	2%	16%	18%	23%	3%	12%	1%
Slovakia	6%	5%	4%	5%	56%	16%	2%	0%	6%
Slovenia	31%	2%	0%	3%	36%	24%	1%	0%	3%
Spain	0%	16%	7%	23%	21%	6%	5%	18%	2%
Sweden	0%	0%	1%	0%	41%	39%	0%	11%	7%
UK	0%	7%	2%	40%	21%	2%	3%	15%	9%
Luxembourg	0%	0%	3%	52%	0%	9%	11%	14%	10%
Malta	0%	0%	14%	0%	0%	74%	9%	3%	1%

Croatia	0%	17%	0%	21%	0%	44%	2%	12%	4%

Source: Agora Energiewende

It is obvious that there are significant differences among EU member states. As it will be stressed in the relevant section, these differences affect the profitability of energy companies.

5.4. FINANCIAL STATEMENT ANALYSIS

Financial statement analysis will focus on four key areas, namely profitability, liquidity, capital structure and operating performance. Initially, profitability analysis will be presented.

5.4.1. PROFITABILITY RATIOS

Profitability indicators are extremely important, since they are directly related to company survival and flourishing. For publicly traded companies, is rather important to deliver positive results each financial year, in order to maintain investment interest.

Gross profit derives from the following formula:

$$Gross\ Profit = \frac{Net\ Sales - Cost\ of\ Sales}{Sales\ (Net)} \quad (1)$$

Sales figures were expressed on net basis. This actually means that any taxes and tariffs were not included in the Sales variable. Gross profit is depending on two variables. Initially selling price and secondly, the cost of materials used in the production process. Selling prices are influenced by competition status, as well as quality standards. In this case, the product has no diversification opportunities. Inevitably, competition is a driving force for the shaping of selling prices. This fact increases the magnitude of cost administration. Usually the cost of materials also includes the cost of CO_2 certificates acquisition, alternatively stated as “emission allowances”.

Table 35 depicts average gross profit margin for the energy companies in Europe. There is a slight downward trend. In most years, Oil and Gas sector presents superior figures in comparison to Electricity reciprocals. Renewable sector manages to attain margins well over

30% (with the exception of years 2011-2012). This margin is a result of the nature of the production process and the absence of CO_2 certificates' cost.

Table 35 Gross Profit %

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Electric	31.9	33.6	34.0	30.7	29.5	27.5	28.1	27.0	29.3	30.9
Oil & Gas	34.5	36.7	35.4	33.2	30.1	29.6	27.9	29.8	34.2	32.6
Renewables	79.6	79.0	78.3	77.7	78.6	77.4	76.5	76.7	77.2	79.9

Source: Own calculations

The concurrent study of the sales and cost of sales evolution divulges the variables affecting the profit margin. For the companies that had negative changes in annual income, as a result of lower prices or depressed business activity, management teams adopted cost reduction policies in order to maintain profitability. In most cases cost figures are relatively more suppressed than the sales respective, as presented in **Table 36** and **Table 7**.
Consequently, profit margins are maintained or even improved for this group of companies.

Table 36 Sales & Cost of Sales (Negative Changes Averages) - Electricity

	2009	2010	2011	2012	2013	2014	2015	2016	2017
Sales Change	-6.3%	- 15.2%	-5.5%	-7.6%	-7.1%	-7.8%	-2.0%	- 13.3%	-2.1%
Cost of Sales %	-9.6%	-8.9%	-6.0%	-8.9%	-7.6%	-9.2%	-5.1%	- 17.8%	-7.9%

Source: Own calculations

Table 37 Sales & Cost of Sales (Negative Changes Averages) – Oil & Gas

	2009	2010	2011	2012	2013	2014	2015	2016	2017
Sales Change	- 26.5%	-	-	-6.9%	-5.4%	-9.6%	- 29.2%	- 12.9%	-

Cost of Sales %	-28.3%	-	-	-0.1%	-5.3%	-9.6%	-33.2%	-20.0%	-

Source: Own calculations

The aggregate downward trend in gross profit margins stems from the companies that succeeded to improve turnover. **Table 38** and **Table 39** are justifying the argument. Improved income was, in most cases, accompanied by relatively more associated cost, resulting, ultimately in lower profit margins. Companies that managed to attain increased sales had to sacrifice profit margins.

Table 38 Sales & Cost of Sales (Positive Changes Averages) - Electricity

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Sales Change	23.3%	10.1%	13.4%	7.9%	3.6%	4.3%	2.4%	-	6.2%
Cost of Sales %	42.9%	15.2%	15.7%	10.8%	9.7%	4.4%	4.8%	7.2%	8.2%

Source: Own calculations

Table 39 Sales & Cost of Sales (Positive Changes Averages) – Oil & Gas

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Sales Change	9.9%	24.6%	22.4%	11.1%	1.9%	15.0%	6.1%	0.6%	18.5%
Cost of Sales %	7.3%	27.8%	26.4%	13.9%	3.0%	12.1%	8.4%	13.1%	21.4%

Source: Own calculations

Apart from the cost of sales there are numerous cost variables that affect profitability. Operating profit margin indicates the profitability attained after incurring all costs and is a rather crucial variable that defines management efficiency. The formula applied to derive operating profit margin follows:

$$Operating\ Profit\ Margin = \frac{Earnings\ Before\ Interest\ and\ Tax\ (EBIT)}{Sales\ (Net)} \quad (2)$$

Table 40 depicts operating profit margin for the energy sector in the last ten years (2008-2017).

Table 40 Operating Profit %

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Electric	13.1	14.7	14.0	11.3	10.2	5.9	7.3	4.0	5.5	10.9
Oil & Gas	14.6	12.5	12.4	13.6	11.9	10.3	8.8	2.8	4.1	9.9
Total[56]	13.9	13.6	13.2	12.4	11.0	8.1	8.0	3.4	4.8	10.4
Renewables	43.6	35.6	34.5	36.4	38.9	38.4	36.6	42.8	38.8	50.1

Source: Own calculations

Operating profit margin dwindles constantly and starts to revive only in the last financial year. Other operating expenses comprise personnel cost, depreciation and impairment charges, as well as other expenses, such as advertising, general administration expenses and exchange rate results. Energy companies could not adjust operating expenses to decreasing gross margin, probably because of the inelastic nature of these expenses. Electricity and Oil and Gas companies do not exhibit significant differences in average operating profit margin.

The metrics presented so far, do not incorporate cost of debt. The next step of profitability analysis is pretax profit margin. Pretax profit margin takes into account the cost of financing, since it deducts interest charges from earnings and estimates the remainder margin relating to sales figure. The mathematical formula is the following:

$$Pretax\ Profit\ Margin = \frac{Earnings\ Before\ Tax\ (EBT)}{Sales\ (Net)} \quad (3)$$

[56] "Total" comprises the "Electric" and "Oil and Gas" sectors. Renewable sector was not averaged since it includes only one company and its relative weight would alter substantially company averages.

The depressed margins are further diminished by interest charges, since these payments are constant, irrespective of financial result. The figures in **Table 41** indicate possible excessive debt financing, which is going to be analyzed in next section.

Table 41 Pretax Profit Margin %

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Electric	9.6	10.7	10.2	7.0	6.7	2.4	3.8	1.2	4.2	8.7
Oil & Gas	14.5	13.4	13.4	14.7	12.2	10.8	6.6	1.4	4.7	9.3
Total	12.1	12.1	11.8	10.9	9.4	6.6	5.2	1.3	4.4	9.0
Renewables	30.3	25.2	14.4	12.4	15.7	18.3	16.8	21.5	14.7	31.5

Source: Own calculations

Diminished pretax margins leave little space for positive net profits. However all annual averages are positive. Decisive role play the deferred taxes amounts that ultimately expunge losses in turbulent years. The bottom line of the income statement is net profit available to shareholders. All analysts and investors are focusing on the bottom line metric, the net profit margin.

$$Net\ Profit\ Margin = \frac{Net\ Profit}{Sales\ (Net)} \quad (4)$$

This formula delivers net income after the deduction of interest charges and the taxes imposed by state authorities.

Table 42 Net Profit Margin %

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Electric	7.1	7.6	7.3	5.0	5.2	1.7	2.8	1.0	-0.5	8.2
Oil & Gas	7.7	7.6	7.7	8.5	6.8	5.9	3.3	-0.3	2.9	5.9
Total	7.4	7.6	7.5	6.7	6.0	3.8	3.0	0.4	1.2	7.0
Renewables	21.1	18.2	9.9	9.5	11.7	13.7	15.4	18.2	12.1	28.5

Source: Own calculations

The performance of energy companies in Europe is disappointing. Net profit margins deteriorate and insignificant amounts of money remain for shareholders (**Table 42**). In years 2015 and 2016 negative observations occur. Figures start to revive only in year 2017 where they jump from 1.2% to 7.0% on average. Probably this is a result of the market conditions improvement, already discussed in the macroeconomic environment section.

Two key financial ratios, included in every financial analyst' coverage, are Return on Assets (ROA) and Return on Equity (ROE). Return on Assets measures profitability in comparison to total assets of the company. It can also be considered as a measurement of management effectiveness.

$$Return\ on\ Assets = \frac{Net\ Profit}{Total\ Assets} \quad (5)$$

Table 43 presents the average Return on Assets for each subsector and its evolution during the last decade. Returns, as a percentage of the total assets, exhibit a clear downward trend. Negative returns occur in years 2015 and 2016. The trend seems to reverse in the last year.

Table 43 Return on Assets (ROA) %

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Electric	3.2	3.0	3.5	2.2	2.0	0.5	0.9	0.0	-1.8	3.6
Oil & Gas	8.2	5.1	5.7	7.3	6.1	4.9	2.7	-0.2	1.5	3.7
Total	5.7	4.0	4.6	4.7	4.1	2.7	1.8	-0.1	-0.1	3.7
Renewables	1.2	1.0	0.6	0.7	1.0	1.3	1.2	1.6	1.1	2.8

Source: Own calculations

Investors also focus on the return achieved over the capital invested in the company. Equity is the total sum of funds that was entrusted by shareholders in the form of direct fund transfers, or alternatively, in the form of retained earnings.

Table 44 presents the evolution of the ratio. The figures are superior to the ROA respective, since this ratio concerns only equity holders and not all creditors

Table 44 Return on Equity %

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Electric	16.6	15.1	15.4	8.7	9.0	1.7	3.9	-0.8	-7.2[57]	19.0
Oil & Gas	17.8	10.9	12.3	15.8	12.6	10.2	5.7	-1.5	2.5	7.7
Total	17.2	13.0	13.9	12.2	10.8	6.0	4.8	-1.1	-2.3	13.4
Renewables	2.2	2.2	1.5	1.7	2.4	2.8	2.8	3.6	2.3	5.8

Source: Own calculations

Incremented values may unveil relatively inadequate equity funds. Electricity sector recovered sharply in 2017. Nevertheless, Oil and Gas sector follow also an upward trend. It would be interesting to compare these values with estimated equity premiums implied in the same originating countries. Equity premium is the expected return on equity investment after deducting the risk free rate. In the context of this thesis, equity premiums for each country were derived from specialized internet sources[58] (**Table 45**). To attain an average for each sector, an approximation was performed by weighting the sovereign equity premium with the number of companies originating in each country. The estimates are presented in the two last rows of **Table 45**.

Table 45 Equity Premium %

Country	Equity Premium
Germany	5.08%
UK	5.65%
France	5.65%
Italy	7.27%
Spain	7.27%
Sweden	5.08%
Russia	7.96%
Austria	5.54%
Norway	5.08%
Electricity (Weighted Average)	5.75%

[57] An outlier observation of EON for the year was omitted because it was altering the average dramatically. At that year EON had a massive loss because of a discontinued operation.
[58] Damodaran Online, Stern University, USA

Oil and Gas (Weighted Average)	6.53%

Source: Damodaran Online[59] (Last Update 01/2018)

The Return on Equity average of the sample outperforms the suggested equity premiums either at subsectoral or at aggregate level. Energy sector outperforms equity premiums, indicating that it still remains an attractive investment opportunity.

Only the renewable sector scores below the weighted average thresholds. Since only one company is involved in the comparison process, any conclusion should be carefully stated. Nevertheless, depressed return on equity in this case, is owed to equity funds abundance, rather than unsatisfactory financial results.

5.4.2. LIQUIDITY RATIOS

Liquidity measures the ability of a company to cover short term liabilities. Liquidity ratios are indispensable in every financial analysis, since they affect business performance, survival and efficiency. The most common ratio is Current ratio, a simple comparison of assets and liabilities that concern the same time horizon.

$$Current\ Ratio = \frac{Current\ Assets}{Current\ Liabilities} * 100 \quad (6)$$

The generally accepted threshold is 1.5 times, or 150%. Since it is difficult to attain perfect match of maturities for claims and liabilities, analysts require a pillar of extra asset value to cover possible liabilities.

Table 46 Current Ratio %

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Electric	98.3	105.5	110.6	111.5	113.6	107.4	105.9	109.5	103.9	103.5
Oil & Gas	118.8	130.3	137.5	137.7	147.1	145.1	142.0	139.2	130.8	134.5
Total	108.5	117.9	124.1	124.6	130.3	126.3	124.0	124.4	117.3	119.0
Renewables	93.7	88.7	97.6	82.3	82.4	90.3	80.8	68.2	86.5	62.5

[59] http://pages.stern.nyu.edu/~adamodar/New_Home_Page/wacccentral.html

Source: Own calculations

The two groups of companies exhibit distinct characteristics. While Oil and Gas companies have adequate current assets to meet short term liabilities, Electricity companies have –on average- current assets of nearly equal value to that of reciprocal liabilities. This cannot be a satisfactory result, since current assets are also comprised of relatively illiquid assets, such as inventories and trade receivables. The time required to turn these illiquid assets to cash may exceed the maturities of short term debt, causing ultimately liquidity problems. The uncomfortable situation can be addressed by short term bank credit, albeit this actually implies additional financial cost and reduced earnings. The renewable sector, on the other hand, presents serious liquidity problems, since assets fall behind liabilities.

Quick ratio attempts to address the issue of illiquid current assets by not considering inventories in the category.

$$Quick\ Ratio = \frac{Current\ Assets - Inventories}{Current\ Liabilities} \qquad (7)$$

Table 47 Quick Ratio %

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Electricity	89.3	94.8	99.6	99.6	101.3	94.6	94.6	99.0	95.1	93.3
Oil & Gas	94.1	96.8	105.3	103.7	112.9	111.2	115.0	114.9	103.9	108.4
Total	91.7	95.8	102.5	101.7	107.1	102.9	104.8	106.9	99.5	100.8
Renewables	92.2	87.8	95.7	80.1	81.0	88.5	79.1	66.7	84.7	60.7

Source: Own calculations

The importance of inventories is not crucial either for the subsectors or on aggregate level. The deduction of inventories stresses a potential problematic situation, especially for Electricity companies and poses serious doubts also for the Oil and Gas. Electricity companies' liquid assets fall behind current liabilities. The respective figures for Oil and Gas companies are marginal. On aggregate level, current assets are almost equal to current liabilities. This is not safeguarding the liquidity of the companies that must depend on short term credit to satisfy debt maturity dates. Renewables are the only sector with minimum inventories. Consequently, the conclusions for this sector cannot differ to the current ratios respective.

Lastly, the category of liquidity ratios concludes with the cash ratio. This financial ratio captures the amount of liabilities that can immediately be paid using cash and cash equivalents. The existence of cash is desirable. However, cash ratios that indicate abundance of cash do not lure investors. The latter case describes ineffective management that cannot find positive Net Present Value (NPV) investments. The mathematical formula is:

$$Cash\ Ratio = \frac{Cash\ and\ Cash\ Equivalents}{Current\ Liabilities} \qquad (8)$$

Table 48 below depicts the evolution of the cash ratio for the sample of companies throughout the ten year period 2008-2017.

Table 48 Cash Ratio %

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Electric	13.0	11.5	13.6	14.5	16.4	16.0	16.2	16.4	19.1	16.4
Oil & Gas	17.1	17.2	23.7	20.9	31.1	31.5	35.6	37.6	33.1	38.3
Total	15.1	14.4	18.6	17.7	23.8	23.7	25.9	27.0	26.1	27.4
Renewables	29.4	35.6	38.8	20.3	21.6	30.8	30.7	29.2	47.2	24.4

Source: Own calculations

The figures unveil two different policies from the companies in each subcategory. Electricity companies manage to maintain cash reserves equal to 15% -on average- of current liabilities. Oil and Gas companies pursue a policy of increasing cash constantly. After the great market turmoil in year 2009, cash reserves jumped from 17% to 38%. This percentage is extremely satisfactory in liquidity terms. Nevertheless, it may disguise lack of investment projects or unwillingness to commit funds to new projects because of unfavorable market prospects. The renewable sector follows the Oil and Gas pattern. This is peculiar for the sector, since the potential for renewable resources infrastructure projects is rather promising.

Another holistic liquidity ratio is “Cash Conversion Cycle”. The cycle comprises three components relating to inventories, trade receivables and trade accounts payable. This ratio approximates the number of days required to receive cash from ordinary activities, taking simultaneously into account the indirect credit that the company receives from its suppliers.

$$\begin{aligned} &Cash\ Conversion\ Cycle \\ &\qquad = Days\ Inventory\ Outstanding + Days\ Sales\ Outstanding \\ &\qquad - Days\ Payables\ Outstanding \quad (9) \end{aligned}$$

Cash conversion cycle is interrelated with liquidity, since shorter periods are translated to reduced financing needs and subsequent interest burden. The first component of the ratio is presented in

Table 49.

Table 49 Days Inventory Outstanding

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Electric	39	47	41	41	38	36	38	34	35	37
Oil & Gas	30	50	46	41	37	38	34	36	49	42
Total	34	48	43	41	38	37	36	35	42	39
Renewables	41	27	45	39	22	22	30	28	29	32

Source: Own calculations

The differences observed are not so crucial. In the first years of the analysis, when economic crisis prevailed, the days average increase. This is a result of the demand slowdown. Figures improve as economy revives to positive grounds. Increasing days of inventory outstanding imply greater financing needs which are difficult to satisfy in an environment of stricter credit policies applied by banking institutions.

The most important ratio for companies that do not rely heavily on inventories is “Days Sales Outstanding”. Credit sales value is recorded under trade receivables. The time required to transform the latter to cash, depends on the credit policy of the company and the prevailing market conditions. Restrictive credit terms have as a result decreased sale. On the other hand, a looser credit policy may increase credit risk and imply possible losses. **Table 50** depicts average days of sales value outstanding for the sector.

Table 50 Days Sales Outstanding

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Electricity	87	82	77	74	73	69	71	68	72	73
Oil & Gas	50	65	61	58	52	53	53	54	56	50
Total	69	73	69	66	62	61	62	61	64	61
Renewables	57	60	62	56	57	61	46	59	71	74

Source: Own calculations

Electricity sector has significantly more days outstanding. This challenges liquidity, since more days have as an impact, analogous shortage of cash. Market conditions play vital role. Increased days coincide with adverse market conditions. The sector manages to attain fourteen days decrease diachronically, which is a positive change. The rationale behind the differences between the electricity sector and the Oil and Gas equivalent lies within market competition conditions. Market competition is intense. Additional market shares can only occur if certain credit conditions are offered to clients.

Oil and Gas sector has remained on average at the same conditions. Only in years 2009, 2010 was a substantial increase but this negative trend was recalled. Average days decreased thereafter and returned to the initial figure of 50 days. Surely, the sector outperforms the Electricity respective. This is probably owed to market competition as described above. The renewable sector follows an opposite trend. Probably this is a result of the increasing competition in this market niche.

The last component of Cash Conversion Cycle is “Days Payables Outstanding”. This metric approximates the number of days required, on average, to satisfy liabilities to suppliers. The time frame is rather crucial since it is actually an indirect way of financing activities. This source can also prove quite cheap if the suppliers do not charge interest on credit sales.

Table 51 Days Payables Outstanding

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Electricity	124	124	114	107	100	91	103	95	103	105
Oil & Gas	50	66	64	58	53	53	50	50	72	64

Total	87	95	89	83	76	72	77	72	87	84

Source: Own calculations

Table 51 presents once again different price range for the two subsectors. Electricity companies overcome the threshold of 100 days (with the exception of years 2013, 2015). The first years of intense financial crisis the days increase, probably in an effort to counterbalance the increase in days sales outstanding. This simultaneous change moderates financing needs and subsequent liquidity problems. The relative increased values compared to "Oil and Gas" respective, are also related to larger retail activities.

Oil and Gas sector presents significantly lower values. In the last two years an average increase occurs. This is a favorable change since it lowers financing needs. In any case the companies have strong cash flows, presented in detail in the operational efficiency section, and are reliable clients for any supplier.

It would be interesting to study the overall effect of the changes in average days for inventories, receivables and payables. **Table 52** depicts average days of cash conversion. The cycle divulges the number of days the companies need financing to satisfy their obligations.

Table 52 Cash Conversion Cycle

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Electric	1	4	4	8	10	13	6	7	4	4
Oil & Gas	31	49	43	41	36	39	37	40	33	28
Total	16	26	23	25	23	26	21	24	18	16

Source: Own calculations

Electricity sector exhibits remarkable matching between receivables and payables. As already discussed, these companies face liquidity problems. These problems were addressed via supplier credit. Electricity companies expunged shortage of cash, by adjusting appropriately the credit from their suppliers.

Oil and Gas companies have an average cash conversion cycle of 30-40 days. The last two years record a positive change. Strong cash flows guarantee repayment of this kind of short-term debt. The strong cash flows are justified in the relevant operational efficiency section. The average days for the whole sector return to the initial value of 16 days. Renewable energy was not included in this analysis because of extreme observations for the average day's payable outstanding.

5.4.3. DEBT-CAPITAL STRUCTURE RATIOS

The term "Capital Structure" is defined as the mixture of equity and debt, the two broad categories of financing in a company context. Modigliani and Miller (1958) suggested that under certain assumptions, mainly related to perfect competition conditions, the financing decisions do not affect market value of the firms. Consequently, the equilibrium between debt and equity is irrelevant and firm value maximizes only when positive NPV projects are undertaken.

However, the market conditions are not characterized as perfect in the real economy. There is a differentiating characteristic of the two broad sources of financing. In the case of debt, repayment must be made in certain time intervals, irrespective of company performance. On the contrary, equity lenders may not receive any return in case the company performance is not rewarding, or the company decides to retain earnings. Debt proves to be a cheaper financing tool, whereas equity holders demand incremented rates of return as debt increases because they have to bear the risk of default (Brealey and Myers, 2003).

In the context of this thesis, capital structure will be addressed using three financial ratios; debt to equity, capitalization ratio and interest coverage ratio. The first is presented below:

$$Debt\ to\ Equity = \frac{Debt}{Equity} \quad (10)$$

This ratio depicts, in **Table 53**, the relationship between the two forms of financing for the sample of companies.

Table 53 Debt to Equity %

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Electric	451.2	424.0	336.0	335.0	350.5	333.6	384.9	404.4	366.9	374.8

Oil & Gas	122.6	133.0	137.0	127.6	118.4	116.1	119.8	125.2	124.0	119.1
Total	286.9	278.5	236.5	231.3	234.4	224.8	252.4	264.8	245.5	247.0
Renewables	81.2	112.0	138.0	139.4	131.4	115.3	126.1	130.3	121.0	105.5

Source: Own calculations

Two conclusions can be extracted from the above table. Initially, there is a downward trend for the heavily leveraged firms and a stabilizing one for those that had a more balanced mix. Secondly, the Electricity sector depends heavily on debt, which implies increased interest payments and subsequent incremented risks for the companies' profitability. Renewable sector resembles to the Oil and Gas equivalent. This table justifies the figures in **Table 41**, where Electricity sector underperforms the Oil and Gas equivalent. Interest payments absorb earnings and suppress margins.

Capitalization ratio presents, alternatively, the capital structure by comparing debt to total assets.

$$Capitalization\ Ratio = \frac{Total\ Debt}{Total\ Assets} \quad (11)$$

Table 54 portrays capitalization ratio for the sample of companies. The conclusions resemble to the aforementioned.

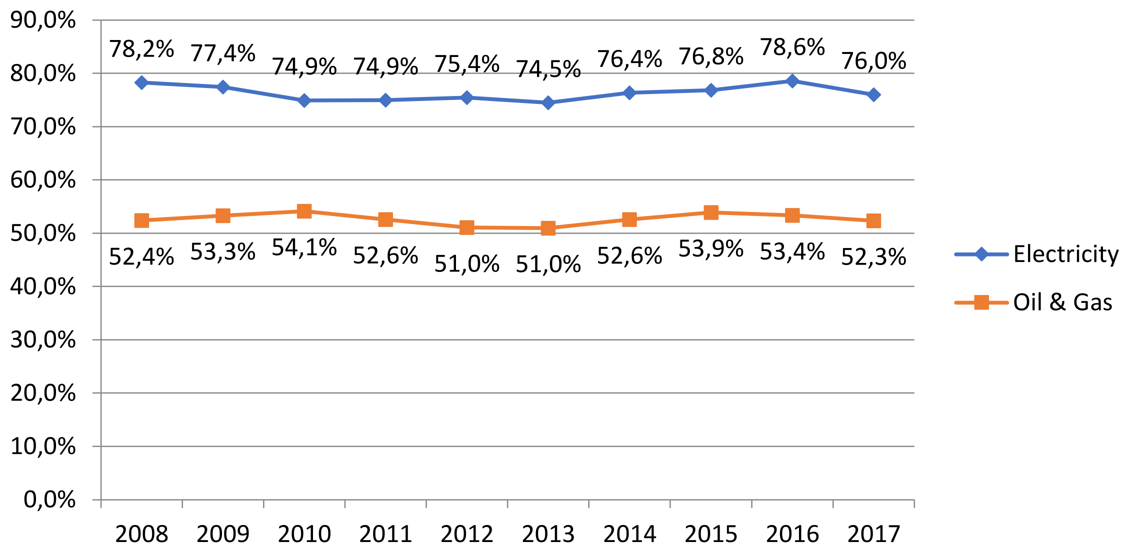
Table 54 Capitalization Ratio %

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Electric	78.2	77.4	74.9	74.9	75.4	74.5	76.4	76.8	78.6	76.0
Oil & Gas	52.4	53.3	54.1	52.6	51.0	51.0	52.6	53.9	53.4	52.3
Total	65.3	65.4	64.5	63.8	63.2	62.7	64.5	65.4	66.0	64.2
Renewables	44.8	52.8	58.0	58.2	56.8	53.6	55.8	56.6	54.7	51.3

Source: Own calculations

Energy sector, in total, seems to be quite balanced with a steady average capitalization ratio of 65%. The industry is capital intensive and this requires significant –in money terms- credit from third parties, i.e. debt. Electricity companies are heavily exposed to debt, which implies a riskier investment opportunity. They constantly have substantial differences compared to the Oil and Gas equivalents (**Figure 3**).

Figure 3 Capitalization Ratio %



Source: Own calculations

It would be interesting to assess the relationship between interest payments and net earnings. The interest coverage ratio measures the times interest payments are covered by earnings before interest and tax. **Table 55** exhibits the relevant metric.

$$Interest\ Coverage = \frac{Earnings\ Before\ Interest\ and\ Tax\ (EBIT)}{Interest\ Payments} \tag{12}$$

Table 55 Interest Coverage Ratio

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Electric	2.8	2.8	3.0	2.9	2.2	2.1	2.2	2.2	3.4	3.1
Oil & Gas	23.1	18.2	18.3	25.3	21.8	13.7	12.3	4.1	3.5	7.0
Total	13.0	10.5	10.7	14.1	12.0	7.9	7.3	3.2	3.4	5.0
Renewables	4.7	5.1	7.6	12.4	9.8	8.3	26.4	12.8	14.8	16.7

Source: Own calculations

Loss - making financial years were omitted from the sample. The average of the sector is satisfactory. Nevertheless the trend is not favorable. This trend is owed mainly to the drop in Earnings before interest and tax. Interest figures remain on average the same, as implied from the stable financing mix adopted by the companies.

Electricity sector has inferior rates, ranging from 2.1 to 3.1 times. This is anticipated because of the heavy indebtness described already above. Renewable sector follows the opposite pattern, stemming from improved Earnings results.

Concluding, earnings are adequate enough to cover interest payments. Oil and Gas companies are relatively in a better position. The downward trend is a result of the profit deterioration rather than an increase in interest payments. The vast majority of companies benefit from the low interest rate environment supported from the European Central Bank (ECB). ECB adopted a highly expansionary monetary policy in an effort to attain better growth rates. This was translated by an extremely low basic rate of 0.25% and negative 0.40% for bank savings[60]. These rates kept financing floating rates at minimum levels and minimized interest burden for EU based companies.

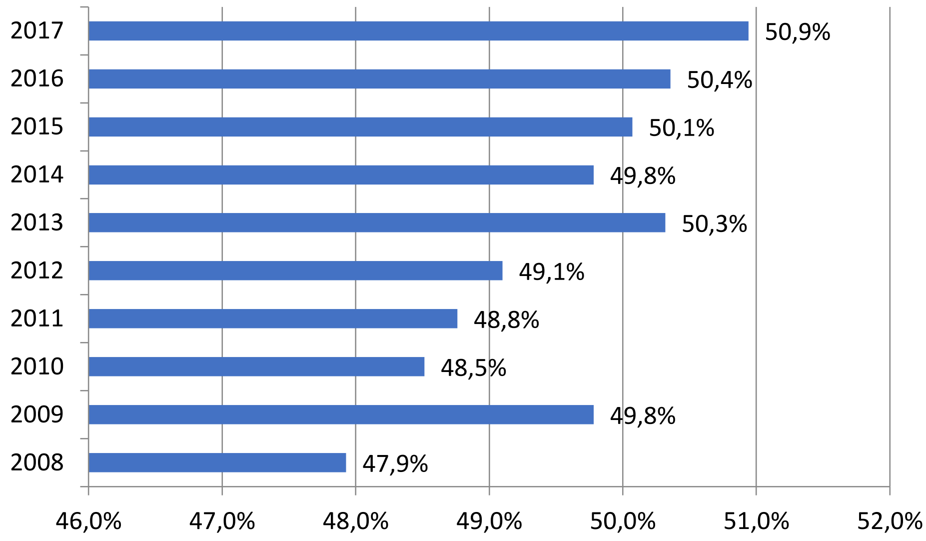
5.4.4. OPERATING PERFORMANCE RATIOS

The ratios studied so far, focused on profitability, liquidity and capital structure. Many analysts are interested though, in the operational efficiency of firms. In the context of this thesis, efficiency is approached by three financial ratios. These ratios are a) Fixed Asset Turnover b) Operating Cash Flow to Sales and lastly c) Operating Cash Flow to Current Liabilities.

The first ratio is rather important for the energy sector, since fixed assets are indispensable for the operations of the firms. As it envisaged in Figure , fixed assets represent on average half of total assets. This stresses the importance of fixed asset utilization and ultimately affects aggregate company performance.

Figure 4 Fixed to Total Assets (Energy Sector Average)

[60] https://www.ecb.europa.eu/stats/policy_and_exchange_rates/key_ecb_interest_rates/html/index.en.html



Source: Own calculations

Generally, all efficiency ratios measure the operational outcome, namely Sales, to the asset utilized to attain them. Accordingly, sales are compared to the fixed asset value employed to attain them.

$$Fixed\ Asset\ Turnover = \frac{Sales\ (Net)}{Fixed\ Assets} \quad (13)$$

The figures in **Table 56** exhibit a homogeneous pattern. Oil and Gas companies used to outperform Electricity ones. This trend changes as the years pass by.

Table 56 Fixed Asset Turnover

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Electric	1.20	1.19	1.14	1.23	1.31	1.30	1.28	1.33	1.11	1.13
Oil & Gas	2.42	1.50	1.78	2.00	2.07	1.87	1.73	1.26	1.09	1.32
Total	1.8	1.3	1.5	1.6	1.7	1.6	1.5	1.3	1.1	1.2

Source: Own calculations

Energy companies manage to attain sales value 1.2 times fixed asset value. Satisfactory result is considered any value that exceeds 1 or 100%. Although satisfactory, the trend is clearly negative. Lower values indicate less efficient use of fixed assets or overinvestment in them.

The above arguments are validated my market developments, as already pointed out in the relevant section.

Operational efficiency is also judged on the grounds of operational cash flow analysis. Accrual accounting records transactions at the time they occur, regardless of the cash transaction. This enhances accuracy of firms' financial data. Nevertheless, cash is necessary for everyday operations. This necessity is envisaged in Cash Flow Statement where cash flows are discriminated on the basis of origin. Cash that occurs as a result of the everyday operations of the company is referred as "Cash from Operating Activities". Analysts compare this cash flow to sales volume in an effort to see the percentage of sales being transformed to cash. **Table 57** presents the above metric for the sample of Energy companies.

Table 57 Operational Cash Flow to Sales %

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Electric	15.8	16.8	17.4	14.5	12.8	13.7	15.6	15.3	14.9	9.9
Oil & Gas	14.8	13.1	14.1	12.0	12.8	12.6	13.4	15.3	14.1	14.3
Total	15.3	15.0	15.8	13.3	12.8	13.2	14.5	15.3	14.5	12.1
Renewables	55.3	60.5	67.5	67.1	57.5	56.9	67.1	56.1	59.8	61.2

Source: Own calculations

Operational cash flow to sales percentages between the two subsectors exhibits convergence. Electricity sector used to record superior results. In year 2017, a sharp drop on average occurs. This is a result of several negative figures in the sample. Negative operating cash flows were observed in German operators RWE, EON, EnBW. Increased operational cash outflows accrue from utilized provisions regarding the decommissioning and the dismantling of nuclear facilities. If this extraordinary event is excluded, then the average for the subsector reaches 15% approximately in 2017. The cash generating ability is crucial for firm performance. The renewable sector records an impressive percentage rate, but as it was already pointed out the sample is not representative to draw final conclusions.

Finally, operational cash flow is going to be compared to current liabilities in an effort to appraise the ability of the energy sector companies to meet their obligations.

Table 58 Operational Cash Flow to Current Liabilities %

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Electric	24.6	29.0	34.5	29.6	26.8	30.0	30.7	30.1	25.3	16.7
Oil & Gas	67.9	48.7	57.1	54.6	62.0	57.2	53.0	54.9	44.7	48.4
Total	46.2	38.9	45.8	42.1	44.4	43.6	41.8	42.5	35.0	32.5
Renewables	37.6	31.5	43.9	59.3	58.6	81.4	64.4	50.5	68.1	61.7

Source: Own calculations

Contrary to the previous indicator, the two subsectors present significant differences. Electricity sector operational cash flow struggles to reach 30% of current liabilities value. In the last two years though, the ratios are disappointing. The decrease in the ratio actually implies greater financing needs to cover short term liabilities.

Oil and Gas sector begins with an impressive 67.9% to ground to 48.4%. While the initial figure is more than satisfactory implying nearly no financing needs, the latter rate describes undoubtedly, an adverse swift. The general downward trend is a combination of weaker operational cash flows and relatively stable current liabilities' level. The renewable energy sector again records quite satisfactory results; it would be interesting to validate this, as an aggregate characteristic.

5.4.5. INTRA-SECTOR DIFFERENCES

The financial ratios and the conclusions presented so far, took into consideration average figures, excluding outlier observations. It is quite interesting though to present some intra-sector differences pertaining to domestic market conditions.

In an effort to highlight those differences we grouped initially Electricity companies based on sovereignty criteria. French companies present incremented profit margins relative to German and UK respective, as presented in **Table 59**.

Table 59 Gross Profit Margin % Electricity Intra Sector

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
France	52.6	55.1	53.5	51.1	47.4	45.1	45.1	46.0	46.4	44.7
Germany	26.8	29.4	27.1	21.3	21.9	19.4	18.4	18.0	17.5	21.6
UK	13.3	12.9	18.9	18.4	15.6	16.1	16.2	17.3	16.7	16.5

Source: Own calculations

The profit margin is directly related to the energy production source mix. Germany relies, to a great extent, on lignite, coal and other fossils. These three sources account for 42% of the energy source mix. Lignite and coal imply more costs as sources of energy. Extraction and energy production are rather demanding and costly. The productivity is low and requires large quantities of raw materials. CO_2 emissions are relatively more, and this implies extra cost, since the companies have to buy costly certificates to comply with market rulings. The disarming of nuclear facilities imposed by German law, rather aggravates profitability.

France on the other hand relies heavily on nuclear power. The energy source mix exhibits the huge 73% deriving from nuclear premises. Initial investment for such infrastructure is vast. Nevertheless, it is a quite efficient energy source and this fact reflects in advanced profit margins.

Finally, UK relies on gas, recording 40%, as the main energy source. However, domestic production can only cover 43% of the demand. The remainder is imported from pipelines originating in Norway and Russia (44%) and via sea, in the form of Liquified Natural Gas - LNG (13%) (Source: British Gas, 2018). It is obvious that the purchases of the raw material affect negatively profit margins.

Oil and Gas sector does present some differences. Nevertheless, these have no so intense character and it is doubtful if they can be attributed in regional and production characteristics.

Table 60 Gross Profit Margin % Oil and Gas Intra Sector

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Russia	53.0	46.0	47.4	47.0	42.7	42.3	39.5	36.7	32.1	30.0
UK	24.8	30.2	26.2	23.6	20.8	21.5	21.3	26.3	29.1	26.0

Source: Own calculations

Unfortunately, there are no data available for the energy mix of Russia. This hinders any conclusions based on energy market characteristics. It should be noted however that Gazprom (one of the two Russian companies) had adopted domestic accounting principles until year 2013. From year 2014 and onwards International Financial Reporting Standards apply. The application of the standards is coinciding with profit margin decrease. Eventually, the Russian companies' gross profit margin equates to the sector's average. UK companies still possess relatively lower profit margins. In this case this is related to production processes.

6. CONCLUSIONS

Energy sector in Europe faced a lot of challenges in the last decade. Financial market turmoil greatly affected the sector. Some companies lost even 50% of their capitalization. The financial crisis had also impact on fundamentals, such as power demand. At the same time European Union policies, as well as national initiatives pertaining to environment protection influence companies' investment policies and performances.

This thesis embarks on a study of the Energy sector in the European continent. The companies that were under scrutiny are key players of the sector. Most of them are based in European Union countries. However, the sample of companies is not confined to EU but also expanded to other European countries, such as Russia and Norway.

Aggregate sector was split in three segments; electricity, oil and gas and lastly, renewable energy. The first two segments comprised ten companies each. Unfortunately the renewable energy segment comprised only one company, since no financial data was available for other candidates. This had as a consequence to reach conclusions based on the first two segments. When it was necessary and for informational purposes only, renewable sector financial data was indicatively presented.

Financial analysis of the sector was based on financial ratios. The focus was placed on profitability, liquidity, capital structure and operational performance. Starting with profitability, the most popular area for analysts and investors, energy companies witnessed decreasing trends. Gross profit margins declined. A careful analysis of the sales and cost of sales figures unveils that this trend is attributed to companies that managed to increase sales but simultaneously had to increase relatively more the associated costs. Improved sales demanded lower margins, indicative of fierce competition conditions.

Operating profit margins dwindles constantly and revives only in year 2017. Operating expenses exhibited inelastic nature and could not adjust appropriately to lower gross profit margins. Operating expenses could also have been influenced by national policies regarding abortion of certain power generating production processes. Pretax margins incorporate cost of debt. Electricity companies present significant differences indicating possible indebtness, which is proved by relevant capital structure ratios. Oil and Gas companies present a more balanced image. Lastly, net profit margins follow a steady downward trend until year 2016.

Net profits were sometimes supported by deferred taxation. Nevertheless, the aggregate sector records 7% in 2017, slightly less than the 2008 respective (7.4%).

The Return on Assets (ROA) could not exhibit a different behavior. Creditors witnessed significant losses in their returns. The assets employed could not provide incremented returns. This is indicative of less efficient use or even overinvestment. Equity holders had relatively more returns. Nevertheless, Return on Equity was also decreased during this decade. If the time frame confines to 9 years, then the drop is more than sharp (from 2008: 17.2% to 2016: -2.3%). Year 2017 was a reviving year, as already pointed out and the average ROE escalated to 13.4% on aggregate. In general, ROE of energy companies outperforms equity premiums implied for the countries that make up the sample.

Liquidity was also approached. Traditional ratios such as current, quick and cash ratio indicate potential problems, especially for the electricity companies. The latter have on average fewer current assets than respective liabilities. Oil and Gas companies have adequate cash reserves, reaching 38% on average for 2017, as a result of strong cash flows. The respective ratio for the electricity sector is exactly the half (2017: 16.4%).

Interestingly, the cash conversion cycle unveils less serious problems for the Electricity companies. They manage to tackle liquidity problems by stretching credit from suppliers. Cash conversion cycle is single digit, suggesting less financing needs. This strategy was actually imposed by the circumstances, since these companies are heavily exposed to debt and do not have easy and cheap access to further third party financing sources. Oil and Gas companies on the other hand, have a cash conversion cycle of 30-40 days on average. This does not seem to cause liquidity problems, since they have strong cash flows and cash reserves.

The topic of capital structure was also discussed. At this point extraordinary differences between the two subsectors occur. Electricity is heavily exposed to debt. Debt comprises over 70% of total capital. This implies riskiness for financial results, incremented interest payments and increased required equity rates of return. These variables affect cost of capital and may affect negatively the net present value of possible investment projects. Immediate debt servicing problems are not likely to occur, since interest coverage for these companies reaches the price 3 in 2017 and 2.2 in turbulent year 2016.

Oil and Gas sector exhibits a more balanced financing mix. Debt marginally overcomes 50%. This kind of companies is surely offered lucrative financing terms, since they are considered less risky and they can easily repay. Interest coverage ratio reaches the price of 7 in year 2017. EU based companies also benefit from the expansionary policy adopted by the European Central Bank, which implies extremely low interest rates.

The last group of financial ratios examined is operational efficiency ratios. Initially, the importance of fixed assets was stressed. Fixed asset turnover indicates efficient use of fixed assets in order to deliver sales. Electricity companies exhibit steady figures, which actually imply an effective strategy of adjusting to new market conditions. Oil and Gas companies saw their respective ratio deteriorating. This is not surprising, since for this kind of companies is really difficult and timely to disinvest.

Operational cash flow is also used to ascertain operational efficiency. Initially is compared to Sales value. On aggregate the differences between the years are not significant. The only exception is the last year of the study. The lower operational cash flow figure, which is responsible for the drop, accrues from nuclear facilities disarming in Germany. Lastly, the comparison of operational cash flow to current liabilities, once more, splits the sample in two distinct groups. Electricity companies struggle to maintain 25% on average, whereas Oil and Gas companies easily reach over 50% of current liabilities. The latter justifies the argument that Oil and Gas companies face no liquidity problems.

The epilogue of this analysis goes even further, trying to analyze intra sector differences. Averaging can sometimes hinder crucial observations. The most important observations were made for the electricity sector. Individual ratios of companies unveiled substantial differences, especially in profitability. French operators have gross profit margins exceeding 45%. At the same time German counterparts record 20% on average and UK rivals struggle to maintain 16%. The reasons that lie behind these differences are country specific policies and special market conditions. UK suffers from excessive CO_2 certificate prices that affect cost of sales. German operators bear the cost of nuclear power phase out and simultaneously run hard coal units that are costly. France, on the other hand, relies heavily on nuclear power and this has direct impact in enhancing profit margins.

Concluding, the energy sector in Europe faced adverse conditions. Investment in such companies remains attractive. All companies seem to revive in year 2017 and return to procrisis levels. Electricity companies are a riskier choice, because of their exposure to debt. Oil and Gas companies constitute a safer investment choice. The indications from the renewable sector imply great potential. Many of the traditional energy companies invest either direct or indirectly via other business entities, in the sector. European policies pave the way to adjust business models and change the energy mix of the continent in the long-run.

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