Lecture Notes in Energy 31

Rossella Bardazzi
Maria Grazia Pazienza
Alberto Tonini *Editors*

European Energy and Climate Security

Public Policies, Energy Sources, and Eastern Partners

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Enhancing European Energy and Climate Security: Eastern Strategic Partners, Unconventional Sources and Public Policies

Rossella Bardazzi, Maria Grazia Pazienza and Alberto Tonini

Abstract Energy security has become a heavily discussed topic due to rising energy demand worldwide, increasing import dependence in many European countries, geopolitical tensions and conflicts and the need for a regulatory and policy response. The papers collected in this volume aim at analyzing how energy security in Europe influences international relations and environmental issues with a multidisciplinary perspective, corresponding to the book three sections: international relations, focusing on Eastern EU partners; energy economics, highlighting the current unconventional hydrocarbons revolution and its impact on EU energy and climate strategies; public policy perspective, with the analysis of EU policies and two case studies. The issues considered in the volume represent a selection of hot topics in the debate that are framed together by this introductory chapter where the editors give an overview of the research themes, outline the structure of the book and summarize the contents of the individual chapters.

1 The Issue: Energy and Climate Security

Recent years have seen increasing attention being paid to the broad issues of energy security and climate change, which are of the utmost importance for the European Union and its member states. Energy security has become a heavily discussed topic due to rising energy demand worldwide, increasing import dependence in many European countries, geopolitical tensions and conflicts, the globalization of formerly regional markets, and the need for a regulatory and policy response.

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A possible forthcoming fossil fuel depletion, geopolitical instability, and competing energy demands from high-growth countries are only a short list of the emerging and long-standing energy issues for the EU. These challenges are strictly intertwined with the climate change issue. The objective of building a low-carbon economy in Europe implies a reduction in fossil fuel use in residential and industrial activities. This goal is consistent with the energy security strategy, which includes a moderation of energy demand, an improvement in energy efficiency, increases in domestic energy production through renewables, and the development of new technologies. Indeed, these are some of the pillars of the European Energy Security Strategy, which was approved by the European Commission in May 2014 (EC 2014). This communication states very clearly that the strategy is '*an integral part of the 2030 policy framework on climate and energy*' (p. 3).

However, the energy security strategy is also based on diversification of energy sources, including traditional fossil fuels. For instance, electricity generation still partly depends on the use of coal and lignite (about 27 % at the EU level), and coal—which is highly polluting—is gradually becoming more available on the international markets in increasing quantities and with decreasing prices. Meanwhile, the Commission considers the exploitation of oil and gas from unconventional sources to be an option to compensate for declining conventional hydrocarbon production. These examples show that pursuing energy security could mitigate climate change, but in some cases it could harm the environment as well. Therefore, we refer to *energy security* and *climate security* as an interlinked issue, to be tackled through energy policies which should consider their implications for both aspects of the problem.[1]

The concept of energy security, although ubiquitous in the debate about energy, is often considered to be 'abstract, elusive, vague, inherently difficult and blurred'.[2] Indeed, the meaning of the concept has changed over time and has a different focus in different disciplines, but it definitely emerges as a multidimensional concept. As an example, Brown et al. (2014) define energy security as "equitably providing available, affordable, reliable, efficient, environmentally benign, proactively governed and socially acceptable energy services to end-users". Moreover, definitions of energy security are highly context-dependent (Pointvogl 2009; Yergin 2006) as they are influenced by the different perceptions of the relevant stakeholders due to national characteristics (resource-rich or resource-poor, industrialised or developing countries, market-oriented or state-oriented economies). Finally, it is a dynamic concept needing to be tackled with flexible strategies which adapt to changing circumstances.[3] Therefore, following Winzer (2012) and Sovacool (2011), we can affirm that energy security has a multidimensional definition including physical

[1]Luft et al. (2011) argue that because of complementarities and trade-offs between energy and climate security, analysis of the two issues should not be mixed. Specifically, climate change should not be factored into the energy security debate.

[2]See Chester (2010) and the references cited there.

[3]This characteristic is also acknowledged in the European Commission communication (EC 2014).

availability, price stability, competition, sustainability and supply security.[4] There is a broad consensus that energy security is promoted by open and competitive markets that favour the exchange of information, the availability of resources and investments, and lead to a diversified supply structure.

However, there is less consensus on the relation between energy security and environmental objectives, in particular CO_2 mitigation, since restrictions in this area may limit the options for diversifying energy supplies. On the other hand, climate change policies may help the transition towards a larger use of renewable energies, which at least partially increase energy security. This trend is taking the pressure off fossil fuels, on the way to a hydrogen—or solar—energy system. In this changing picture, the future of natural gas depends on its ability to establish itself as a 'clean' energy in a low-carbon world. The traditional wisdom that gas is a clean source of energy is no longer valid in a Europe with more ambitious climate targets. Thus, natural gas is threatening to become a 'sunset industry' by 2030, caught in the middle between 'clean' coal (carbon capture and storage), biogas and other renewable sources of energy.

These issues can only provide a rough idea of the complexity of energy problems. For example, the physical availability of energy sources may be interpreted as their being able to satisfy levels of reserves and as providing reliability, which implies analysing infrastructure efficiency and natural risks. The issues are deeply interrelated and too complex to be adequately tackled by a single discipline or from a single point of view. Multidisciplinarity—meaning that the subject is approached from different perspectives with different methodologies—is therefore a prerequisite for advancing in knowledge and comprehension. This needs to be done because the energy issue deeply influences both international relations and environmental quality.

At the EU level, energy is becoming an issue of both integration and disintegration, and will perhaps turn out to be the ultimate test of political and economic unity. External policy is a central component of Europe's new integration phase, in which climate and energy policies represent two interrelated issues for which the definition of a common stance will be of critical importance. Demand uncertainty is even greater than before, and it is driven both by the quest for sustainable energy systems in a low-carbon world and the effects of the economic and financial crisis in Western countries. Therefore, the challenge for Europe is to reassess some of its internal instruments in the light of the need for a single foreign policy stance regarding its major partners and suppliers. This is a somewhat complicated task, as current European energy and climate policies are often the outcome of a fragile compromise between national sovereignty over resource exploitation, industry structure strategy and energy taxation issues on the one hand, and EU competence, both for ensuring an efficient energy market and energy security and for promoting interconnections of grids and low carbon technologies, on the other.

[4]For a discussion which stresses the roles of vulnerability and resilience, see Cherp and Jewell (2014).

Regarding security, the EU currently has a relatively well-composed mix of imports (Lévêque et al. 2010). The role of Russia as a strategic supplier of natural gas to Europe is well known, but in the future its share of European natural gas imports is unlikely to exceed 35–40 %. With rising production costs and rising domestic demand, Russia's cost advantage will diminish in the medium term. This will make room for new suppliers, namely the Caspian and central Asian countries, whose hydrocarbons can reach European consumers via Turkey, the Mediterranean, and the Balkans. Conflicting views on the main energy partners (Russia, Turkey, North Africa or eastern countries), on the best gas pipeline routes, and ambitious and competing smart or super-smart grids are only some examples of issues on which European countries often disagree.

Finally, at the global level, LNG exporters compete with traditional gas suppliers. The increasing share of LNG in the international natural gas trade will allow a further diversification of EU imports, but at higher prices than previous long-term pipeline gas supplies. Europe has the capacity to import more LNG and the problem, at present, is inelastic supply. US shale gas production may increase potential LNG exports to Europe and, although the infrastructure is not yet in place, large investments are being made to increase export capacities in North America. This transformation has already triggered changes in fuel prices and therefore in interfuel substitution, with LNG volumes diverted from North America to Europe and with coal more competitive than natural gas for power generation. These dynamics must therefore also be considered in analysing the energy market conditions in Europe and beyond.

The purpose of this collection of essays is to shed some light on the complex relationships between energy and climate security, between Europe and its eastern suppliers, between traditional and unconventional energy sources, and between the different policies which can be adopted by EU member countries and by the EU as a whole.

2 Structure of the Book

This book aims to analyse some of the aforementioned issues through the lens of energy security from different perspectives. The three sections of the book correspond to these different perspectives: international relations, focusing on the EU's eastern partners; energy economics, highlighting the current unconventional hydrocarbons revolution and its impact on EU energy and climate strategies; and public policy, with analysis of EU policies and two case studies. Obviously, the issues covered by this volume are not sufficient to exhaustively depict the overall energy security question for Europe. However, they represent a selection of the hottest topics now being addressed in the institutional and academic debate.

Europe suffered a big energy crisis as a consequence of the 2009 Russian-Ukrainian conflict over gas transit fees. The ongoing new conflict between Russia and Ukraine has exposed EU vulnerability once more, and in March 2014 the EU heads of government told the Commission to conduct an in-depth study of EU energy security and to prepare a comprehensive plan to reduce EU energy dependence. These crises constituted an abrupt warning, as the weakness of European external energy policy was clearly revealed and its key role came to general attention. Development of new cross-border interconnectors and additional routes through Eastern Europe, and investigation of ways to facilitate natural gas exports from North America to the EU are very high priorities on the European agenda. This is why the first part of the book deals with energy diplomacy and geopolitics, with a special focus on Russia as energy supplier and Turkey as a transit country. These two energy partners for Europe embody some typical issues for EU energy security concerning the future availability of resources and the construction of routes to transport them. In the first chapter, Alberto Tonini investigates the last three decades of European diplomacy towards supplier countries as part of the effort to create a common European energy policy, together with the growing institutional role of the European Commission in the field of energy and climate security. The EU Commission's long struggle for a greater role in energy policy and the birth of a European energy policy prepares the ground for discussing the conflicting views on future pipelines by the other contributors to the first section. In the following chapter, Matteo Verda deals with the development of the western Europe-Russia gas pipeline network over recent decades, investigating the economic and political underpinnings of the Russian strategy. He also points out the current and future trends in the European final demand and the role of Russia as the major gas supplier to Europe. According to Verda's analysis, several challenges are looming, ranging from increasing competition, to an uncertain regulatory framework, to geopolitical risks in Eastern Europe.

To reduce these risks, in her chapter Nursin Guney explores the current and future potential of Turkey as an energy hub for Europe. In her analysis, Guney recalls that the periodic discovery of new energy sources in the regions surrounding Turkey stimulates the desire of both Turkey and the EU countries to have new suppliers and diversified routes. The changing geopolitics in Eastern Europe has revived debates about the Southern Gas Corridor (SGC) and notions of strengthening the SGC by simply reaching more supply countries through Turkey, Turkey's neighbourhood and beyond.

The final chapter in the first section, by Valeriy Kryukov, deals with current trends in Russian oil production and Russia's alternatives arising from the development of the eastern Asian markets. In Kryukov's view, Russia is facing a new challenge in its role of major energy supplier to Europe. To a large extent, the pace of integration of Russian hydrocarbon production with the European market is still based upon old economic foundations: economies of scale in developing large rent-bearing fields. However, nowadays the situation is changing rapidly with oil development from unconventional sources (shale and bitumen) and the old production model may no longer be able to dominate—especially in the case of a deteriorating and fast-changing resources base. Kryukov's final considerations focus on the Russian oil fields (becoming smaller and more expensive), and on the resultant new challenges and options for Russian energy producers. Although the geography of new fields is a driving force explaining the growing role of Russia's exports to eastern Asia, westward oil exports have been and will be the most substantial in the years to come. This is due not only to infrastructure availability but also to deeper ties between the Russian oil sector and the EU countries' economies.

The second section of the volume investigates the role of unconventional hydrocarbons in the supply and security of energy in Europe, and their impact on world energy markets. The sharp rise of shale gas and other unconventional fossil sources has led to a reconsideration of national energy strategies, and can even affect gas pipeline plans. In the recently-published Energy Union Package, the European Commission supports investment in liquid gas hubs in northern Europe to exploit the potential of liquefied natural gas and enhance supply security with imports from the US and other LNG producers (EC 2015). Moreover, unconventional hydrocarbons can also affect the pattern of other fuel flows by changing world prices and diverting traditional international energy trade routes. Recent trends in some European countries concerning a new shift in the production of electricity away from natural gas toward coal—a cheaper but more polluting input—may exemplify how fast energy flows can change after relative price variations and how dangerous the consequences of such changes can be for the environment. While shale gas will not be produced commercially in Europe in the short term due to the time needed for exploration and licensing, in the US this energy source could already be a real 'game changer'. The role of shale gas in the US market is analysed in Douglas Meade's chapter, together with a quantitative assessment of future increased exports of it to Europe. North American gas supplies have increased dramatically since 2006, leading to a reduction in prices and an increase in their use in electric power generation and industry. Meade describes the results of a scientific collaboration between Inforum and the Mitre Corporation to use the LIFT and MARKAL models in a coupled system in order to understand some of the implications of the shale gas revolution. He uses scenario analysis to assess the impact of increased gas supplies on the structure of production, and on aggregate measures of wellbeing such as GDP and disposable income. A crucial question is whether the potential for increased US gas exports to Europe in the form of LNG can improve the state of energy security in Europe. The infrastructure is not yet in place but significant investments are beginning. In the final part of the chapter, the potential of these increased exports to affect gas supplies in both the US and Europe is explored.

Shale gas is also a potential energy source to be exploited in European countries. This option has raised several concerns about environmental risks associated with the high volume hydraulic fracturing technique, to which the Commission has responded with a recommendation and a communication inviting Member States to follow minimum principles in exploration or production using fracking.[5] Indigenous shale gas will not resolve short-term security issues, as exploration and development will take 5–15 years and serious doubts about the economic viability

[5]See the Commission Recommendation of 22 January 2014 (2014/70/EU) and the Communication COM (2014) 23 final.

of exploitation are arising, given the falling world energy prices and the difficult geological conditions for drilling. Virginia Di Nino and Ivan Faiella critically investigate these issues in their chapter. High energy prices, abundant reserves, a firm-friendly business environment and a de facto moratorium on environmental rules boosted the adoption of hydraulic fracturing in the US, causing a sea-change in the energy landscape within a few years. Nonetheless, the economic benefits accruing from shale fuel production must be weighed against higher extraction, logistic and environmental costs. The authors argue that technical and social hurdles and stricter environmental regulations limit the possibility of replicating the US experience on the same scale elsewhere.

In the final chapter of this section, Laura Castellucci addresses the energy and climate security issue from an economic perspective, arguing that if energy security is defined as reliable and adequate supply of energy at reasonable prices, prices should include all the costs borne by society as a whole. In particular, environmental damage incurred by unconventional sources should be accounted for in comparing the costs and benefits of this option. In general, it appears that not only is technical progress in energy production driven by a search for increases in resource productivity which are not always environmentally friendly, but it is driven by market prices, which are increasingly sensitive to financial speculation. Therefore, there is room for an active government policy. Beside shale gas, unconventional oil from bituminous sands represents an interesting case study. Oil sand production results in environmental overexploitation and high greenhouse gas emissions causing air quality depletion. The author claims that imports of this unconventional oil to Europe—as well as indigenous production of shale gas—need to be discouraged on the basis of their negative effects on climate change. For Europe to retain its leadership in climate change policy and at the same time enhance its energy security, it suffices to maintain its renewable energy orientation policy and support the promotion of investment in energy storage technologies.

In addition to diplomacy and general strategic choices, other public policies can drive changes in European agents' behaviour to enhance energy and climate security. Under this perspective, the third part of the book deals with two general policy issues—namely new technology opportunities and the use of market-based instruments—and each theme is analysed both from an international perspective and through a national case study. These two policies should jointly focus on the aim of raising the share of carbon-free resources and increasing energy efficiency, so that energy dependency can be reduced and the quality of the environment simultaneously increased. These two goals can be reached mainly through a technology discontinuity and a change in agents' behaviour, induced by monetary incentives or market-based instruments. The need for a technological advance able to trigger a jump in the share of renewables and in the common market is analysed in a chapter discussing the state of the art of European intervention, and in a second contribution considering the economic impact of a very successful intervention, the German Energiewende. After reviewing the general rationale for a public intervention in innovation policy, Sophia Ruester's chapter analyses why a discontinuity in EU energy-related innovation policy is urgent, and calls for an increase in R&D

activities. Despite several funding programmes, EU innovation policy cannot be considered totally effective because of its complex regulations, limited financial resources, and a lack of a reliable long-run strategy, which is very important when considering new and expensive energy sources. Although the author argues that no energy technology policy can work properly without a certain degree of coordinated supra-national governance, there are several examples of uncoordinated national actions. Among these, competitive national schemes aimed at fostering renewable energy sources constitute an interesting example because many member countries are generously incentivizing renewables with the goal of increasing energy security and fostering economic growth. However, insufficient interconnections between national grids make these efforts not fully efficient at the European level. Ulrike Lehr and Christian Lutz analyze the German case. The policy shift towards a cleaner more efficient and technologically advanced energy system is the focus of the chapter, and an assessment of the 2011 *Energiewende* package is performed using a macro econometric model. The analysis is partially based on historical data (an ex post analysis) and partially devoted to forecasting the long-run impacts of *Energiewende* on macroeconomic variables and the energy mix. The *Energiewende* scenario is compared to a counterfactual scenario: the results indicate that this energy transition concept can be seen as a positive example of a "green growth" policy, as it shows positive impacts not only with regard to energy intensity, the share of renewables in the German energy mix, and therefore on emissions, but also on GDP and employment levels. However, the study warns about the adverse effects of price changes driven by renewable incentives: on the one hand, a merit order effect contributes to a reduction in electricity prices; on the other hand, subsidies to finance renewables in Germany are mainly paid for by household electricity bills, meaning electricity price increases. A significant price increase can also occur as an effect of energy taxation, the main pillar of market-based policy instruments. After discussing the economic rationale for energy taxation, Michelle Harding, Chiara Martini and Alastair Thomas's chapter gives a snapshot of patterns of energy use and energy taxation in EU and OECD countries. The authors estimate and compare effective tax rates based on the energy and carbon content of different energy products, and highlight that in EU countries different fuels and users of fuels face different tax rates, thus making the energy taxation directive substantially not binding, and the idea of a unique carbon price very distant from reality. Behind this result, governments make different uses of fiscal policy to attain energy security and decarbonisation, and also different competitiveness protection policies, with selective use of tax expenditures. Inefficiencies and incoherencies in the use of market-based instruments occur not only among countries but also within national economies: Rossella Bardazzi and Maria Grazia Pazienza's chapter deals with the Italian case, traditionally one of the most energy dependent and energy efficient countries in the EU, but also characterized by a wavering and inconsistent energy and climate policy. The chapter discusses how the low energy content of Italian GDP has been driven down by high energy prices and tax rates. However, it also shows that in the last decade Italy did not make improvements in this respect, notwithstanding the relative inefficiency of specific sectors, such as public and private buildings, for which a coherent policy and adequate public funds are still lacking. The authors review the use of market-based instruments in Italy and highlight cases in which different policy signals overlap, thus generating an inefficient policy framework. They suggest a review of energy taxation in a direction able to produce a coherent price signal to economic agents.

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Part I
EU and Eastern Energy Partners: Some Key Issues

The EEC Commission and European Energy Policy: A Historical Appraisal

Alberto Tonini

Abstract Tonini's paper focuses on the interrelationship between the attempts to create a common European energy policy, on one hand, and the institutional development of the European Union (and its predecessors), on the other hand. In particular, this paper investigates the EU Commission long struggle for a larger role in energy policy and security, the birth of the European energy policy, and its first outcomes. The EU members have in common a predominance of fossil fuels use and a reliance of foreign gas and oil imports, despite the apparent differences in their energy mixes. Realizing that once united, they would be stronger, in the 1970s member States started to seek common solutions. Markets have so far ensured proper supplies, but the growing tendency for importing from Russia and the Middle East makes governments' intervention increasingly necessary. Given that markets do not function optimally everywhere, and that many fuel suppliers are State-owned companies, State level discussions are becoming more relevant.

This chapter focuses on the interrelationship between the attempts to create a common European energy policy on the one hand, and the institutional development of the European Union (and its predecessors) on the other. In particular, it investigates the EU Commission's long struggle for a larger role in energy policy and security, the birth of an European energy policy, and its first outcomes.

The EU fits no existing model of international relations. It is not a federal nation state—a kind of United States of Europe—although there are plenty who think it should become one. Nor is it just another international organization within which countries collaborate without giving up important elements of sovereignty. The whole European Integration process has been a process of attempts, experiments, successes and failures. This applies to many single European initiatives and policies, including the common energy policy.

Is there any rationale for a common European energy policy? In order to provide a meaningful answer, it is worth remembering that despite apparent differences in

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their energy mixes the member states have in common a predominance of fossil fuel use and a reliance on foreign gas and oil imports. Realizing that once united they would be stronger, the member states started to seek common solutions. The markets have so far ensured sufficient supplies, but the growing tendency to import from Russia and the Middle East makes government intervention increasingly necessary. Given that markets do not function optimally anywhere, and that many fuel suppliers are state-owned companies, state-level discussions are becoming more relevant.

If the European Union is to succeed in increasing its global competitive capacity and to achieve its aim of higher living standards for its citizens, it will need a steady flow of energy supply and it will have to ensure efficient utilization of it. It is therefore absolutely fundamental to the future prosperity of the European economy that there should always be enough energy available to cover the steadily rising demand; this energy should be available on terms that will allow the European Union to keep its costs genuinely competitive, and also afford the less developed areas of the 28 member countries a fair chance to catch up.

From these considerations stems the apparent need for a common energy policy, and the EU member states have thus agreed on the principle of speaking with one voice on energy matters. To date, this has not yielded a transfer of competences to the European Commission, as all the member states are very much attached to their sovereignty in this field. However, the mere agreement on the principle illustrates their awareness of the necessity of a common approach.[1]

From a historical perspective, three stages in the development of EU energy policy can be distinguished. In the first period, from 1957 to 1972, energy was not regarded as an issue of great concern. The three Treaties at the origin of the first European Communities (ECSC, EEC, Euratom) contained no word about a common energy policy or a timetable for its introduction. In those years, the energy supply to Western Europe was positively influenced by the following factors:

1. Discovery and exploitation of substantial reserves of cheap new energy in the Middle East and in other parts of the world;
2. Major economies in transportation, including a reduction in costs resulting from bigger and faster ships and increasing reliance on new facilities, such as oil and gas pipelines, methane tankers and high voltage electricity transmission networks;
3. Exploitation of new energy sources in the European Community itself, especially natural gas and nuclear power;
4. Rationalization of the European coal mining sector, through pit closures and productivity increases to adjust production to the changed features of the European energy market.

[1]Oliver Geden, Clémence Marcelis, Andreas Maurer, "Perspectives for the European Union's External Energy Policy", Working Paper FG1 2006/17, SWP Berlin, December 2006, p. 3.

To cope with the huge growth in demand, the private oil companies decided to organize their operations on a more elastic basis by diversifying the areas in which they were prospecting and by stepping up production. After World War II, the rapid development of the oil market in Western Europe was complementary to the success of the oil companies in finding new oil fields, notably in the Middle East, under what were exceptionally favourable conditions. Although differently placed one from the other, the seven major companies all had important Middle East oil interests in which the royalty and price structure operated in such a way as to give the companies a comfortable share of the economic rents. In these circumstances, with the oil companies enjoying a high after-tax income and therefore a high cash flow from their upstream operations, it came to seem natural to them to develop the Western European market as a complementary activity which disposed of their oil through refining and market activities, often conducted on a break-even basis or even at a loss. Action by the United States government in the form of import quotas to protect its home production caused the bulk of the increased supply to be directed to Europe.

Throughout the 1960s, downstream operations in Western Europe were not conducted in a profit-hungry way because the upstream operations took care of the profits. The result was that market realizations were lower than they should have been, costs were probably higher, and cheap oil came to dominate Europe's energy supply.[2] The pressure on prices caused by this increase in supply was further aggravated by the appearance in the world market, alongside the established major oil companies, of new independent operators seeking to carve out a share for themselves by offering extremely low prices to the final consumers. To make matters more difficult, from the late 1950s the Soviet government, which had not operated in the world oil market for years, decided to start selling oil again as the easiest way to earn hard foreign currency.

Cheap imported oil replaced coal, and although this was a period of marked advances in European co-operation this was not reflected in the oil and gas sector. The different energy sources came under a number of separate national authorities and Community institutions, and each member country had its own set of enactments and regulations, particularly regarding pricing, commercial policy, taxation and investment. Throughout the 1960s and the 1970s, the European Communities were working hard to create a Common Market with common rules applying to the main fields of economic policy, but because of government resistance and oil company unwillingness the energy sector was not among these fields and remained "a pocket of resistance to integration".[3] Even though numerous policy proposals were made by the Commission or its predecessor, these proposals came to nothing with member states variously rejecting or ignoring them.

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[2]Interview with Georges Brondel, former Head of Directorate General for Energy of the EEC Commission, (in French) by Éric Bussière, Julie Cailleau et Armelle Demagny, Paris, 25 February 2004, in *Histoire interne de la Commission européenne 1958–1973*, Historical Archives of the European Union, Florence.

[3]European Community Information Service, *Europe and Energy*, Luxemburg 1967, p. 10.

1 Oil Shocks in the 1970s

In 1972, before the oil crisis erupted, the primary sources of energy for the European energy market (composed of the 9 EEC countries) were as follows:

Total primary energy in million tons of oil equivalent		
Coal	231	24.1 %
Hydro and geothermal	12	1.3 %
Nuclear	14	1.5 %
Natural gas	113	11.7 %
Oil	589	61.4 %
Total primary energy	959	100 %
Imports of primary energy	**605**	**63.1 %**

Source OECD, *Energy Prospect to 1985*, Paris, 1974. In 1950, the oil share was 14 %

The oil crises of 1973–1974 and 1979 brought energy to the fore as a crucial concern. On three occasions since World War II, Arab members of the Organization of Petroleum Exporting Countries (Opec) have deliberately reduced their outflow of oil in order to influence the settlement of their dispute with Israel. The 1973–1974 reduction in the aftermath of the October Yom Kippur war was the longest and largest: it lasted five months, and Arab oil supplies were reduced from the September 1973 level by 24 % in November 1973, 23 % in December, 16 % in January 1974, 14 % in February, and 12 % in March.[4] These supply reductions affected nearly ever European country that relied on imports from Opec, despite the fact that only the United States, the Netherlands and a few other nations were specifically embargoed. Countries that imported oil faced two related threats: increases in price and reductions in supply. The price set by Opec in December 1973 created widespread fear in Western Europe that many countries would be simply unable to pay for the oil imports required to fuel their domestic economies, or that they would amass such large payment deficits that they would slide into bankruptcy. At the same time, the reduction in the Arab oil supply created a fear that the quantity of oil on the market would be insufficient to support the desired national production and employment levels. In response, many European governments declared they would make major changes in their national energy systems in order to reduce their need for imported oil. As a consequence, in this second

[4]Estimates from the U.S. Senate Committee on Foreign Relations Subcommittee on Multi-national Corporations, *U.S. Oil Companies and the Arab Oil Embargo: The International Allocation of Constricted Supplies*, a report prepared by the Federal Energy Administration, 94th Congress, 1st Session, 27 January 1975, Washington (DC), p. 7.

stage energy came onto the European agenda, as a problem of oil prices and supplies.[5]

It took the shock of the October Yom Kippur War and the resulting Arab oil embargo to suddenly illuminate the magnitude and consequences of European vulnerability. The impact of this experience was not so much that a modest reduction in oil supplies for a few months threatened disaster, as a dramatic realization at both the governmental and public levels that Western Europe was desperately vulnerable. Not only did the 1973–1974 crisis evoke old memories of war-time privation, but it also brought awareness that, as a result of its oil import dependence, Western Europe ran the risk of seeing its industry, transportation and entire economic life brought to a halt through some future upheaval in the international energy supply system. In short, energy and oil had become security issues *par excellence*.[6]

Since 1974, energy problems in their broadest sense, together with a group of important and substantially related economic issues, have become fundamental European security concerns. Although the importance of traditional military and strategic issues should not be minimized, for most Europeans, including the informed public and even those generally attuned to foreign policy, discussion of European deterrence and defence has tended to become somewhat abstract and removed. By contrast, economic and energy security issues have become pressing and important subjects of great attention in both public and elite arenas. The significance of this change was profound. Not surprisingly, security of supply in an emergency, storage, and diversification of energy sources suddenly became areas of government concern in Europe (and elsewhere).[7]

Instead of stimulating the members of the European Community to greater efforts of cooperation in the face of necessity, the 1973–1974 crisis proved painfully disruptive to the Nine. This recurring 'downstream' disunity was a key characteristic of the European Community in the 1970s and its implications for energy security were profound. When the Western companies controlled the level of supply, instead of Opec, oil production gave the Arab states no means of exerting pressure on the West. The modern era of oil politics was ushered in when the demand for oil supplies reached such levels that there was no more shut-in capacity under the control of the major companies, and the Opec countries realized they could advance their individual interests by working together, and they learnt to

[5] In Europe, the northern countries—Britain, West Germany, the Netherlands and Belgium—could be distinguished from southern Europe by their lower dependence on oil (48, 55, 44 and 57 % respectively) and by their domestic coal and gas production. France and Italy (and Japan) used imported oil for 70 % or more of their energy needs and did not produce significant quantities of oil or gas. Edward Krapels, "Oil and Security: Problems and Prospects for Importing Countries", in Gregory Treverton (ed.), *Energy and Security*, International Institute for Strategic Studies, London, 1980, pp. 40–42.

[6] Robert Lieber, "Energy, Economics and Security in Alliance Perspective", in *International Security*, Vol. 4, No. 4. (Spring, 1980), p. 144.

[7] Ibid, p. 139.

divide their adversaries. Europe and the West, in turn, faced a new situation: their energy security was no longer exclusively in the hands of multi-national companies, but also in those of governments which had a political—and not only a commercial—objective.[8]

In those years, the political and security implications for Europe of this dependence and vulnerability could be viewed in two ways. First, dependence on imported oil could only be reduced gradually. It would take years to find new oil supplies or to develop alternative energy sources, and in addition most energy analysts did not believe it was possible to reduce the level of energy consumption in the Western economies without retarding—or stopping—overall economic growth. However, the problem of the long-term sufficiency of energy resources became overwhelming when oil imports were disrupted during the crisis.

Nevertheless, in the aftermath of the 1973–1974 oil crisis the problems connected to short-term oil shortages and vulnerability were largely neglected, because the short-term adaptability of the modern European economies was surprisingly great, especially when the crisis was widely perceived to be as such and therefore evoked co-operative behaviour among the European governments. The role of the oil companies during the crisis also needs mentioning. What they did was to maintain an uninterrupted supply of oil from producing to consuming countries. This was the role to which the world had grown accustomed, and which had enabled the producers to see their revenues grow, and the consumers to rely on an assured source of supply.[9] The benefit of a multinational supply system again proved its worth: the oil companies' ability to replace embargoed Arab oil by oil from other neutral sources was a decisive factor in maintaining the supply to Europe during the crisis. The ultimate risk was that as adaptability was great enough, dependence and vulnerability could not be considered a major concern.[10] Even after the 1973–1974 crisis, the whole structure of European government regulation was based on the implicit assumption that the oil industry was still capable of moving large supplies of oil internationally on a continuous and uninterrupted basis, and was able to invest the growing sums of money required for the maintenance of this capacity. It is true that the producing sector of the oil business outside Europe was then largely controlled by sovereign nations, but even there multinational companies continued to operate in different forms of integration with local governments, through minimal equity holding or through long-term offtake agreements. Many countries in the developing world still had a clear need for providers of services, technology and management. The companies' role was consequently shifting from

[8]Krapels, op. cit., p. 63.

[9]Leo Wesseling, "Present Structure of Europe's Petroleum Market", in Edmond Völker (ed.), *Euro-Arab Cooperation*, Leyden, 1976, p. 76.

[10]Richard Cooper, "National Resources and National Security", in *The Middle East and the International System* (*Part II*): *Security and the Energy Crisis*, Adelphi Paper, n. 115, International Institute for Strategic Studies, London, 1974, p. 11.

an emphasis on investment and production to an emphasis on services and technology transfer.[11]

This new situation, dating from long before the 1973–1974 oil crisis, concerned the changing role and position of the oil companies, as well as the structure of the oil market. Both in the oil-producing and in the consuming countries, the previously rather independent position of the oil companies was tendeding to melt away. In the former countries, governments stepped into the advantageous production process itself and controlled the oil companies more strictly. In the Western European countries, governments assumed an ever increasing role with respect to the production and marketing of oil and regulated the market more tightly. For, if the production and sale of crude oil was to become a matter of public policy in the producing countries, governments at the end of the pipeline could not stay out of this delicate business for long. Oil and the production, sale and distribution of it inevitably came to affect relations between governments and tended to become a matter of diplomacy and foreign policy itself. Moreover, European governments could hardly avoid interfering with the production and distribution of a resource which was continually becoming scarcer, more expensive and crucial. Unavoidable though these changes may seem to be, they also meant the loss of a 'non-political' channel of procurement of the valued resource. From that time forth, everything touching on oil immediately engaged the responsibilities and powers of governments, and occupied the centre of the political stage in Western Europe.

An adaptation of a more directly political nature at the level of Western Europe as a whole should have consisted in closer cooperation and a better coordination of the EEC states' policies regarding the exploitation of energy sources, and the distribution and consumption of energy—in short, a European energy policy. Necessary though such a policy may have been, and as the problems involved were well beyond the powers of any national government, it would also have represented an achievement of vast political consequences for the European integration process. But the European reaction to the oil crisis, or rather the lack of it, showed clearly how difficult the thing was going to be.[12]

The key factor in the management of the aftermath of the 1973–1974 oil crisis was the difference in vulnerability among the European countries. A related factor was the tendency of some countries to give energy security a lower priority than others. This tendency was an important factor creating divisions among ostensible allies in the 1973–1974 crisis. The newly-acknowledged power of the oil-rich countries to use their oil as a tool of coercion produced a wedge in Western Europe: according to Yergin and Charakova, right from the beginning the Arabs' plan was to split the consumers by differentiating among them: Britain and France had learned the lesson of 1967, when only countries considered to be pro-Israel were embargoed. In 1973 they avoided expressing support for Israel and even increased

[11]Wesseling, op. cit., p. 79.

[12]Georges Brondel, "Europe's Petroleum Market. Alternatives for the Present Structure", in Völker, op. cit., p. 84.

arms shipments to their Arab clients in an effort to placate the oil-exporter governments.[13] In October 1973, the selective embargo announced by the Arab Oil Producers (OAPEC) divided the Europeans into three categories: favoured countries (France and Britain) receiving normal shipments; disfavoured countries (the Netherlands)[14] being totally embargoed; and others (the remaining members of the EEC) experiencing phased reductions of 5 % each month. National anxieties about the supply of oil thus predominated during the initial weeks of the crisis. Brussels tried to get the national governments together, but this effort no longer addressed the real problem: ‘getting together’ would not loosen the grip of the Arab producers on the level of the oil supply, and nor could it any longer prevent damage. At best, it would only spread the damage to countries which did not want to get involved in the dispute. In any case, although the oil shortage could be spread evenly, the economic damage varied. In the 1970s, Britain enjoyed a well-diversified energy supply, not particularly vulnerable to any individual producer country, whereas France and Italy had less diversified energy mixes and were terribly vulnerable to their primary suppliers. Britain was in a position to be able to afford to take a hard line against the Arab producers, while France and Italy simply could not.

Having said this, the EEC member states introduced a number of policies to tackle the crisis, including rationing in some countries, none of which was coordinated with other members. On the contrary, crisis deliberations within the EEC Council were marked by disaccord: efforts at cooperation within the Community and other multilateral frameworks were mostly unavailing, and some members of the Community adopted a *sauve qui peut* approach, in the hope of negotiating bilateral deals with particular oil-producing countries.[15] Most strikingly of all, some of the Europeans, including Britain and France, were willing to comply with the Arab boycott of the Netherlands—in flagrant contravention of Community rules. The Arab oil producers warned the European countries not to ‘break’ the embargo on the Netherlands at the risk of being targeted themselves if they disregarded the warning.[16] It took a month before the rest of the Nine quietly moved to support their Common Market partner, and this only occurred after Dutch threats to curtail natural gas exports to France, Belgium and Germany, and a realization that in any case the oil companies were able to successfully allocate the available oil supplies among all the consumer countries.[17]

[13]Vessela Chakarova, *Oil Supply Crisis: Cooperation and Discord in the West*, Lexington Books, Lanham (MD) 2013, p. 62.

[14]The Netherlands (as well as the US and UK) played an important role in the oil industry until the 1970s through its “parenthood” of oil majors. Royal Dutch Shell, while not government-owned, did closely cooperate with the Dutch government, and government-business cooperation proved to be one of the most important factors in times of crisis in the 1950s and 1960s. Cfr. Chakarova, op. cit., p. 34.

[15]Chakarova, op. cit., p. 68.

[16]*International Herald Tribune*, November 28, 1973.

[17]Robert Lieber, “Europe and America in the World Energy Crisis”, in *International Affairs*, Royal Institute of International Affairs, London, Vol. 55, No. 4. (Oct., 1979), p. 533.

During this period, however, the Community did not prove able to bring about the significant, even radical, changes which the energy situation dictated, particularly with regard to dependence on imported oil. It was prevented from developing a powerful and effective energy policy by internal differences over the questions of floor-prices for British North Sea oil, subsidies for European-produced but costly (twice the world price) British and German coal, the development of nuclear power, and the balance between free-market and state-ruled economic strategies. Nevertheless, it did succeed in taking some small and not insignificant steps in encouraging modest measures of energy conservation, promoting efforts to reduce energy import dependence, and subsidizing pilot projects for energy research and development. But these steps remained limited in scale and impact, and the main results which were achieved in Europe were due primarily to the single national policies. In sum, the Nine succeeded in modestly lowering their energy import dependence from 59 % in 1973 to 55 % in 1978, and they reached a figure of between 48 and 50 % in the years 1985 to 1990.[18]

2 The Role of Oil Stockpiles

In addition to putting restraints on domestic energy demand, the 1973–1974 oil shock shed new light on the role of oil stockpiles. They existed—at substantially different levels—in every European country, although their utility for emergency purposes was limited by several factors.[19]

Assuming that the minimum oil stock level required by the industry to provide the economy with the necessary kinds and amounts of products is 50 days of consumption, and that a 40 % reduction of oil imports occurred, it is possible to determine the number of days the governments could use stocks to maintain a given level of oil consumption. Oil stocks in the 1970s could even out the differences in economic vulnerability among the European countries. This apparently lay behind the production patterns which to some extent existed; some countries (e.g. France, Italy and Japan) maintained higher stock levels, measured against consumption, than others (e.g. Germany). Certainly, by agreeing in advance how they would respond to a supply cut-off, the European governments could greatly reduce the risk that another embargo would result in the type of conflict and strain in their overall relationship which occurred in the 1973–1974 crisis. Moreover, by demonstrating their collective determination to increase their ability to withstand a supply interruption, they could limit the effectiveness of the so-called oil weapon.

[18]Ibid, p. 536.

[19]The data shown in Table 1 should be interpreted as only a very rough approximation since stock levels fluctuate to a considerable extent during the year. These estimates should not be considered to provide a realistic assessment of the number of days each country could do without imported supplies. As a rule of thumb, about half of the stocks held should be considered the working inventory of the oil industry. Krapels, op. cit., p. 72.

Table 1 Average month-end stock level for selected countries (1975)

Country	Stock level (million barrels)	Days' consumption
Britain	140	88
France	214	113
Italy	157	83
West Germany	169	73
United States	922	57
Japan	324	66

Source Office of Economic Research, CIA, *International Oil Development: Statistical Survey*, Washington (DC), 1976

However, it was clear that in the EEC there were some obstacles to such success. First of all, some countries were clearly more vulnerable to oil losses than others. Among the EEC members, Britain, the Netherlands and West Germany would suffer less from a given oil shortage than Italy, Belgium and Denmark, because oil constituted a smaller percentage of their total energy requirement. Second, although stocks could reduce the differences in vulnerability among the two groups, few of the European countries seemed committed to significantly increasing their stock. Although the International Energy Agency members agreed to reach a stock of 90 days of oil consumption by 1980, the conclusion that this agreement "greatly reduced" the risk of another embargo assumed that the oil producers would be deterred simply because they would have to hold a given reduction in oil exports a few months longer. On the contrary, the unwillingness to agree to substantial increases in stocks in Europe in the late 1970s was the Achilles' heel of the agreement, and it implied that many European countries did not take the threat of a significant reduction in oil supplies seriously.[20]

Estimates of the availability of stocks in Europe varied widely. From the mid-1970s the European Economic Community, the International Energy Agency and various national governments imposed stock guidelines and requirements on the oil companies, but the definition of stocks differed, and an estimate of how much of those stockpiles could be used without replacement in an emergency was not available. In the initial discussion, both at the IEA and the EEC, it was decided to use the standard OECD definition of stock levels, to deduct from this figure the oil used to fill pipelines and held in various industrial facilities, deduct an additional 10 %, and then call the remainder an "emergency reserve". Later on, it was generally agreed that the IEA definition of "emergency reserve" overstated the amount of oil that could be withdrawn; oil industry managers believed that, as a rule, 40–50 days of oil supplies must be held in stock to allow smooth operation of the distribution system. Thus, the amount of time purchased by oil importers through their stock policies was more limited than a first examination suggested,

[20]Krapels, op. cit., p. 50.

and once emergency reserves were depleted, there was little the EEC members could do to help one another cope with a large import loss.[21]

As was noted by other observers, these estimates created an unrealistic picture of the situation: “the European governments are giving the appearance of a strategic reserve, but what they are really doing is talking about the oil that is in the pipeline system”.[22] Whether the stock levels were adequate, however, depended (and depends) on the level and duration of a supply reduction: the higher the level of oil stocks, the more severe and protracted a disruption of oil imports an economy could withstand. Thus, oil stocks were simply a kind of insurance policy, but there was a financial risk involved in over-insuring. The fear of over-insuring prevented many European governments from building the really massive stockpiles that would materially increase their security against even the most dire prospects.[23]

Most proponents of stockpile security benefits argued that the oil producers could not afford to curtail their oil production long enough to exhaust such reserves held by the consumer countries, but in the 1970s the countries most likely to curtail oil production were also those which were generating funds in excess of their immediate requirements (e.g. Saudi Arabia and Kuwait), and much of the oil that was used to fill the storage tanks came from their fields. It was certainly true that the Arab states could best afford to use oil reductions for political purposes, because Saudi Arabia, Kuwait, the UAE and Libya did not need their immediate revenues; they amassed sufficient foreign exchange surpluses to do with less oil revenues for months, if not years, if needs be.

Since the Arab countries had been the only exporters to curtail oil supplies for political purposes, it was thought that the countries most dependent on them (e.g. Western Europe and Japan) were the most vulnerable, and that countries relying more on Venezuelan, Nigerian and Iranian oil were less vulnerable (e.g. the United States and Canada).[24] In any case, however, stocks in Europe were valuable because they “bought time”, creating a lag between the day of import disruption and the day the import shortage could not be replaced.[25] Nonetheless, it should not be thought that they provided—or even provide today—absolute security against deliberate supply reductions. Rather, oil and gas stockpiles should be considered an element which energy suppliers must take into account if and when they plan any disruption strategy.

[21]Statistical Office of the European Communities, *Energy Statistics Yearbook, 1970–1975*, Luxembourg, January 1976, pp. 32–33.

[22]Opinion expressed by U.S. Senator Henry Jackson during his hearing before the Senate Committee on Interior and Insular Affairs, Washington (DC), August 5, 1975.

[23]National Petroleum Council, *Petroleum Storage for National Security*, Washington (DC), 1975.

[24]Article by Walter Levy, *The Economist*, 31 July 1976.

[25]Krapels, op. cit., p. 48.

3 France as a Case Study

After the 1973–1974 oil crisis, and taking into account energy supplies, an oil-importing government's desire to respect the wishes of its oil suppliers seemed more in the national interest than ever before. France was among the first to allow apprehension about oil supply security to influence her relations with Arab states and to back away from close identification with Israel. This was due to the country's higher dependence on oil compared to other European countries: Germany and the UK had coal reserves and oil was 53 and 44 % respectively of their energy mix. For France, this figure was 62 %.

The difference in French reactions to the oil disruptions in 1956 (Suez Crisis) and 1973 illustrates this shift starkly. In 1956, France (and Britain) joined Israel to launch an attack on the Suez Canal, at that time the main passageway for Persian Gulf oil bound for Europe; in 1973 France endorsed the political demands of the Arab states and actively sought 'most friendly' nation status to avoid losing oil supplies. The reasons for France's choice of bilateralism are to be found in its tradition of Gaullist-type policies of political and economic independence. For example, unlike the UK and Germany, the French government had a monopoly on the oil industry. During the 1973 crisis, France was the most fervent opponent of common action within the EEC or the OECD. The French government also signed more bilateral agreements with producers than any other consumer.[26]

As it turned out, however, these actions did not protect France from oil losses, because oil distribution was still under the control of the oil companies, who refused to favour France over their other customers and claimed that their contractual obligations took priority over instructions from their shareholders, i.e. the governments. Therefore, despite being on the Arab "friends" list, France also experienced supply cuts, mostly due to efforts by the companies to allocate oil equally among the final consumers. At the end of November 1973, they notified the French government that they would reduce oil deliveries by 10–15 %. This reduction never materialized, and between December 1973 and March 1974 the availability of petroleum in France was only about 5 % lower than a year earlier.[27]

Nevertheless, the French government's reply was not delayed. If up to 1973 the geographic oil patterns were largely dominated by the major oil companies, after the Arab oil disruption some European governments began to consider ways to gain access to oil supplies directly, skipping the mediation of the oil companies. As soon as the embargo was announced, the French government started negotiations with several Middle Eastern oil producers. For instance, in 1974 the French government pursued special supply arrangements with Saudi Arabia and concluded a contract to buy 200 million barrels over three years. This was an unprecedented incursion into the domain of Aramco, the producing company owned by Exxon, Socal, Mobil and Texaco. France was more ambitious still, and sought to make a much larger

[26]Robert Stobaugh, "The Oil Companies in the Crisis", in *Daedalus*, Fall 1975, p. 189.

[27]Chakarova, op. cit., p. 63.

arrangement with Saudi Arabia, involving 6000 million barrels over twenty years. This deal was discarded because Saudi Arabia would not give France access to oil on the same terms as Aramco enjoyed, and France was unwilling to build an export refinery in Saudi Arabia and agree in advance to import its products.[28]

Besides Saudi Arabia, in 1974 France signed agreements with Iraq, Algeria, and Iran. These deals guaranteed the much-needed oil, but they had no effects in terms of lowering the oil price as most of the contracts were signed at very high prices. While they brought a higher level of security to France, they did not alleviate the most nefarious consequence of the 1973 oil crisis—high prices.[29]

Successive French governments increasingly tailored their foreign policies in the light of the problem of energy security and its economic effects. After this setback, French bilateral agreements with Opec countries usually involved industrial development projects, credits and cultural exchanges, and left oil trade to the established companies. Closer relations with oil exporters were desirable for several reasons. Increased trade would obviously ease French payment problems and might give the oil producers a greater awareness of, and stake in, the importer's welfare. In effect, this could be a kind of economic deterrence against oil disruptions: in general terms, it was intended to make the oil countries more sensitive to economic changes in their customer. It is doubtful, however, whether the increase in import purchases by the Arab countries created significant economic vulnerability to disruptions in those imports. Many of the industrial goods imported by Opec states were components of construction projects that would take years to complete. Thus, a trade counter-embargo by France was unlikely to have as dramatic and sudden effect on Saudi Arabia or other Opec members as an oil supply loss had on Western European countries. Moreover, increased exports to Arab states made a rupture in relations all the more costly for France, by giving the oil producers one more option for influencing the oil importer: the threat of suspending purchases of its exports. Although such a threat was never made, the possibility had to be included in assessing the vulnerability of an oil-importing nation such as France. As with oil supply curtailments, the general trade 'lever' in the hands of Saudi Arabia was the most powerful, because it had the most revenue to dispose of.[30]

To varied extents, these adaptations brought France into conflict with its allies, and particularly with the United States. France's foreign policy response included three related components:

1. A pro-Arab policy vis-à-vis the Middle East conflict;
2. An effort to establish special bilateral relationships with individual oil-producing states;
3. Opposition to concerted action which would have aligned the oil-consuming states against the oil producers.

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[28]Horst Mendershausen, *Coping with the Oil Crisis*, Baltimore, Johns Hopkins U.P., 1976.

[29]Chakarova, op. cit., p. 63.

[30]Krapels, op. cit., p. 59.

With these ends, in the aftermath of the October 1973 Arab-Israeli war France sought to lead the European Community in a direction divergent from that favoured by the United States. Ultimately, this effort failed under strong pressure from the Nixon-Kissinger Administration and due to the priority which most of the Europeans continued to give to their security links with the United States. France even briefly abandoned EEC solidarity with its willingness to comply with the Arab oil boycott of the Netherlands, although the Pompidou government backed away from this position after threats of retaliation involving supplies of Dutch natural gas to France. French opposition also failed to prevent the establishment of what was to become the International Energy Agency. Following the death of President Pompidou and the spring 1974 election of Valery Giscard d'Estaing, a less Gaullist and more Atlanticist figure from the centre-right, France mitigated its hostility toward the IEA. Despite becoming loosely associated with it through OECD and EEC mechanisms, domestic political considerations caused France to remain outside the Agency.[31]

French policies sought to promote a series of international dialogues in which France would serve as the *interlocuteur valable,* and in which the influence of the superpowers, particularly the United States, would be attenuated or altogether absent. Initially, this took the form of promoting a Euro-Arab Dialogue between the countries of the EEC and those of the Arab League. This, however, was slow to develop because of a diffuseness of topics and of national interests (e.g. division among the Arabs between oil and non-oil producers and the absence of non-Arab OPEC members), long delays involving symbolic political issues (e.g. Palestinian representation), and difficulties in agreeing upon an agenda. French initiatives did eventually lead to the major Paris conference on North-South issues, the CIEC (Conference on International Economic Cooperation), but this ended in May 1977 without significant results.

The French government continued to call for cooperation between oil-producing and consuming countries in order to seek agreement over supply and demand patterns, investment, and other forms of long-term cooperation. While this led to exploratory contacts between representatives of the EEC and OPEC, it did not precipitate dramatic new initiatives.

The French continued to call for dialogue in other forums and sought to promote a "trilogue", grouping Western Europe, Africa and the Arab world, based in part on references to France's historical Mediterranean vocation. Conspicuously absent from this format were both an Atlantic perspective and any role for North America, Eastern Europe, or the Soviet Union. These over-arching diplomatic gestures were also accompanied by tangible individual policies and actions. Among these, arms sales played a particularly important role as a means both of recycling Arab petrodollars to France and of courting certain regimes. For example, during mid-1979 France carried out negotiations with Iraq for arms sales with a potential value of \$1.5 billion and made commitments to deliver Mirage F-1 fighter-bombers,

[31]Lieber (1980), op. cit., p. 147.

missile-launching patrol boats and other advanced weapons system. France also began delivery to Libya of ten missile-launching patrol boats, equipped with surface-to-surface "Otomat" missiles with a range of 160 km—rather more than might be required for a mere coastal defence capability.[32]

4 The Euro-Arab Dialogue

The fact that, in contrast with the three earlier Arab-Israeli wars, the October 1973 war did not end in a decisive Israeli victory produced an abrupt rise in morale throughout the entire Arab world. Thanks to feverish diplomatic efforts on the part of Henry Kissinger, American Secretary of State since August 1973, direct negotiations got underway for the first time between Israel and two Arab states, Egypt and Jordan, in Geneva in December 1973. Kissinger achieved a military disengagement agreement between Egypt and Israel, resulting in restoring Egyptian control over both banks of the Suez Canal. In May 1974, together with the diplomatic support of his Soviet colleague Gromyko, Kissinger managed to get Syria, which had been reluctant at first, to accept a similar disengagement agreement with Israel. UN forces were stationed on both fronts between the hostile armies. In the Arab world, tensions grew over whether the Palestinian Liberation Organization, under Yassir Arafat's presidency, should be acknowledged as the sole representative of the Palestinian people. The Jordanian king Hussein bitterly opposed this, but had to give in at the Arab summit in Rabat at the end of October 1974. After this summit, the PLO scored an enormous diplomatic and political success when Arafat was officially invited to the General Assembly of the UN. On November 13, he delivered a speech to the General Assembly.

Regarding inter-Arab relations, the willingness of most Arab oil producers to make use of oil as a political weapon during the October war was viewed by an important sector of Arab public opinion as an impressive proof of Arab solidarity. The effectiveness of the oil weapon was plain to see: most members of the European Common Market began to take a somewhat more balanced attitude to the Arab-Israeli conflict, which in practice meant a greater willingness to also listen to the Arab point of view. To what extent the Western European countries could give a contribution to the search for a peace settlement in the Middle East remained to be seen. Such a specific European role had been repeatedly called for by Egyptian president Sadat and other Arab leaders. Still more significant were the many voices heard in the Arab world since the October war calling for a "Euro-Arab Dialogue", in order to reach closer cooperation in the economic, technological, cultural and political fields. There was a willingness in Western Europe to enter into such a dialogue. The motive was not solely the painfully-proven vulnerability of Western Europe to the Arab oil embargo, but rather a sincere wish to put aside a long history

[32]Lieber (1980), op. cit., p. 148.

of rivalry and mutual suspicion, which for so many centuries had existed between Europe and the Arab world.[33]

With this aim, and on a French initiative, the nine EEC member countries attempted to engage in a so-called Euro-Arab Dialogue. On the European side, responsibility for the talks was entrusted not to the Commission but to a special committee dealing with foreign policy cooperation, the Davignon Committee. On the Arab side, the interlocutor was not the Organization of Arab Petroleum Exporting Countries (OAPEC), but the Arab League, a purely political and diplomatic body. In addition to this, the United States, regarding this initiative as a complicating factor in an area where it had assumed major diplomatic responsibilities, succeeded in removing the subject of oil from the agenda of the preliminary meetings, which took place in Cairo and Paris during the summer of 1974.[34] The U.S. stance on the Euro-Arab Dialogue as a form of European associative diplomacy is today well known: in March 1974 the EEC Council of Ministers transmitted a policy proposal to the Arab League for the opening of a wide-ranging discussion on cooperation and trade between the two shores of the Mediterranean Sea (later named Euro-Arab Dialogue). The American reaction was harsh and swift: on March 5, George Vest, spokesman for the U.S. Department of State, expressed negative comments on the EEC proposal, claiming that the Department of State "was not consulted. It was informed after it became public".[35] A few days later, the height of the crisis was reached when U.S. President Nixon warned the European countries not to "gang up against the United States", or they would face a reduction in the number of American troops deployed in Europe.[36] In a letter to West German Chancellor Willy Brandt, President Nixon criticized the EEC decision and said that he saw it as an anti-American move.[37] The U.S. Senate Committee on Interior and Insular Affairs, in its 1974 study *Implications of Recent Organization of Petroleum Exporting Countries Oil Price Increases*, stated: "Although there will be great temptations and occasional *peccadilloes*, it is essential that the oil importing nations recognize the futility and potential chaos which would result from competing among themselves. They should especially avoid competition to reduce their trade deficits by worsening the deficits of other oil importing nations, as well as competition that will have the effect of bidding oil prices up".[38]

The Secretary of State, Henry Kissinger, made all possible efforts to prevent the European allies from seeking their own oil agreements with the Arab producers and not under the aegis of the United States—a policy which condemned the EEC

[33]Leonard Biegel, "The Camel's Hair Curtain: The Arab World and the West", in Völker, op. cit, pp. 65–67.

[34]Guy de Carmoy, *Energy for Europe. Economic and Political Implications*, American Enterprise Institute for Public Policy Research, Washington 1977, p. 105.

[35]*The New York Times*, March 6, 1974.

[36]*The New York Times*, March 16, 1974.

[37]Benjamin Shwadran, *Middle East Oil Crises Since 1973*, Westview Press, London 1986, p. 100.

[38]U.S. Senate, Committee on Interior and Insular Affairs, *Implications of Recent Organization of Petroleum Exporting Countries* (*OPEC*) *Oil Price Increases*, Washington D.C., 1974, p. 12.

member countries to a continuous satellite status. This American policy at times needed the dispatch of high-ranking officials to the Arab governments to dissuade them from any oil agreements that might exclude the United States. In November 1975, on the eve of the Abu Dhabi meeting of the Euro-Arab Dialogue, Kissinger sent his special envoy, Gerald Parsky, to persuade the Arab oil producers to remove the issue of oil supply from the meeting agenda. He was successful, but such diplomatic pressure earned him resentment in Brussels and in some other Western European national capitals.[39]

This omission left industrial, financial, and cultural cooperation as the main items for discussion, but the final overall task for the dialogue was not an easy one: since the end of the Second World War the global role of Europe and the political situations in the Arab world had changed drastically. The process of political decolonization deprived the European nations of their worldwide powerful position. Although the Arab countries were not colonies in the formal juridical sense, their factual condition was the same and their political independence was completed only after 1945—or even later. This political independence did not include real economic self-rule for the time being and, since the process of human societies adapting to sudden changes is much slower than changes in the ranks of power, in the early 1970s many Arabs still looked upon the European governments as being just as influential as they had been before.

The date for the first meeting was set for July 31, 1974. The EEC participants were the French foreign minister and the chairman of the Davignon Committee. The Arab League participants were its secretary-general and the Kuwaiti foreign minister. The agreed topics for discussion included potential cooperation in science, technology, meteorology, environment, and education. It should be noted that since the Euro-Arab Dialogue was first proposed the richest Arab oil-producing countries had shown no particular interest in it.

The 1970s oil shocks, marked by substantial increases in oil prices, were the spectacular starting point for a much greater economic independence for some Arab nations than had existed since the beginning of the Ottoman Empire. The newly acquired wealth of the Arab oil-producing countries was crucial to reaching a developmental take-off point which could change the existing international balance of power. They clearly preferred their own bilateral negotiations and agreements with individual European countries, especially as their revenues were rising so much and the means of cooperation were under their control. In addition, Saudi Arabia and the other oil-rich monarchies were not interested in being involved in the plans of the Arab League, which was dominated by the oil-poor Arab members.[40]

The management of this new balance of power in the Middle East, as the outcome of the huge transfer of wealth, was imperative and urgent for Western Europe. As Ibrahim Obaid, Director-General of the Saudi ministry of Petroleum observed in 1976,

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[39]Saleh Al-Mani, *The Euro-Arab Dialogue. A Study in Associative Diplomacy*, Frances Pinter, London 1983, p. 125.

[40]Shwadran (1986), op. cit., p. 101.

> The Europeans should bear in mind that their future […] depends on their willingness to orientate themselves to the Arab countries of the Middle East, as much or even more than they do to the United States. This is not to suggest an adversary and less cordial relationship with America, but it should be emphasized that the Middle East is not only a source of the energy which is indispensable for a modern industrial economy like that of Europe, but it also possesses the capital formation which is essential to Europe in order to meet the technological advances and to face the economic and commercial expansion of both America and Japan. I cite this situation only to dramatize the fact that the European interest is different to that of America. […] The Arab oil producing countries possess the energy, the financial assets and the markets that Western Europe cannot do without. On the other hand, the Arab oil producers in general, and Saudi Arabia in particular, are embarking on huge industrial plans and need technology, machinery, skilled manpower and access to the European markets. […] In a situation such as this, where each participant can materially contribute to the well-being of the other, fields of cooperation are endless, and their potential enormous, as was illustrated by the Euro-Arab Dialogue conducted so far in Cairo, Rome and Abu Dhabi.[41]

From 1974 to 1979, the stumbling block to progress in the Euro-Arab Dialogue was a difference of opinion regarding political issues in the Middle East, notably the Arab-Israeli conflict. In the press statement released at the conclusion of the November 1975 Abu Dhabi meeting it was stated that "The two sides announced that the political aspect of the dialogue must be taken into consideration to allow the dialogue to make progress in an effective manner, conducive to the fulfilment of its aims".[42] When in May 1976 a new meeting opened in Luxembourg, the Arab League secretary-general devoted most of his statement to practical issues of cooperation, but the other Arab delegate, the Bahrein Foreign Affairs minister, addressed his entire speech to the Palestinian issue. The atmosphere immediately became tense, and the stalemate was not resolved. Two years later, and after two more Euro-Arab diplomatic gatherings, Qatar's minister of Finance declared that the Western European countries had been responsible for the failure of the dialogue between the EEC and the member states of the Arab League.[43]

5 Reviving European Energy Production

The omission of energy topics from the Euro-Arab Dialogue and the oil-rich Arab governments' draconian approach to energy relations with Western Europe led some European governments and the Commission to look for an indigenous solution to their energy security. In fact, some EEC members had been objecting to the Euro-Arab Dialogue since its inception: Britain, while agreeing in principle to

[41]Ibrahim A. Obaid, "Political Preconditions for Cooperation with Western Europe", in Edmond Völker (ed), *Euro-Arab Cooperation*, proceedings of the International Conference on "Changing Political and Economic Relations between Western Europe and the Arab Countries", organized by the Europa Instituut of the University of Amsterdam, Sijthoff Publishing Co., Leyden 1976, p. 172.

[42]*Europe*, November 28, 1975.

[43]Shwadran (1986), op. cit., p. 110.

the dialogue, had proposed continuous consultation with the United States on the dialogue itself. Therefore, in the late 1970s the northern European countries (UK, Denmark, and the Netherlands) turned to favouring more energy autarky at EEC level. Their analysts were convinced that self-sufficiency in energy was a goal near at hand for Western Europe, and that it was also preferable, in order to ensure a higher degree of economic and political certainty than was likely to exist in a situation in which there was a high degree of dependence on energy imports from the Middle East.[44]

According to these optimistic scenarios, a set of appropriate policies at the national and European levels could end in a high degree of energy self-sufficiency, thanks to the exploitation of off-shore and natural gas resources—in the first instance by using those in the North Sea area. The development of the North Sea fields, however, implied a *compact* between the EEC producing and consuming nations. Only in this case would the potential producers be persuaded to agree to the fullest and most rapid exploitation possible of their oil and gas reserves in exchange for guaranteed markets for all they produced at fixed prices—maintained by this agreement irrespective of the world price of oil. Thus, the importing nations in Western Europe had to agree to give preference to indigenous oil and gas over imported supplies of energy. Moreover, as a matter of priority they also had to make available whatever resources were necessary (finance, hardware, expertise, etc.) to help to develop the North Sea production capacity.

For the potential northern European producers, the basis for such a *compact* at the European level existed. From their perspective, this could lead to the elimination of uncertainty, as exploitation of the new fields would not be undermined by the return of cheap foreign oil. From the oil-importing countries' perspective, the aim was to overcome dependence on external supplies and price volatility of a commodity as essential as oil. In the most optimistic scenario, this policy would enable Western Europe to ignore the OPEC cartel and to refuse to deal with it. Instead, Western Europe could offer a special relationship to non-European energy-exporting countries which were prepared to supply energy products at a level below the internal European price.[45]

6 Further Developments: The Single European Market and the Internal Energy Market

As we have seen, in the aftermath of the 1973–1974 oil crisis the approach of the EEC member states to energy was driven by "non-market" factors, such as interventionist policies to ensure security and diversity of supply. In the 1970s, the EEC

[44]P.R. Odell and K.E. Rosine, *The North Sea Oil Province: an Attempt to Stimulate its Development and Exploitation*, Kogan Page Ltd., London 1975, *infra*.

[45]Völker (1976), op. cit., pp. 114–115.

Commission's role in energy policy was limited mainly to funding certain R&D programmes (notably nuclear fusion) which individual Member States could not finance in full themselves because the costs were too high and the benefits too speculative. Later on, the prospect of revitalizing domestic European production of energy, combined with the creation of the Single European Market (SEM), suggested a rather different logic of how energy security in Europe should be addressed. From the traditional agenda of energy policy stressing measures to limit vulnerability to price increases and supply shocks, the EEC member states moved towards a new strategy based on the dynamics of market forces to allow for greater competition and trade at the European level. This strategy implied a different configuration of power among the different members and institutions of the Community. Whereas the previous energy policy had relied mainly on the national governments and their will to cooperate, with the Commission confined to a goal-setting and subordinate role, in the new market-based strategy the Commission could be more active and utilize its new role under the Single European Act (adopted in 1987) and the SEM (launched in 1988).

This new role and strategy for the Commission was closely related to the revitalization of the EEC: the Single European Act strengthened supranational authority in a number of policy areas, although not specifically in relation to energy policy. Such initiatives represented a form of political spillover, where resourceful actors exploited new opportunities within a new institutional framework.

The creation of a unified European market opened the way for a number of initiatives in the energy sector as part of a general deregulation policy. This was an area covered by new rules of majority decision-making, and where the Commission gained a stronger role. In this perspective, the question was not whether national energy sectors performed well in relation to various national objectives, but whether the organization of the industries was consistent with the principles of competition policy.[46]

In 1988 the Commission published its Single European Market (SEM) proposals, which were intended to create a unified internal energy market without barriers to internal trade and competition. The authority for this was the preceding Single European Act, under which the Member States agreed to complete the common market by extending EEC competition rules into previously excluded areas, including energy, transport, telecommunications and public procurement. The overall SEM strategy was to deregulate many aspects of the Community economy where existing controls proved to be unnecessary barriers to trade. Partly as a reflection of past energy policy failures, however, the Commission did not include energy on the initial agenda for SEM. The prospects for successful Commission initiatives in the field of energy were assisted by changes brought about by the Single European Act and in the overall revival of the Community's profile following the

[46]Svein Andersen, "Energy Policy: Interest Interactions and Supranational Authority", in Svein Andersen and Kjell Eliassen (eds), *Making Policy in Europe*, 2nd Edition, Sage Publications, London 2001, p. 109.

"eurosclerosis" of the early 1980s. Undoubtedly, the SEM programme played a major role in restoring confidence in the Community and Commission as the forum for European economic restructuring. In this context, it even became possible to address difficult sectors like energy.

There were signs of a different policy towards energy prior to the 1992 proposals. At the Community level, from the early 1980s onwards there were attempts to regulate national pricing policies and, while the moves failed, they indicated a rekindled Commission interest in this issue. The Commission was also increasingly interested in curbing energy-related subsidy policies. In some member states it sought to control the provision of cheap energy supplies to particular industries (as in the case of Dutch support to its horticultural industry with cheap gas sales).[47] At the national level, in some cases governments had reshaped their energy strategies: since the early 1980s the British government made an explicit move to rely on market forces to determine supply and demand. A major plank of British policy was deregulation, with attempts to introduce competition into the supply of gas and electricity. Similar policies were under review in other EEC member states, although these were often less ambitious. These changes in some national political economies was not confined to the energy sector: the 1980s were a decade in which for many Western European nations a tendency to disengage replaced the tendency to intervene.[48]

The changes in energy balances in the priorities of member state policies and in the approach and prerogatives of the Commission meant that the idea of a market-oriented energy policy was back on the agenda in the late 1980s. Even if the SEM architecture was not an attempt to introduce a coordinated energy policy, it put into force a set of competition rules for the energy sector. On a strict interpretation basis, these new rules could give free rein to short-run market forces and, by banning subsidies and other forms of state intervention, they could dismantle the apparatus of national energy policies.[49]

The Commission's new approach to energy policy was presented in the 1988 *Internal Energy Market* report, which set out the potential benefits of a unified energy market in Western Europe. According to this report, such a market would increase security of supply by increasing the integration of energy industries, and would provide lower energy costs for the final consumers and greater complementarity among the different supply and demand profiles of the member states. The 1988 report revealed that the Commission was determined to implement an internal energy market and would scrutinize all the obstacles to its development. From the time the report was published, the Commission began to put the new

[47]On the Commission's investigation into cheap gas supply, see EEC Commission, *14th Report on Competition Policy*, Office for Official Publications of the EEC, Luxembourg, p. 152.

[48]Dieter Helm, John Kay and David Thompson (eds), *The Market for Energy*, Clarendon Press, Oxford, 1989, pp. 32–40.

[49]Francis McGowan, "Conflicting Objectives in European Energy Policy", in Colin Crouch and David Marquand (eds), *The Politics of 1992. Beyond the Single European Market*, Basil Blackwell, Cambridge (MA), 1990, pp. 127–128.

strategy into practice. It introduced directives aimed at improving price transparency, increasing the coordination of investments and encouraging greater trade in electricity and gas. The pace of these changes was not only helped by changes in Commission decision-making procedures (notably the majority voting procedures allowed by the Single European Act), but also by the prospect that the Commission could use its own powers under the 1957 Treaty of Rome to investigate and reform the European energy sector. In this respect, the Commission was following the same model it pursued concerning other utilities, such as air transport and telecommunications. As the momentum of the SEM in these sectors increased, so did the determination to apply it to energy.[50]

7 Conclusion

When a common energy policy finally started to emerge, it was partly because the traditional energy actors—the national governments and the oil companies—were loosing their exclusive control over the energy arena. After the 1970s oil shocks, and more clearly in response to the 1980s "eurosclerosis", there was a real change in the balance of power in the Community. In this sense, the emergence of a common energy policy demonstrated the momentum of European integration. The Commission was far more involved in energy policy-making than was previously the case, and its proposals were harder for the member states to ignore. This outcome was in no small part due to the overall single market debate. The success of the internal energy market agenda owed much to the favourable circumstances in energy markets and to the balance of power between states and the market in the EEC. There are those who underline that the revived role of the Commission would not have been possible without some of the reassessment of national economic policies which occurred in the member states during the 1980s. It is worth recalling how much the single market programme was in fact a response to "eurosclerosis" and the perceived failure of the economic policies of the previous decade.[51]

The initiatives aimed to the internal market and environmental protection were based on supranational authority, which the Commission tried to extend to the energy sector. As noted before, the internal energy market was part of a wider strategy of "integration by deregulation", a key aspect of the Commission's programme to reinforce the economic and physical infrastructure of the Community. Deregulation was largely a phenomenon of the 1980s in Europe, a response to specific circumstances in particular sectors, as well as to the overall political climate. After the 1980s, some conflicts emerged between the different energy policy agendas. A certain degree of mismatch emerged between the new proposals and the way in which energy policy had been pursued in the past. Choosing between

[50]Ibid, p. 129.

[51]Crouch and Marquand, op. cit., p. 137.

policies was a challenging task for the Commission and national governments, with all of them working to determine how the balance should be struck. In some cases, the prospects of the deregulatory thrust policy were sacrificed in the energy sector, when the "cost of Europe" proved politically less acceptable than the economic "cost of non-Europe".

Recent developments in EU energy policy demonstrate how interests in the sector have been overwhelmed by actors invoking different policy contexts within the general framework of EU development, based on broader and more robust supranational authority. It is the dynamic interaction between several policy contexts and the impetus of the more general development that explain the direction of EU energy policy.

A Link of Steel. The Western Europe-Russia Gas Pipeline Network in the Post-Soviet Era

Matteo Verda

Abstract Natural gas represents the most recent fossil fuel to be exploited and traded between Russia and Europe. However, its importance has steadily grown during recent decades, reaching the point that gas trade is currently considered one of the key political issues at the regional level. The relevance of natural gas is driven by several factors: it is cheaper than oil and less emitting than coal for power generation; it is cleaner than other fossil fuels for heating; and finally it is reliable and always available for final use, unlike discontinuous renewables. Coupling all these features with large reserves and low production costs created the basis for natural gas penetration in the European market. While generally representing a cheaper alternative to other technologies, in particular liquefaction of gas and transport via tanker, pipelines also entail a strong rigidity in natural gas supplies. Indeed, once built, pipeline indissolubility connects one field to a final market, or a few fields to a few final markets. Considering that a pipeline is usually an investment involving several tens of billion euros, conceived to stay in place for at least several decades, the evolution of the pipeline network between Russia and Europe is particularly important not only for the energy trade it allows, but also for its impact on political dynamics at the regional level.

1 Russian Gas for Europe

Energy rests at the core of economic relations between Russia and Europe. The huge Russian landmass holds enormous reserves of oil, gas and coal, which have been exploited by eighteenth century barons, Soviet planners, and post-Soviet oligarchs and *siloviki* with constant efforts and remarkable results. The Russian natural endowment represents an export potential with few equals in the world.

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At the same time, European countries have large and industrialised economies, whose dependence on imported energy is a long-term structural feature. Thus, supply and demand inevitably met at the regional level, creating an uninterrupted and tight energy exchange.

In this context, natural gas represents the most recent fossil fuel to be exploited and traded between Russia and Europe. However, its importance has steadily grown during recent decades, reaching the point that flows of it are currently considered one of the key political issues at the regional level. The relevance of natural gas is driven by several factors: it is cheaper than oil and less emitting than coal for power generation; it is cleaner than other fossil fuels for heating; and finally it is reliable and always available for final use, unlike discontinuous renewables. Coupling all these features with large reserves and low production costs created the basis for natural gas penetration in the European market.

The simplest and cheapest way to transport natural gas is via pipeline. Indeed, like other gases, natural gas is difficult to store and once extracted it needs special infrastructure to contain and transport it over long distances without significant leaks. A long string of steel pipes, welded in sequence and connected with a few compressor stations allows natural gas to be transported from a remote field to a final market up to several thousand kilometres away.

While generally representing a cheaper alternative to other technologies, in particular liquefaction of gas and transport via tanker, pipelines also entail a strong rigidity in natural gas supplies. Indeed, once built, pipeline indissolubility connects one field to a final market, or a few fields to a few final markets. For an exporter, building a pipeline therefore means an irreversible coupling with an importer for several decades.

In fact, a gas exporter is dependent on one specific customer: if the latter does not import and consume its gas, the pipeline is doomed to sit idle. However, this dependence is generally bilateral: operators in an importing country have many incentives to limit the redundancy of their importing infrastructure and contain costs. Therefore, an importer relies on its major suppliers and depends on them for the stability of its supplies.

Considering that a pipeline is usually an investment involving several tens of billion euros, conceived to stay in place for at least several decades, the evolution of the pipeline network between Russia and Europe is particularly important not only for the energy trade it allows, but also for its impact on political dynamics at the regional level.

2 Gas Production and Exports During the Soviet Period

Despite its ultimate dominance in the Soviet energy mix, USSR economic planners adopted natural gas as the fuel of choice relatively lately. Until the end of the 1970s, coal represented by far the most important energy source, due to its availability and to the low technological level of mining it. However, from the 1950s oil attracted more and more attention due to its higher calorific content, its flexible use in the industrial sector and its non-energetic final uses, i.e. in petrochemicals.

Natural gas was the least used fossil fuel, despite a conspicuous growth in demand for it during the 1960s triggered by the sixth five-year plan. Like oil, gas could be used for industrial and petrochemical processes, but it was more difficult to transport and manage, requiring the construction of expensive pipelines to reach the final consumers.[1] The importance of transport infrastructure has indeed affected the whole evolution of the gas industry since its inception, and not only in Russia.

Nonetheless, the situation was set to change rapidly. During the 1960s, Soviet geologists and petroleum engineers discovered massive reserves in Western Siberia, attracting the attention of central planners who needed more and more energy to fuel the largely inefficient industrial growth of the Soviet Union. New projects in Russia (Orenburg, Urengoy, Yamburg), Central Asia (mainly in Turkmenistan) and Ukraine (Shebelink) represented the industrial foundation for a steep increase in the overall gas output. Moreover, from the beginning of the 1970s oil shocks raised the value of oil exports, creating a strong incentive to supply Soviet consumers with relatively cheap natural gas while freeing volumes of oil for international markets. Rising oil prices also entailed higher energy prices for other sources through indexation, improving the profitability of natural gas exports.

Overall, Soviet gas production boomed during the 1970s, rising from 192 billion cubic metres (Bcm) in 1970 to 423 Bcm in 1980, and peaking at 803 Bcm in 1990.[2] Soviet internal consumption absorbed a large share of this production, but more and more volumes were also available for exports. Between 1975 and 1980, Soviet exports rose from almost none to 36 Bcm, fully exploiting the existing potential and creating a demand for a further expansion in export capacity.[3] In 1990 Soviet exports eventually totalled 112 Bcm (see Fig. 1).

The first destination for this surplus of natural gas was the Soviet allies in Eastern Europe, grouped in the Council for Mutual Economic Assistance (CMEA) through complex agreements which included barter exchanges.[4] Although the first exports of Soviet gas to Eastern Europe took place at the end of the 1940s, when a small pipeline was built to supply Poland from Belarus, natural gas played a completely marginal role in the economic integration of the eastern bloc for decades. The total amount supplied was limited to less than 1 Bcm per year until the end of the 1960s when the first big export corridor was created. In 1967 the USSR commissioned the Urengoy-Pomary-Uzhgorod pipeline—also called "Bratstvo"

[1]See Victor and Victor (2006).

[2]Unless otherwise stated, in this chapter the source of all energy statistics is BP (2014). Natural gas volumes are standardised at 39 MJ/Standard cubic metre of gross calorific value.

[3]Until the 1970s, the Soviet Union was also an importer of natural gas from Iran and Afghanistan; therefore even though westbound exports started at the end of the 1940s, imports were greater than exports until 1974.

[4]Bulgaria, Czechoslovakia, East Germany, Hungary, Poland and Romania—nowadays all members of the European Union. See Smeenk (2010).

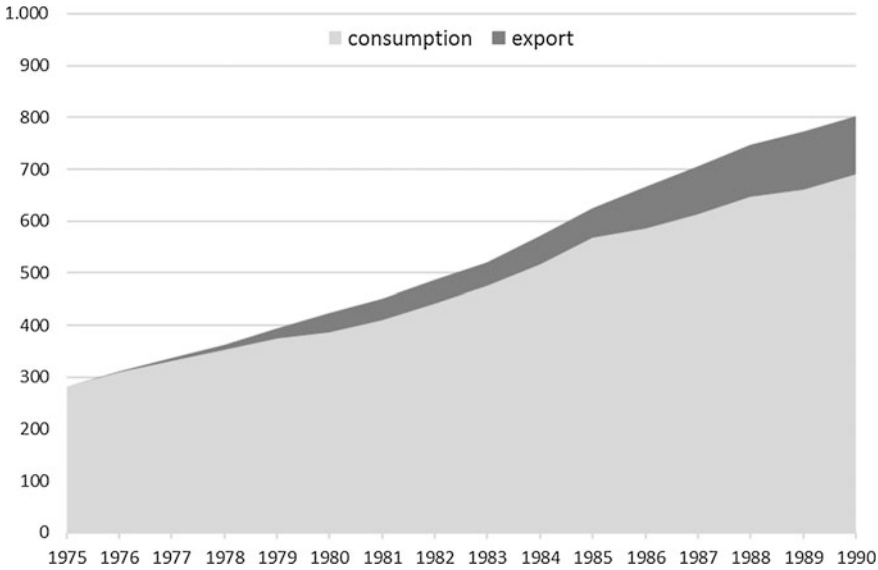

Fig. 1 Soviet Union consumption and exports of natural gas (1975–1990) (billion cubic metres). *Source* Elaboration on BP (2014)

(Brotherhood)—running from Western Siberia to Czechoslovakia, with a secondary branch to Poland.

Demand for natural gas as a substitute for oil products in power and heat generation also increased in Western Europe, where the effects of the first oil shock led to a rethinking of energy policies. The European economies were already largely dependent on energy imports and represented an ideal market for Soviet exports, which could easily reach German, Italian and French markets by extending existing pipelines supplying Eastern Europe.

Cooperation with Western Europe was important for the Soviet Union at several levels. The most obvious reason was access to hard cash through exports to market economies, which allowed the Soviet government to stockpile currency reserves and above all increase imports, which were becoming more and more important to compensate the inefficiencies of the planned economy. Moreover, European banks also provided a significant share of the investment, easing capital requirements for the Soviets.

Soviet gas supplies were based on long-term contracts, which allowed the companies involved to spread their capital expenditure over a long time span. Captive European markets allowed national incumbents to reduce their risks by passing the costs onto final customers, who paid regulated prices. At the same time, Soviet supplies were indexed to the price of oil, which gas was replacing and which enjoyed a global price that the parties could not manipulate as a political tool.[5]

Beside cash, access to Western technology was also important for Soviet planners. German—and to a lesser extent Italian—industry provided machinery, such as gas compressors, and large diameter pipes made with special steel. These industrial supplies were particularly important for the development of the Soviet gas transport infrastructure, not only for westbound exports but also for internal Soviet use. Technological supplies were therefore included in the agreements between Western countries and the Soviet Union, enhancing the exploitation of Soviet reserves, in particular those located in Western Siberia.

Energy trade with the Soviet Union clearly also had a strong economic rationale for the western European countries, since it allowed a much-needed diversification of their energy mix away from dependence on oil. At the same time, industrial exports to the Soviet Union increased industrial activity, exactly in the period of economic hardship triggered by the oil shocks.

On top of that, the Soviet gas exports to Western Europe had a significant political rationale for both parties. Military division between the NATO and Warsaw Pact countries still traversed the continent, but a climate of *détente* allowed a more intense commercial exchange. Natural gas and its pipelines played a special role: a shared infrastructure would bind the two blocs together.[6] Soviet gas could not be exported elsewhere because the pipes had only one westbound route, while European countries could not replace the Soviet gas in those pipes with supplies coming from somewhere else. Considering the scale of investment and the mutual economic benefits, a shared interest and a structural incentive to cooperate clearly emerged.[7]

Gaining momentum thanks to oil shocks, the gas infrastructure system linking the Soviet Union and Europe was developed along two major pipeline systems, both transiting through Ukraine. The previously-mentioned Bratstvo pipeline was the USSR's largest pipeline in Europe, and after 1967 it was extended several times. Bratstvo ran from the Western Siberian fields to the Ukrainian-Czechoslovakian border at Uzhgorod, where it fed a pipeline called Transgas. From Czechoslovakia, Soviet gas reached Austria and Italy through the Trans Austrian Gasleitung (TAG) and Germany and France through the Mittel-Europäische-Gasleitung (MEGAL).

The second pipeline running through Ukraine was the Soyuz ("Union"), from the Orenburg hub located in Russia to the Ukrainian-Czechoslovakian border at Uzhgorod. This pipeline was built between 1975 and 1978 to supply Central Asian and Russian gas to Central and Eastern Europe.

A third and smaller pipeline exporting Soviet gas was commissioned in 1974 to export a few billion cubic metres per year directly from Russia to Finland. Eventually, a fourth export direction was developed in 1987 when a pipeline named

[5]See Victor et al. (2006).

[6]Victor and Victor (2006).

[7]About cooperation mechanisms and power dynamics in an anarchical arena, see Stoppino (2001).

Fig. 2 The Soviet export pipeline system to Western Europe and Turkey (1991)

the Trans-Balkan Pipeline began to supply Turkey and the Balkan countries, running from Ukraine through Romania and Bulgaria (see Fig. 2).[8]

During the last years of existence of the Soviet Union, expansion of the export infrastructure was a priority because of the financial difficulties of the communist economies and the need for export revenue to underpin the economic viability of the Soviet system. The Bratstvo pipeline reached its full capacity in 1991, and an upgrade of the pipeline system transporting Soviet gas across Germany was conceived during the 1980s but was eventually completed in the aftermath of the Soviet collapse: Sachsen-Thüringen-Erdgas-Anbindungsleitung (STEGAL) from east to west was commissioned in 1992 and Mitte-Deutschland-Anbindungsleitung (MIDAL) from south to north was commissioned in 1993. The rationale for this project was to exploit existing infrastructure and to avoid transit through Poland and East Germany, which were deemed less reliable than Ukraine and Czechoslovakia by both the Soviet and West German governments.

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[8]Several other minor pipelines were commissioned during the following decades, crossing the borders between the CMEA countries, and between the CMEA countries and the Soviet Union. See EEGS (2014).

Table 1 Soviet Union gas exports to the CMEA and Western Europe (1975–1990) (Billion cubic metres)

	1960	1965	1970	1975	1980	1985	1990
Eastern Europe	0.3	0.4	2	10	27	34	49
Western Europe[a]			1	7	22	28	49
Soviet share in EU28 consumption (%)[b]	<1	1	3	7	17	20	28

[a]Including Turkey
[b]Excluding Estonia, Latvia and Lithuania prior to 1985 and Slovenia prior to 1991
Source Elaboration of Smeenk (2010), BP (2014)

The Soviet pipeline system underwent a continuous expansion until 1991, which increased both the number of countries reached and the overall transport capacity (see Table 1). The Ukrainian territory and its infrastructure endowment were at the centre of this evolution. Indeed, with the exception of a secondary line from Belarus to Poland and the small pipeline to Finland commissioned in 1974, all flows from Russia to non-Soviet countries transited through Ukrainian territory.[9]

The Ukrainian dominance as a transit country reflects not just geography, but also path-dependence. Early fields in Ukraine required the creation of a gas infrastructure in the region, and the first pipelines to Central and Eastern Europe tapped that infrastructure before being expanded.[10] When the Soviet Union broke up and Ukraine became an independent country, this technical feature turned into an economic and political one.

3 Post-Soviet Period: New Projects Reinforcing the Link

Along with the title of successor state of the Soviet Union, the Russian Federation emerged from the collapse as the largest producer and the largest exporter of natural gas in the world. Moreover, Russian territory was the centre of all the Soviet infrastructure systems: central Asian countries, such as Turkmenistan, had no other option beyond exporting to Russia. At the same time, former Soviet republics which were net importers of natural gas, such as Ukraine and Belarus, remained dependent on Russian cooperation to get their supplies.

Overall, the Russian Federation as a gas producer was more export-oriented than the Soviet Union. In 1990, Soviet net exports (112 Bcm) accounted for 14 % of total production, while in 1991 Russian net exports (176 Bcm) accounted for 28 % of total production. Moreover Gazprom, which operated the Russian gas transport system, could earn transit fees from central Asian producers and use their imports as

[9]See Victor and Victor (2006).

[10]Ukrainian gas production peaked in 1975 at nearly 70 Bcm, and then began a constant decline. See Naftogaz (2015).

a buffer for its own production, reducing imports from them when it was more profitable to boost its own output.

Nevertheless, the Russian situation presented several criticalities, starting with the reliability of its export system. The Soviet breakup created two tiers of sovereign states where for decades there had been a hierarchical order centred on Moscow. In Central and Eastern Europe, former Soviet satellites abandoned planned economies and began their political convergence with western European organisations. While moving towards market economies and loosening ties with Russia, these countries remained heavily dependent on Russian gas supplies, but more and more on a purely commercial basis as is shown by prices rising nearer to western European standards. The three post-Soviet Baltic republics—Estonia, Latvia and Lithuania—also followed a pattern of rapid westward transition while retaining their dependence on Russian supplies.

Other western post-Soviet republics—Belarus, Moldova and Ukraine—instead followed a different path. They were much more integrated with the Russian economy and loosening their ties with Moscow was a more complex and long-term prospect. Indeed, in the Soviet republics natural gas was provided to households as a basic welfare service, while it was used inefficiently as a production input due to distorted incentives provided by the planned economic system. For these countries, access to cheap gas supplies represented a fundamental input for economic and social stability. In order to support their transition, avoid instability at its borders and exercise influence, Russia continued to supply gas to these countries at heavily discounted prices after 1991.[11] However, this situation became the object of ongoing political bargaining for two decades, especially in the case of Ukraine.

Ukraine was the largest consumer of natural gas in the former Soviet Union after Russia, but it was a net importer. In 1991, its net imports totalled 103 Bcm, supplied by Russia and Turkmenistan through the Russian transport system, an amount similar to Russian exports to the present-day European Union. Supplying Ukraine at a discounted price instead of exporting to Western customers therefore represented a continuing economic loss for Russia and, in particular, for its state-owned gas company, Gazprom.[12]

In 1989, the USSR Gas Industry Ministry was restructured into Gazprom—State Gas Concern. After the Soviet collapse, Ukraine and other post-Soviet republics gained control of their territorial branches of Gazprom and renamed them accordingly, while the Russian Federation retained control over Gazprom's central structure.

In Ukraine, the new state-owned national company Ukrgazprom—renamed Naftogaz in 1998—inherited all the gas infrastructure on its territory, including export pipelines directed to Europe and the storage system connected to them.[13]

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[11]See Pirani (2007), pp. 18–27.

[12]For a more detailed account of the transition period after the Soviet collapse, see Engerer and von Hirschhausen (1998).

[13]Storage facilities are particularly important since they provide flow stability and reliability during the cold season, when demand peaks due to household consumption for heating.

The situation was potentially critical for Gazprom: a country heavily dependent on cheap gas supplies was also the owner of all the export pipelines serving the most lucrative markets for Russian gas exports.

Gazprom also relied on its access to western customers for domestic purposes: the Russian market was inefficient and regulated pricing mechanisms prevented any significant increase in profitability for Gazprom. Therefore, exporting to Western Europe was of paramount importance to sustain investments upstream and to match the operating costs of all Gazprom activities. Consequently, the Gazprom strategy aimed at expanding the volumes exported to Europe and strengthening the relationship with major European utilities. From the perspective of Russia's main customers, this opportunity was particularly interesting: EU production outside the UK had been stable since the beginning of the 1980s but it was expected to start a structural decline towards the end of the 1990s (and, indeed, it peaked in 1996). At the same time, European final demand continued to grow and natural gas was gaining a larger share in power generation and heating buildings. The Russian need to expand its exports perfectly matched that of European utilities, which were essentially state-owned monopolies. The size of the Russian reserves guaranteed long-term supplies with a high level of predictability, as confirmed by the experience of the previous decades.

The German, Italian and French governments were keen to improve the integration of Russia in the western economic system by increasing trade relations. From an economic perspective, the Russian Federation had a potentially massive trade surplus and a large, albeit relatively poor, domestic market where European goods could be exported. From a political perspective, a stronger trade relationship between Russia and Western Europe was expected to foster Russian integration in the western liberal order.

At the beginning of the 1990s, increasing Russian gas supplies to Western Europe was a shared priority for both Moscow and its main European partners. The immediate option was to exploit and improve the existing pipelines, but new infrastructure represented the medium-term priority. This expansion also offered Gazprom the opportunity to secure its exports by diversifying its export routes away from Ukraine and thus reducing Kiev's potential for blackmail (see Fig. 3). The importance of this diversification became evident in 2006 and 2009, when all flows of Russian gas through Ukraine were halted due to a dispute between Gazprom and Naftogaz about the pricing of Russian supplies to Ukraine.[14]

3.1 Yamal-Europe

The exploitation of reserves located in the Yamal peninsula, in the Arctic part of Western Siberia, represented the first opportunity to devise a new route to reach Europe without transiting through Ukraine. In particular, Gazprom could now

[14]For reconstructions of this crisis, see Bigano and Hafner (2009), Pirani et al. (2009) and Stern (2006). About April 2010 agreement between Russia and Ukraine, see Pirani et al. (2010).

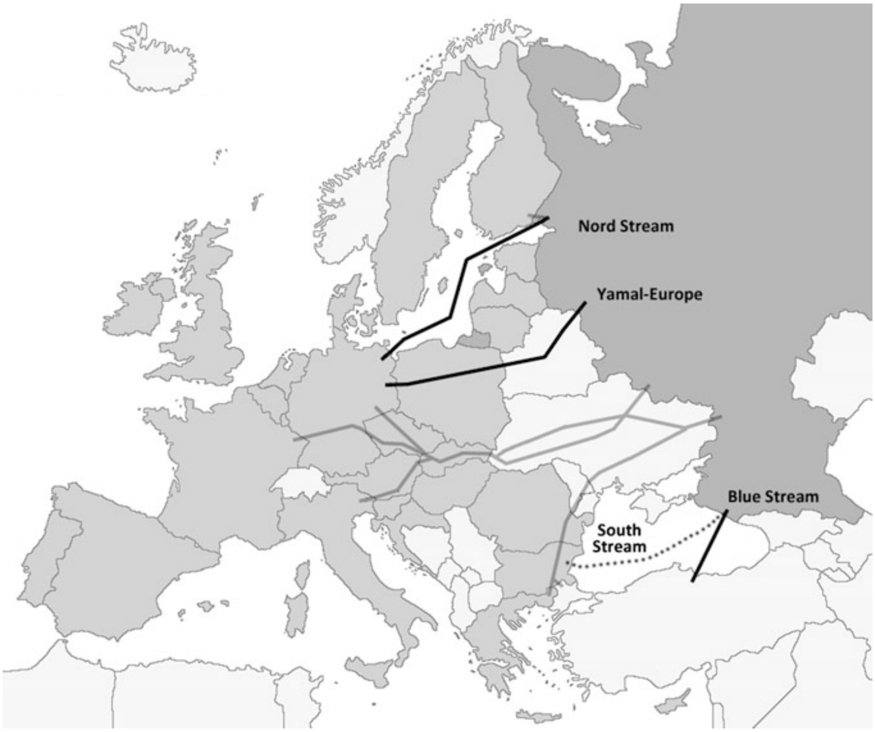

Fig. 3 Russian export pipeline system to the European Union and Turkey (2014) Soviet routes in *light grey*, post-Soviet pipelines in *black*, abandoned projects—*dotted line*

supply its German customers using the shortest route: through Belarus and Poland. While during the 1980s Poland was one the most problematic European Soviet satellites, after independence Warsaw pursued a pattern of convergence with Germany, which improved its reliability as a transit country. Moreover, the Polish economic system was undergoing a reform process and it was also expected to become a large final market for Russian gas.

Construction of the 56-in. pipeline began in 1994 and the first gas flowed towards Germany in 1997. For Gazprom, Yamal-Europe also represented a diversification in terms of partnerships. Instead of its traditional German partner, Ruhrgas, Gazprom cooperated with Winternshall, a subsidiary of BASF, trying to reinforce its overall presence in its main importing market. Through a joint venture, Wingas, Gazprom indeed gained direct access to the final market, pursuing a strategy of vertical integration to earn a larger share of the final price of Russian natural gas. Construction continued in the following years by adding more compressor stations and reaching a maximum capacity of 34 Bcm/year. Gazprom also involved state-owned national companies along the Yamal-Europe route in order to gain stable political support for its infrastructure. In Belarus, Gazprom joined Beltransgaz, its former local branch, while in Poland it joined EuRoPol Gaz.

Despite good cooperation, the original plan to double the capacity of Yamal-Europe by adding a second line was shelved due to a slower than expected growth of the Polish market and a decision to further improve route diversification by avoiding any transit country between Russia and Germany, i.e. by building the Nord Stream project.

3.2 Blue Stream

The first export line directly connecting Russia to one of its major customers did not supply Gazprom's main markets but its fastest-growing one: Turkey. Economic development in the country was consistently increasing its energy demand and its dependence on imported fossil fuels, even though the 2001 economic crisis slowed the pace of the expected growth.

Russian gas supplied the Turkish market after the construction of the Trans-Balkan pipeline, a long project the design of which was deeply influenced by the structure of previously existing Soviet pipelines. A significant expansion of the volumes exported to Turkey required new infrastructure, which could also exploit the geographical proximity of Russia and Turkey, separated only by a few hundred kilometres of the Black Sea.

Gazprom therefore joined the Italian Eni, which through its subsidiary Saipem had the expertise to build subsea infrastructure, and formed a joint venture named Blue Stream. Two 24-in. twin pipelines were eventually commissioned in 2003, adding 16 Bcm/year to Russia's export capacity to Turkey. In the following years, flows between the two countries increased dramatically, from 12 Bcm in 2003 to 26 Bcm in 2013, making Turkey the third export destination for Russian gas in terms of volume.

3.3 Nord Stream

The creation of a direct link between Russia and its customers proved to be a successful solution in the case of Turkey, so Gazprom decided to replicate it to supply Germany. A pipeline from Russia to German territory running on the Baltic seabed for Gazprom represented the opportunity to increase the volumes exported and to definitely secure its flows avoiding any transit country.

Gazprom's strategy aimed to consolidate its presence in Germany using the German pipeline network as a hub to supply the French, Dutch and Belgian markets.[15] For German operators, becoming the entry point of Russian gas, and thus

[15]Even though the Netherlands is a net exporter of natural gas, Dutch operators trade volumes for customers in the rest of Europe. Analogously, British operators nominally import gas from Russia, while there is substantially no physical flow of Russian gas towards the British gas network.

substituting flows through Ukraine, was economically convenient. At the same time, for German decision-makers the opportunity to improve security of supply while consolidating the role of German infrastructure as the core of the European transport system was a major political achievement.

As in the case of Yamal-Europe, Gazprom joined Wintershall, but it also involved another German operator, E.ON, and two operators from other countries: the French GDF Suez and the Dutch Gasunie. Such a large joint venture had a strong economic rationale, since it secured a final market for the volumes of gas imported. Moreover, from a political perspective, a partnership including operators from several countries could appeal to a broader consensus at the European level, especially in the case of legal hurdles involving the European Commission.

The first 48-in pipeline was eventually commissioned in 2011, quickly followed by a twin pipeline commissioned in 2012, with a total investment of 7.4 billion euros.[16] The overall declared capacity of the system is 55 Bcm/year, larger than the total amount of gas exported by Russia to Germany (40 Bcm in 2013[17]) and therefore virtually eliminating German dependence on Ukraine and other transit countries. Arguably, Nord Stream represented the most relevant achievement of Gazprom's diversification strategy in the post-Soviet period.

3.4 South Stream

After the construction of Blue Stream and Nord Stream, the south-eastern European countries were the only Gazprom customers not to be reached by a direct flow of Russian gas (see Fig. 3). In particular Italy, Gazprom's second European market (30 Bcm in 2013[18]), is the only large consumer in Europe still depending on Ukrainian transit, together with other minor markets in Eastern Europe, such as Bulgaria, Hungary, and Slovakia.

The construction of South Stream would have completed Gazprom's diversification strategy: with four 32-in. lines and an overall capacity of 63 Bcm/year it would have directly connected Russia and Bulgaria running on the seabed of the Black Sea, and then reached other Balkan states and eventually Italy. Once South Stream was built, the overall export capacity bypassing Ukraine would have totalled 167 Bcm/year, more than the total amount exported to the EU, Turkey and the Eastern Balkans in 2013. In fact, the construction of South Stream would have deprived the Ukrainian government of much of its blackmailing potential, providing an alternative to Ukrainian transit for all Gazprom's western customers.

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[16]See Nord Stream (2014).

[17]Eurogas (2014). The amount of Russian gas consumed in Germany is higher, but the accounting system for gas contractually imported into another EU country and then exported to other countries does not allow a more detailed reconstruction based on official statistics.

[18]MiSE (2015).

Beside Gazprom, the project involved the Italian Eni, the German Wintershall, and the French EDF, creating a large base of interested parties, both at the economic and political levels. Despite the high costs (14.2 billion euros for the offshore section alone), the Gazprom management was strongly committed to supporting the financial burden, with a clear backing by the Russian government.

The project began preliminary construction operations in 2014 but was abandoned in December, after President Putin suddenly announced the withdrawal of political and financial support for the infrastructure. This decision stemmed from several factors and a full assessment of its genesis and consequences will only be possible in the coming years. However, the most relevant driver is the hardship faced by the Russian economy after the dramatic slump in oil prices which began in June 2014. Since the energy sector accounts for the majority of Russian exports and a large share of the Federal budget, the oil-price collapse triggered a recession in the Russian economy, forcing the Russian government to cut large and expensive projects which were less relevant for preserving support from the population.

Continuing tensions between Russia and several western countries over Ukraine were also a major driver for Putin's decision. EU sanctions on the Russian oil and financial sectors reduced incentives to cooperate, and the European Commission has adopted an increasingly challenging stance towards Gazprom in the last few years. Consequently, investing money in a large new pipeline to the EU without any guarantee of recovering costs by fully exploiting it became unattractive to the Russian company.

Currently, Gazprom has replaced the South Stream project with the announcement of a new pipeline called Turkish Stream, supplying virtually the same volumes as the scrapped project but directly to Turkey. The details of the new project are still undefined, but considering the difficult context the most likely outcome currently appears to be the construction of a pipeline more similar to Blue Stream than to the South Stream project in terms of total capacity. Thus, the new pipeline should mainly supply the Turkish market, the only large Russian customer in the region expected to significantly increase its energy consumption in the coming decades.

4 Gazprom Strategy: Consolidation and Diversification

Despite the eventual abandonment of South Stream, the evolution of the post-Soviet pipeline system nonetheless has resulted in a more diversified network, far less dependent on the Ukrainian gas system than twenty years ago. The new pipelines have led to a dramatic reduction in the relevance of the Ukrainian gas system to Russian exports to Europe and Turkey. While in 1991 Ukrainian pipelines accounted for more than 85 % of the total capacity, in 2014 their share amounted to slightly more than 50 % (see Table 2).

During the post-Soviet decades, the European and Russian contexts changed dramatically and often unpredictably, but Gazprom followed a relatively consistent

Table 2 Russian export pipelines to Europe and Turkey (2014)

	Country of entry	Daily max capacity (million cubic metres)	Yearly max capacity[a] (billion cubic metres)
Ukrainian gas system[b] of which:	(various)	452	148
	Slovakia	*281*	*92*
	Romania	*103*	*34*
	Hungary	*55*	*18*
	Poland	*12*	*4*
Nord Stream	Germany	160	53
Yamal-Europe	Poland	102	34
Blue Stream	Turkey	49	16
Others	Finland, Baltic Republics	72	24
Total		835	274

[a]Assuming a utilisation factor of 90 %
[b]Reported. The actual obsolescence of the Ukrainian pipeline system is not verifiable
Source Elaboration of GIE/ENTSOG (2012)

strategy. However, the consistency of Gazprom's management decisions should not be overestimated, since the Russian government's approach to the energy sector evolved.[19] It is possible to identify three main priorities that have characterised its action and in each of them the pipeline system played a central role.

The first priority was to expand the volumes exported to the European markets, essentially for economic reasons. Resource exports dominated the post-Soviet Russian economy, especially during the 1990s, and rents represented a key part of their viability.[20] Moreover, revenues from gas exports allowed Gazprom to continue to cross-subsidise the domestic market and several other post-Soviet markets. Furthermore, especially after 2000, Gazprom revenues accounted for a growing share of the Russian federal budget, as much as 14.8 % in 2012.[21]

European energy markets represented an obvious target for revenue expansion: European operators could absorb more volumes due to the steady growth of their import demand and they could pay a far higher price for Russian gas, especially when compared to the post-Soviet republics. Moreover, Gazprom inherited several long-term contracts from the Soviet period and a sound base of common practices for a further expansion of Russian gas supplies to Europe (see Table 3).

[19]Moreover, Gazprom's internal structure also evolved, including the involvement of senior managers as shareholders. For a complete account of the evolution of the structure, strategy and context of Gazprom, see Vavilov (2014).

[20]According to World Bank (2015) figures, total natural resource revenues accounted for 44.5 % of GDP in 2000. See also UNCTAD (2015).

[21]See Nazarov (2014).

Table 3 Russian gas exports to the European Union and Turkey (billion cubic metres)

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
To EU28	101	94	93	98	109	114	105	111	114	117	114	117
To Turkey	4	4	5	5	5	6	6	6	8	10	11	11

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
To EU28	123	127	134	132	126	131	111	107	110	105	123
To Turkey	12	14	17	19	22	23	19	17	25	26	26

Source Elaboration of Eurogas (2014), Eurostat (2015, nrg_124a), Gazprom Export (2014)

The existing pipeline system lay at the core of these long-term commitments. By relying on the Soviet pipelines with relatively cheap technical interventions, Gazprom could fulfil its obligations and even increase the volumes exported. However, a significant increase in its exports needed new infrastructure and large investments, which created the need to consider new routes while also pursuing other priorities.

As noted, the bulk of the Soviet export infrastructure was located in Ukrainian territory and Gazprom had to heavily discount gas for Ukrainian consumers in order to secure the cooperation of Kiev. In the aftermath of the Soviet collapse, political proximity and heavy economic interdependence represented strong incentives for the Russian government to force Gazprom to renounce profits and consider the demands of Naftogaz. Moreover, the sheer amount of Ukrainian pipeline capacity would have required a massive investment to totally replace, a choice far beyond the means available to Gazprom.

Nonetheless, diversification clearly became a long-term strategy in order to curtail Naftogaz's potential to blackmail while preserving the economic competitiveness of Russian supplies to Europe.[22] In fact, every new pipeline route carefully avoided Ukrainian territory, progressively reducing the share of transit through Ukraine to 55 % of the total flow towards the EU in 2013.[23] Export trends show that the volumes flowing did not keep pace with the expansion of capacity, highlighting the progressive substitution of Ukrainian transit with new pipelines (Fig. 4).[24] Moreover, the obsolescence of the Ukrainian network and the lack of adequate investments by Naftogaz have resulted in a progressive erosion of its actual transport capacity. Considering current financial problems in Ukraine, in the

[22]Economic competitiveness was also at the basis of the choice to resort to pipelines instead of liquefied natural gas terminals for exports to Europe.

[23]See Pirani (2014).

[24]The European economic crisis amplified this trend, as explained later.

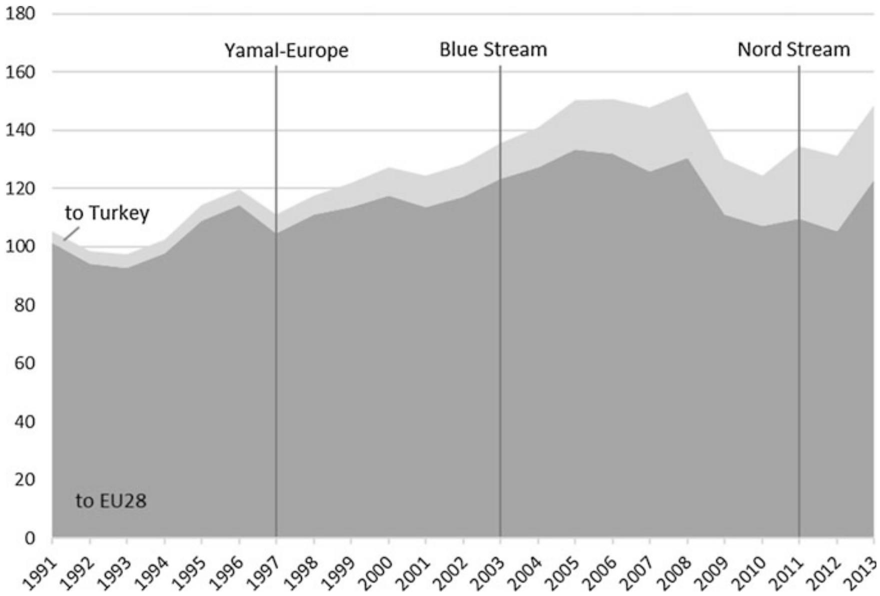

Fig. 4 Russian gas exports to the European Union and Turkey (1991–2013) (billion cubic metres). *Source* Elaboration of Eurogas (2014), Eurostat (2015, nrg_124a) and Gazprom Export (2014)

coming years maximum transit capacity through the country could progressively shrink due to missing investment in maintenance.[25]

A third priority, strictly related to diversification, was control over exports to Europe. Domestically, Gazprom enjoyed a monopoly over all gas exports, which was formally enshrined in Russian legislation in 2006.[26] Externally, there was a need to control pipelines up to the EU border, after which EU law strictly regulated ownership and use rights. For Gazprom, owning a share in a pipeline on EU territory, within the limits of EU legislation, would not increase its control over the use of the pipeline nor increase the security of the flows.

Beyond EU jurisdiction, the situation was significantly different, as shown by the Ukrainian case. Therefore, Gazprom strictly retained a majority share in every new project outside the EU borders. In the case of offshore projects created in partnership with European principals, Gazprom undisputedly retained a control stake from the beginning of the projects, which also reassured its international partners about its commitment.

[25]Gazprom Export estimates the cost of upgrading Ukrainian transit system at 19.5 billion dollars. See the letter to the Financial Times from Sergey Kupriyanov: *Gazprom offers a logical solution to gas woes*, 2 September 2014.

[26]Russian Federal Law of 18 July 2006, No. 117.

Table 4 Gazprom's sales of natural gas (billion euros)

	2006	2007	2008	2009	2010	2011	2012	2013
Russia	10	11	13	11	15	18	19	18
FSU countries	6	8	10	8	11	16	13	10
Other countries[a]	25	25	35	25	27	35	38	40
Total	41	44	57	45	54	68	70	68

[a]Since 2008, gas sales are provided net of trading operations
Source Gazprom (2012, 2014)

In the case of land pipelines, Gazprom actively sought to recover control over its previous local branches and their transport infrastructure. This strategy was aimed both at securing gas flows towards Europe and at abiding by the political priorities of the Russian government, whose influence in the post-Soviet region was at risk due to the increasing attractiveness of western connections.

In the case of Ukraine, several times Gazprom sought to acquire a stake in Naftogaz as compensation for the debt accumulated by the company, but the Ukrainian government consistently refused and used its control over Russian transit as a bargaining chip. In the case of Belarus, even after the commissioning of Yamal-Europe, the potential for blackmail was far lower, while at the same its economy was smaller and its government more inclined to cooperate with Moscow. Gazprom progressively acquired increasing shares in state-owned Beltransgaz, eventually reaching full control in 2011.

By two decades after the end of the Soviet Union, Gazprom's strategy had successfully increased its exports to Europe and Turkey and secured the supplies by diversifying the routes. All these achievements were made possible by the evolution of the pipeline system, which attracted investments of tens of billions of euros and reinforced the link between the Russian supplier and its European customers.[27]

The strengthening of this link benefitted Gazprom's balance sheet (see Table 4). However, it also represented a major vulnerability for the company: by focusing almost exclusively on its European customers, Gazprom further increased its dependence on European demand. The economic crisis which began in 2009 exposed the full scale of Russian vulnerability and the lack of flexibility built into the pipeline system on which Gazprom's current competitiveness is based.

5 Russian Gas in European Energy Security: Its Role and the Challenges

In 1991 the Soviet Union ceased to exist, dramatically changing the European political geography. In that year, Gazprom was the major international supplier of natural gas to Europe, as it had been during the previous decade and was to be in the

[27]See Engerer et al. (2014).

following ones. Indeed, natural gas flows proved to be extremely resilient to geopolitical change and crisis. In fact, Soviet supplies continued undisturbed during the 1980s despite US sanctions over Poland, and Russian supplies regularly continued in 2014 despite US and EU sanctions over Ukraine.

The gas trade shows substantial long term-inertia, the main drivers of which are supply, the availability of the transport infrastructure, and demand. From the Russian perspective, the supply potential is unquestionable: 46,900 Bcm of proven reserves—the largest in the world and equal to more than 70 years of current production.[28] Consequently, for Russia the actual supplies are just a function of its investments in upstream activities. As regards the transport infrastructure, it is, as noted, a function of the strategies of the operators and their ability to collect investment in their projects. Import demand is the last and most challenging driver: the trends in this have a deep impact on the producer, and at the same time are almost completely beyond its influence.

5.1 *The Constant Importance of Russian Supplies*

Gazprom enacted a strategy of improvement and diversification of its gas supplies to its western customers, relying on the assumption that European final demand would constantly grow. Between 1991 and 2005, this assumption proved to be quite safe: the EU gas demand increased from 363 to 534 Bcm. Moreover, at the same time EU domestic production reached its historical peak in 2004, at 257 Bcm, beginning a declining trend which has continued uninterrupted for a decade without any sign of reversal. In this context, the Russian share of the EU market since 1991 has fluctuated between 20 and 30 %, firmly holding the second place behind domestic production (see Fig. 5).[29]

Russian supplies appeared to be a constant feature of the European markets, exploiting their competitiveness in terms of production and transport costs. However, the combined effect of increasing demand and decreasing production was so strong that the demand for imports grew steeply during the last decade and outpaced the increase in Russian supplies. Other suppliers began to challenge the Russian dominance in the European market. In particular, the expansion of Norwegian production and the increased availability of LNG import facilities improved competition exactly when the growth in the demand for imports weakened, thus oversupplying the market towards the end of the last decade.

[28]See EIA (2015).

[29]In 2013, Russia exported 123 Bcm to Europe, Norway 97, Algeria 39 and Qatar (via LNG) 24, according to Eurogas (2014).

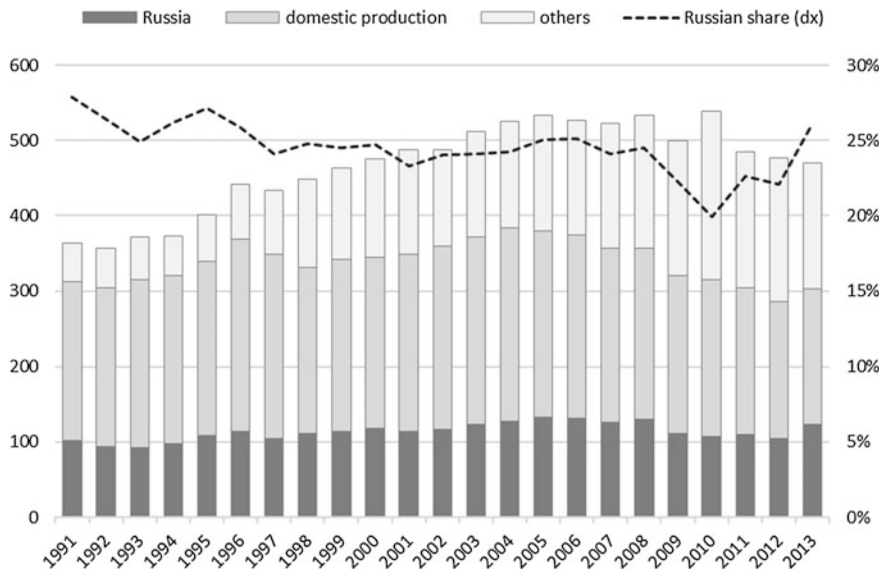

Fig. 5 Origin of gas consumed in the EU and the Russian share (1991–2013) (billion cubic metres). *Source* Elaboration of BP (2014), Eurogas (2014) and Eurostat (2015, nrg_124a)

Gazprom and the other operators could hardly have foreseen the economic crisis that began in 2008, the consequences of which have deeply affected the overall European demand for energy. Moreover, almost all operators substantially underestimated the scope and effect on gas consumption of EU legislation on renewable energy sources and emission targets.[30]

In particular, European regulation put a double pressure on gas-fired power plants. On the one hand, subsidised renewables eroded market shares due to financial support and regulatory preference in the final market. On the other hand, the economic crisis reduced industrial activity and consequently the price of carbon emission allowances plummeted, increasing the competitiveness of high-emission coal-fired plants, which was also helped by low international prices of coal supplies. Eventually, the final demand for gas for power generation decreased from 153 Bcm in 2010 to 104 Bcm in 2013, deeply affecting the total final demand.[31]

[30]In 2009, the EU adopted legislation—the so-called “climate-energy package”—setting two binding targets for 2020: 20 % of energy consumption produced from renewable sources and a 20 % reduction in greenhouse gas emissions from 1990 levels. New more stringent targets are expected to be adopted for 2030 (27 % of renewables and 40 % emission reduction), placing the EU at the forefront of international efforts to combat climate change. However, the impact on European economies of these measures is still hotly debated, especially since so far other major world economies have not expressed intentions of adopting comparable provisions.

[31]See Eurogas (2014).

Table 5 EU primary energy consumption forecasts, by source (million tonnes of oil equivalent)

	2012	2020	2025	2030	2035	2040
Gas	392	403	423	434	448	459
Oil	526	476	441	403	369	336
Coal	294	249	218	180	144	131
Nuclear	230	223	202	206	211	207
Renewables	199	263	298	330	361	390
Total	1.641	1.615	1.582	1.552	1.534	1.523
Gas share (%)	*24*	*25*	*27*	*28*	*29*	*30*

Source IEA (2014), New Policies Scenario

5.2 *The Evolution of the European Energy Mix and the Role of Natural Gas*

Long-term forecasts of energy demand are usually more informative about current bias than about actual trends, since too many factors influence energy markets to be consistently factored into a workable model. Nonetheless, consensus forecasts and scenarios retain their importance since they provide a clue to the expectations of the operators. Since upstream and transport capacity investments in gas take a relatively long time to bear fruit, the expectations of operators are relevant to understanding which projects will be realised and which will remain on paper.

The first step in understanding the future of Russian supplies is to consider the role of natural gas in the European energy mix. According to the International Energy Agency (IEA), within 20 years natural gas will overtake oil as the main source of energy in the EU, being the only fossil fuel to grow in absolute terms (see Table 5).[32]

This expectation is based on the fact that natural gas emits far less carbon than coal when burnt and the assumption that European policies on climate change will increase the cost of emission allowances (or any equivalent solution), thus reducing the competitiveness of coal-fired plants. This assumption is clearly uncertain, since it rests on the political will of the European decision-makers to take on further unilateral commitments, while other major economies have not so far shown any intention of adopting measures comparable to the European ones.

Basing on this assumption, gas demand for power generation is expected to recover consistently but slowly. The only other significant source of new demand is expected to be the consumption of gas for heating buildings. In this case too, the

[32]IEA's forecasts do not take full account of the scope and the results of the oil slump that began during the second half of 2014, which may slow the expected decline in oil consumption at the global level. However, in the long term oil consumption is expected to become more and more concentrated in the transport sector, where competition with natural gas is limited. Moreover, over the medium and long term, oil prices are expected to rise again, accelerating the relative decline in demand for oil.

Table 6 EU28 natural gas demand and supply forecasts (billion cubic metres)

	2012	2020	2025	2030	2035	2040
Consumption	468	481	505	518	534	548
Domestic production	170	141	126	121	112	104
Imports	297	340	378	397	423	444
Imports/consumption (%)	64	71	75	77	79	81

Source Elaboration on IEA (2014)

increase in demand will be significant but slow. According to IEA forecasts, European demand will only recover to the 2010 level after 2030.

Considering that after 2010 several new pieces of import infrastructure were commissioned in Europe, including Nord Stream, the overall need for new investment in transport capacity seems to be uncertain. Indeed, the European import capacity is underutilised, and in particular a large share of the existing regasification capacity most of the time sits idle. Therefore, even though some minor items of import infrastructure are under construction for security and political reasons—such as LNG regasification plants in Eastern Europe—no new large investment is expected soon.

However, a second driver of import demand—and the related infrastructure—is expected to play a relevant role: a further decrease in domestic production. Several European fields, especially in the North Sea and in the Netherlands are mature and are expected to decrease their output as they approach the end of their lifecycles.

Substituting this missing output is expected to nearly double the European import demand over the next two decades (see Table 6), bringing forward to the beginning of the next decade the recovery of 2010 import levels.

Considering the massive underutilised import capacity already existing in Europe, many suppliers will be ready to compete for a larger share of the European market. Their effectiveness in expanding their export volumes will depend on an expansion of intra-EU interconnections, which are essential to allow gas flows between the national gas networks.

Interconnectors will be particularly important for the ability of the LNG regasification terminals to compete. Indeed, LNG supplies at the global level are expected to expand towards the end of the current decade, in particular due to the commissioning of new export facilities in Australia.[33] However, the European LNG regasification terminals are mainly located in the UK and Spain. Particularly in the latter case, the lack of suitable interconnections with the core market (Germany) may strongly limit the growth of LNG imports. Moreover, the competitiveness of LNG supplies will be influenced by the level of demand in Asian markets, where final prices are higher than in Europe.

Supplies coming from other sources via pipeline will instead face quantitative limits. In the case of Norway this is because the largest and most accessible fields in

[33]Australian LNG exports are expected to drive some Qatari supplies towards European markets.

the North Sea have already been exploited. In the case of North Africa, despite large available reserves the current political situation is blocking (Libya) or slowing down (Algeria) the new investments which are necessary to increase production. In the case of Azerbaijan, which is expected to supply Europe through Turkey by the end of the current decade via the Southern Gas Corridor, the size of its proven reserves is a major limit to any significant expansion beyond current plans.

5.3 *Risks and Challenges: The Enduring Relevance of Russian Supplies*

Gazprom's strategy of consolidating its role as the main European supplier and diversifying its transport routes will come under increasing pressure in the future due to several challenges at different levels. Nonetheless, Russia retains relevant advantages and it is likely to remain a major EU supplier. The first pillar of Russian potential are its reserves, which are far larger than those of its competitors (see Fig. 6).

The Russian reserves, which are mainly located in Siberia, can be exploited at competitive, albeit rising, costs. Indeed, Russian operators—Gazprom or other future competitors for exports—will increasingly have to invest in high-cost projects to access geographically remote fields in the north or to adopt more expensive and better performing technologies.[34] The most challenging aspect will be the involvement of foreign partners to access a larger financing base and to share risks, but the rising costs are not expected to jeopardise Gazprom's competitiveness, especially when the limits experienced by Russian competitors such as Central Asia or North Africa are considered.

Moreover, by exploiting the existing and mostly amortised pipeline system, Gazprom also remains competitive in terms of its transport costs, especially when compared with new infrastructure, such as the Southern Gas Corridor. However, transport infrastructure will be a more challenging issue. The most relevant problem is uncertainty regarding the European regulatory framework because European regulation is not backed by a consistent energy policy. Before its abandonment, the case of South Stream was a clear example of competing visions and interests at the national and European levels, which prevent a more consistent approach to the regulation of energy markets.

Nord Stream is also facing problems with European regulation, since the current application of the third energy package is preventing exploitation of the full

[34] See Valery Kryukov in this volume.

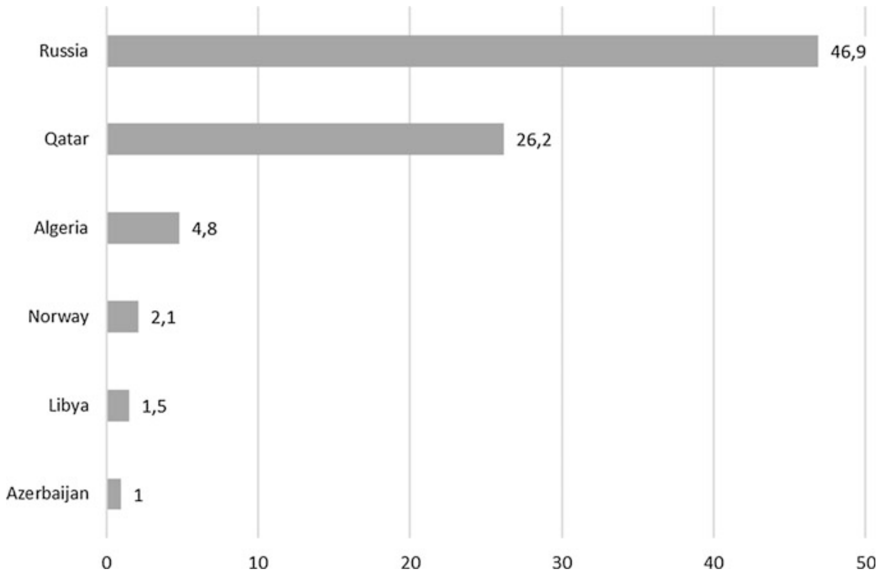

Fig. 6 Natural gas proven reserves (thousand billion cubic metres). *Source* Elaboration of EIA (2015)

capacity of the pipeline by limiting access to internal pipelines on German soil.[35] Moreover, since 2012 Gazprom has also been under formal investigation for alleged limitation of competition in Eastern Europe, but the case is still pending.[36]

The Russian government perceives these interventions as politically driven. In general, contrasts between Gazprom and the European Commission may further increase the uncertainty deriving from European market regulation and lead the Gazprom management to reconsider any expansion of its export capacity towards Europe. At the same time, this uncertainty reduces the potential for a diversification of the European gas system.

The need for more transport capacity and more diversification may become even less relevant for Gazprom according to the evolution of the situation in Ukraine. Until the beginning of 2014 and the ousting of President Yanukovych, Ukraine had represented a source of uncertainty and risk for the security of Russian exports, since Kiev used its transit position as a tool to negotiate better terms with Gazprom for its supplies, as in the case of the 2006 and 2009 disputes. However, the new situation that emerged in the course of 2014 is reducing the blackmailing potential of the Ukrainian government, which is now forced to maintain predictable

[35]The third energy package is composed of Regulation (EC) No 713/2009; Regulation (EC) No 714/2009; Regulation (EC) No 715/2009; Directive 2009/72/EC; and Directive 2009/73/EC. The pipelines to which access is limited are the Nordeuropäische Erdgasleitung (NEL) from east to west and the Ostsee-Pipeline-Anbindungsleitung (OPAL) from north to south.

[36]Competition case No 39,816.

behaviour to preserve the support of Western donors and borrowers, such as the EU and the International Monetary Fund. These institutions are now directly involved in the financial stability of Kiev and will act as indirect guarantors of Gazprom credits.

Paradoxically, this new situation in Ukraine will make it a more reliable partner for Russian transits. The existing pipelines can accommodate an increase in Russian exports towards Europe with an investment in maintenance and upgrading which would be mainly financed by Western institutions, such as the European Bank for Reconstruction and Development. Thus, Gazprom can abandon its pursuit of further diversification: indeed, since the solvency and predictability of Naftogaz now rest upon the commitment of western European countries—i.e. the customers for Russian gas transiting through Ukraine—Gazprom could resort to the use of existing infrastructure and achieve a similar level of security while avoiding the cost of a new pipeline.

The major uncertainty for Gazprom will come from the dynamics of the European market. Expectations about import demand may prove to be too optimistic, the European market may be very slow to recover, and the current excess of supply may endure for a decade, increasing competition among suppliers and therefore reducing margins. Another negative impact on Russian exports may come from the increasing availability of liquefied natural gas, which, even though it cannot directly displace Russian exports—Germany, for instance, has no regasification terminal in its gas system, nor are there any in Eastern Europe outside Lithuania—may further increase competition.

The evolution of EU regulation on gas markets may also hamper Gazprom activities, further reducing profitability.[37] In particular, the development of the European market is also challenging one of the tenets of the Gazprom business model: oil-indexed long-term contracts. This type of contract, conceived in the 1970s when gas was substituting oil products and European incumbents operated in captive markets, has been progressively revised over the last decade. Even though they still represent a large share of the portfolios of the main European operators, Gazprom has been forced to renegotiate all major contracts of this kind, thus reducing its margins.[38]

The future evolution of market integration at the European level is not likely to forbid this type of contract, but its economic sustainability in a more liquid hub-based European market could prove to be challenging.[39] At the same time, without long-term commitments by the importers, the construction of new pipelines will be far more difficult to finance. Thus, Gazprom, which already has an export network, will more easily maintain its presence in the European market and manage to survive better than many competitors due to a long period of a buyers' market. Overall, despite competition from LNG and piped gas coming from other sources,

[37]See Yafimava (2013).

[38]See Bordoff and Hourser (2014, p. 17).

[39]See Franza (2014).

Gazprom's supplies seem to retain a large enough competitive edge to defend their market share in Europe on a purely economic basis. Gazprom is also beginning a process of significant diversification of its final markets, aiming to reduce its dependence on European demand while at the same time increasing the volumes exported. The most important step in this direction is the agreement between Gazprom and China National Petroleum Corporation for 38 Bcm/year, beginning in 2018 and in force for 30 years.[40] Indeed, China is expected to account for a large share of new gas demand at the global level in the coming decades, absorbing increasing volumes of Russian gas.

The construction of this pipeline exporting Eastern Siberian gas to Eastern China will be a major step towards a more balanced position for Gazprom at the international level. In any case, the Chinese market does not represent a substitute for the European markets, since its will absorb only a fraction of the current European imports of Russian gas. Moreover, the fields used to supply Europe and China are very far apart, so they need different investments and their flows cannot be re-routed without notable price increases, confirming once again the lack of flexibility imposed by pipelines.

6 A Link Bound to Stay

The pipeline system is the best representation of the trade relationship between Russia and its European partners. Construction of it was the embodiment of a mutual commitment which transformed enemies into trade partners during the 1970s, and during the 1990s accompanied and sustained the transition of the post-Soviet republic. Trade flows between Russia and Europe have steadily grown over time, while the pipeline structure has expanded and evolved to pursue new strategies of route diversification.

Nowadays, Russia is the main supplier of natural gas to the European markets, accounting for approximately 30 % of EU consumption. At the same time, Europe is by far the most important market for Russian gas exports, accounting for more than three quarters of the overall volumes exported. Inevitably, the stability and reliability of the flows directed to Europe will remain a key priority for the Gazprom management.

As regards the future, the existing pipelines provide Gazprom with an established and scalable export capacity which is still largely associated with long-term contracts. Even in the likely case of an evolution of the European gas markets towards a hub-based model, this infrastructural endowment will provide a sound basis for maintaining a large share in the final market for Russian gas.

Moreover, the expected evolution of the European demand for imports is creating the conditions for a further expansion of the volumes imported from every major supplier, starting with Russia. If the financial commitment of western

[40]See EIA (2015b).

institutions continues and a progressive stabilisation of Ukraine emerges, Gazprom will be able to significantly increase its exports towards Europe even without building new infrastructure.[41]

In a long-term perspective, going beyond the next decades, the main uncertainty will still concern the size of the European energy demand. Indeed, even when Gazprom's diversification strategy becomes effective, the Russian reserves will be large enough to secure supplies for all its customers. The risk is that they will remain idle due to the effects of the European energy transition.

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[41]The only new pipeline may instead be towards Turkey, whose dynamic final demand is likely to attract new infrastructure investment over the medium term.

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Turkey as an Energy Hub for Europe

Nurşin Ateşoğlu Güney

Abstract Like other energy-dependent countries in the international system, Turkey is naturally in need of a diversification of its energy sources. While doing this, Turkey also seeks to benefit from its unique geopolitical situation, which provides the most cost-effective means of transformation and which connects countries located on the demand and the supply sides of energy, in a region where energy transportation routes can carry hydrocarbons from the Middle East and Caspian basin to the European Union. Due to the increase in its demand for energy and in the light of Europe's imminent need to diversify energy transit routes, as proclaimed in 2008 EU commission Green Paper, Turkey is attempting to refashion itself as an energy hub between the demand side of Europe and the various resource suppliers.

1 Introduction

Over the last two decades, Turkey's importance in the energy market has been on the rise, in parallel with its economic development. According to the International Energy Agency (IEA), energy use in Turkey is expected to double over the next decade, while the demand for electricity is expected to increase at an even faster pace (IEA 2014).[1] Turkey currently imports nearly 70 % of its energy from abroad at an annual cost of nearly 60 billion dollars. It can easily be described as an energy-dependent country. In the face of today's energy security requirements, Turkey thus needs to satisfy its energy demand from a reliable and environmentally-friendly source at a reasonable

[1]Turkey: Country Analysis Brief Overview, (2014), EIA, US Energy Information Administration, http://www.eia.gov/countries/country-data.cfm?fips=tu. Accessed 20 February 2014.

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cost, and without the risk of interruption of supplies. Like other energy-dependent countries in the international system, Turkey is naturally in need of a diversification of its energy sources. While doing this, Turkey also seeks to benefit from its unique geopolitical situation, which provides the most cost-effective means of transformation and which connects countries located on the demand and the supply sides of energy, in a region where energy transportation routes can carry hydrocarbons from the Middle East and Caspian basin to the European Union. Due to the increase in its demand for energy and in the light of Europe's imminent need to diversify energy transit routes, as proclaimed in an EU commission Green Paper (Green Paper 2008), Turkey is attempting to refashion itself as an energy hub between the demand side of Europe and the various resource suppliers. Within the limits of the changing geo-political conditions, Turkey has so far tried to make progress in this ambitious strategy via three aims: first, to meet its own energy demands; second, to pursue the prospect of becoming a fourth alternative partner state in the EU's strategy to meet its hydrocarbon demand; and third, to use pipelines—since they are able to transcend the various borders—as instruments for constructing new relations based on the concept of 'good-neighbourliness' between Turkey and her immediate neighbours and beyond. For this reason, Turkey has tended to interpret the pipeline routes from Russia to the EU not as rivals but as complementary to the ones that go via Turkey to the EU.

Under the current fluctuating geopolitical conditions, Turkey today faces an environment that is embroiled with risks but also with opportunities. The discovery of new energy sources around Turkey from time to time has stimulated the desire of Turkey and the EU countries to acquire new sources and diversify routes. The aim of the two sides is to meet their ever-increasing energy demands. After the Ukrainian crisis, the Euro-Atlantic world's cooling relations with the Russian Federation have surely encouraged Brussels to strengthen its current energy policy in favour of diversification of both energy sources and pipelines that bypass the ones from Russia. Of course, this situation has revived debates surrounding the Southern Gas Corridor (SGC) (Cutler 2014) and hence ideas of strengthening the SGC by simply reaching new source countries and routes from around Turkey's neighbourhood and beyond have been raised. Consequently, a question that needs to be tackled is that of the prospects for Turkey to become Europe's energy hub under the present fluctuating geopolitical conditions.

2 Turkey's Energy Outlook

The history of energy in the 20th century is primarily about oil; all efforts were made to find oil, secure supplies, and bring it to the market at an affordable price. Since the 1970s, after the OPEC oil embargo, greater efforts have been made to try to decrease and possibly avoid a dependency on oil. The developed world today is thus using far less oil than previously. For instance, consumption in the OECD is in long-term decline: in 2012 the industrialised countries used the same quantities of oil consumed in 1995, and European countries have returned to consumption levels last seen in 1967 (BP 2014; Kalichi and Goldwyne 2013). It has thus become possible to state that a decrease in the consumption of oil has become a reality on the ground in terms of the EU's energy quotas over the last two decades or so. However, with the increasing demand for natural gas, securely obtaining it (at affordable prices) from source countries has in turn become a challenging task due to many factors, such as geopolitical changes, a shift in demand from west to east, technological advances in drilling and their effects on various countries, and the many conflicts that have erupted or are continuing in many regions around the world. These important developments around the world have pushed many countries, and the Euro-Atlantic world in particular, to focus on the attainment of energy supply security. So as to meet the requirement of credible energy supply security and to ensure uninterrupted access to environmentally-friendly energy supply sources at an affordable cost, many western countries have launched action plans. In the push to realise this objective priority has been given to several aims. In order to meet rising demands for energy at home, countries have first of all decided to diversify their energy mix with various kinds of energy source, such as renewables, nuclear and indigenous fossil fuels. Second, with the aim of ensuring their energy supply security, they have also decided to diversify both their potential energy source countries and energy transit routes. Moreover, these energy-dependent countries hope to find solutions to the acute problems of energy supply security by decreasing the excessive demand for energy at home with the help of technological advancements and diversification methods. Simultaneously, they hope to reduce domestic energy consumption via the realisation of energy efficiency and through investment in alternative energy.

As happened in Europe, over the last decade Turkey's per capita income has increased. Together with positive demographic tendencies and a high rate of urbanisation, this has naturally led to an increase in energy demand. Turkey's demand for petroleum and other liquids has naturally increased, and Turkey's future demand for energy has been estimated to increase yearly by about 7 % until 2023. This particular state of economic affairs has made Turkey one of the fastest growing energy markets in the world. Even more striking is that over the last decade Turkey has become the second country after China to experience an increase in demand for both natural gas and electricity. However, due to its limited domestic reserves, which currently only meet 26 % of its energy consumption, Turkey imports nearly 70 % of its oil and gas (Ministry of Foreign Affairs 2014).

With its rapidly growing economy, a phenomenon seen in other countries too, Turkey has been described as an energy-hungry country as it is still forced to import most of its fossil fuels from abroad. Knowing that the *energy equation* has two sides—supply and demand—Turkey is in fact acting in a rational and balanced way to guarantee its overall energy security. On the one hand it is focusing on ways to reduce domestic energy consumption (the demand side) and on the other it is trying to fortify its energy supply security by ensuring access to various energy sources.

2.1 Turkey's Energy Outlook: The Demand Side

According to the International Energy Agency (IEA 2013), Turkey is expected to see the fastest medium-to-long-term growth in energy demand among IEA member countries. It is estimated that total final energy demand will more than double by 2020 (EIA 2014a, b, c). Likewise, it is also estimated that Turkey's electricity, natural gas and oil demand will reach 398.434 billion kWh, 59 bcm and 59 million tons respectively. According to the Investment and Promotion Agency of Turkey (ISPAT), the total financial outlay required to meet Turkish energy demand by the year 2023 is approximately USD 120 billion (Ministry of Foreign Affairs 2014; Turkish Perspective 2014). What is most striking is that this amount is over twice the amount of investment that has already been made over the last decade in the Turkish energy sector (Ministry of Foreign Affairs 2014).

In the face of this rapidly growing energy demand and with the aim of facilitating the required financial investment, the Turkish government has tacitly given utmost priority to the private sector. Among the necessary major steps in this direction, it has become a party to the Energy Charter Treaty (ECT), which requires its members to create fair conditions for international investors. Turkey has therefore established mechanisms for arbitration and enforcement. Direct international investments in Turkey in 2011, mainly in the energy sector, reached USD 4.2 billion. The Turkish government's future investments, particularly in the energy sector, are expected to increase yet further in the forthcoming years. In order to boost the pace of investment—with the objective of facilitating and attracting more foreign investment in the energy sector—the Turkish authorities established an Incentives Implementation Authority for Foreign Investments and passed a new petroleum law. It is because of these newly introduced legal and political measures that the number of foreign investors in the energy sector in Turkey has increased to the extent it has over recent years. New important incentives such as VAT exemptions and certain tax breaks encouraging exploration and production have also played an important role in encouraging an increase in the number of foreign investors (Ministry of Foreign Affairs 2014).

With the aim of meeting the growing energy demand, Turkey has introduced a strategy of diversification of its energy mix, via development of its own indigenous resources. Turkey believes that these indigenous sources could in time become major preventive measures to meet the increase in domestic energy consumption. Following its stated Energy Strategy Plan for 2010–2014, Turkey declares that by 2030 it will be meeting 30 % of its electricity needs from renewables (Energy Strategic Plan 2010–2014 2010). Turkey has thus decided to increase the share of renewables in its energy mix by promoting the future use of its hydro, wind and solar energy sources.

Knowing that 70 % of its energy requirements currently rely on imported fossil fuels, Turkey has decided to sanction the gradual commissioning of nuclear power into its energy base. The aim is to at least reduce and at best roll back the cumbersome dependency on fossil fuels in favour of the development of indigenous energy sources. In parallel with a growth in renewables, Turkey envisages producing 10 % of its electricity from a nuclear capacity of more than 10,000 MV by 2030. In accordance with this new approach, Turkey has signed an intergovernmental agreement with the Russian Federation, which is expected to undertake both the construction and operation of a nuclear power plant at Mersin-Akkuyu. A second nuclear energy power plant, a venture between French and Japanese firms, will be built at Sinop and it is estimated to be completed in 2017. Finally, with the aim of decreasing the pace of energy demand and reversing or at least halting the current energy dependency on imported fossil fuels, Turkey has decided to take measures related to energy efficiency. An Energy Efficiency Coordination Board has been formed to recommend the use of certain means of energy efficiency in the transportation and building sectors (Ministry of Foreign Affairs 2014).

2.2 Turkey's Energy Outlook: The Supply Side

Despite all these plans to diversify Turkey's energy base with renewables and nuclear energy, the Turkish economy still relies heavily on fossil fuels.[2] Turkey thus declared, via the Ministry of Energy and Natural Resources, a strategic plan for 2010–2014, a plan that first and foremost aims to achieve and guarantee energy supply security on the condition that it is environmentally suitable. This proposal has four declared objectives: first, to diversify Turkey's energy supply routes and source countries; second, to increase both the share of renewables and of nuclear energy in the energy base; third, to take steps to ensure that the country's overall energy efficiency is improved; and finally to contribute to Europe's imminent energy security needs.

Turkey's particular location on the world map, positioning her at a critical juncture and making her a bridge between east and west will eventually help it become a crucial energy hub for Europe. Turkey's ambition in this regard was openly revealed in the Strategic Energy Plan for 2010–2014, in which it stated that Turkey supported the idea that when major multi-pipelines—either realised or proposed—became operational, in line with the basic aims of the Strategic Plan for 2010–2014, as a transit country Turkey would be expected to play an important role in the flow of hydrocarbons between the energy-rich Caspian basin and Middle Eastern countries and the energy-hungry European countries in the west. In this way, Turkey expects to be able to meet its increasing demand for hydrocarbons and also has the declared target of assisting the EU in its efforts to diversify both energy sources and pipeline routes (Energy Strategic Plan 2010–2014 2010).

[2]The share of coal, for instance, is still 26 % of Turkey's production of total energy.

3 The Diversification of Oil Pipelines: Turkey as a Reliable Transit Country

Turkey's total liquid fuel consumption averages 734,800 bbl/day and more than 90 % of the crude oil is imported. According to the IEA (2014), Turkey's crude oil imports are expected to double over the next decade. Since Turkey has only modest on-shore oil reserves situated in the south-eastern region of the country, oil imports are expected to continue in the foreseeable future.[3] New oil exploration efforts both in the Black Sea and the Mediterranean over recent years have yet to yield any substantial outcomes. The same holds true for shale oil and gas exploration. This explains why diversification of both source countries and pipelines has become a priority in Turkey's recent attempts to balance its energy-security equation. It aims to not only play an effective role as a reliable transit country between east and west, but also on the north-south energy axis. Every possible opportunity has been evaluated to ultimately establish multi-pipelines passing through Turkish territory. In its aim to become the energy hub for Europe and diversify its source countries, Turkey has not hesitated to opt for other available opportunities, for instance those emerging from the Russian Federation to commission pipelines running through Turkey on a north-south axis.

The Turkish economy today still remains largely reliant on fossil fuels. The present situation on the ground has shown that the heavy weight of oil, gas and coal in Turkey's energy base will continue to be a constant factor for some time in the future. For this reason, the strategy of attaining a diversification of resource countries and pipeline routes today still continues to play an important role and is a substantial factor in Turkey's future plans regarding overall energy security.

Presently, the Baku-Tbilisi-Ceyhan (BTC) pipeline and the Iraq-Turkey (Kirkuk-Yumurtalık) line are the two oil lines operating in Turkey. The BTC is also one of the main components of the East-West Corridor. Since this crude oil pipeline became operational in 2006, nearly 1.5 % of the world's oil consumption has been transported via Ceyhan. The Kirkuk-Yumurtalik oil pipeline continues to transport the oil that is produced in both Kirkuk and in other areas of Iraq to the Ceyhan (Yumurtalık) marine terminal. The capacity of this pipeline in 1984 was 45.5 million tons. Later on, with the construction of a second parallel pipeline in 1987, the annual capacity was upgraded and increased to 70.9 million tons (Ministry of Foreign Affairs 2014).

Along with Turkey's two main oil pipelines, the Turkish Straits also currently play a pivotal role in the international transportation of oil by connecting the major resource countries in the east and north to consumers geographically situated in the west.

[3]Turkey, is said to have on-shore reserves around the Aegean Sea, the Mediterranean and the Black Sea. However, the exploration efforts that have been initiated so far in the Black Sea have not brought any substantial outcome. Currently, the territorial disputes among Greece, Israel and Southern Cyprus continue to impede Turkey's chances of having access to the development of these fields.

Since 3 % of the world's daily oil consumption is shipped through the Turkish Straits, this makes it one of the most important global transit points (Ministry of Foreign Affairs 2014).

4 Diversification of Gas Pipelines: Turkey as a Reliable Transit Country

Over the last three decades, the share of gas in Turkey's energy mix has substantially increased. Between 2003 and 2013 Turkey's gas consumption doubled from 20.9 to 45.6 bcm. As Turkey has very limited gas reserves, it continues to import its gas requirements from abroad. Currently, it both imports its gas supplies via pipelines from source countries like Russia, Iran, and Azerbaijan and acquires it in LNG form from Qatar, Algeria, Nigeria and Norway. In 2012, the Russian share of Turkey's gas imports was about 56 %, making it the primary source country; imports from Iran constituted 18 and 8 % came from Azerbaijan. In 2011, the remaining gas requirements were either met via LNG (16 %) or via Turkey's own resources (1 %). Hence, Turkey's dependency on gas imports from Russia continues today and in amounts that far outstrip other source countries. This situation is very much similar to the current situation of the EU, which is still very much dependent on its natural gas imports from the Russian Federation, more than any other supplier country (IEA 2014).

In addition to the natural gas pipelines related to the Southern Gas Corridor known as BTE-ITGI-TANAP,[4] which have a total import capacity of 46.6 bcm, Turkey currently has four operational international gas pipelines: the Russia-Turkey West Gas Pipeline, via Kofcaz on the border with Bulgaria with a capacity of 16 bcm; the Russia-Turkey Blue Stream Natural Gas Pipeline via Samsun on the Black Sea with a capacity of 14 bcm; the Iran-Turkey Pipeline via Doğu Beyazıt close to the border with Iran with a 10 bcm capacity; and lastly the Baku-Tbilisi-Erzurum Pipeline running through Georgia via Ardahan with a capacity of 6.6 bcm (IEA Turkey 2014).

4.1 *The Southern Gas Corridor, TANAP, and TAP: What Is Next?*

Since the 2000s, the EU has regarded the diversification of both gas sources and supply routes as an unavoidable factor in assuring part of its energy supply security, and so it has given special importance to the introduction of the SGC as a means of

[4]The TAP and ITGI pipelines have already become operational. TANAP will become operational in 2018.

overcoming its dependency on Russia. Turkey, on the other hand, gives greater importance to the diversification of gas sources and pipeline routes as prerequisites of its Energy Security Plan for 2010–2014; Russian-origin pipelines are not seen as projects rivalling the future of the SGC. Turkey regards all possible pipelines running through the east-west corridor or the north-south axis—including Russian-origin ones—as complementary to one another. Thus, in 2005 it completed the Blue Stream gas pipeline with Moscow to bring Russian gas across the Black Sea to Turkey.[5] Once the TANAP project—part of the SGC—was finalised, as part of her gas supply security strategy Turkey did not hesitate to grant approval in 2011 for the South Stream pipeline project, which will transport natural gas to Europe through Turkish territorial waters in its exclusive economic zone. Furthermore, in contrast to its experience with Iran, Turkey, has always acknowledged Russia as a reliable gas supplier. Today, Russia's South Stream project is stalled because of the EU's recent suspension of talks aimed at bringing it into line with EU laws and because of the Union's latest attempt to force Bulgaria to freeze construction work on its section of the pipeline. On the eve of this recent problem with the South Stream pipeline project, Turkey recently came up with a new proposal to route it through the Thrace region of northwest Turkey rather than Bulgaria as an alternative means of resumption of the stalled project (Reuters 2014). Although no decision has been made in this regard, this alternative proposal has once again shown that Turkey is ready to cooperate with Russia, whether it be related to South Stream or some other pipeline project. In its gas deals with Moscow, Turkey has so far generally managed to complete relatively trouble-free arrangements, with certain profits also being obtained, such as cuts in natural gas prices, etc.

As stated, the present cold relations between the West and Moscow have forced the EU to focus once more on re-evaluating its overall energy supply security strategy. The Russian annexation of Crimea last year refocused Brussels' gaze on the idea of the SGC project.

Having witnessed gas shortages in some member states, it was natural for the EU to reinvigorate its energy security policy back in the 2000s, specifically in the aftermath of the 2006 and later 2009 Ukrainian crises. Indeed, after these two gas crises, the mutual interdependency between Moscow and Brussels surely played a crucial role in the EU taking several important initiatives that aimed at preventing any future gas shortages. In 2008 the EU Commission published a Green Paper[6] on energy security (Green Paper 2008; Cutler 2014). In issuing this Green Paper, the EU Commission in fact acknowledged that a great challenge lay before Europe in the field of energy security. However, the same Commission also brought two further possible solutions to the fore. The first was that European states should develop a common energy strategy for Europe. In the second proposal, EU countries were simultaneously advised to invest in new energy forms—such as renewables, etc.—so

[5]Lately, a new decision has been taken to expand the capacity of Blue Stream.

[6]Cutler (2014), The Role of the Southern Gas Corridor in Prospect for European Security Strategy, *Caspian Report*, (6), 28–42.

that they could reduce the Union's overall dependence on imported fossil fuels. Since that date, the EU Commission has taken several more important initiatives, notable amongst which was the November 2009 'Southern Corridor-New Silk Road', made public at the EU's May 2009 Summit in Prague. This initiative was first introduced in the EU Commission's communication 'Second Strategic Energy Review—An EU Security and Solidarity Action Plan' (COM/2008/781) and it aimed to bring a diversified gas supply to Europe from either the Caspian or the Middle East (Green Paper 2008). Under the rubric of this initiative, the European Union has identified a number of partner countries that could represent new sources of energy supply, many of which are located in the Caspian region and include countries such as Azerbaijan, Turkey, Georgia, Turkmenistan, Kazakhstan, Iraq, Egypt, the Mashreq countries, Uzbekistan and Iran. With this initiative the EU made certain that the potential gas resource countries in the Middle East (such as Iran and Iraq) or those in the Caspian region (such as Kazakhstan, Turkmenistan and Uzbekistan) could be part of the Southern Gas corridor if and when political conditions proved conducive to such agreements. As part of the EU's new energy resource diversification strategy, it decided to launch three new pipelines (the ITGI interconnector, the Nabucco and White Stream), which are expected to be of great strategic importance in the Union's Trans-European Networks Energy (TEN-E) project. So far, only the ITGI has been completed.[7] What is more interesting, however, is that although the Trans Anatolian Natural Gas Pipeline (TANAP) was not initially part of the EU's TEN-E framework, it has over time taken the place of the Anatolian section of the planned Nabucco pipeline. TANAP has thus finally been able to replace Nabucco's projected role in transporting Azerbaijani gas to Europe. At the inception of the EU's SGC project the expectation was to obtain approximately 100 bcm/year[8] (Enerji Enstitüsü 2014). This amount is roughly equal to a little less than 20 % of the EU's current consumption. What is more important in the EU's latest 'Energy Security project for 2035' (BP Energy Outlook for 2035 2014) is the need to diversify amongst resource-rich Middle Eastern and Caspian basin countries such as Azerbaijan, Turkey, Georgia and Turkmenistan. The possibility of having Iran and Iraq join the SGC are also mentioned in this document, again provided the political conditions are suitable. Presently, with ongoing crises and instability in the Levant and the Middle East, Azerbaijan with its rich gas reserves seems to be the best alternative available for TANAP, which will carry Azerbaijani

[7]Gas interconnectors can be considered an important means of diversification. ITB (Interconnector between Turkey and Bulgaria) is being commissioned for the end of 2017. The Interconnector between Bulgaria and Romania is planned to begin operating in 2015. The Interconnector between Greece and Bulgaria is also scheduled to be commissioned at the end of 2016. The interconnector between Bulgaria and Serbia is scheduled for commissioning towards the end of 2016.

[8]Over the next 20 years, one of Turkey's objectives is play a central role in the transporting of 100 billion cubic meters of gas to Europe. Therefore, it aims to increase TANAP's capacity in phases from a projected 16 billion cubic meters in 2018 to 31 and 50 % respectively. Türkiye Avrupa'ya Yıllık 100 Milyar Metreküp Doğalgaz İletmeyi Hedefliyor (2014), *Enerji Enstitüsü*, dlvr.75NLyl. Accessed 31 September 2014.

gas via Turkey to TANAP's starting point, namely Greece. In today's challenging Middle East landscape, Turkey still stands out as the most reliable transit country connecting the Balkans to the Caspian basin, two regions that are potential areas of stability and peace both now and in the foreseeable future. In this regard, TANAP represents an important catalyst that may provide a net gain for the countries involved—especially the countries in the Balkans and the Caspian basin—in that it has the capacity to create a win-win situation, instead of the generally accepted zero-sum mentality.

5 How Has the Future of the Southern Gas Corridor Changed After the Annexation of Crimea?

Since security conditions changed dramatically on the northern and southern flanks of the Euro-Atlantic world, due to acts of belligerence by Russia in the Ukrainian crisis and ISIL's advance in the Levant, EU capitals have become more and more concerned about predicting Russian behaviour and its reliability as an energy supplier. Once again, alternative sources have gained in importance for Brussels. Consequently, in the aftermath of the annexation of Crimea by Moscow, the SGC returned under the spotlight. Since then, a debate has arisen as to whether the SGC can become either a short-to-medium or a long-term major solution to the problem of the increasing gas demands of Europe. A further question has arisen of whether all the possible supply routes that are expected to come from alternative sources can be transferred via Turkey. The question of whether Turkey can become an energy hub has been widely debated among energy experts for some time in the midst of Europe's current energy re-assessments based on Brussels' drive to relieve itself of dependency on gas imported from Russia.

After the annexation of Crimea in late March 2014, EU leaders came to the conclusion that European efforts to reduce Europe's high gas energy dependency rates should be intensified. EU representatives asked the European Commission to conduct an in-depth study on EU energy security and formulate a comprehensive plan that would reduce EU energy dependency. When at the end of this in-depth analysis the EU Commission released its '*European Energy Security Strategy*' in June 2014 (European Energy Security 2014), the conclusion was that the Union's natural gas and energy supplies would continue to be in a state of vulnerability in the medium and long term.[9]

Thus, after the release of the EU's '*European Energy Security Strategy*' debates surrounding the SGC and the prospect of Turkey becoming a European energy hub

[9]The EU imports more than half of all the energy it consumes. Its import dependency is particularly high for crude oil (more than 80 %) and natural gas (66 %). The price of these imports is more than €1 billion a day, which is more than a fifth of total EU imports. European Energy Security Strategy (2014), European Commission, http://ec.europa.eu/energy/security_of_supply_en. Accessed 12 September 2014.

have been revived. 56 % of Turkey's natural gas needs are currently met by a single source, namely Russia. Furthermore, 7.5 bcm of gas a year are purchased—at a high price—from Iran. With the help of crucial new resources like the TANAP project, Turkey aims to reduce its natural gas import bill, which amounted to USD 60 billion in 2014.

The energy map of the Middle East, the Caspian and the Mediterranean is still in the process of being drawn up. When the natural gas from the Şahdeniz-2 reservoir is extracted and finally transported to Europe through Turkey via the TANAP, this will most certainly be a boon to Turkey's plan to diversify its energy security strategy. Together with its successor, TAP,[10] TANAP currently stands as the most convenient alternative diversification route to meet and balance Europe's pressing energy demands. More pertinently, the TANAP/TAP project remains in line with Turkey's 2014 Strategic Energy Plan, which aims to assist in the European objective of overcoming its dependency on energy imports via a diversification of source countries and pipeline routes.

For some time the IR community has been debating the issue of whether there are enough potential gas sources around Turkey ready for the use of the SGC to help Turkey become an energy hub for Europe. There are still several potential sources in and around Turkey's immediate vicinity that may yet join the SGC via Turkey. The EU has given serious weight to the notion of Mediterranean gas reserves being among the potential sources of energy that could be merged with the SGC via Turkey. However, the recent breakdown in the Cyprus negotiations and the new Israeli-Egyptian agreement (Johnson 2014) finalised in August 2014 now make this option only a faint possibility. Iraqi gas, which is expected to provide 8–10 bcm by 2020, has also been seriously considered by both the European and Turkish authorities as an alternative energy source for the SGC. However, this too has become a remote probability for two reasons. First, the international community knows that the Kurdistan Regional Government (KRG) has for some time been in serious financial straits. Second, the rapid advance of ISIL has now put the future of relations among the Turkish government, the KRG and the central government of Iraq in jeopardy (Chalabi 2014). The current geopolitical landscape is undergoing severe fluctuations due to the ISIL advance and the ongoing civil war in Syria, a complex situation that has created a dangerous and negative spillover effect, not only for Iraq but for the entire region. Moreover, when the nuclear negotiations that started in Geneva in October 2013 between Iran and the P5+1 eventually reached the signature of an interim agreement (Reuters 2013), the new situation naturally ushered in a new optimistic international climate and hence led Europe to consider Iran another potential alternative supplier for the SGC. The continuing work at the giant South Pars field has played a major role in encouraging the Europeans to think in this way (EAI 2014a). On the other hand, Iran is planning to transform the

[10] As part of the SGC, TAP will make a significant difference to the energy supply security of countries like Greece, Bulgaria and Italy. For instance, the gas delivery that will be made to Greece and Bulgaria via the TAP route currently represents approximately one-third of their natural gas demand.

available surplus into actual exports only after meeting its domestic needs from this South Pars field. Presently, two prerequisites are needed for Iranian gas to become a new source for the SGC. First and foremost, the nuclear negotiations have to be completed successfully. For the time being, they do not yet seem to be leading to a comprehensive agreement. Even if they result in success sometime in the future, the current status of the Iranian gas and oil sector and the need for new infrastructure will be a first barrier before any additional gas from the South Pars field can be extracted and transported to European markets via Turkey.

Azerbaijan, in comparison with other source countries located in Turkey's vicinity, today seems to be the most likely candidate to guarantee further supplies of gas to the SGC in addition to the current 16 bcm/y from the Shah Deniz 2 field. The good news is that six new wells have already been drilled in the Caspian Shah Deniz 2 field (Caspian Barrel 2014). This new situation has created an environment exciting enough for Europeans to think about obtaining extra volumes of Azeri gas by joining the SGC. Nevertheless, the gas that will be transported to Turkey from the new wells in the Shah Deniz 2 field will have to wait until 2020 to join the SGC due to continuing operational processes.

Another prospective future source for the SGC is Turkmenistan. The recent purchase by the Malaysian state-owned company Petronas of Statoil's 15.5 % stake in Azerbaijan's Shah Deniz production-sharing agreement is a promising development in terms of fostering European expectations regarding Turkmen gas. Approximately 5–10 bcm of gas can be expected. The Russian gas company Gazprom recently declared that it would like to bring to an end its annual purchase of 10–11 bcm of natural gas from Turkmenistan. Freeing this quantity of Turkmenistan gas from Russian influence means there is now a greater possibility that at least some Turkmen gas may be transported westward—namely to Europe. Moreover, as it currently risks being left with only one export market—China—Turkmenistan now seems more interested in seeing its gas supplies joining the SGC, in line with its own diversification strategy (Finance Asia 2014).

Under these constantly changing geopolitical conditions, since both Turkey's and Europe's energy supply security concerns and priorities intersect, the idea of reinvigorating the SGC project can be said to currently represent the optimum available option for both sides. At present, first Azeri surplus gas and then some amounts of Turkmen gas seem to be the most likely candidates to join the SGC in the near future.

6 Conclusion

Over the last couple of years, Turkey has often been associated with concepts such as 'energy corridor' or 'energy hub' among IR experts. This characterisation of Turkey has mainly resulted from Turkey's unique geographical position—at the crossroads of central Asia, the Middle East and Europe. With the radical geopolitical changes of the last decade, the main debate centred on Turkey for both the IR community and the natural gas markets is whether it could truly become a European hub as an energy transit country. To tackle the question of whether Turkey as a regional gas hub is mere myth or potential reality, we first need to know the energy outlooks of each of the natural gas-producing countries in conjunction with the existing geopolitical conditions. Without knowing the contours of the existing geopolitical landscape, it is impossible to forecast the prospects of the countries in Turkey's neighbourhood becoming alternative sources for the SGC and Europe.

In terms of Azerbaijan and Turkmenistan's present energy outlooks, much debate has focused on whether additional gas from these two countries could be supplied to the SGC. Once the TANAP project is completed, 10 bcm of gas from Shah Deniz Phase 2 is expected to flow from Azerbaijan to the SGC via Turkey in 2019. It is certain that this will represent a major historical moment in terms of the realisation of a fourth gas corridor supply in addition to Russia, Nigeria, and Norway.

On the other hand, it is true that the 10 bcm of gas from Azerbaijan via the TANAP/TAP pipelines will constitute less than 3 % of the EU's current natural gas imports, which is in fact equal to the current proportion of EU imports from Nigeria. The general view regarding TANAP is that with its current capacity it will not be able to meet future European demands for gas unless it is upgraded. Energy experts are now suggesting an expansion of this project so that it can provide a greater volume of gas flow from source countries to the SGC (Koranyi 2014).

Under the present geopolitical conditions, the prospect of bringing gas from countries in Turkey's vicinity to the SGC in the short to medium term (meaning by 2020–2025) may prove problematic (Koranyi 2014). Thus, the reality of not having enough gas for the SGC today naturally makes Turkey's chances of becoming a hub for Europe an unattainable objective. However, many people in the energy sector support the idea of bringing an expanded TANAP project to the fore so that Europe's urgent demands for gas may be addressed in the near future with gas from Azerbaijan and Turkmenistan.

Under the present conditions, it is possible to state that Turkey may well become a regional gas hub for Europe, perhaps not in the immediate future but after 2020, providing geopolitical conditions are favourable. Moreover, it is true that it is generally the *sensibilities* and *vulnerabilities* between states (in this case those between Turkey and its neighbouring gas source countries) that shape and determine the complex interdependencies (Esakova 2012) that ensure the sustainability of gas flows, whether the countries are on the supply or the demand side of the equation.

Any decision about the passage of gas or oil is primarily a matter of economic and political considerations, but such decisions are also directly related to the notion of a secure supply and demand for hydrocarbon reserves. Although EU gas demand is currently down due to European economic conditions, it is highly likely that Europe's needs for gas supplies will again be on the rise. This stems from Europe's current (and possibly continuing) inability to overcome its dependency on gas imports either by means of indigenous renewables or other non-conventional sources. This dependency is not expected to be resolved before 2035.

The reality of the EU's continuing energy dependency on overseas sources strengthens the credibility of the demand side of the SGC. From the future perspective of the SGC, this would mean that demand from Europe would be guaranteed. To also guarantee the supply side of the SGC, the preferences of one of the great powers (Russia or the US) need to be in synchronisation with the interests of both Turkey and the regional source countries. The future evolution of geopolitical conditions certainly stands as one of the most important factors that will affect the demand and supply sides of any future gas/oil transaction that is to be realised between the West and the source countries which may be expected to supply the SGC.

The Russian state-owned Gazprom today still meets more than half of Ukraine's gas demand and its supplies amount to nearly one third of Europe's imports. Of this amount, roughly half goes through Ukraine. It is certain that in the future the EU will be in need of more gas. In particular, when the EU countries start phasing out both coal and nuclear sources from their energy mix in line with the decision made by the 2014 EU Commission's Energy Supply Security targets for 2035, then natural gas will surely continue to be the most convenient back-up source until these targets are met. The current uneven performance of renewables among the 28 members of the EU is testimony to the reality on the ground.

The EU's recent decision to reinvigorate the supply of additional gas sources to the SGC surely overlaps and intersects with Turkey's priorities in this regard. However, until the future geopolitical conditions become convenient for source countries to freely supply gas to the SGC (through multi-transiting pipelines that are expected to be pass through Turkey), there seems to be only a very limited chance of additional gas for SGC use becoming available.

In this situation, it is worth taking into consideration some remarks regarding the EU's current energy supply security strategy from energy experts. For instance, Antony Froggatt of the London-based Chatham House think-tank currently believes that there is a need for the "EU [to] push for the completion of Southern Gas Corridor projects, one of which, TANAP, passes through Turkey" (Anadolu Agency 2014). According to Froggatt, the main issue confronting the completion of the SGC is that of finding the financial resources needed for this and related projects to be completed (Anadolu Agency 2014). Similarly, David Koranyi has also discussed the current status of TANAP. According to Koranyi, it is still not too late to upgrade TANAP and to give it expanded capacity so that it can begin to carry the surplus gas that is needed for consumers in the West. He therefore suggests the EU take all the necessary financial measures so that efforts to expand the capacity of TANAP can begin forthwith (Koranyi 2014).

If the present geopolitical conditions in the greater Caspian basin and the Middle East improve in the future, then it will be easier for some of the regional powers to initiate and implement gas and oil transactions. However, for the time being it seems only Azerbaijan and to a certain extent Turkmenistan are able to supply additional volumes of gas to the EU/SGC via Turkey. Since large amounts of both on-shore and off-shore gas and oil reserves are located in and around Turkey and since future EU demand for hydrocarbons is also expected to increase by 60–80 % towards 2030, we can expect most of the pipelines bringing gas and oil from these source countries to be a part of the SGC and to pass through Turkey.

It is therefore still possible for Turkey to become an energy hub for Europe some time in the future, so long as the new geopolitical conditions in and around Turkey's neighbourhood where the energy sources are mostly situated improve accordingly. Until then, so as to meet its constantly increasing energy demands Turkey will continue to search for and create alternative and better sources of energy in its immediate vicinity and beyond. Turkey will continue to assess both the source countries in her vicinity that might join the SGC as well as those seen as contenders—such as the Russian Federation.

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Russia's Oil Dilemmas. Production: To Go North-East or to Go Deep? Exports: Is a Compromise Between Westward and Eastward Directions Possible?

Valeriy A. Kryukov

Abstract The main topic of Kryukov's chapter is the economic foundation of liquid hydrocarbon production in Russia and its availability for exports to the EU. This chapter shows the basic trends in Russian hydrocarbon production and the steps and measures required to develop production and to export the products. Development of mature areas is a natural source of exports westward, while new fields and new areas are located in the north-east of Russia, closer to the Asia-Pacific market. At the same time, northern and central Arctic fields are close to both the European and Asian markets and the exact itinerary depends on transportation facilities and price conditions. Both the volume and type of hydrocarbons exported depend not only on production itself but also on consumption within Russia and on public policy. All these factors and conditions are subjected to analysis and discussion.

Russia is one of the biggest oil and gas producers and one of the main exporters of hydrocarbons. Hydrocarbon production plays a crucial role in the Russian economy, financial system and its economic and political negotiations with many countries abroad. However, this has not always been the situation. Russia has exported oil products since hydrocarbon production started during the second half of the 19th century but the situation changed completely when giant and super-giant fields were discovered in the 1950s and later in the 1960s and 1970s. The discovery of large fields allowed Russia not only to satisfy internal consumption but also to start to deliver initially oil and later gas in growing volumes abroad. Behind this process was not only the energy crisis of the early 1970s with its price increases and the growing vulnerability of the oil delivery system all over the world, but also attempts to satisfy the needs of the Eastern Bloc countries (and thus to tie them more closely with each other) and the growing needs of the Soviet economy for various industrial goods and technological equipment.

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All the Russian hydrocarbon exports until the mid-1990s were oriented westward. In order to do this, an enormous infrastructure and all the necessary facilities were built. Despite findings of giant fields always further from the western border, this was nevertheless both reasonable and economically viable, the main reason being economies of scale and the extremely low costs of getting oil and gas out of remote places.

Oil production and exports are determined by a large range of economic and political factors:

> Because Soviet planners have a range of options open to them involving various mixtures of supply-side and demand-side remedies to current energy problems, the implication is that they have choices to make. Underlying the choices is a complex and important set of economic and political issues. There is an energy 'problem' in prospect in the Soviet economy not because energy-supply growth rates may fall off far enough that energy exports will fall (but remain positive). Those exports carry economic and political benefits for the system. Yet to maintain those exports will be increasingly costly in the 1980s, either because of the rising capital and labour costs involved in maintaining energy supply growth rates, or because of the rising resource costs involved in conservation measures (Hewett 1984, p. 6).

To a large extent, the pace of the integration of Russian hydrocarbon production with that of the rest of the world is still based upon the same economic foundations: the economies of scale in developing large rent-bearing fields. However, nowadays the situation is changing rapidly with oil development from new sources (like shale and bitumen) and the old production model may not be able to dominate any more—especially in the case of a deteriorating and fast-changing resources base. Fields are getting smaller and more expensive, and this creates many new challenges and options.

The main topic of this chapter is the economic foundation of liquid hydrocarbon production in Russia and its availability for exports to the EU. The chapter will show the basic trends in Russian hydrocarbon production and the steps and measures required to develop production and to export the products. Development of mature areas is a natural source of exports westward, while new fields and new areas are located in the north-east of Russia, closer to the Asia-Pacific market. At the same time, northern and central Arctic fields and areas are close to both the European and Asian markets and the exact itinerary depends on transportation facilities and price conditions. Both the volume and type of hydrocarbons exported depend not only on production itself but also on consumption within the country and on public policy. All these factors and conditions will be subjected to analysis and discussion.

1 Russia's Liquid Hydrocarbon Production Economy: Getting Further Away and More Expensive

The Russian Federation possesses one of the world's largest mineral bases and holds a leading position in a few key areas in the energy sector of the global economy. According to the BP Statistical Review, Russia's subsoil contains nearly

25 % of the world's natural gas and 10 % of its oil reserves.[1] Russia is one of the largest oil producers in the world. Oil and gas development is not only a dynamic business but it also has much inertia: once solutions are identified and are materialised in fixed assets they continue working for decades. Despite the reforms during the last 23 years, Russian oil and gas production still largely depends on decisions and approaches that were implemented within the centralised planning system and by the leadership of the former Soviet Union. The main specific feature of the centrally planned economy was an 'economics of shortage' (as defined by Kornai 1980). Among other characteristics, this means a shortage of investment and especially of material resources to realise fast-growing ambitions. One of the main obstacles used to be a shortage of steel and construction materials.

We can indicate the following characteristics to sum up the main features of the previously developed approach:

- a commitment to switching from one oil and gas province (as it becomes more mature) to another new one. The path of development from the 1930s to now has followed this pattern. First it was the Volga-Ural petroleum province, then Western Siberia and the Far East, together with the shelf area of the Arctic and far eastern seas. The main driving idea is to find and put into production new fresh reserves of better quality (bigger, lighter, easier to extract) as fast as possible; but among many other negative effects was the transportation distance from the fields to the main industrial centres (the same problem applies to exports);
- a main emphasis on locating and rapidly developing major and giant fields taking advantage of economies of scale. Economies of scale not only allow cheap extraction of oil from the subsoil but also compensate the high transport costs arising from growing distances. Moreover, they allow huge economic rents to be extracted;
- creation of the capacity to produce hydrocarbons aimed not only at domestic consumption but also for export to other countries. This feature is also a by-product of the economies of scale approach (the abundant oil and gas reserves discovered in the 1950s–1970s were much bigger than any possible consumption within the USSR, and afterwards in Russia);
- because of the planned economy, a single tightly-integrated infrastructure to deliver, process and transport oil, petroleum products and natural gas was built from the oil and gas provinces to existing refineries (and quite often to refineries which could process oil of a certain quality from a certain area).

A very important feature of Russian oil development is that the fields and refineries are located quite far from each other. While the main fields are located in Siberia, most of the refineries are in the European part of Russia at distances from the fields exceeding 1.5 thousand km. This means a low level of flexibility of the producing companies in the case of oil delivery to other destinations. Behind this

[1] BP Statistical Review of Energy.

feature there was the logic of the centrally planned economy with one decision-making centre. In the case of market- or price-driven necessities it was not easy to realise producer (seller) intentions to deliver oil to other refineries or to other destinations. Historically, all the pipelines were oriented from east to west. Only two ran in other directions: from West Siberia to the south (to Kazakhstan) and to the east (to the Angarsk refinery located in eastern Siberia). All the volumes of oil and refined products delivered east of Angarsk were transported only by rail.

The development of the oil and gas industry has been analysed well in many reports and papers. According to Hewett (1984), “the problem Soviet leaders face is that their relatively abundant energy reserves are poorly located and expensive to exploit. They must devise a strategy to exploit them in a way to minimise the cost to society of achieving their goals” (Hewett 1984, p. 29).

This trajectory of oil production development—from one province to another and from one field to fresher ones—is not new and not a Russian invention. It is a general feature of the development of the oil industry all over the world. The specific Russian feature is a clearer and more straightforward orientation to the development of giant fields, with other fields and areas usually receiving much lower priority in terms of access to capital and construction activity.

> Historically, planners have tended to persist in pushing older fields and to delay the exploration of new fields until under-fulfilled oil-output plans left them no alternative (…) In the 1930s virtually all the USSR’s oil came from the North Caucasus and Azerbaidzhan (the fields around Baku), where some fields dated to the turn of the century (…) In the late 1930s those fields began to decline, and total output stagnated – leading to under-fulfilled output plans – in the absence of new fields capable of supporting further output expansion. Indeed, despite the fact that the Soviets knew of potentially large deposits in the Volga-Urals fields, they did not turn to seriously exploiting and developing them until the 1950s. As a result of the efforts there, oil output in the Volga-Urals expanded rapidly (25 percent a year in the 1950s), so that by 1960 the Volga-Urals accounted for 71 percent of the USSR’s output. That move into the Volga-Urals fields was partly facilitated by technical advances in drilling deep wells. By the mid-1970s, when the Volga-Urals fields had peaked, the oil industry was moving into Western Siberia, where output began to rise rapidly (Hewett 1984, pp. 51–52).

At the beginning of the 1960s, major oil and gas fields were discovered in Western Siberia. Since 1965 11 large deposits have been discovered, of which five are named ‘billionaires’ because of their original oil in place (the Samotlor Field—6684 Mt, the Fedorov Field—1822 Mt, the Mamontov Field—1349 Mt, the Lyantor Field—1954 Mt, and the Priob Field—1987 Mt). In the mid-1980s, 78 deposits in commercial development were producing 389 Mt of oil a year. The production was mainly from major deposits with recoverable reserves over 100 Mt. (Vakhitov 2005).

There is no need to talk about oil reserve depletion per se: Russia still has abundant reserves. However, questions arise regarding the industry organisation and the resource management which are behind the permanent changes in the resource base which are taking place. The industry started in the 1930s, then changes took place in the 1980s, and other changes will take place now, i.e. in the 2010s. This trend is accompanied by a slow movement of major oil discoveries from west to east (with few exceptions). Thus, changes in the resource base are accompanied by changes of geography, which creates the natural prerequisites for also transforming oil exports.

> The bosses in Moscow did not recognise the falling size of new discoveries as a natural evolution (…). There was indeed more oil to be found, but from today's perspective it is clear that the huge oil discoveries of the first few years were not to be repeated (…). The rate of decline in the size of new discoveries in West Siberia was roughly the same as it was in the Volga-Urals basin. In both cases, the average size of new fields fell by half about every eight years. The variance in the size of discoveries made each year in West Siberia remained high. This means that even with fast dropping average discovery size, large fields continued to be found (Grace 2005, p. 39–40).

Attempts and solutions only based on increasing investments in exploration and production were not profitable and did not improve the situation.

> By the mid-1980s the Soviet energy problem had become virtually the exact opposite of that of the West (…). In the West, energy consumption has become much more efficient than before; in the Soviet Union it has not. In the West, energy investment and exploration are sharply down; but the Soviets are investing and exploring more and more, as energy continues to drive leader's choices (Gustafson 1989, p. 8).

The quantity of the current oil reserves has become evident from two big discoveries made in 2014. The Velikoe (Great) field was discovered in March in Astrakhan Province, with proven oil reserves up to 300 Mt (nearly 2000 million barrels). As the Minister for Natural Resources has said, it is the biggest onshore discovery in the last twenty years. The field conditions are very heavy, with a very deep pool (4900–5100 m) with a high sulphur content. Preliminary investment estimates are as high as 1.5 billion USD and the estimated capacity is 38 million tons of production per year. It might take at least 7 years to reach this production target.[2] The second discovery is the Pobeda (Victory) oil field, offshore in the Arctic waters of the Kara sea. The reserves confirmed by the end of 2014 are about 130 Mt (900 million barrels).[3]

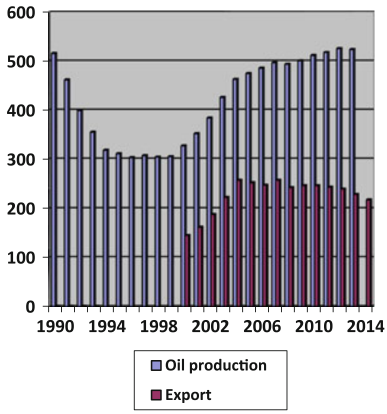
At the end of the 1980s a solution was found for the transformation of the oil and gas sector. In 1992–1995 the sector structure was drastically transformed. The main features were the following (Kryukov 1998):

- the formation of vertically integrated companies, including for the production, processing and sale of oil products;
- an (initially) partial privatisation of the newly-formed companies;
- leaving the oil trunkline system in state hands;
- opening windows for companies to export oil and oil products.

[2] GazpromNeft Great Acquisition: http://www.vedomosti.ru/companies/news/37768351/velikoe-priobretenie-gazprom-nefti.

[3] Arctic Victory; Prospects of Northern Offshore Fields Development //Arcticheckaya pobed: perspectuvy osvoenia shelfa severnykh morey. 16th October 2014. URL: http://glasru.ru/arkticheskaya-pobeda-pe.rspektivyi-osvoeniya-shelfa-severnyih-morey/.

Fig. 1 Oil production and oil exports. *Source* Minenergo RF



Among the most urgent and important outcomes of the changes was the opportunity for the newly-formed companies to decide how and where to allocate money. The transformation resulted in a revival of oil production in Russia (see Fig. 1). Among the main drivers of this were access to capital, the use of modern technology, and the opportunity to allocate resources according to company priorities.

As a result of the reform carried out in the 1990s–2000s (Kryukov 1998), Russia has managed to propel the economic indicators for field development in its oil industry to the nearly word-class levels currently witnessed. Nevertheless, at the same time the main emphasis of the production activities of the newly-formed companies (resulting from restructuring and later privatisation/deprivatisation) was put on fields already in production ('brown'—existing—fields, or under development). Among the fields under development a main priority was again given to big and giant fields. The use of modern technology allowed Russian companies to restore production and to start moving to 'green' field areas.

In practice, Russian oil production from existing fields is quite profitable, even at very low prices of 30–40 USD/bbl. However, production of oil from new fields—including recently discovered fields—is not at all. The development of such fields requires not only new tax incentives but also new technologies and a new competitive environment to reduce excessive costs. Despite recent tax breaks, most new projects for the development of tight oil remain unprofitable. Moreover, the new tax initiatives do not sufficiently change the results for most producers. Despite their importance in general, the fiscal advantages—including a zero mineral tax base—could not decrease production costs below the 60 USD/bbl level.

While prices are falling, the companies are planning their activities at different levels. For example, LUKoil has announced a decrease in investment in infrastructure development (which influences longer-term production).[4] Moreover, 2014 was

[4]The company's budget at the end of 2014 for 2015 was balanced at a price level of 80–85 USD./bbl.

marked by an enormous weakening of the rouble/USD and rouble/euro exchange rates (the rouble lost almost 80 % of its parity). Like any currency devaluation, this has a certain positive effect for local producers. A relatively low OPEX of 5 USD/bbl makes rouble-nominated costs much lower. A low OPEX in combination with new customs duties introduced on 1 December 2014 (more than a 40 USD/bbl decrease) are somehow to compensate for the oil price drop, but these compensations do not provide any incentive for new—offshore, and therefore costly—oil projects.[5]

Among the key issues for stable oil production development are new technology (above all, a heavy rig fleet) and a more adaptive and flexible industry structure. However, the problem is that Russia has only taken some first steps towards creating a modern oil industry. High oil prices (since 2000) and the use of modern technology (hydrofracturing, horizontal drilling and 3D seismic techniques are some important examples) had allowed almost all the Russian companies to be highly profitable and do their business well enough. Therefore, further changes to develop a dynamically adaptive industry (looking for better solutions based on improving both technology and its practices) have been almost neglected. Why improve your business in the longer run when you have plenty of previously-discovered reserves and you have the chance to use the regulations for your own priorities? This framework has been defined by Kryukov and Moe (2013) as a 'soft institutional environment'.

As explained above, Russia has a significant resource base to maintain and even increase production of liquid hydrocarbons. However, that resource base is under the influence of the above-mentioned natural evolution. This means that field sizes are getting smaller, wells need to be drilled deeper, the hydrocarbon composition is getting heavier, and rocks are getting tougher and less familiar to geologists. The result is not only growing technical difficulties and new challenges but first and foremost very high cost growth rates.

According to estimates from the Ministry of Natural Resources, costly (or expensive to produce) oil could reach a level of 52 Mt a year by 2015. This will require up to 100 billion USD of additional investments.[6] All the major and giant fields previously discovered and brought into development are now in a declining state of production, while newly-discovered deposits have much smaller reserves per field (see Fig. 2).

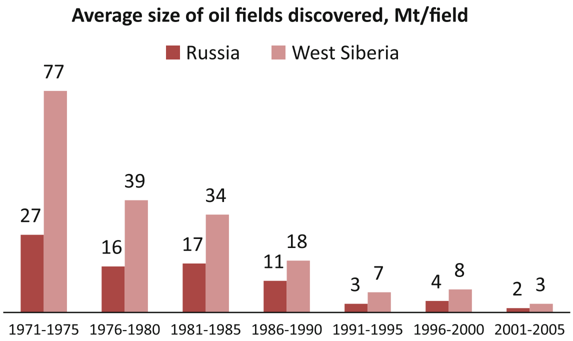
On the other hand, not only are the sizes of deposits decreasing, but the conditions of oil production are also changing, with a drastic increase in the numbers of deposits with difficult reservoir characteristics (which makes the use of traditional water-flow technology problematic) and containing oil of high viscosity.

In the main area of liquid hydrocarbon production in West Siberia, the Khanty-Mansiisk Autonomous Okrug (Yugra), the category of hard deposits includes 386 deposits in 96 fields with total original recoverable reserves of nearly

[5]http://www.vedomosti.ru/companies/news/36421101/deshevaya-neft-ugrozhaet-dobyche.

[6]Ministry of Energy—Results for 2012.

Fig. 2 The "natural evolution" of oil discoveries in Russia. *Source* Rosnedra RF



1.8 Gt of oil.[7] The subsoil in this area has enormous oil resources located in shale rock (so-called 'Russian shale'), the Bazhenov Formation. This area of the West Siberian Plain accounts for more than 1 million km^2 and the oil in place in its productive sediments is estimated to range between 100 and 170 Gt, while the original oil in place in Russia is 23–30 Gt. Using traditional methods, the recovery factor for the deposits in the Bazhenov Formation is in the 3–5 % range. Oil shale is abundant in more than 40 % of the Khanty–Mansiisk Autonomous Okrug. According to expert estimates, the recoverable oil reserves in the Bazhenov Formation exceed 3 Gt, and the oil in place amounts to 11 Gt. Currently, the formation produces 0.5 Mt of oil a year.

Besides heavy oils and complex fields, Russia has a significant potential for natural liquid gas production (light and ultra light oil and gas condensates). The long-term production of these hydrocarbons is related to the development of gas condensate deposits in the northern part of West Siberia, in the Yamal-Nenets Autonomous Okrug (YaNAO), and in the shelf area of Russia's Arctic seas. Nowadays, increases in the production of this type of liquid hydrocarbons is one of the factors sustaining the total liquid (oil and condensates) production in Russia (natural liquid gas production currently surpasses 21 Mt). Nonetheless, this source should not be viewed as a leading one, despite its important role (3–4 % of gross liquid hydrocarbon production).[8] Condensates are a by-product of gas production and this source's main limiting factor is the low level of gas production, which is limited not only by market size but also by both pipeline system capacity and investment levels. The level of growth in condensate production is very low, mainly due to emphasis on the development of projects approved and started earlier with certain specific characteristics: deeper and smaller pools with higher reservoir pressures. These need more advanced technology and more experienced personnel.

[7] http://www.oilnews.ru/10-10/razrabotka-neftyanyx-mestorozhdenij-xanty-mansijskogo-avtonomnogo-okruga-v-2001-godu/.

[8] URL://http://www.vedomosti.ru/companies/news/32110451/neftyanoj-udar-po-byudzhetu#ixzz3CE4w4lTV.

Certain conclusions can be drawn from this brief historical overview of Russian oil development and production and the resource base. Russia has a significant resource potential of liquid hydrocarbons which can allow production to be both maintained and increased in the foreseeable future (until 2030–2040). However, potential itself does not mean high and efficient production levels. The abundant resources require not only investments but also a different industry structure (oriented towards economic efficiency) and a more appropriate competition-oriented resource regime: a growing portion of the oil resources in Russia are now classified as hard to extract. As the conditions of the reserves and hydrocarbon production have become much more complicated—the composition of the hydrocarbon mix has drastically changed towards heavy and highly-viscous hydrocarbons—different technologies and, above all, a change in the institutional system are required, ranging from overhauling taxation on hydrocarbon production to encouraging new entrants into the sector. During the period of high prices and intensive redevelopment of existing fields, the structure of the oil industry became much more monopolised than before (large and vertically-integrated companies produce more than 80 % of Russian oil). The combination of the changing resource base and much lower oil prices now requires a 'balanced approach' to developing liquid hydrocarbon production, taking the following steps: (a) further development of major fields previously brought into development, (b) exploration of new regions with a potential for 'fresh reserves' (Eastern Siberia and the Far East), and finally (c) increasing the production of heavy and highly-viscous oil [Tatarstan, Bashkortostan, Western Siberia, the Republic of Sakha (Yakutia)].

All the above-mentioned trends are to a large extent determined by the natural evolution of any mineral extraction industry in any country. As resources become more mature and more difficult and costly to extract, resource regimes (i.e. the regulatory framework and industry structure) change in order to give the chance to more flexible and more adaptive players to realise their ambitions. Instead, in Russia the market is developing in a quite opposite direction, with only partial changes in the fiscal system and a growing role for the state as a major directly-involved player. The principal indication of this trend is the diminishing role of small and medium-sized independent companies (their share decreased from 15 to 3 % between 1997 and 2013) and the growing role of state-owned Rosneft.[9]

The dynamics of liquid hydrocarbon production in Russia, as well as of exports to foreign markets, will largely depend on how well Russia can adapt to these challenges. In this respect, access to technology plays a crucial role; not only access to modern and advanced solutions, but in many cases access to new equipment in general (like heavy rigs). The current situation of Russian foreign policy—such as sanctions and growing animosity between Russia and other major industrial powers—makes the solution process even more complicated. Above all, this affects the

[9]Rosneft is following the traditional approach to developing the oil business, getting access to new areas (such as the Arctic and big 'strategic' fields) with the support of the state, and using this support to gain access to new markets and new sources of financing (see the chronology of Rosneft-China deals below).

exploration and development of the shelf areas and heavy oil fields (both heavy and residual), not to mention 'non-traditional' oil deposits. Such projects require not only a different institutional environment, but also modern technology, large investments, and new organisational models (involving many high-tech supporting companies).[10]

2 The Role of Hydrocarbons in Russia's Economy and the Importance of Oil Exports

The oil and gas sector in Russia is 'responsible' for:

- 20 % of GDP;
- 52 % of the federal budget receivables in 2013 (31.4 % in 2004);
- 67 % of export revenue;
- 25 % of fixed capital investments.

The importance of the oil and gas sector for the entire Russian economy lies not only in its enormous earnings, but also in its support to the other sectors. Hydrocarbon production—and especially exports—is a supplier of rent to the entire economy. This could be extracted and further redistributed in many ways. The main sources of rent are taxes and payments which the government imposes on both the internal consumption and exports of oil and oil products (Sagers et al. 1995). Since 1991, rent extraction has become more visible and at the same time started to play a much more important role than in many countries (Gaddy and Ickes 2010). This phenomenon has been defined as 'rent addiction':

> Many countries earn rents from resources. But what makes Russia different is the addiction to these rents. Addiction is the key phenomenon that explains how the financial crisis was manifested in Russia, and it is the most important factor shaping the future of the Russian economy (…). Russia's addiction is not any form of consumption-related dependence. It is the

[10]The sanctions which are now imposed on Russia are influencing not only access to technology and equipment but also to capital markets and financing in general. They have put a significant brake on the Russian oil production potential. The restrictions on access to capital markets are the following:

- A US prohibition of debt with a maturity of longer than 90 days to Rosneft, Novatek, GazpromNeft and TransNeft;
- An EU ban on selected financial instruments with maturity of more than 30 days in the case of Rosneft, GazpromNeft and TransNeft.
- Restrictions on access to equipment, technology, and services for use in selected project categories:
- Sanctions target deepwater, Arctic shelf, and shale oil projects (impacting all Russian oil industry projects in these areas).

Uncertainty over the precise scope of various sanctions itself acts as a significant brake on international investment and joint ventures.

result of structural changes in the nature of the economy brought on by accumulation of rents. Addiction refers to a condition in which there is an imperative to allocate rents to maintain and expand specific production sectors of the economy, notably those that the Russian economy inherited from its Soviet predecessor (Gaddy and Ickes 2010, pp 292–293).

Formally, oil production targets and the role of oil exports are regularly underlined in the updated versions of the Energy Strategy of Russia (the latest is the Energy Strategy of Russia for the period up to 2030, dated 2010; a new version up to 2035 is under discussion) (Institute for Energy Strategy 2010). According to this document, the main aims for the development of the energy sector are the following:

- stable and reliable delivery of oil and oil products to the internal market;
- a growth in energy efficiency in all sectors and spheres of the national economy;
- financial stability of the energy sector and its subsectors and stimulation of productivity growth in the economy;
- environmentally sound behaviour by all actors in the energy sector.

A big difference in the latest versions of the Energy Strategy is a special attention to foreign economic relations and the participation of Russia in different energy markets. This is underlined by emphasis on a growing importance of taking into account changes in the development of EU energy markets. Regarding the development of the oil sector, special attention has been given to the following issues (some of which have a clear 'addiction' character):

(a) stable and economically viable delivery of oil and oil products;
(b) stable financial flows of state budget receivables;
(c) the formation and sustenance of high demand for the production of the supply sectors of the economy.

All the above-mentioned principles are being transformed in a process of implementation and realisation of certain projects and solutions. In 2013, Russian oil companies produced 523 Mt.; in 2014, despite growing difficulties in sustaining it, production increased to 525.3 Mt. An Energy Ministry forecast predicts a level of 525 Mt in 2015–2017.

It is important to link the development of the oil sector to its effects on the rest of the economy to be able to understand the driving forces behind oil exports in general, and to the EU in particular.

(a) **stable and viable delivery**

The departure points for determining the oil production level are the existing capacity and projects under implementation, and therefore it is determined as much by state policy as by companies taking decisions. At present, the situation in this respect is quite different to the past. Few big fields are present and few production increments can be achieved in the areas and fields under development. In the 1960s–1980s period, an enormous oil surplus was determined by giant fields (like the aforementioned Romashkino and Samotlor). Nevertheless, Russia's oil production is now almost twice its internal capacity for oil refinery products.

Russia is trying to convince and stimulate the oil companies to increase the efficiency of their refineries and to cut the volume of residual oil exported (at a price lower than the oil price). However, despite these efforts exports of gasoline and quality refined products are not following the stimulus and the measures enacted by the authorities (mainly in the form of export duties). In 2013, net crude exports dropped by 1.4 % to 235.8 Mt and at the same time net exports of refined products jumped 9.7 % to 150.0 Mt (mostly low-quality residual oil—51.9 % of the total, followed by diesel at 27.8 %). In the same year, domestic consumption of refined products went down by 4.7 % to 125.3 Mt (with gasoline 27.3 % of the total). This dynamic of falling crude and rising refined product exports has been quite stable over the last few years.

Russian diesel fuel, the main refinery product for export to Europe today, may no longer find purchasers in the future. In 2013, Russia exported half of all the diesel fuel produced in the country, i.e. 35.9 Mt; by 2020 the figure will have increased by 16 Mt. However, Europe is gradually cutting down oil refining processes, and the growth rate of diesel fuel consumption is declining. At that the same time, the share of the medium distillate supply from the USA to the EU market is growing: in 2002, the US share of European imports only accounted for 2 %; in 2012 this figure had risen to 17 %. As for China, it has no demand for diesel fuel. On the contrary, the country is building up the export trade of its own petroleum products, and becoming a fuel supplier. Therefore, should deliveries to Europe stop, it may result in processing units being shut down in some Russian oil refineries.

(b) **stable financial flows**

The next step in determining the volume of oil to produce (for both internal needs and export) is to consider how much money the oil companies need and the state budget needs. The answers to this are determined not only by the price level but also by taxation policy. Among the important and decisive factors that have to be considered is the economic development of certain remote areas (monoindustrial centres in the far north and far east).

The basic trend of oil production in Russia follows the Energy Strategy's targets and indicators. However, while it is easy to formulate the above-mentioned requirements it is not easy to fulfil them in reality. In fact, for the last 15–20 years there has been a "struggle" between the fiscal needs of the state and the companies' needs. So far, the winner has been the Ministry of Finance: the taxation system in the mineral sector is more fiscally oriented and only to a very weak extent takes into account the economics of field development (although the number of exemptions is growing). Moreover, the state is trying to extract rent not only through taxes and payments but also through growing direct participation in the oil and gas sector. By 2013, state-owned company Rosneft's share of the entire oil production was 36 %, while other big companies accounted for much smaller shares: Lukoil—17 %, Surgutneftegas—12 % and GazpromNeft—6 %.

The share of oil-generated taxes in the state budget receivables is steadily growing—from less than 20 % in 1995 to 52 % in 2013 (see Fig. 3). Oil taxes are playing a crucial role in balancing Russia's state budget and consequently in

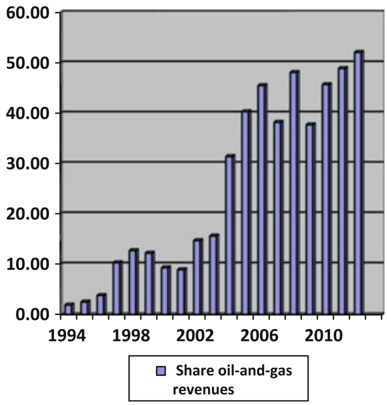


Fig. 3 Oil and gas revenue in the state budget (in millions of roubles). *Source* Ministry of Finance

financing state and social expenditure. They are the main guaranteed means of paying pensions, social expenditure (most importantly housing utility rates), education and medical expenditure. In fact, it was probably due to the growing role of oil and gas receivables that Russia smoothly overcame the period of crucial transformation in the 1990s. Of this income, oil and petroleum products provide four times more revenue for the budget than natural gas.

In his annual state of the nation address in April 2014, President V. Putin mentioned that the revenue for the state budget from oil production in 2013 accounted for $191–194 billion, whereas gas production provided only $28 billion. Thus, when oil prices fell from $100 per barrel to $50 or $60 per barrel—as was seen in the second half of 2014—Russia effectively lost half of its export revenue in a single year.

As for the economic rent that the state receives from oil, it is important to stress that a substantial portion of it depends on the volume of exports. Consequently, when the oil price drops by 10 USD/bbl, the state budget receivables fall by close to 10 billion USD. Russia's gross exports are illustrated in Fig. 4.

The Federal government is concerned about the trend of constantly declining revenues from oil exports in the last 2–3 years: in the first quarter of 2014, they decreased by 9.9 %.[11] Crude exports have been declining but production has risen. In 2013, 44 % of production was exported, compared to the peak of 55 % in 2004. A dominant portion of crude oil is exported by pipeline (especially via the East-Siberia Pacific Ocean (ESPO) pipeline, which has displaced most rail exports to the Asia-Pacific area).

One of the ways to compensate the shortfall in income from oil exports is the export of refinery products. Thus, in the first quarter of 2014 Russia's revenue from petroleum product exports grew by 12.4 % (compared to the same period in 2013) and reached $27,145 billion. However, the room for manoeuvre here is quite

[11]Federal Customs Service.

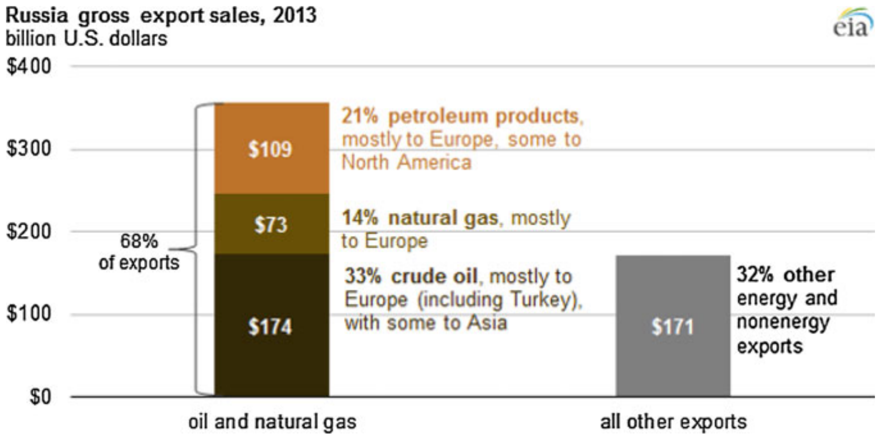


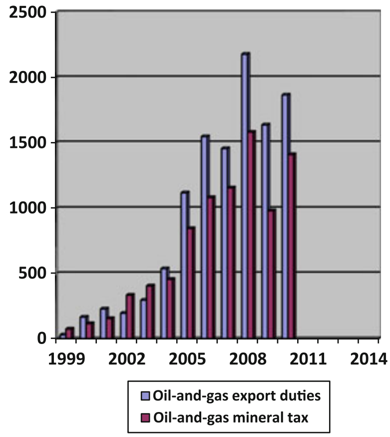
Fig. 4 Russia's export sales

limited because of the growing domestic demand for petroleum products, which should first be satisfied.

Nevertheless, despite their slightly declining export share, oil export revenues are still at quite a high level. Export duties constitute approximately 60 % of the entire oil and gas revenues in the state budget (Fig. 5). However, from 2015 the situation will change: as a result of a tax manoeuvre the main emphasis will be given to production taxation (mineral taxes).

The significant exposure of the Russian economy and financial system to price fluctuations in the global hydrocarbon markets was the core reason behind the formation of special "budget funds". The first example was the Stabilisation Fund, which was established in 2004 in accordance with the new Budget Code with the intention of accumulating revenue from hydrocarbon export duties and mineral

Fig. 5 Volume of export revenue versus mineral production taxes (billion roubles). *Source* Ministry of Finance



resource production taxes (see Footnote 1). The Stabilisation Fund was designed to collect revenues from oil prices that exceeded the cut-off price set at $27 per barrel in order to balance the federal budget should oil prices fall below the cut-off level. The Fund's resources were then invested in foreign assets, converted into foreign currency, or deposited in foreign banks. The Fund was thus created to protect the national economy from negative consequences in the case of falling oil prices and to provide stabilisation of the national currency in times of higher prices. It also played an important role as a mechanism to prevent inflation surges and to ensure currency stabilisation during periods of trade surplus. In January 2008, the Ministry of Finance split the Stabilisation Fund into the Reserve Fund and the National Welfare Fund. The foreign currency reserves of both Funds are denominated in US dollars (45 %); Euros (45 %) and GB pounds (10 %). Since 2008, oil and gas revenues have been calculated separately from other federal budget revenues. They are based on:

- the production tax for hydrocarbon resources;
- the export duty on oil, natural gas and petroleum products.

A portion of oil and gas revenues, termed 'oil and gas transfer', is used annually to finance federal budget expenditures (Kryukov et al. 2011).

As of April 2014, the budget funds of the Ministry of Finance of the Russian Federation had accumulated $175 billion (or 8.6 % of GDP). As previously discussed, both the creation of the original fund and its splitting were attempts to reduce state budget reliance on oil and gas revenues and to save up for "unforeseen circumstances". However, the deficit of the consolidated budget is currently tending to grow (since 2012) due to the declining share of oil and gas revenues, falling profits and steadily increasing high government expenditure.

These tendencies—the low yield from the other sectors of the economy combined with the growing challenges in maintaining production in the oil and gas sector—have created a complex situation. In many official forecasts,[12] the government expects to maintain exports of hydrocarbons, primarily of oil and gas, at a high level (along with a certain reduction in exports of petroleum products). According to the International Energy Agency, in the next five years growth in domestic demand for oil in Russia will move ahead of the growth in its extraction. Note that the energy consumption of the Russian economy, i.e. the energy input per GDP unit, is one of the highest in the world. At the same time, exports of hydrocarbons need to not only maintain a large share of the tax inflows into the state budget, but also assure a substantial income of financial resources to explore new (more complicated and less traditional) sources of hydrocarbons.

The main problem is that the Russian financial system is not large enough to satisfy the financial needs of the biggest oil and gas companies. The companies in this sector previously attracted the necessary financial assets from foreign financial

[12]The main directions of Russian fiscal policy for 2015 and the 2016–2017 period. Ministry of Finance of the Russian Federation. URL: http;//www.minfin.ru/common/upload/library/…/ONBP_2015-2017/pdf.

Table 1 Foreign service companies in Russia

Foreign service companies operating in Russia	Share of market (%)	Income, billion USD
Schlumberger	10	3.0
Weatherford	3	1.0
Halliburton	2	0.5
CAT oil	2	n.a.
Baker Hughes	1	0.5

Source Neftegazovaya Vertical—2015—issue 23–24—page 9

markets. One of the results of this is that the external debt of the corporate sector of the Russian economy has increased from $500 billion to more than $700 billion over a period of three years (2012–2014). Meanwhile, the ability of the largest Russian government banks to attract long-term debt financing from the US and the EU has decreased due to sanctions.

(c) **Formation and sustenance of high demand for the production of the supply sectors**

The oil and gas sector does not only play the role of energy and financial supplier. Project development requires enormous investments in equipment for the technical support of exploration and production services.[13] All countries are interested in a high local share of oil and gas activities and Russia is no exception to this common practice. The specific feature of Russian practice is that during the transformation period—i.e. the 1990s and the 2000s—no attention was paid to this side of oil and gas activity. As a result, the Russian economy became one of the biggest equipment buyers and one of the leading users of services delivered by companies like Schlumberger, Baker Hugh, Halliburton (see Table 1).

As a result, the money received by Russian companies is going back to the EU, US and China to buy equipment and pay for services. On average, up to 50–60 % of the equipment in the Russian oil sector is supplied by imports. The amount of this dependency varies according to the type of project—up to 20 % for traditional fields, 40–60 % for oil which is hard to extract, and more than 80 % for offshore oil, and the bulk of these purchases are from EU countries.

It is interesting to look at the historical trend. In the 1980s, the energy share of Soviet exports was close to the current figure, while exports of equipment were much higher than now (50.2 and 18.7 % of entire exports respectively). Recently, mineral product exports (including oil and gas) have constituted 71.4 % of all exports, while exports of equipment have only been 5.1 %. At the same time, in 2012 imports of machinery equipment exceeded 157 billion USD, i.e. 50.2 % of all imports. A substantial portion of this equipment was destined to the oil and gas industry and delivered by EU, US and Chinese companies.

[13]Investment in exploration and production in the oil sector in 2012—according to MinEnergo—was more than 25 billion USD.

From the figures and comments above, the conclusion follows that the quantity of exports of oil and hydrocarbon products is a function of many variables: developed and ready-to-be-developed resources, the financial needs of both the oil and gas companies and the state, and also the demand for equipment and high tech services. Nevertheless oil prices, costs and the industry structure are among the key drivers.

When the reserves were fresh (which means the capacity had only recently been created) there was no need to import new equipment and to use sophisticated recovery technologies in the short term. But as we have seen, and will examine in more detail, the period of giant fresh reserves is almost over. To sustain production, Russia needs to export at least at the present level and it needs access to modern and advanced technologies. This means that to sustain the required rate of hydrocarbon production Russia needs to export to the EU: only in this way can Russia bear the additional costs and time needed to expand new export directions. Moreover, Russia needs to maintain the export of hydrocarbons at a relatively high level because of the associated tax revenue. The "Addiction" of the entire Russian economy to the oil and gas sector requires access to the financial resources and modern technologies of foreign markets to explore new more complicated and less traditional sources of hydrocarbons.

What is behind Russia's demand for new technology and quantities of high tech equipment? Not only its inability to produce such equipment but above all the very narrow fiscal-oriented political policy of the state. This is why it is very important to look at where new oil could come from. What are the characteristics of new sources of hydrocarbon production in Russia? Where and how might oil from these new sources be transported to?

3 New Sources—Where Could Oil for Export Come from?

Russia's oil delivery to the EU depends on many factors, but first and foremost amongst these is the level of oil production and the availability of oil for export. The basic production trend is following the path of natural evolution: a maturing of fields put into production earlier and the discovery of new fields in new provinces (East Siberia, the Far East and offshore—especially in the Arctic).

Among new features, there is a growing importance of knowledge and the high-tech service sector in supporting the tailoring of energy extraction, in particular from old fields.[14] The most attractive example of this is the US shale oil and gas and tight oil "recovery". The US experience is quite unique—not only in terms of the resource regime developed in the country but also in terms of the level of knowledge and expertise accumulated in the industry and surrounding service sector over quite a

[14]Tailoring can produce a longer period of production despite a maturing and changing resource base.

long period. In this particular respect, Russia is in the initial stages of following worldwide trends and tendencies. So far, although many traditional fields have been put into operation, they produce oil which is hard to extract.

Over the past 20–25 years, the dynamics of oil production (and the availability of oil for export) have been characterised by the following stages:

- 1980–1990: a decrease in rates of growth, and then an absolute decrease in quantities extracted;
- 2000–2005: an enormous increase in extraction rates (the fastest increase was 13 % a year in 2005) and, consequently, a rapid accumulation of the oil production output; among the main drivers behind this phase were the privatisation of oil companies and access to modern equipment and technology (horizontal drilling and hydrofracturing). The recovery of the production level was achieved mainly due to better work on fields previously put into operation;
- 2006–2010: a decrease in the growth of oil extraction rates and the beginning of difficulty in sustaining the production of liquid hydrocarbons previously achieved. The decline was driven by an inability to further increase oil production only by intensifying production from existing fields using the traditional approach (starting with taxation and ending with a decrease in the motivation for oil companies to explore "green field" areas);
- 2011–2014: a halt in the growth of oil production (with increases some years due to new deposits, which, nonetheless, do not help to overcome the general trend in the longer run). New fields in East Siberia were put into production (but the average size of the new big fields in this area is more than ten times smaller than the giant fields in West Siberia).

From the viewpoint of transportation, it is important to note that the gradual movement of Russian oil production from the west to the east (East Siberia, Yakutia, the Far East) makes it more reasonable to deliver oil to the Asia-Pacific countries. At the same time, Arctic project development (Prirazlomnoe in the Pechora sea and Novo-Portovskoe in the Yamal peninsula) are more attractive in terms of oil delivery to the West (EU countries via the Northern Sea Route).

In December 2013, JSC GazpromNeft started oil production from Prirazlomnaya, a field in the Pechora Sea 60 km off the coast with an offshore ice-resistant stationary platform. In April 2014, the first oil tanker left the station with 70,000 tons of cargo and it is planned to ship more than 300,000 tons of oil. The new grade of oil from the Prirazlomnoye field is called ARCO (Arctic Oil), part of which will be sold on the basis of long-term contracts. The planned production is about 6 million tons per year (after 2020).[15]

[15]Интерфакс " «Газпром нефть» купила недропользователя Приразломного за 2,7 млрд рублей" ["Gazpromneft buys Prirazlomnoye's subsoil user for 2.7 billion roubles", *Interfax*], April 25, 2014.

http://www.vedomosti.ru/companies/news/26877361/gazprom-neft-kupila-nedropolzovatelya-prirazlomnogo-za-27#ixzz34QIQwCkH.

A particularly interesting case is the Novo-Portovskoe oil and gas field. According to estimates by GazspromNeft—the licence holder for the field development—it is more convenient to deliver its high quality light oil to Rotterdam instead of Japan or China. The overall production from the Novo-Portovskoye field is estimated to be 220 million tons of oil and 260 bcm of natural gas. A year-round oil export terminal near Mys Kamennyy on the Gulf of Ob was opened in 2014, and the field will be brought into production in 2015. Novatek plans to build a liquefied natural gas plant (Yamal LNG) at Mys Kamennyy, which is approximately 400 km to the south of the Port of Sabetta.[16] Between 2013 and 2015, JSC GazpromNeft expects to invest 91.7 billion roubles (nearly $2.5 billion USD) in the Novoportovskoye field development and 17 billion roubles (nearly $0.5 billion USD) in the Messoyakha gas field in the Yamal-Nenets Autonomous District (YaNAO).[17]

As underlined several times, among the main drivers of rapid growth in oil extraction in the 2000s are modern oil recovery methods, such as horizontal drilling and, first and foremost, hydraulic fracturing. In general, these are "aggressive methods" to extract oil from fields previously brought into development, but these methods cannot be used in the same fields over extended periods of time. To maintain at least the current level of oil production, companies should drill new wells and explore new deposits. However, this requires immense investment. The strategy described is not supported by efficient taxation of the Russian oil industry. Companies are thus not currently motivated to invest more in more risky projects.

To sustain current production levels and to achieve historically high levels of exports of oil and liquids, Russia is currently facing the complex task of finding an effective combination of the following three steps:

- first, to increase extraction from fields previously brought into development;
- second, to find efficient solutions and approaches to exploring new sources: heavy oil fields and non-traditional deposits (such as "Russian shale" and Tatarstan heavy bitumen oil);
- third, to conduct active geological prospecting and exploration in new regions: the Arctic, Eastern Siberia, the far east, and along the sea shelf.

The first approach is the most attractive: an increase in the oil recovery factor[18] costs 1.3–1.5 times less than creating new capacity in the new capital-intensive fields

[16] Aatle Staalsen. Новопортовское месторождение подстегнёт арктические перевозки нефти ["The Novoportovskoye field is to increase oil traffic in the Arctic" by Aatle Staalsen]. http://barentsobserver.com/ru/energiya/2013/02/novoportovskoe-mestorozhdenie-podstegnyot-arkticheskie-perevozki-nefti-13-02.

[17] "Планы "Газпромнефти" - "Ведомости" ["Plans of Gazprom Neft", Vedomosti], September 16, 2013. http://www.vedomosti.ru/newspaper/article/530041/vkratce#ixzz34WiRqjXh.

[18] "There are three main ways in which the oil and gas industry can meet the growing demand for oil: finding new resources; continuing to develop unconventional resources, such as shale and oil sands; and increasing the amount recovered from existing resources. The third of these might not enjoy the high profile of the first two, but it could make a huge contribution. In 2011, then-president of the Society of Petroleum Engineers Alain Labastie wrote: "The current ultimate average recovery factor for oilfields, on a worldwide basis, is about 35 %. This means that about

in Eastern Siberia and the continental shelf areas. The most typical example is the company JSC Tatneft (in the Volga-Urals area). This company develops mostly worked-out deposits with hard-to-develop reserves of bitumen oil and its main goal is the development of deposits of highly-viscous bitumen in Tatarstan.[19] In Tatarstan,[20] the "easy oil" had been completely extracted by the end of the 80 s. Over a period of 19 years (1975–1994), production output in Tatarstan decreased from 103 to 23.8 Mt of oil. Nowadays, there are more than 5.3 thousand wells which yield less than 1 ton per day, with a total of 22 thousand wells having been drilled. Nevertheless, production in Tatarstan is now growing: in 2013 it exceeded 33 Mt.

The second approach is in line with the natural evolution of the oil resource base throughout the world. The majority of fields in Russia, regardless of their geological characteristics, have been developed with traditional technology using water flooding. As previously discussed, the projected oil recovery factor (ORF) has decreased from 44–46 to 33–34 % due to deterioration of the structure of the reserves, i.e. the need to develop fields with hard-to-develop reserves, including shale oil, highly-viscous and super-viscous oil and bitumen. The water flooding method is ineffective in fields with carbonate and fractured porous reservoirs—the highly-viscous and shale oil ORF amounts to 2–15 %. Around the world, in order to develop such fields advanced technology is widely applied: thermal, gas, chemical and microbiological methods, together with modifications, combinations and integrations of them.

As a base for the second step, the proportion of hard-to-extract oil reserves has increased by 70 % over the past two decades. The global production of hard-to-extract oil accounts for 19.4 % of the total production; in Russia this figure is only 0.2 %. The Energy Information Administration at the IEA reports that Russia holds first place for the proportion of scavenger oil reserves (shale oil) which can be extracted with the help of existing technology—75 billion barrels, or 10.3 Gt. The US possesses 58 billion barrels, Chile has 32 billion barrels, and Argentina and Libya have 27 and 26 billion barrels respectively. Nearly 65 % of all the scavenger reserves are located in the oil fields of Western Siberia and the Komi

(Footnote 18 continued)

two-thirds of the oil that has been discovered is left within the reservoir. We have under our feet, in well-known locations, enormous prospects for booking new reserves. Increasing the average ultimate recovery factor from 35 to 45 % would bring about 1 trillion barrels of oil!"

URL: http://www.bp.com/en/global/corporate/press/bp-magazine/innovations/the-recovery-factor.html

The Oil recovery factor (ORF) is the volume of oil extracted compared with the initial volume of reserves; in the 1960s the ORF in the USSR exceeded 46 %; now it varies between 31 and 33 % in Russia. Because of frequent changes in the reserves, the ORF can also vary substantially. ORF changes characterise technologically driven changes in oil field development strategies. Among the most successful in this respect are the Norwegian shelf areas, where the ORF is steadily growing despite maturing fields and it is estimated to be more than 50 %.

[19]http://www.tatneft.ru/proizvodstvo/razvedka-i-dobicha/povishenie-effektivnosti-neftegazodobichi/?lang=ru.

[20]Tatarstan is located in the European part of Russia and is the starting point of the Druzsba export-oriented trunkline, which ends in Austria and Germany.

Republic. In the Khanty-Mansiisk Autonomous Okrug, only 64 % of the resources are considered to be commercially viable; the rest are not developed because of the heavy tax burden.

The oil and gas sector is following the third approach for the following reason. According to the Federal Agency for Subsoil Use, in 2013 the Russian unallocated subsoil reserve fund had only three significant deposits: Rostovtsevskoye (YaNAO, 61 Mt), Nazymskoye (KhMAO, 43 Mt), and Gavrikovskoye (40 Mt). In total, the unallocated fund holds about 885 tons of recoverable reserves. Not long ago, the fund had nearly 614 deposits with total recoverable reserves amounting to 884.7 Mt, which was approximately 3 % of all the recoverable reserves. The unallocated reserves all are situated on land and so private companies can get access to these fields, while shelf deposits are closed to them. Besides large fields, the unallocated subsoil reserve fund still has under-explored (and consequently high-risk) sites both near ones that are being developed and far from the infrastructure. It is clearly just a question of allocating these fields to companies.

New giant deposits are unlikely to soon be discovered and prospective discoveries of new large deposits are associated with remote regions of Eastern Siberia, and the Arctic and far eastern shelf areas. Although since 2006 increases in reserves in Russia have exceeded production output (according to the ABC1 Russian reserves classification category), new fields only account for 80 Mt of oil, while the rest is reserve additions resulting from revaluation of previously developed fields (Khramov 2013).

Nevertheless, oil production in East Siberia is steadily but slowly growing (see Table 2).

However, because of the high costs the development of inland East Siberian reserves of oil and gas needs substantial tax breaks to make them economically viable. For example, development of gas/oil fields using the general tax regime (with export duty exemptions) results in a project IRR of just 4 %.

East Siberian producers remain a key element in recent Russian oil production growth, but all three of the first generation fields in this region are expected to reach their production plateau in the near future (Vankor: approx. 22 Mt in 2014; Verhnechoskoye: 8 Mt in 2014; Talakanskoe: 8 Mt in 2015).

Table 2 Regional distribution of oil production in Russia (in Mt)

	2008	2009	2010	2011	2012
European Part	142.3	150.3	153.7	154.1	153.2
	29.1	30.4	30.4	30.1	29.6
West Siberia	331.8	322.1	318.3	316.3	317.2
	67.9	65.2	63.0	61.8	61.2
East Siberia	1.51	7.5	19.7	27.2	35.1
	0.3	1.5	3.9	5.3	6.8
Russia	488	494	505	511	518
Total	100	100	100	100	100

Source Neftegazovaya Vertical, TSDU TEK

3.1 Leading Company Strategies

Russian leading oil and gas companies are trying to combine all three of the approaches discussed above. However, not all the companies are succeeding. Thus, the strategy until 2030 of state-owned JSC Rosneft (West Siberia, East Siberia, Far East and the Arctic), which is the leader in oil production, incorporates the following development steps. The first step involves "ensuring extraction" from the existing fields owned by the company. The second one is to launch new projects in Eastern Siberia, first and foremost in the Vankor group: the Suzun, Tagul, Lodochnoye, Yurubcheno-Tokhomskoye and Kuyumbinskoye oil fields. The same strategy is planned to launch gas assets: in Rospan, and fields in the Kharampur and Kynsko-Chaselsk groups. The third step envisages a significant production gain due to a massive development of scavenger reserves, and the fourth step is aimed at developing deposits in shelf areas.[21] Rosneft manages the largest non-traditional resource projects, as well as shelf area exploration projects. The company needs $500 billion just to develop the Arctic shelf, which holds resources of more than 35 billion boe.[22]

Lukoil (Volga-Urals, West Siberia) faces zero growth in the years to come and then an inevitable drop in production. Another private company, JSC Bashneft (Volga-Urals, Timan-Pechora), is expecting to extract nearly 17.5 Mt (+8 % compared to 2013) and in the next few years the company plans to keep production in developed fields at 15 Mt and develop extraction from its new assets in Nenets Autonomous Okrug (Bashneft-Polyus) and Tyumen Oblast (Burneftegaz).[23]

To sustain production and the level of its exports, Russia increasingly needs more complex technology and equipment in order to explore hard-to-develop fields (including shelf areas, Eastern Siberia and the far east) and to recover shale "Bazhenov" oil (so-called "Russian shale" oil). At the beginning of 2014, direct investment in new Russian fields was estimated at 500 billion USD until 2030.

As mentioned earlier, a reduced sovereign credit rating and less access to international financial markets—due to general sanctions—are much more destructive for Russian oil and gas companies than direct sectoral sanctions. According to Bloomberg, in July 2014 no Russian companies took dollar-, euro- or Swiss franc-denominated loans. In the first half of the year, they borrowed 3.9 times less from Western European banks than the previous year: $6.7 billion. This figure includes borrowing by mineral companies of $3.5 billion, which is the lowest amount since 2009. Russian companies have no other ways to attract capital than borrowing from the Western banks, due to the low capital investment potential of the Russian banking system. They are also saddled with servicing previously received loans and debts, the size of which exceeds 700 billion USD. So far, no major companies have announced a delay in or cancellation of any specific projects

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[21] http://www.rosneft.ru/Upstream/Overview/.

[22] http://www.vedomosti.ru/companies/news/32865731/v-rossii-dlya-kitaya-ogranichenij-net#ixzz3CE0vWoP7.

[23] http://www.vedomosti.ru/companies/news/32919511/rosneft-snizhaet-dobychu#ixzz3CDz2zYKh.

due to the sanctions and funding problems, but nevertheless there is a chance of capital expenditure being reduced and certain projects being postponed in the future. This may affect oil and gas production in Russia.[24] According to a forecast by Bank of America Merrill Lynch (BofA), without sanctions production would have been decreasing by 1.5 % a year. Now, it might drop by 25 % in 10 years. The industry may not receive nearly $1 trillion of its due share of investment over the next 30 years, which will lead to declines in production and budget revenues of $27–65 billion by 2020, BofA claims. The restrictions may greatly affect the investment climate in Russia and production figures in the longer run (for the first time they are affecting new projects).

Not only difficulties regarding investment and technology hinder the maintenance and improvement of hydrocarbon production. No less important is the changing industry structure of the oil and gas sector (Kryukov and Moe 2013). It is not easy to overcome the growing importance of new innovative approaches without having a competitive high-tech service sector. This could not only improve the technological level of projects, but also costs would reflect real expenditure more accurately. Initially, all technical services were performed by the companies themselves (because certain oil companies used to be the only players in large areas), but later—at the end of 1990s—steps were taken to achieve vertical disintegration and service companies were established as separate entities. Unfortunately, many service activities have gone to "pocket" service companies, which have privileged relationships with the oil companies. It is clear that they charge much higher prices than really independent companies would. These prices would surely go down from the current level if they were set on a basis of transparency and market-determined solutions. The size of the service activity market in the Russian oil and gas sector is enormous. According to Barclays Capital, estimates of the expenditure on services related to exploration and development by Russian oil and gas companies for the year 2014 were close to 51.7 billion USD. Close to 20 % of this sum is allocated to western service companies.[25]

The regulatory regime in the Russian mineral sector needs to be generally updated to stimulate companies to efficiently combine the three steps indicated above. Improvement of the regulatory framework for licensing should encourage exploration and a more balanced development of the resource base. To a large extent, the existing licensing approach follows the principle "one company—one license" and the main criterion for allocating licenses is the size of auction bids. In practice, this simplicity leads to an expanding role of one leading company in a large area, forming a regional monopoly.

It goes without saying that new projects in new areas are highly risky and costly in terms of capital. The implementation practice requires joint forms of involvement —by both Russian and foreign companies (such companies from the EU as BP,

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[24]http://www.vedomosti.ru/companies/news/32442601/tek-bez-deneg-ne-prozhivet#ixzz3CE445Jjx.

[25]http://www.vedomosti.ru/companies/news/32059811/schlumberger-podschitala-poteri#ixzz3AFot82BP.

Total, Wintershall and Statoil were—and still are—involved in many projects in the Russian oil and gas sector).

Unfortunately, in Russia the hydrocarbon industry is not the subject of any particular fiscal or regulatory procedures. This creates a wide use of cross subsidies and inaccuracies in evaluating the real efficiency of projects. Whether Russian oil companies are state owned or privately owned, they seem to be in the hands of physical persons who show little interest in solving the "insider problem". The exchange market does not play a sufficiently strong role and the capital market offers few incentives to the development of long term projects. Much as before, the trend is still to try to take advantage of economies of scale. The rapid growth of JSC Rosneft in the past few years has resulted in the concentration of the bulk of oil production in the hands of one company despite decreasing economic and financial efficiency. The goal of economies of scale is still sought even though a different approach would be more appropriate: big new projects now need to be developed with the support of research and technological innovation. Being big is not enough in the situation of a deteriorating resource base.

Clearly, an effective regulatory system cannot be built overnight. Moving in this direction does not necessarily mean liquidating large enterprises. In the foreseeable future they will remain strong in the international markets and continue to act as a "backbone" for the hydrocarbon production and processing sector. If these companies were reduced somewhat in size, it would allow them to become even stronger and it would improve their performance and international competitiveness. Therefore, the reforms suggested here could be considered acceptable by many of those who are interested in the status quo.

Apparently, planning and management in the Russian oil sector depend on previously made decisions (Gustafson 2012). The modern structure of the industry is rooted in the past, which impedes its further development. More specifically, what hinders it from making full use of market mechanisms is the technological structure and main production infrastructure established within the centralised system of the Soviet oil and gas sector. In addition, the matrix of property components and methods of company operation were mostly developed during the second half of the 1990s, in the post-Soviet period when the country had a weak federal structure and no policy to actually control its oil and gas resources. The current organisational structure and approach to regulating the sector do not satisfy the growing need to actually develop the resource base. This creates a problem that will become more and more urgent over time.

What should the oil production level in Russia be and how much oil should be available for export to the EU? Answering this question depends upon finding the right combination of the three steps discussed. Increasing recovery rates and exploiting hard-to-extract and new oil sources need to be substantially pursued to maintain production at the current level and sustain exports. The two first steps are much closer to the EU in terms of distance and the availability of oil for export, while the third step is more eastward-oriented.

4 Is It Possible to Sustain Exports Westward and to Develop Eastward?

Historically, Russian oil exports have mainly gone to EU countries (see Fig. 6) and the lion's share of Russian crude exports still goes out via westward routes to western (mainly EU) markets. Moreover, Russian companies are major players in the European downstream, since they have stakes in 11 European refineries and own over 3100 retail sites across Europe.

In the last few years, Russia has been stimulating its oil companies to not only export crude oil but refined products too. The tax system has created considerable advantages for refiners enabling them to export to Europe profitably. Without this tax advantage, Russian refiners would need to be structurally competitive. The best positioned players in the export market would be complex refiners with a high light production yield.

As mentioned above, hydrocarbon exports are not only related to the fact that the centralised administration system set up the oil and gas sector within the borders of modern Russia with more capacity to produce hydrocarbons than Russia needed. Among the key reasons for this decision was the existence of a previously established transport infrastructure to deliver hydrocarbons to Europe via port terminals, pipelines and rail.

At the end of the last century, insolvency of domestic market participants also encouraged the oil and gas companies to increase their export supplies of hydrocarbons. However, there was a lack of port terminals and export routes for liquid hydrocarbons. To overcome these difficulties, a set of improvements was proposed: increasing the capacity of the port terminals in Novorossiysk and Tuapse, and building new terminals near St. Petersburg and new facilities in Northern Russia—in Murmansk, Arkhangelsk, and the Pechora Sea (Varandey oil terminal) among others. While it was overcoming the flow capacity limitations in the west and north-west, Russia started to construct the Eastern Siberia-Pacific Ocean oil pipeline (ESPO pipeline) and develop port infrastructures in the Far East (see Table 3).

Fig. 6 Russia's oil delivery to the EU. *Source* European Commission)

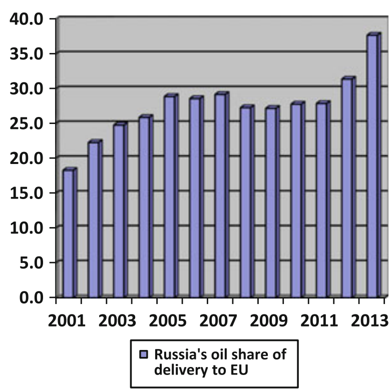

Table 3 Oil export through sea ports

Year	Transneft	Port			
		Black Sea	Baltic Sea	Baltic Sea	Japan Sea
		Novorossiysk	Primorsk	Ust-Luga	Kozmino
2010	213.8	42.0	71.7	…	15.3
2011	210.0	43.2	70.0	…	15.2
2012	212.5	42.5	68.2	14.3	16.3
2013	205.8	37.1	54.4	23.3	21.3
2014	…	31.0	52.2	17.2	…

Source JSC Transneft, TSDU TEK

To date, the overall shortfall in capacity in the western part of Russia has been overcome. As for eastward exports, the infrastructure there is under active development. This eastward expansion of supplies is affected by a number of factors:

- a desire to diversify hydrocarbon delivery destinations—the Asia-Pacific is one of the fastest growing regions in terms of its economy and energy consumption;
- the development of oil and gas production directly in territory near the Asia-Pacific countries (more than 10 years ago new facilities on the Sakhalin island shelf started operation, LNG plants were brought into production and gas transmission infrastructure was constructed);
- the chance to attract a large amount of financial resources (for future oil and gas supplies), primarily within the framework of intergovernmental agreements between Russia and China.

Russian crude exports to the Asia-Pacific have been increasing—in 2013 by 12.9 %, reaching 49.5 Mt.[26] On the other hand, westward exports declined by 8.9 % in 2014, but still account for nearly 80 % of total exports. Among the reasons for the decline in westward exports are not only sanctions but also a diversion of flows eastwards because of access to capital from China. The initial steps in the Rosneft-China deal were taken in 2004. At that time, Rosneft needed additional capital to acquire the assets of the dismantled company YuKOS. The China National Petroleum Corp. (CNPC) signed a contract for the delivery of 48.8 Mt of oil by rail until 2010. Rosneft received advance payment pf 6 billion USD. JSC Rosneft now has significant contractual obligations to CNPC. A contract for the supply of 15 Mt of oil a year was signed in 2009 and is valid until 2030. In 2013, an additional contract was signed for the supply of 360.3 Mt over a twenty-five-year period, valued at $270 billion.

The Vankor oil field is one of the main fields in Eastern Siberia and Rosneft is building up this oil and gas cluster. Nowadays, nearly 70 % of the oil from this field goes to China via the ESPO pipeline and its planned annual production will reach

[26]An increase in the East Siberia—Pacific Ocean (ESPO) pipeline flows was a key factor, as the Kozmino terminal alone handled 21.3 Mt in 2013.

50 Mt by 2020. Furthermore, China is directly producing oil in Russia: Sinopec has a joint venture with Rosneft named Udmurtneft. In October 2013, Rosneft and CNPC signed a memorandum establishing this joint venture (with a 51 % Rosneft stake) to explore and recover oil in Eastern Siberia.

Not only geography and capital access issues but also prices and the greater dynamics of the Asia-Pacific economies explain the growth of exports eastward. Energy prices in Asia are a third higher than in Europe and on average oil prices are $5 per barrel higher. Despite the slowdown of the Chinese economy, the Asia-Pacific market (above all China) remains the chief engine of world demand growth. According to one of an IHS CERA scenario, overall Asia-Pacific oil demand is expected to rise 48 % in the period 2014–35 (an average growth of 1.8 %).

The biggest supplier along this route is Rosneft, and it also aspires to make supplies to India. Other Russian companies would also like to increase their share of supplies along the ESPO pipeline. One of these, JSC GazpromNeft, hopes to export oil to Vietnam. However, Russian oil exports to China are growing less quickly than expected because of the slackening demand from the slowing Chinese economy. This is despite sufficient pipeline and terminal capacity being available to handle all the planned increases in exports.

The worsening of Russia-EU relations as a result of the Ukrainian crisis provides another impetus to the eastward redirection of exports. Even before 2014, the Russian government was intent on diversifying markets in search of a better price (the Urals discount to Brent was perceived as excessive). The latest tensions are increasing the incentives for greater exposure to the Asia-Pacific market in the interest of the "security demand".

Although demand from the European market (the traditional focus of Russian exports) has been falling during this period, Europe is still the main market for Russian oil and gas. Moreover, Russia is not capable of transporting all the oil from Europe to Asia due to its limited export capacities in the eastern part of the country. There are reasons to suppose that China, given the necessary capacities, would be able to receive a share of oil redirected from Europe in the course of three-five years. However, this would decrease the price in the Asian market.

5 Final Remarks—Oil Production Trends and Prospects for Exports to the EU

The Russian oil resource potential is large enough for it to sustain oil production and export volumes at the levels of previous years. At the same time, the Russian oil and gas sector is facing a series of compelling challenges. The main one is the depletion of large traditional hydrocarbon deposits previously brought into development. The characteristics of the resources are changing quite rapidly and this requires both more investment and new technology. We also observe a fast increasing role for deposits of heavy and non-traditional oil. Changes in the resource base change the priorities in terms of sustaining and moreover increasing oil production. The main goal has to be to develop the necessary technology and a competitive and more adaptive industry structure.

The importance of the changes involved and of a proper and efficient response to these changes lies not only in the role of the oil and gas sector in budget receivables, but also in a very specific phenomenon: the 'oil rent addiction'. This phenomenon determines a key role for oil and gas exports in the modern Russian economy. For many years the EU countries were among the main importers and the difficulties and bottlenecks for oil exports which were substantial in the 1990s and 2000s do not exist anymore. The infrastructure is able to export close to 200 Mt of oil a year and more than 100 Mt of refined products. However, access to capital, equipment and technology is more important. Despite the geography of new fields being a driving force explaining the growing role of Russia's exports to East Asia, westward oil exports have been and will be the most substantial in the years to come. This is determined not only by infrastructure availability but also by deeper and more comprehensive ties between the Russian oil sector and the EU countries' economies. Indeed, Russia's cooperation with EU countries in the energy sector does not only concern energy supply, but is also related to access to technology, skills and new organisational approaches to realising its oil resources' potential.

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Part II
Unconventional Hydrocarbons: New Patterns and Impacts on Europe

Game Changer: Industrial Impacts of the Shale Gas Revolution in the U.S.

Douglas S. Meade

Shale gas is a game changer for the U.S and for the world.
Wilbur Ross (2013)

Abstract North American gas supplies have increased dramatically since 2006, leading to a reduction in prices, and an increase in electric power generation and industrial use. The Stanford Energy Modeling Forum (EMF) has organized several meetings to analyze the economic and climate implications of this increased natural gas supply. This paper describes a collaborative effort between Inforum and the Mitre Corporation to use the LIFT and MARKAL models in a coupled system, to understand various implications of the shale gas revolution. Scenario analysis is used to assess the impact of increased gas supplies on the structure of production, and on aggregate measures of well-being such as GDP and disposable income. A crucial question is whether the potential for increased U.S. gas exports to Europe, in the form of LNG, can improve the state of energy security in Europe. Infrastructure is not yet in place, but significant investments are beginning. In the last section, we explore the potential of these increased exports to affect gas supplies in both the U.S. and Europe.

1 Introduction

North American natural gas supplies have seen a remarkable increase since 2006, with the rapid expansion of horizontal drilling and hydraulic fracturing. Although the estimates of economically available gas supplies vary widely, there is general agreement that the recent U.S. shale gas boom will continue into the foreseeable future. Naturally, the increased supplies have led to a reduction in price, and even the long-range projections of the gas price have come down from previous projections of just a few years ago.

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Natural gas use has recently seen dramatic increases in the electric power sector, with a corresponding reduction in the share of electricity generated from coal. Beyond the power generation demands for natural gas, there is an extensive search for new markets where natural gas may compete effectively with other energy sources. For example, there is potential for increased direct use of natural gas in transportation. Natural gas use in the transportation sector is currently relatively small, but may increase dramatically if the necessary infrastructure is put in place. There is a possibility for indirect use of natural gas, via transformation of natural gas to a liquid fossil fuel, such as diesel. The industrial sector, already a large user of gas, will probably experience an increase in exports and production, due to increasing competitiveness from cheaper natural gas. Sectors that use gas heavily as an energy input or a feedstock, such as fertilizers and inorganic chemicals, are already showing new signs of life. This has led to the characterization of the current stimulus in manufacturing as a "U.S. Manufacturing Renaissance".[1] Finally, US natural gas may eventually be exported on a large scale, if liquefied natural gas (LNG) facilities are built quickly enough. Price-driven substitution of gas for other fuels is expected to be occurring world-wide, leading to an increase in demand by gas importing countries. In the short-run, the export potential is constrained by the capacity of existing LNG transport facilities, but with sufficient investment, this constraint will be ameliorated over time. Finally, substitution may occur in the residential market, with substitution of natural gas for electricity.

This chapter describes a collaborative effort of Inforum and the Mitre Corporation to use the LIFT and MARKAL[2] models in a coupled system to address the study objectives of the Energy Modeling Forum (EMF) 31. Inforum is a research group headquartered at the University of Maryland. Founded by Clopper Almon, Inforum has pioneered development of interindustry macro models. These models embody input-output quantity and price relationships at their core, and include econometric equations for final demand and value added by industry. The models build up to the macroeconomic aggregates, producing many of the same output variables as a typical macroeconometric model. Inforum has built several generations of models for the U.S., and has worked with a team of international partners to build similar models for other countries.[3] The models are linked through a bilateral trade model (BTM). This trade model can be used to investigate bilateral trade flows of energy commodities such as crude oil, refined petroleum products,

[1]See especially the industry-funded studies by the American Chemistry Council (2011), IHS Global Insight (2011) (See also US DOE (2012)), PWC (2011) and ICF International (2013).

[2]The LIFT model is Inforum's flagship interindustry macro model of the U.S. The MARKAL model, originally developed at Brookhaven National Laboratory, is an optimizing model that works with a detailed database of systems characteristics of energy conversion processes and technologies.

[3]See the contribution by Lehr and Lutz in this volume, who use the German Inforum models INFORGE and PANTA RHEI. Plich (2013) describes an analysis of the economic effects of possible shale gas development in Poland.

pipeline gas and LNG, based on forecasted trajectories of economic demand and relative prices.

The MARKAL model is an energy systems model that combines an optimizing approach with a detailed database of technologies for end uses of energy. MARKAL can be used to study the adoption of a certain type of equipment or technology based on relative prices, capital costs and technical advancements.

The focus of EMF 31, "North American Natural Gas and Energy Markets in Transition",[4] is on the natural gas market, and is motivated by the increased availability of shale gas discussed above. The Energy Modeling Forum is based at Stanford University. The Forum meets on different energy issues to bring together insights from many different types of model applied to the same research question. Previous recent EMF symposiums dealing with U.S. natural gas have included EMF 25 and 26.

The EMF 31 examines factors that play a role in each of these markets, and studies the implications of different economic environments on the interplay of gas supply and demand. Some of the particular issues outlined in the introductory summary for the study include:

- Which end-use sectors will absorb most of the increased natural gas supplies and by how much?
- Which energy sources in these sectors will be replaced by natural gas supplies?
- What is the likely range of natural gas prices at the wellhead and by end-use sector?
- How do these energy-market transformations influence carbon dioxide and other greenhouse gas emissions?
- Will North America become a major gas exporter in world markets?

2 The Energy Modeling Forum (EMF) 31 Study

The objectives for the EMF 31 were to apply scenario-based analysis using a broad array of economic and energy models, and to glean lessons about natural gas supply and demand issues through a comparison of the models and their results, and an understanding of their differences. Inforum teamed with the Mitre group to use the Inforum LIFT model, with the MARKAL optimization model. As described below, LIFT is particularly well suited for examining the interactions between energy industries and other industries, as well as providing a consistent picture of demand

[4]At present, there are no publications from the EMF 31. The URL https://emf.stanford.edu/projects/emf-31-north-american-natural-gas-and-energy-markets-transition describes the project and provides a few links. Results from the forum are planned to be published in a future issue of *Energy Journal*. Steckley et al. (2011) was from a previous EMF 25, and describes similar work using a coupled system of LIFT and MARKAL. Other papers in that issue present analysis from other contributors to EMF 25.

and supply in all industries. LIFT contains industries for natural gas extraction and natural gas utilities, and can trace the sources of demand for each industry to other industries and final demand, including exports and imports. The sectors and final demand categories in LIFT are mapped to the residential, commercial, industrial, transportation and electric power sectors identified in the National Energy Modeling System (NEMS) and many other energy models. The input-output structure in LIFT can be used to introduce hypothetical new industry relationships, such as those determined by an expansion of biofuels or synthetic liquid fuels production. LIFT also tracks investment at the detailed industry level, so that capacity requirements for the construction of new synthetic fuel production facilities or LNG transport facilities can be modeled in a way that directly shows their impact on total investment and GDP. MARKAL is used to show detailed microeconomic optimization decisions that may occur in response to changes in prices and/or technology. Alternative assumptions about fuel prices, capital costs and technology costs can be introduced to understand how different types of equipment or production processes may be chosen to satisfy a particular end use requirement. Outputs from MARKAL can then be fed to the LIFT model as exogenous or auxiliary assumptions, to examine the implications for the industry and macro economy.

3 LIFT and MARKAL

3.1 Overview of LIFT

The LIFT model (Long-term Interindustry Forecasting Tool) is the U.S. representative of the INFORUM style interindustry macroeconomic (IM) model.[5] As is typical of this family of models, the LIFT model builds up macroeconomic aggregates such as employment, investment, exports, imports and personal consumption from detailed forecasts at the industry or commodity level. This modeling framework is not only applicable to scenario analysis where the interaction of macroeconomic and industry behavior is important, but also for the development of satellite models to study issues such as energy use, greenhouse gas emissions or research and development expenditures.[6] In the current study, we make use of the consistent database of input-output (IO) tables in current and constant prices, detailed investment and capital stock matrices, and the full set of value added data.

[5]Grassini (1997) portrays the typical features of an INFORUM model. Meade (1999) introduces an earlier version of the current model.

[6]Meade (2009) is an example of using an expanded module for crops and biofuels to study economic impacts of increased ethanol production and use in the U.S.

The newest version of LIFT is based on the U.S. 2002 Benchmark IO table, and a series of annual IO tables from 1998 to 2011. INFORUM has compiled a time series of estimates of the detailed IO framework at detailed level, using information from the 2002 Benchmark, the annual IO, and time series of industry output from BEA and commodity imports and exports from the Census Bureau. All industry data in LIFT is now classified according to the same sectoring scheme. These industry data include employment, hours, labor compensation and other value added components, investment and capital stock, and industry output. The LIFT model has 110 commodities, and this is the level of detail maintained for the IO table, final demands and commodity output. The IO quantity and price solutions are calculated at the commodity level. Value added at the industry level is bridged to the commodity level using an industry to commodity value added bridge, and the commodity output solution is converted to industry output using a commodity output proportions matrix.

The LIFT model includes econometric equations for each of the main categories of final demand and value added. Both output and prices are solved using the fundamental IO identity, so there is complete interdependence of all prices and quantities. A macroeconomic accounting structure (the "Accountant") handles aggregation of industry and commodity data as well as the relationships and identities in the national accounts. (See Fig. 1 for a block diagram that summarizes the operation of LIFT).

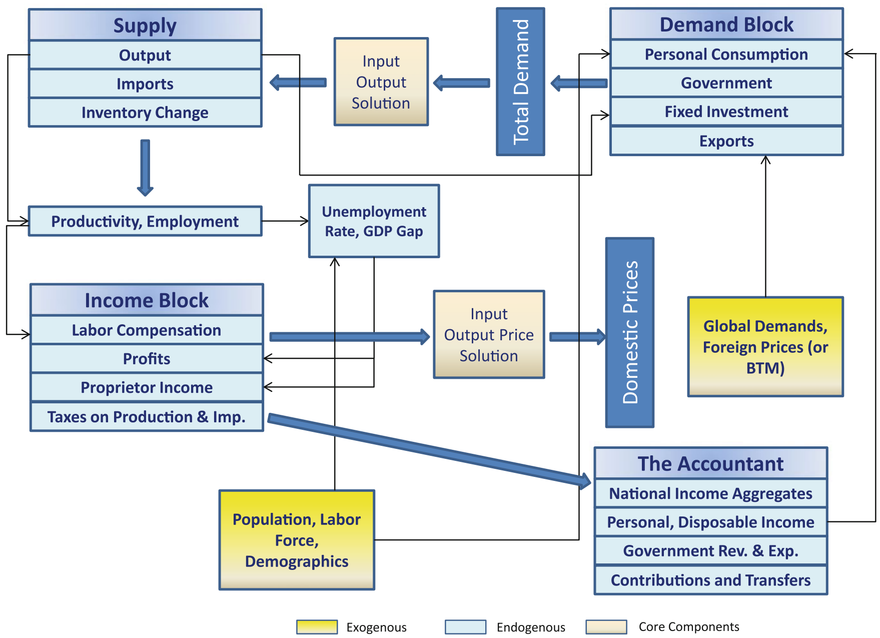

Fig. 1 Block diagram of the LIFT model

3.2 The MARKAL Model

The MARKAL (MARKet ALlocation) model is a data driven, bottom-up energy systems model. The initial version of the model was developed in the late 1970s by international teams at Brookhaven National Laboratory and elsewhere. The model currently is used by many countries for research and energy planning. At its core, MARKAL is a least cost optimization model which incorporates numerous dynamic relationships and user-defined constraints which allow for a simulation of the energy system.

The MARKAL energy system representation is formed by an input database that captures the flow of energy and technology adoption associated with the extraction or import of resources, the conversion of these resources into useful energy, and the use of this energy in meeting the end-use demands. MARKAL optimizes technology penetrations and fuel use over time, using straightforward linear programming techniques to minimize the net present value of the energy system while meeting required energy service demands and various energy, emissions, and behavioral constraints. Outputs of the model include a determination of the technological mix at intervals into the future, estimates of total system cost, use of energy carriers (by type and quantity), estimates of criteria and greenhouse gas (GHG) emissions, and estimates of marginal energy commodity prices. MARKAL outputs a least cost pathway to meet energy needs, but using scenario analysis, the model can also be used to explore how the least cost pathway changes in response to various model input changes, such as the introduction of new policy measures like a carbon tax or subsidies on energy efficient technologies. The multi-sector coverage of a MARKAL database allows simultaneous consideration of both supply- and demand-side measures in meeting emissions or other system goals.

The basis of the MARKAL model framework is a network diagram called a Reference Energy System (RES), which is pictured in Fig. 2. The RES represents energy sources and flows that comprise an energy system. Coverage of the energy system ranges from the import or extraction of primary energy resources, to the conversion of these resources into fuels, and through the use of these fuels by specific technologies to meet end-use energy demands. End-use demands include items such as residential lighting, commercial air conditioning, and automobile vehicle miles traveled. Data used to represent these items include fixed and variable costs, technology availability and efficiency, and pollutant emissions. For a more detailed description of MARKAL see Loulou et al. (2004).

3.3 Model Coupling

The idea of the model coupling is to combine the detailed treatment of the energy system and technology options for energy supply and utilization in MARKAL with the detailed treatment of the U.S. economy in Inforum LIFT. The aim is to capture insights on the response of the energy system to the various scenarios, including

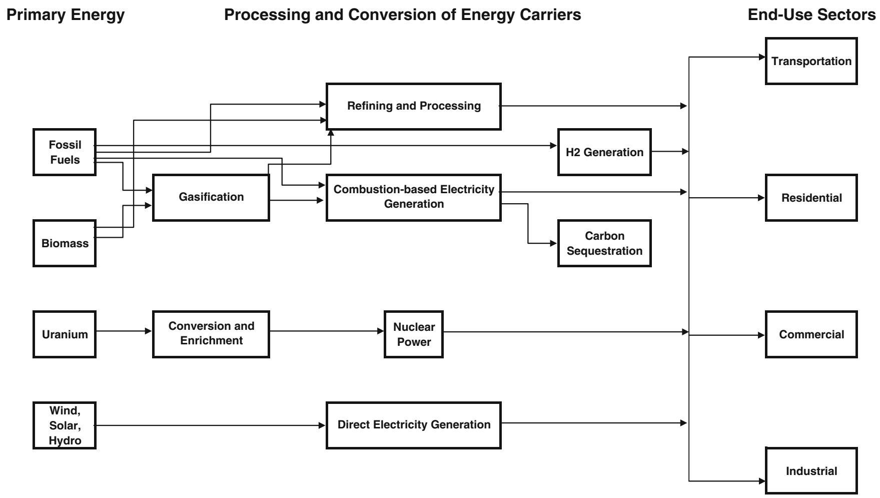

Fig. 2 MARKAL reference energy system

changes to the energy mix and end-use technologies, and see how these changes interact with the broader economy.

In this application, prior to the coupling, both models ran a reference scenario calibrated to Annual Energy Outlook (AEO) (2014) published by the U.S. Energy Information Administration. For each of the policy scenarios, the policy was first implemented in MARKAL and the resulting fuel mix and efficiency changes for the entire period out to 2040 relative to the reference case were then incorporated into a LIFT scenario. The LIFT scenario therefore captures the interaction of the broader economy with the policy and energy system responses induced by the policy as measured in MARKAL. Following the LIFT scenarios energy service demands from the LIFT run were estimated and compared to the exogenous MARKAL energy service demands. For any deviations judged to be significant the MARKAL service demands would have been adjusted and the coupling procedure repeated. The methodology used to guide the coupling is shown in Fig. 3.

4 Overview of Scenarios

The EMF 31 working group decided on a set of 7 common scenarios to explore, using 15 different modeling teams.[7] The scenarios were chosen to highlight both demand and supply issues in the U.S. natural gas market. The full set of scenarios included:

[7]Models represented in EMF 31 include: LIFT, ADAGE, AMIGA, CRA, CTEM, DIEM, DIW-MFM, Energy2020, FACETS, GCAM, MARKAL_US, MARKAL_EPA, NEB, NEMS, and RWGTM. See Table 6 in the appendix for a list of the organizations and taxonomy of these models.

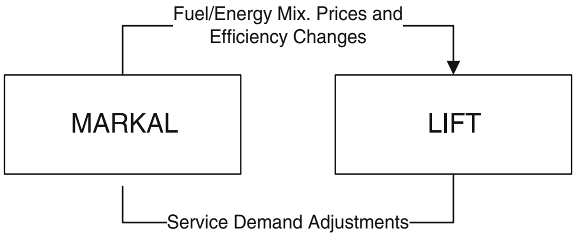

Fig. 3 Model coupling methodology

1. *Reference case*: This case was calibrated as closely as possible to the *AEO 2014* reference case.
2. *High resource case*: This case assumed faster growing U.S. shale gas and petroleum supply, with a corresponding lower prices than the reference case.
3. *Restricted access*: This case incorporates more pessimistic assumptions about shale supply growth, with a corresponding higher gas price.
4. *Technology performance standard* (TPS): The TPS sets a fleet average CO2 emissions rate standard across all existing and new fossil fuel generators, and allows trading of credits to achieve this standard. It is somewhat like a carbon tax in its effect, but will actually subsidize some producers who already have low carbon emissions.
5. *High international demand*: This scenario assumes increased demand for U.S. gas due to replacement of coal generation by combined-cycle gas, and adoption of natural gas vehicles.

The Inforum /Mitre modeling team implemented the five scenarios listed above, in both LIFT and MARKAL. We will discuss all but scenario 4 in this chapter.

5 The Reference Case

LIFT is a closed, standalone interindustry macroeconomic model. With a few assumptions supplied on for the path of exogenous variables, a projection can be made that embodies the interaction of the model equations and structure with the exogenous variables. However, the model can also be *calibrated* to closely match the forecast or projection of another model, either through the modification of the exogenous variables, or modification of input-output coefficients and other relationships.

The Reference case of this study in the LIFT model was calibrated to the *Annual Energy Outlook* (*AEO*) 2014 Reference Case. The calibration exercise brings about consistency between the LIFT forecast and the *AEO*. This calibration was done in two stages. In the first stage, industry variables, macroeconomic variables, and IO coefficients were modified to produce a macroeconomic forecast consistent with the *AEO*. In the second stage, imports, exports, personal consumption expenditures, and IO coefficients were modified to calibrate energy and carbon projections from the *AEO*. The current forecasting horizon of both AEO 2014 and LIFT is 2040.

Calculations native to the LIFT model are in either constant 2005 dollars or in current dollars. Prices in LIFT are price indices, with base year 2005. Many of the modules link energy quantities (barrels, gallons, kWh, btus) to constant price measures in LIFT.

The general strategy of deriving a Reference case for LIFT consistent with the *AEO* forecast consists of a number of steps:

1. Calibrate exogenous variables, such as population and labor force, government spending, exports, and oil, natural gas, and coal prices.
2. Calibrate final demand categories, such as personal consumption, equipment investment, and construction to *AEO*. Demand for imports is derived from import requirements for other final demands and for intermediate consumption. Adjust imports demand to be consistent with *AEO*.
3. Once all final demands have been calibrated, derive the components of personal income. Change the federal and state and local tax rates to calibrate disposable income.
4. Change labor productivity by industry to calibrate to aggregate labor productivity in the *AEO*. Adjust employment to get close to the *AEO* unemployment rate forecast.
5. Calibrate energy consumption by sector by type. Energy consumption can be traced in the LIFT model at several different levels. Energy consumed in final demand includes personal consumption of gasoline, heating oil, natural gas, and electricity; government purchases of fuels and electricity, and energy consumed in building residential and nonresidential structures. Energy flows in the intermediate demand part of the model include industrial consumption of energy for space heat and light, stationary power sources, transportation fuels, and electricity for many uses. These flows also include the conversion of energy from one type to another, such as the refining of crude oil into petroleum products, and the generation of electricity from coal and other fuel sources.
6. Calibrate carbon emissions at the level of major demand sector by major energy source.

A summary table of the Reference case is shown in Table 1. The column at the far right shows average exponential growth rates over the period from 2015 to 2040. GDP in the Reference case is projected to reach \$27.4 trillion by 2040, with an average growth rate of 2.5 percent. Natural gas prices are expected to grow at an average of about 3 % per year in real terms, growing to \$7.87 (2012\$) per million Btus by 2040.[8] From 2000 to 2013, gas prices actually declined at an average rate of 2.7 %, but they are considered currently to be too low to stimulate further exploration. Total energy consumption grows more slowly than GDP, at an average

[8]See Table 5 for units explanation and conversion ratios.

Table 1 Summary table for the reference case

	2013	2015	2020	2030	2040	15–40
GPD and macroeconomic summary (billions of chained 2005 dollars)						
Gross domestic product	13,818	14,660	16,880	21,275	27,378	2.50
Personal consumption expenditures	9765	10,243	11,534	14,228	17,671	2.18
GDP deflator	116.7	119.4	128.0	152.0	185.9	1.77
Real disposable income, billion 05$	10,424	10,935	12,423	15,450	19,562	2.33
Energy prices						
Natural gas Henry Hub price-2012$/MMBtu	3.59	3.74	4.42	6.13	7.87	2.97
Crude oil price-2012$/barrel	89.48	81.79	82.15	101.97	122.66	1.62
Avg. electricity price-2012c/kWh	9.71	9.87	10.19	10.56	11.41	0.58
Energy consumption (quadrillion Btus)						
Total energy consumption (quad Btus)	96.5	97.9	101.3	104.0	106.6	0.34
Total electricity generation (billion kWh)	3880	3959	4147	4473	4721	0.70
Total carbon emissions (Mmt)	5451	5456	5541	5797	6606	0.77

rate of 0.34 % per year. Total carbon emissions are expected to reach 6606 million metric tons by 2040, an average growth of 0.77 %.

6 The High Resource Case

The High Resource case represents a larger resource base and improved productivity and well spacing in both U.S. domestic shale oil and natural gas production. This has the result of reducing both inflation-adjusted crude oil and natural gas prices. In the High Resource case, natural gas production reaches a level 30 per cent higher than the reference, and price level 42 % below the reference case. Net exports of gas are higher than in the reference case. Demand for natural gas grows, particularly in the Electric power sector. Power plants take advantage of the low prices by shifting to natural gas in preference to coal, which does not experience a similar drop in price. As a result of the abundance of cheap gas, power plants produce much cheaper electricity than in the alternative cases.

7 The Restricted Access Case

The Restricted Access case tests the effects of more expensive natural gas supplies. In this scenario, the price of natural gas increases drastically, while coal and oil prices are held constant. Coal remains the primary fuel for the electric sector, with production and consumption continuing on the same trajectory as in the reference. Electricity prices are buffered above the reference case, but continue on the same trajectory, ending about 50 cents per kilowatt hour ahead of the reference.

Figure 4 compares production in the Reference, High Resource and Restricted Access cases.

8 Implications of Lower Natural Gas Prices

It is useful to examine the effect of the lower gas prices on the prices of other sectors that use natural gas. Figure 5 shows the top industries ranked by the share of gas cost in the value of total output, shown in percent. The data in this chart are derived from the LIFT IO table. The IO table does not distinguish between gas used as a feedstock and gas burned for energy.

Sectors with a larger share of natural gas input will benefit proportionally more from a decline in natural gas prices. These sectors will become more competitive internationally. The LIFT export equations determine exports based on relative export prices to those of competing exports. Each commodity has its own equation. Price elasticities vary significantly across commodities. Figure 6 shows the sectors having the highest increase in exports in response to the increase in competitiveness. The figure shows that chemicals, metals, plastics and stone, clay and glass all show significant increases in exports.

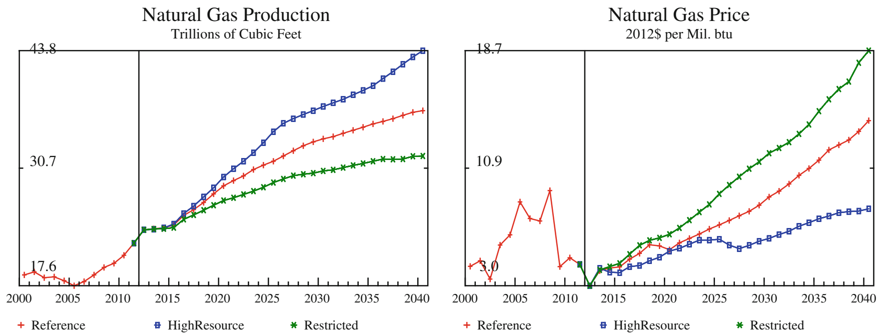

Fig. 4 Comparison of natural gas production and price in the reference, high resource and restricted access scenarios

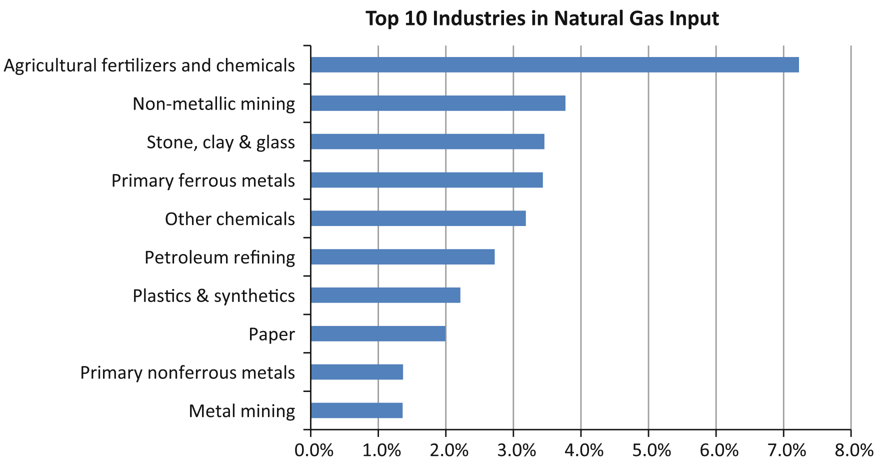

Fig. 5 Gas intensive sectors

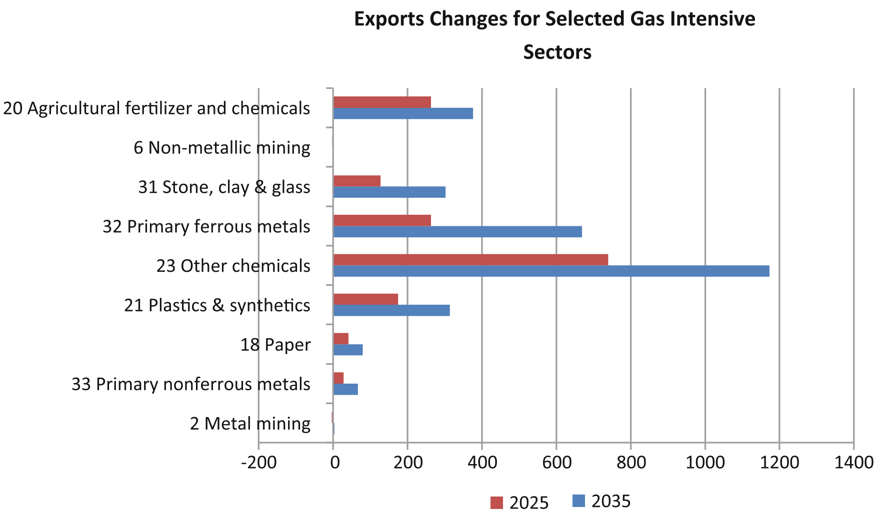

Fig. 6 Export changes

Table 2 shows the mix of electric power generation by type, comparing the reference case and the TPS case, in 2030 and 2040. Power generation in total is lower by 104 billion kWh by 2040. The overall decline consists of an even larger decline in coal generation, offset by a rise in generation from natural gas. This substitution of gas for coal generation is the main factor causing the reduction in total carbon emissions.

Table 2 Electric generation in reference and TPS cases

	Reference			TPS			Difference		
	2020	2030	2040	2020	2030	2040	2020	2030	2040
Production by type (*billion* kWh)									
Coal	1620	1658	1624	1408	1418	1384	−211	−240	−240
Oil/Gas	1141	1366	1547	1335	1538	1689	194	171	142
Nuclear	779	782	811	770	786	816	−9	5	5
Hydro	288	294	297	298	295	298	10	1	1
Renewable	319	372	442	285	360	430	−34	−12	−12
Total	4147	4473	4721	4096	4397	4617	−51	−76	−104

9 High International Demand

The objective of this scenario is to explore the possibility for expanded natural gas exports, due to increased international demand for U.S. natural gas. The increase in demand compared to the High Resources case is specified in Table 3.

If the U.S. develops the necessary export infrastructure of sufficient LNG export terminals and conversion facilities, an increase of this size would translate into an addition 12 tcf of gas exports from the current level by 2040. There are numerous possible developments that may warrant this assumption of increased export demand. Examples include:

- Nuclear plants in South Korea and Japan are replaced by combined-cycle natural gas plants.
- A large percentage of coal plants in China and India are replaced by natural gas plants.
- China and other Asian economies adopt more compressed natural gas vehicles than expected in the Reference case.
- Europe’s demand increases, due to reduced supply from Russia or other sources.

The High International case takes the High Resource case as its starting point, and then specifies the addition percentage of exports from Table 3. Figure 7 shows the result of that assumption, and includes the Reference, High Resources, and High International cases. By 2040, U.S. natural gas exports reach levels of 8.1, 12.7 and 14.5 tcf in the three cases.[9]

We expect the main impact of the export expansion to be a shift in effective demand, resulting in a move up the supply curve. This should result in an increase in the domestic U.S. price for natural gas, which will affect decisions to use gas in all sectors. This expected price increase has been widely mentioned as a concern amongst industrial users of natural gas, stating that increasing gas exports will increase their costs and make them less competitive. It is also a concern with

[9]See Table 5 in the Appendix for conversion to bcm or Exajoules.

Table 3 Increased international demand

	2015	2020	2025	2030	2035	2040
Demand increase (%)	2	6	8	10	12	14

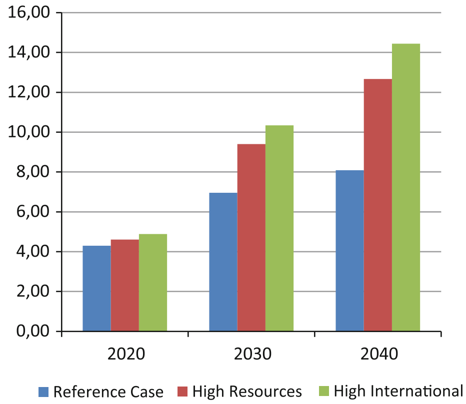

Fig. 7 U.S. natural gas exports in 3 cases

electric power producers, who have already invested significantly in natural gas combined cycle generation capacity.

Table 4 compares the High International Case with the High Resources Case, upon which it is based. Real GDP is slightly higher in the High International Case, but gas prices, electricity prices, and the aggregate GDP deflator are all higher. Total energy consumption is reduced by one quad by 2040. This is partly due to reduced natural gas consumption, but also due to reduced electricity consumption.

Non-gas exports (not shown) are up slightly in the earlier years of the simulation, but up slightly from 2035 to 2040. On balance, there does not appear to be a significant anti-competitive effect of the increased natural gas exports, at least with exports at this level.

10 Scenario Discussion

We have presented selected results comparing several scenarios from the Inforum / Mitre collaboration in the EMF 31 study. The Reference case reflects current thinking among experts at the U.S. Department of Energy of the outlook for the U. S. macroeconomy, industry developments and many special features of energy markets and technology. Although the *Annual Energy Outlook* Reference case has seen dramatic changes in its natural gas outlook in recent years, these changes reflect the high degree of uncertainty in natural gas markets, particularly on the supply side. DOE regularly publishes both a high and low supply case in the *AEO*, and it is notable that the most recent Reference case has high natural gas production than the high supply case of the *AEO* 2011, only 3 years prior to the *AEO* 2014.

Table 4 Summary comparison of high international with high resources case (Alternatives are shown in deviations from the base values)

	2013	2015	2020	2030	2040	15–40
GDP and macroeconomic summary (billions of chained 2005 dollars)						
Gross domestic product	13,817	14,680	16,949	21,427	27,672	2.54
	(0)	1	3	10	19	0.00
Personal consumption expenditures	9765	10,261	11,599	14,363	17,905	2.23
	(0)	0	(0)	(0)	(0)	0.00
GDP deflator	116.7	119.3	127.1	149.7	181.2	1.67
	0.0	0.0	0.1	0.2	0.4	0.01
Real disposable income, billion 05$	10,421	10,952	12,462	15,542	19,719	2.35
	(1)	(0)	2	5	9	0.00
Energy prices						
Natural gas Henry Hub price-2012$/MMBtu	3.75	3.41	4.37	4.30	4.69	1.27
	0.00	0.07	0.13	0.22	0.34	0.20
Crude oil price-2012$/barrel	89.77	79.97	77.66	90.91	107.45	1.18
	0.01	0.00	−0.04	−0.11	−0.25	−0.01
Avg. electricity price-2012c/kWh	9.71	9.73	9.79	9.83	9.86	0.05
	0.00	0.05	0.15	0.29	0.59	0.21
Energy consumption (quadrillion Btus)						
Total energy consumption (quad Btus)	96.6	98.4	102.8	107.1	112.3	0.53
	−0.1	−0.2	−0.3	−0.6	−1.0	−0.03
Total Electricity Generation (bil kWh)	3881	3977	4207	4589	4962	0.89
	(1)	(3)	(8)	(14)	(32)	−0.02
Total carbon emissions (MMT)	5434	5438	5547	5880	6780	0.88
	6	13	20	13	18	0.00

Titles of alternate runs
Line 1 High resources
Line 2 High international

The High Resource and Restricted Access cases serve to bracket a range of production and prices for U.S natural gas, premised on possible upside or downside risks in production. Natural gas prices still rise in real terms in the High Resource case, but very slowly, implying that U.S. gas prices will still be among the lowest in the world by 2040. This has important competitive implications for industries that are heavy users of natural gas, either as an energy source, a feedstock or both. This scenario also explored some interesting features of industrial demand for natural gas, including the potential for increased production of ethylene from ethane, and the possibility of the development of significant gas-to-liquids production. The Restricted Access case explores the implications of the still very real possibilities of limits on production due to environmental air and water quality worries, as well as issues relating to lack of infrastructure or increased congestion.

The High International case explores the possibility of increased exports of U.S. natural gas, mostly through expansion of the development of LNG terminals. Although projecting the global destinations for this gas were beyond the scope of this study, it is appropriate to discuss global implications to put the current quantitative analysis in context. The U.S. currently has about 10 × 10 export terminals either approved or awaiting approval, for a total of more than 15 billion cubic feet (bcf) a day capacity, or about 5.5 tcf annually. If all of this capacity was built and utilized, it would account for the total exports in either the High Resources or High International cases. By 2030 and 2040, the exports in the High International case reach over 10 tcf and 14 tcf, respectively. The construction of export capacity at this level seems feasible, and the technology and costs are well understood. The profitability of such investments is premised on the U.S. price being at least $3.50 below competing supply costs for at least 12 years, the time taken to recoup the cost of an LNG terminal.

With the expansion in capacity of the Panama Canal, it is likely in the near-term that most U.S. LNG exports would go to the Pacific area, particularly to countries such as South Korea and Japan. Gas costs are particularly high in South Korea, and demand in Japan is likely to increase significantly as nuclear production is reduced.

However, in the mid-term, Europe emerges as a likely market, with reduction in nuclear and coal electric power generation in Germany, and increased gas consumption in other countries. Russia will mostly likely continue to be one of the largest sources of supply to the EU area, currently providing 24 % of the European supply. However, uncertainty due to the conflict in Ukraine makes the dependability of Russian gas problematic.

Hopefully, with the rise of the LNG market, sources of supply will become more diverse. For example, Qatar is already one of the largest suppliers to the UK. Also, as noted in another chapter in this volume[10] France and Poland may also develop their shale gas resources.[11] The EU's Joint Research Center estimates Europe's technically recoverable unconventional gas resources at 11,700 bcm, which is about a quarter of that of the U.S. However, environmental laws, public opinion and lack of drilling and exploration expertise for shale gas make European shale gas harder to extract.

It is exciting to consider the prospect of U.S. shale gas helping Europe out of its gas supply difficulties. However, it will take a little while. For starters, there are not yet any U.S. export facilities ready yet. Sabine Pass on the Texas-Louisiana border, with a capacity of up to 2 bcm, will only start pumping LNG in 2015. Two dozen export applications are pending, and HIS calculates that a burst of projects coming online in 2018–2020 will bring US LNG export capacity up to 66 bcm by early next decade. This needs to be put in perspective. The International Energy Agency (IEA) estimates that the world LNG market may be up to 540 bcm per year by that time. And, as mentioned earlier, US LNG would be tempted towards Asia, where the prices are

[10]Di Nino and Faiella.

[11]See Plich (2013) for the outlook for gas development in Poland.

higher, at least for the foreseeable future[12]. So, the U.S. will likely be only a minor player in the EU market, at least in the near-term, but may add to the diversity of supply, and thus increase the market power of European consumers vis-à-vis Russia.

The increase in U.S. gas production also has helped reduce U.S. gas imports, which has put downward pressure on the global trading prices of LNG, prompting many European consumers such as Germany to attempt to renegotiate contracts with Russia.

There is political pressure in the U.S. to restrict gas exports, due to fears of increases in cost to electric power and industrial users. However, our study finds only a small price increase. The overall results are positive, as the exports bring forth an even higher level of gas production, and a slightly higher level of real GDP in the U.S. It will be quite interesting to monitor these developments over the next several years. If recent history is a guide, the U.S. producers may again exceed expectations, with the implication that U.S. gas may play a larger role in Europe than the current thinking would suggest.

Appendix

See Table 5.

Table 5 Energy units and conversion ratios

Abbrev.	Energy unit	Definition	Conversions
Btu	British thermal unit	Energy to heat one pound of water degree fahrenheit	1055 J
MMBtu	Million Btus	10^6 Btus	1.055 GJ
Quads	Quadrillion Btus	10^{15} Btus	=1.055 EJ
kWh	Kilowatt hour	Power consumption of 1000 W for one hour	=3.6 MJ
Bcf	Billion cubic feet	10^9 cubic feet (unit of natural gas)	=1.022 quads
Tcf	Trillion cubic feet	10^{12} cubic feet	=28.317 bcm
J	Joule	Force of one newton for one meter	=0.947 MMBtu
GJ	Gigajoules	10^9 J	=277.78 million kWh
PJ	Petajoules	10^{15} J	=0.9478 trillion Btu
EJ	Exajoules	10^{18} J	=41.87 GJ
TOE	Tonne of oil-equivalent	Energy released by burning one tonne of crude oil	=39.6 million Btus
Bcm	Billion cubic meters	10^9 m^3	=31.315 Bcf

[12]See Credit Suisse (2012), Levi (2012) and Ebinger et al. (2012).

U.S. 2013 total natural gas production of 24.25 tcf represents 24.78 quads, or 26.15 EJ.

U.S. 2013 total electricity production of 3881 Bil kWh represents 13.23 quads, or 13.97 EJ.

U.S. Projected natural gas exports in 2040 in the High International case of 14.44 tcf translates to 408.9 bcm, or 15.57 EJ.

See Table 6.

Table 6 Models contributing to EMF 31

Model	Organization	Type	Global
ADAGE	Research Triangle Institute	Computable general equilibrium	
AMIGA	Argonne National Laboratory	Computable general equilibrium	
CRA	Charles River Associate	Computable general equilibrium	X
CTEM	CSIRO, Australia	Computable general equilibrium	
DIEM	Duke University	Energy economy	
DIW-MFM	German Institute for Economic Research	Computable general equilibrium	X
Energy 2020	Systematic Solution, Inc.	Systems dynamics	
FACETS	KanORS Inc	Energy optimization	
GCAM	Joint Climate Centre Research Institute/UC Davis Institute for Transportation Studies	Energy-economy	X
MARKAL EPA	US Environmental Protection Agency	Energy optimization	
MARKAL US	National Energy Technology Laboratory	Energy optimization	
NEB	National Energy Board	Systems dynamics	
NEMS	Energy Information Administration	Energy-economy	
RWGTM	Rice University	Natural gas general equilibrium	X

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Shale Fuels: The Solution to the Energy Conundrum?

Virginia Di Nino and Ivan Faiella

Abstract Technological progress has enabled the extraction of hydrocarbons trapped amid shales, resources unexplored until a few years ago. High energy prices, abundant reserves, a firm-friendly business environment and a de facto moratorium of environmental rules boosted the adoption of hydraulic fracturing in the US, causing a sea-change in the energy landscape within a few years. Nonetheless, the economic benefits accruing from shale fuel production must be weighed against their higher extraction, logistic and environmental costs. Moreover, the possibility of replicating the US experience on the same scale elsewhere is limited by technical and social hurdles and stricter environmental regulation.

1 The Energy Revolution that Started Amid the Shales…

Technical improvements in the extraction of hydrocarbons have made it possible and profitable to extract resources trapped in shale formations, triggering what is known as the US shale revolution. Shale gas (SG) and light tight oil (LTO), that is, natural gas and oil confined in the pores of solid and impermeable rocks—shales—are the major products of this revolution.

Hydraulic fracturing and horizontal drilling, although known since the fifties,[1] have been combined with advanced seismological techniques and popularized as

[1]The geophysicist Marion King Hubbert, who discovered the so-called "Hubbert curve" used to appraise oil production peaks, published one of the first works on this technique: Hubbert and Willis (1957).

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"fracking". This process consists of an initial stage of vertical drilling, followed by horizontal drilling, which occurs, according to the characteristics of the field, between 1.5 and 3 km below the surface. Injections of highly pressured liquids (90 % water, 9.5 % sand, ceramic grains and other chemical components) crumble the rocks and free SG and LTO (which we subsequently refer to as Shale Fuels—SFs), which are then channelled to the surface.

2 …and Blossomed in the United States

Many factors interplayed to make the shale revolution a concrete reality in the US: the geological, institutional and market conditions were favourable to this drastic transformation. First of all, oil and gas quotations had remained high for sufficiently long to make investments in hydraulic fracturing profitable, and dynamic medium-sized energy companies took advantage of easy credit conditions to finance their exploration and exploitation projects. Furthermore, the US territories rich in shale reserves are generally scarcely populated and according to US law landowners also own the right to subsoil exploitation. This allows companies to sign contracts with private citizens, overcoming the normative and political obstacles which usually occur when subsoil exploitation is subject to public licensing. Finally, environmental laws, less strict than in other regions of the world, were essentially suspended for hydrofracking when this technique started to proliferate.

After a decade of stagnation, domestic natural gas production grew by a quarter between 2007 and 2013 thanks to SG, exceeding the US 1973 peak by more than 10 %. In 2013, the supply of SG was eight times the volume extracted in 2007 and represented almost 45 % of the overall US natural gas supply (see Table 1). Similarly, as the production of LTO boomed, the crude oil supply resumed, reversing the negative trend prevailing since the mid-eighties with LTO reaching 3.5 million barrels per day (Mb/d) in 2013, out of the total of 7.7 Mb/d of crude produced by the US.[2] The repercussions of the SF surge in the international energy markets have been dramatic: between 2007 and 2013 around two thirds of the increase in the world supply of both oil and natural gas came from SFs. In 2013 SG represented almost 9 % of the global supply and LTO a non-negligible 4 %.

The effects on the US economy were also striking:

1. In 2013 the US extracted 21 % of world natural gas and 11.5 % of oil, becoming the largest gas producer in 2009 and the principal oil supplier in 2012.[3]
2. Its dependence on energy imports shrank: in 2013 the share of net imports in energy consumption fell to 19 from 30 % in 2005. As the volume of oil products

[2] http://www.eia.gov/forecasts/aeo/excel/aeotab_14.xlsx.

[3] This is true using the International Energy Agency (IEA) definition of oil supply, which includes biofuels. See "Definition of oil supply" in http://www.iea.org/oilmarketreport/glossary/.

Table 1 United States: proven reserves and natural gas production (billions of cubic meters and percentages)

Years	Proven reserves			Production			Years of future production	
	Shale gas (a)	Total gas (b)	(a)/(b) (%)	Shale gas (a)	Total gas (b)	(a)/(b) (%)	Shale gas (a)	Total gas (b)
2007	663.4	6731.7	10	36.8	545.6	7	18	12
2008	980.0	6927.9	14	60.2	570.8	11	16	12
2009	1726.3	7716.6	22	88.5	584.0	15	19	13
2010	2774.0	8626.0	32	151.9	603.6	25	18	14
2011	3746.5	9459.7	40	227.6	648.5	35	16	15
2012	3683.3	8722.6	42	295.2	681.2	43	12	13
2013[a]	4305.3	9344.6	46	301.6	687.6	44	14	14

Source Our calculations based on EIA statistics
[a]For 2013 shale proven reserves and production are calculated assuming that the entire variation in natural gas reserves and production recorded between 2012 and 2013 is due to shale. This hypothesis may underestimate effective production and reserves as it does not consider that conventional natural gas production has been declining since 2007

and natural gas exports has doubled over the last five years, the energy component of the 2013 trade deficit was more than half compared to 2011.[4]

3. US energy prices have remained well below the quotations prevailing in the rest of the world and this has boosted industrial competitiveness, especially of energy intensive industries.[5] Lower energy costs have encouraged additional foreign capital to flow into the US,[6] adding to the ample fiscal advantage already existing for energy products, especially in comparison with European countries.[7]
4. Looking forward, the substitution of coal with gas in the production of electricity may reduce air pollution via lower gas emissions. According to the US Energy Information Administration (EIA), in 2013 39 % of electricity was

[4]In 2011, for the first time in 60 years, net imports/exports of oil products were positive. EIA (2012), "U.S. petroleum product exports exceeded imports in 2011 for first time in over six decades", http://www.eia.gov/todayinenergy/detail.cfm?id=5290.

[5]According to the IEA, European petrochemical companies may suffer competition from US companies, which pay even 3–4 times less for natural gas, IEA (2013).

[6]An analysis of US FDI between 2002 and 2012 reveals that inward flows of capitals grew at a rate substantially higher than in manufacturing industry, not only in the mining and refinery industries but also in other energy-intensive sectors such as petrochemicals and pharmaceuticals.

[7]The US does not levy taxes on many energy products employed by industrial users; by contrast, taxation is particularly high in the EU, especially in the Scandinavian countries, in UK and in Italy (see Finnish Energy Studies 2011 and the chapter by Harding et al. in this volume).

generated from coal and 27 % from natural gas (in 2008 these shares were 48 and 21 % respectively).[8]

2.1 Future Developments in the United States

The major energy agencies forecast that US SFs will provide a decisive contribution to the expansion of global gas and oil supplies over the medium term, and in the long run they will represent a relevant fraction of the hydrocarbon supply.

According to International Energy Agency (IEA) projections, the increase in LTO in the US will amount to more than a quarter of the growth in world supply over the next five years, expanding the US share of world supply at the end of the period by another two percentage points. Factoring in the forecast decline in domestic consumption (−420 thousand barrels a day), the US should be able to cut crude imports by around 3.2 Mb/d by 2019.

There is, however, a high degree of uncertainty surrounding these estimates. The US Energy Information Administration (EIA) projects three scenarios for future LTO developments; in the baseline scenario production should reach a plateau around 2020 and then gradually subside, returning to current levels; in the "high oil and gas resources" scenario the extraction of LTO will increase over the next decades up to 13 Mb/d and then level off.

The IEA forecasts that the US will contribute 20 % to the expansion of the world natural gas supply between 2013 and 2019. Around two thirds of this growth will come from SG (69 billion cubic metres), the production of which will exceed half of the total by the end of 2040.

It must also be considered that at current production rates US gas reserves (both conventional and unconventional) will be exhausted in 14 years (see Table 1), while other major gas producers can rely on longer periods of production: 70 years for Russia and over 200 years for Qatar and Iran, which together represent 30 % of the world supply of natural gas.[9] At the same time it is worth recalling that a decade ago, when shale reserves were still not exploited, the predicted years of future US production were definitely less than today (see Fig. 1). Similarly, oil reserves are projected to last for another 11 years, which compares with a world average of 55. In spite of this, every year the amount of new reserves discovered is at least equal to the annual production, leaving the years of potential future supply unchanged.

[8]EIA projections to 2030 indicate that gas-fired plants will generate around a quarter of electricity and the share of coal-fired production will be reduced by a few percentage points (to 37 % of the total). See http://tinyurl.com/jwu5z5d.

[9]The years of future consumption covered with proven reserves are even fewer (around 5 for oil and 12 for natural gas; see Fig. 1).

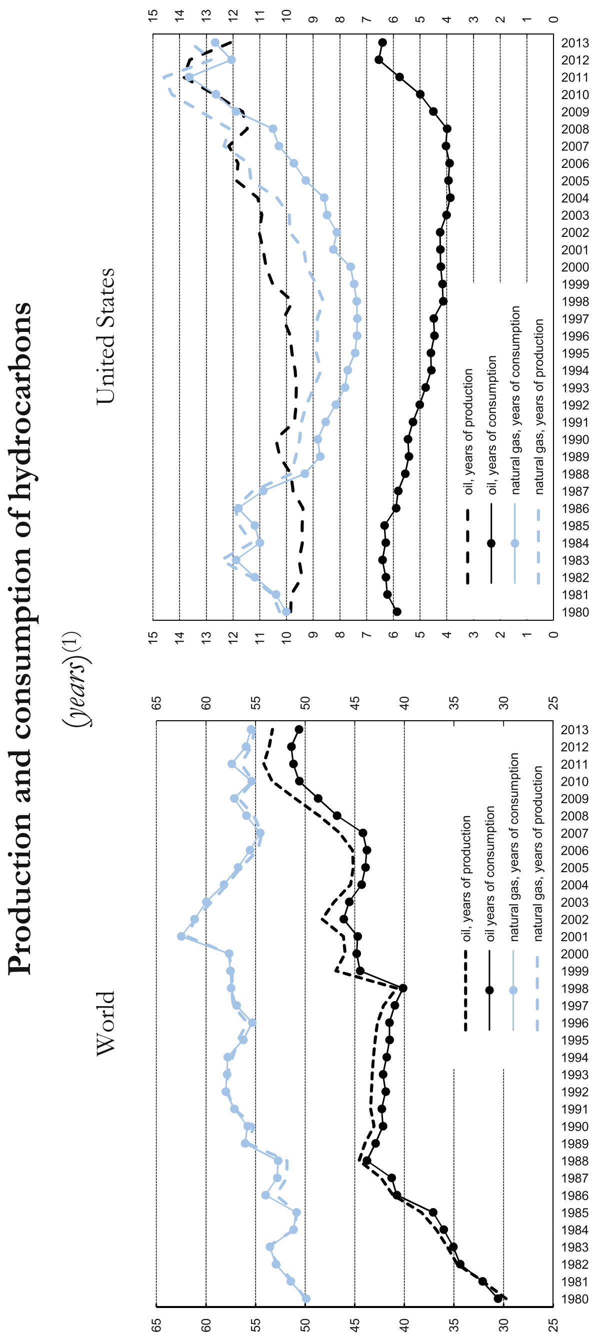

Fig. 1 Production and consumption of hydrocarbons. *Source* Our computation based on BP (2014), "Statistical Review of World Energy", June. [(1)]Ratio of reserves to production and consumption. Oil production does not include biofuels and refinement efficiency gains

3 How Prices Reacted to the Shale Revolution

An overabundant supply, a demand weakened by sluggish economic activity and a lack of export infrastructure (pipelines, storage points and other logistic facilities) led to a strong reduction in natural gas prices in the US, which fell to 3 dollars per million *British Thermal Units* (MMBTU) in 2012 from 9 in 2008 (see Fig. 2). By contrast, in Europe, where prices were still linked to oil quotations, the cost of gas remained high, resulting in an increasing differential (soared to 8 dollars per MMBTU in 2012 from 1.1 in 2007) which penalized European countries (IEA 2012a). Similarly the growing production of LTO explains part of the negative price differential between WTI and Brent, the benchmark crudes for the US and EU markets respectively, which has endured since the end of 2010.[10]

Despite this evidence, it would be unwise to simply deduce that the increased supply accruing from SF production will exercise a downward pressure on prices: unconventional upstream activities are economically viable when market prices are high enough to generate cash flows that cover the higher extraction costs. The IEA estimates that oil prices must remain above 60–80 dollars per barrel for LTO to be profitably exploited,[11] which is three to four times the break-even price estimated for extraction using standard techniques.[12] An analogous evaluation places the break-even point for SG at around 5 dollars per MMBTU, somewhat lower when *Natural Gas Liquids* (NGL), a by-product whose price is anchored to the oil price, is jointly extracted. In fact, the number of active wells decreased substantially in 2012, when the price of Henry Hub (HH), the US gas market benchmark, plummeted to a historical low of 2 dollars per MMBTU, considerably below the break-even price.

Logistic costs also affect the competitiveness of SFs. For instance, SG can only be exported as *Liquefied Natural Gas* (LNG), but on top of transport costs this requires a costly regasification process that entails a 30 % loss of the energy content. Cheniere Energy, which is running the most important project for

[10]Transport bottlenecks are one of the main reasons why the US crude quotes at a discount with respect to the other international benchmarks. Huffington Post and van der Hoeven (2013), 7th February 2013.

[11]There are various sources confirming the IEA estimations of break-even points. "'*U.S. Bakken*' *requires $65–73 and the* '*Permian Basin*' *is relatively high cost at $73–89.*" quoted from "Oil sands are cost-competitive with U.S. crude sources", Scotia report, February 2014; http://blogs.edmontonjournal.com/2014/02/21/oilsands-increasingly-cost-competitive-with-u-s-crude-sources-scotia-report/. "*Our compilation of various cost data shows that to maintain current growth rates, the US shale industry is likely to have to spend close to $100 billion per annum, translating into a hefty oil price required to manage cash flows. While production itself can breakeven at around an average of $65 per barrel, adding in the various upfront capital costs makes the total variable cost far more expensive, taking breakevens well into the $80s for some shale plays. The changing regulatory environment is also adding to costs for some producers*", quoted from "Flooring it: shale oil and marginal cost" by Amrita Sen; https://www.energyaspects.com/publications/view/flooring-it-shale-oil-and-marginal-cost.

[12]See Fig. 9.10 IEA World Energy outlook (2008).

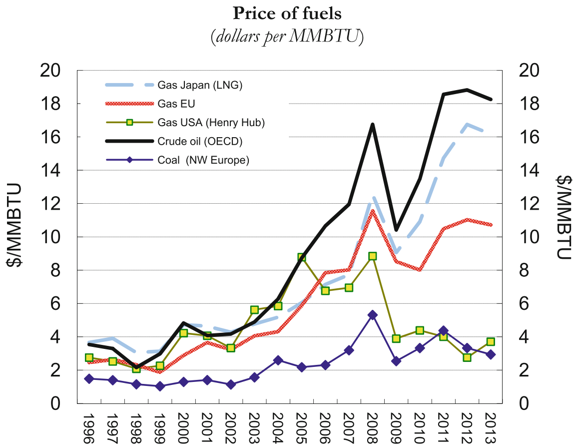

Fig. 2 Price of fuels. *Source* Our computation based on BP data (2014), "Statistical Review of World Energy", June

exporting LNG from the United States (the Sabine Pass[13]), has signed contracts with several Asian countries linking the LNG price to the HH and waiving the standard "*take or pay*" clause. This company estimates that these buyers would pay a price for LNG of around 11–12 dollars per MMBTU if the HH price stays in the region of 4–5 dollars per MMBTU. This is still lower than the 15–17 dollars currently paid by Japan for its LNG imports, although it is somewhat higher than the average price prevailing over 2011–2013 in Europe (10.8 dollars per MMBTU). These figures show that the level of US LNG prices that allows SG to break even would not be competitive in Europe.

Finally, the abundant supply of SG may have indirectly affected other international energy markets, e.g. the replacement of coal with cheaper natural gas in US power generation has increased the volume of US coal available for export. This fact may explain why, starting from 2012, the market price of coal, normally linked to oil prices, has been falling (see Fig. 2). From a global perspective, the relevance of SFs to world supply should increase world average extraction costs, with possible repercussions over the medium term on international market prices.

4 The Shale Fuel Potential

Although SFs yield refined products that are qualitatively equivalent to those derived from conventional crudes, they involve more expensive upstream activities, both in terms of production costs, as previously mentioned, and of energy use. In assessing the potential of SFs to replace conventional sources this difference in energy consumption must be taken into account. For this purpose, one can use the

[13]http://www.cheniere.com/sabine_liquefaction/sabine_pass_liquefaction.shtml.

concept of *Energy Returned On Energy Invested* (EROI), which for any energy source harnessed or technology adopted indicates how much useful energy is available net of the amount absorbed by extraction and processing.[14] According to recent evaluations, the EROI for US unconventional crude (including LTO) at the wellhead would be slightly more than a tenth of that for conventional oil (2 vs. 18), while in terms of the products obtained it would be a third (Cleveland and O'Connor 2011).[15]

Therefore, in assessing the ability of SFs to provide additional resources, one should take into account their different EROI. Turiel (2013) points out that the IEA appraisal of oil supply, resulting from the simple sum of conventional and non-conventional production, could overestimate the contribution of the latter. Assessing the extent of this adjustment is tricky, but if one believes the previously-mentioned EROI estimates, the contribution of unconventional crudes should be reduced by between 30 % (considering their yields in terms of products) and 90 % (taking into consideration the greater quantity of energy required for their extraction). Considering the wellhead EROI, the crude oil production pattern in the US will slowly decline from 2016, in contrast with the sustained growth assumed in the EIA projections (see Fig. 3).

Another element to consider in assessing the potential of SFs is the brisk depletion of reserves. Although there are still many uncertainties about techniques to estimate the decline curves[16] of unconventional gas production, it is a fact that in these fields the production drops dramatically after the first few years (according to Lake et al. 2012, after the first year production drops by 77–94 % of its original value). Moreover, the productivity of SF fields is much lower than that of conventional sources: the recovery factor of a play of conventional gas hovers around 80 %, while that of a SG play fluctuates between 15 and 30 % (JRC 2012),[17] although the productivity of the wells can be increased by using refracturing.[18]

[14]The concept of EROI harks back to the net energy analysis introduced in 1970 by White, Boulding and Odum and is based on the same principles of Life Cycle Analysis, in which the energy and environmental impact of each source or technology is evaluated throughout the chain of research, exploration, production and transportation (Hall 2011).

[15]SFs are more "expensive"—in terms of energy used—if their energy yield is evaluated at the wellhead, i.e. taking into account the greater energy required in the extraction process; in terms of refined products, they are nevertheless penalized by a lower calorific value, which requires a more complex conversion process.

[16]Production decline curve analysis predicts well performance and life on the basis of well production.

[17]The hydrocarbon recovery factor is defined as the ratio of the quantity of product extracted to the quantity originally contained in the bed under similar conditions. The recovery factor for SF basins is between 3 and 8 % in the most favourable cases, while for conventional oil it amounts to 30–35 %.

[18]In order to stimulate oil and gas production, unconventional field operators are increasingly repeating fracking on exploited wells (refracturing); in the Bakken Shale this procedure yielded a 30 % increase in estimated ultimate recovery (Jackson et al. 2014).

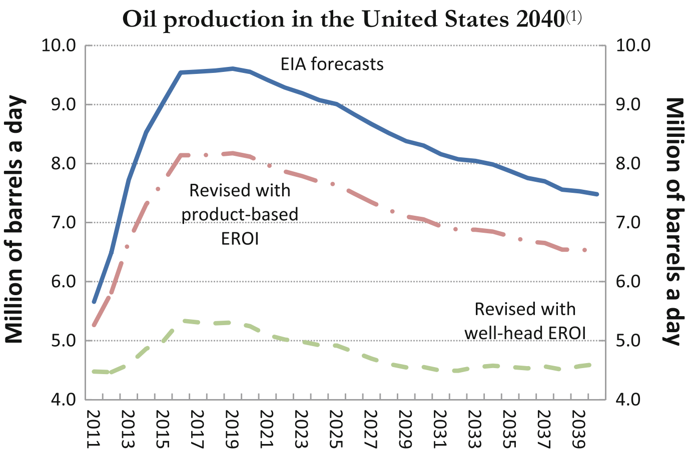

Fig. 3 Oil production in the United States 2040. *Source* Our computation on EIA data: http://www.eia.gov/forecasts/aeo/excel/aeotab_14.xlsx. Wellhead EROI reduces LTO production by 90 %, and product-based EROI by 30 %

There is also greater uncertainty in evaluating the recoverable resources.[19] In 2011, the EIA evaluated at 11.6 trillion cubic metres the resources technically recoverable from the Marcellus play, the most important SG field in the United States, but the following year this figure was reduced to less than 4 trillion,[20] with a significant impact on total US SG resources (down from 24,400 billion cubic metres in 2011 to less than 17,000; Table 2).

These features, which are critical to understanding the relationship between the potential of SFs and the evolution of energy prices, are only partially taken into consideration by the IEA scenarios. Tverberg (2012) shows that the level of LTO production suggested in the 2012 World Energy Outlook (WEO) is not coherent, due to the low EROI, and that there is a need to intensify extraction activity because of the slowing production from marginal fields (WEO 2012d).[21]

The relationship between energy commodity prices and technologies for the exploitation of unconventional resources is formalized in a piece of research which correlates rates of production, conventional reserves and price trends (Benes et al. 2012). According to this analysis, a very substantial increase in prices is required to support the production of unconventional oil, up to a doubling in real terms over the next decade. This is a finding that drastically contrasts with the WEO 2012 scenario (which for the same horizon projected an increase in oil prices of 10 % in real terms).

[19]"*There is considerable uncertainty regarding the ultimate size of technically recoverable shale gas and shale oil resources*", (EIA 2011, p. 6).

[20]http://www.bloomberg.com/news/2012-01-23/u-s-reduces-marcellus-shale-gas-reserve-estimate-by-66-on-revised-data.html.

[21]IEA (2012b, p. 60).

Table 2 World hydrocarbon resources in 2011

Countries	Natural gas (billions of cubic meters)					Oil (millions of barrels)				
	Production in 2011	Proven reserves (a)	Technically recoverable resources			Production in 2011	Proven reserves (a)	Technically recoverable resources		
			Shale (b)	Conventional (c)	Total (a + b + c)			Shale (b)	Conventional (c)	Total (a + b + c)
Europe	**283**	**4106**	**13,309**	**5210**	**22,625**	**1537**	**11,748**	**12,900**	**14,638**	**39,286**
Bulgaria	0	0	481	–	–	1	15	200	–	–
Denmark	0	57	906	–	–	83	805	0	–	–
France	0	0	3879	–	–	28	85	4700	–	–
Germany	0	113	481	–	–	51	254	700	–	–
Netherlands	85	1218	736	–	–	21	244	2900	–	–
Norway	113	2067	0	–	–	733	5366	0	–	–
Poland	0	85	4191	–	–	10	157	3300	–	–
Romania	0	113	1444	–	–	38	600	300	–	–
Spain	0	0	227	–	–	10	150	100	–	–
Sweden	–	–	283	–	–	4	–	0	–	–
United Kingdom	57	255	736	–	–	426	3122	700	–	–
Former Soviet Union	850	61,674	11,751	60,739	134,165	4866	118,886	77,200	114,481	310,567
Lithuania	–	–	0	–	–	3	12	300	–	–
Russia	680	47,799	8127	–	–	3737	80,000	75,800	–	–
Ukraine	28	1104	3625	–	–	29	395	1100	–	–
North America	**906**	**11,412**	**47,714**	**62,948**	**122,102**	**6093**	**208,550**	**80,000**	**305,546**	**594,096**
Canada	170	1926	16,226	–	–	1313	173,105	8800	–	–
Mexico	57	481	15,433	–	–	1080	10,264	13,100	–	–
United States	680	9005	16,056	43,778	68,838	3699	25,181	58,100	139,311	222,592

(continued)

Table 2 (continued)

Countries	Natural gas (billions of cubic meters)					Oil (millions of barrels)				
	Production in 2011	Proven reserves (a)	Technically recoverable resources			Production in 2011	Proven reserves (a)	Technically recoverable resources		
			Shale (b)	Conventional (c)	Total (a + b + c)			Shale (b)	Conventional (c)	Total (a + b + c)
Asia and Pacific	**368**	**11,836**	**45,505**	**24,296**	**81,637**	**2866**	**41,422**	**61,000**	**64,362**	**166,784**
Australia	57	1218	12,374	–	–	192	1433	17,500	–	–
China	113	3511	31,573	–	–	1587	25,585	32,200	–	–
Indonesia	85	3058	1303	–	–	371	4030	7900	–	–
Mongolia	–	–	113	–	–	3	–	3400	–	–
Thailand	28	283	142	–	–	152	453	0	–	–
South-Asia	113	2435	5692	5182	13,309	396	5802	12,900	8211	26,913
India	57	1246	2718	–	–	361	5476	3800	–	–
Pakistan	28	680	2973	–	–	23	248	9100	–	–
Middle East and North Africa	**736**	**88,263**	**28,402**	**46,751**	**163,444**	**10,986**	**867,463**	**42,900**	**463,407**	**1,373,770**
Algeria	85	4502	20,020	–	–	680	12,200	5700	–	–
Egypt	57	2180	2832	–	–	265	4400	4600	–	–
Jordan	0	0	198	–	–	–	1	100	–	–
Libya	0	1557	3455	–	–	183	48,010	26,100	–	–
Morocco	0	0	340	–	–	2	1	0	–	–
Tunisia	0	57	651	–	–	26	425	1500	–	–
Turkey	0	0	680	–	–	21	270	4700	–	–
Western Sahara	–	–	227	–	–	–	–	200	–	–

(continued)

Table 2 (continued)

Countries	Natural gas (billions of cubic meters)					Oil (millions of barrels)				
	Production in 2011	Proven reserves (a)	Technically recoverable resources			Production in 2011	Proven reserves (a)	Technically recoverable resources		
			Shale (b)	Conventional (c)	Total (a + b + c)			Shale (b)	Conventional (c)	Total (a + b + c)
Sub-Saharan Africa	**57**	**6286**	**11,044**	**23,531**	**40,861**	**2264**	**62,553**	**100**	**140,731**	**203,384**
Mauritania	–	28	0	–	–	3	20	100	–	–
South Africa	0	–	11,044	–	–	66	15	0	–	–
South America and Caribbean	**170**	**7617**	**40,493**	**21,691**	**69,801**	**2868**	**325,930**	**59,700**	**258,234**	**643,864**
Argentina	57	340	22,710	–	–	279	2805	27,000	–	–
Bolivia	28	283	1019	–	–	18	210	600	–	–
Brazil	28	396	6938	–	–	980	13,154	5300	–	–
Chile	0	85	1359	–	–	7	150	2300	–	–
Colombia	0	170	1557	–	–	343	2200	6800	–	–
Paraguay	–	–	2124	–	–	1	–	3700	–	–
Uruguay	–	–	57	–	–	0	–	600	–	–
Venezuela	28	5522	4729	–	–	909	297,570	13,400	–	–
World	**3511**	**193,658**	**203,909**	**250,377**	**647,944**	**31,875**	**1,642,354**	**345,000**	**1,369,610**	**3,356,964**

Source EIA (2013)

5 The Environmental Effects of Shale Fuels

When considering the future role of SFs in meeting world energy demand, the environmental effects of a widespread use of hydraulic fracturing should also be taken into account. Hydrocarbon exploitation is traditionally viewed with suspicion regarding the impact of upstream activities on the environment: research and exploration (such as seismic surveys), harnessing of plays (which requires the management of special waste such as sludge and drilling debris), and the recovery and disposal of equipment when the exploitation ceases (Eni 2004).

The exploitation of SFs raises problems akin to those related to traditional hydrocarbons, but it also has some specific features.

1. **Effects on land**. Unlike conventional oil extraction, SF plays cover a more extensive area: structures for the exploitation of SFs occupy an average area of about 3.6 ha per drilling block, about twice that for conventional drilling (AEA 2012).[22] Consequently, production per occupied area is much lower: in the case of SG production is in the range of 0.04–0.6 per square km, against the 2 cubic metres for conventional plays (IEA 2012d).
2. **Effects on the hydrosphere**. Hydraulic fracturing requires a massive amount of water resources, of several thousand litres per ton of oil equivalent extracted, one order of magnitude more than the volume required for the extraction of conventional gas.[23] Furthermore, the liquids injected in the ground are mixed with chemical compounds such as acids, anti-corrosives and water disinfectant (for bacteria elimination) to extend the fractures, add lubrication and to carry proppant[24] into the formation. These chemical elements must be disposed of appropriately. There is also the risk that one or more of these compounds, or the hydrocarbon itself, migrates from the rock formations and pollutes the water table.[25]
3. **Effects on the atmosphere**. Extraction of SFs affects the air through the emission of chemicals, such as volatile organic compounds, and the uncontrolled leakage of high Global Warming Potential (GWP) greenhouse gases

[22]As a consequence of the low productivity and EROI, in order to sustain SF production a large number of wells must be drilled. As an example, consider that the wells of the Marcellus Shale in the United States cover an area of over 250,000 square km, about ten times more than the conventional gas play in Hugoton, Kansas, the largest in the country (IEA 2012c).

[23]As the refracturing of wells becomes more common (see previous paragraph), water withdrawal will rise. The refracturing of oil wells in the Bakken Shale cited (which increases ultimate recovery by a third) requires twice as much water as the original fracking (Jackson et al. 2014).

[24]Proppant is a solid material, typically treated sand or ceramic materials, designed to keep the fracture open.

[25]According to Osborn et al. (2011) the quantity of methane in drinking water aquifers located in the proximity of SG plays is systematically higher than the natural level. An EPA investigation in Wyoming found a level of benzene in groundwater 50 times higher than safe levels together with several hazardous pollutants commonly adopted in hydraulic fracturing (DiGiulio et al. 2011).

(such as methane).[26] Recent studies find that in a life-cycle perspective the production of SG involves 40–60 % more greenhouse gas emissions than the extraction of conventional hydrocarbons and coal (Howarth et al. 2012).

4. **Effects on the lithosphere**. Fracking can induce seismic events such as small local earthquakes (e.g. earthquakes produced by the sliding and detachment of faults).[27]

These environmental concerns require a prompt answer. The extraordinary rate at which hydraulic fracturing has been deployed in the United States is partly due to a de facto suspension, at least until 2010, of environmental regulation. In a 2004 report the US agency for the environment (EPA) concluded that the use of this technique had limited effects on the environment (EPA 2004), but on the basis of incomplete knowledge. At the time, the EPA did not even have access to information regarding the chemical compounds injected together with the water and sand, because this was safeguarded under intellectual property right laws.

Hydraulic fracturing is excluded from the *Safe Drinking Water Act,* which regulates the injection of fluids into the ground in order to protect the water table. Since 2010, fracturing activity has been regulated and subjected to the approval of *Underground Injection Control*, a programme that requires limitation of the effect of upstream activity on the environment.[28] Recently, Congress has ordered disclosure of the chemical compounds that companies employ in the fracking process and the EPA has commissioned a study to assess the relationship between hydraulic fracturing and groundwater pollution. This report should specifically evaluate the effect of the extraction process on water withdrawal and contamination because of the dispersion of injected fluids, and examine the treatment of waste water and other waste products. The EPA report,[29] which will be based on data analysis, case studies, simulation models, laboratory studies and toxicity assessments, should identify a set of technological solutions to mitigate the risks posed by fracking (EPA 2012).[30]

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[26]GWP is a measure of how much each greenhouse gas contributes to global warming using carbon dioxide (CO_2) as a reference. GWP considers the combined effect of the gas remaining in the atmosphere and its ability to absorb infrared radiation emitted from earth. The GWP of methane is more than twenty times that of CO_2.

[27]Earthquakes supposedly generated by the injection of liquids into the ground during the extraction of SG occurred in the fields at Cuadrilla (UK) and Youngstown (United States). In both cases, small-scale earthquakes were recorded (about 2° on the Richter scale) without apparent damage to the surface (IEA 2012e).

[28]The minimum requirements set by the EPA concern the authorization and regulation of all injection wells, the construction and the location of exploratory platforms and the ex-post evaluation of the permissions granted. http://water.epa.gov/type/groundwater/uic/basicinformation.cfm.

[29]All information about the objectives and progress of the project is available through this website: http://epa.gov/hfstudy/.

[30]For example, a requirement for wellhead containment systems could protect aquifers and avoid the dispersion of fracking fluids into the soil.

However, while there is evidence on the environmental effects of hydraulic fracturing there are almost no estimates of the associated economic externalities. One study analyzes how proximity to SG plays affects the value of residential property: there is a positive effect due to greater economic activity induced by upstream operations, but this is counterbalanced by the risk that aquifers become polluted. In the latter case, the property value of units relying on groundwater can be reduced by a quarter (Muehlenbachs et al. 2012).

In conclusion, understanding of the environmental effects of SF extraction is still scanty and a serious economic assessment of these energy sources would require a full-fledged cost-benefit analysis based on the economic assessment of their physical impact along the lines indicated by Kinnaman (2010), and more recently by Jackson et al. (2014).

6 Shale Fuel Developments Outside the USA

SFs have the potential to reduce the geographical concentration of supply and hence increase the energy security and competitiveness of energy markets, but the extent to which other countries will be able to replicate the US success is not clear. Only the EIA has produced a comprehensive assessment of shale resources outside the US. In its latest evaluation, which dates back to June 2013, it extended the number of plays and regions analyzed compared to its 2011 assessment, and showed that China, Australia, Argentina, Mexico, Canada and Algeria are rich in shale resources and shale oil is also plentiful in the Russian subsoil (Table 2). Although there is no overall evaluation of the proven reserves outside the US, those technically recoverable from the countries considered are 13 times those in the US for SG and 6 times for LTO (EIA 2013).[31]

China and Australia, which have so far promoted the production of other non-conventional gases (mainly *coalbed methane*), have only recently turned to SG development. China has twice the shale resources of the US and holds the largest share of technically recoverable shale oil. Nonetheless, the deposits have been discovered in lands difficult to frack with present technology and moreover many basins are poor in water resources.[32] While Australia is still trying to ascertain its reserves, China is trying to acquire foreign technology by supporting inward foreign direct investments in the sector, requiring joint ventures between foreign and

[31]The relationship between resources and reserves must be interpreted carefully. While the former denotes hydrocarbons unexplored and non-extractable under current market conditions, reserves indicates hydrocarbons which can be exploited under the prevailing market conditions and with the technology available.

[32]http://www.technologyreview.com/news/508146/china-has-plenty-of-shale-gas-but-it-will-be-hard-to-mine. Indeed, according to an industry website and a government source, early exploration efforts to unlock unconventional fuel proved challenging due to complex geology and high production costs.

Chinese companies. The first partnership between Shell and the national energy company was signed in 2012 using a production sharing agreement, but has not gone beyond a preliminary exploration stage. Effective production is turning out to be far below the initial expectations: barely 0.2 billion cubic meters were produced in China in 2013, forcing the country to severely downgrade its 2015 targets. The projection for 2015 has been more than halved from the 15 billion cubic meters (less than 1 % of current US production) expected in 2012 to 6.8 bcm. This postponement of the exploitation stage is due to several hurdles, such as a lack of infrastructure and a scarcity of technological and human skills, and more generally to poor business experience. There are also bureaucratic and legal barriers linked to state concessions and to landowner compensation.[33]

6.1 Shale Fuel Prospects in Europe

SFs may affect European energy supplies through two channels: (1) changing the energy endowment in Europe; (2) influencing the international supply of energy and therefore the dynamics of energy commodity prices (crude oil and gas and their substitutes, such as coal) in international markets.

The few available studies provide estimates of technically recoverable resources in Europe greater than the conventional ones, but with a large degree of variability that—considering SG only—goes from 2300 billion cubic meters to 17,600 (with an average of 7100 billion cubic meters) (JRC 2012),[34] values that compare with the 1823 billion of proven reserves of conventional gas in the European Union. These resources are not evenly distributed across Europe but are mainly concentrated in France and Poland (Table 2), where there are currently—as in Sweden and Germany—active projects for the cultivation of SG[35] (Philippe & Partners 2011). Recent EIA assessments (June 2013) based on more stringent criteria have led to a downward revision of estimates of the resources available in Poland.[36] Moreover, the meagre outcomes of the exploration projects undertaken on Swedish territory have led to exclusion of the presence of unconventional resources in Norway (in the 2009 EIA assessment, Norway was the third country in Europe in terms of SG resources), confirming the great uncertainty associated with estimates of unconventional resources.

[33]In the US, landowners have been compensated with up to 25 % of royalties (or 25,000 dollars per acre).

[34]The EIA estimates summarized in Table 2 remain at the upper limit (about 13.3 trillion cubic meters).

[35]In 2011, France established a moratorium on all concessions for the production of SG, followed by Bulgaria in 2012; http://www.bbc.co.uk/news/world-europe-16626580.

[36]The low profitability of Polish deposits has hindered the exploration activities of some US companies: BBC, "North American firms quit shale gas fracking in Poland", http://www.bbc.co.uk/news/business-22459629.

Taking into account the relationship between resources and proven reserves, SG estimates in Europe could contribute to an expansion greater than that in the United States: European resources of SG should be more than three times the proven reserves of conventional gas against less than twice in the US (which is nevertheless richer in shale oil[37]). But even if these estimates are reliable, there are other factors that may hinder the development of SFs in Europe with respect to the stunning US expansion: differences in population density and legal, environmental and infrastructure constraints.[38]

Population density. According to the Census Bureau International Database, in 2011 US population density (34 people per square km) was less than a third that of France, a quarter that of Poland and a sixth that of Italy. In Europe, in comparison with conventional resources the SFs are dispersed over a wider area and this makes their extraction in densely populated zones more expensive and challenging.

Another constraint on SF development in Europe concerns *rights of exploitation of the subsoil*. Unlike the US, where the landowner owns the subsoil resources, in most European countries these are state-owned. To some observers, this would complicate the process of exploration as companies should either purchase the land from the owners or request the right to explore the subsoil from the state (Checchi and Galletta 2010). Indeed, the situation is somewhat variable (both among European countries and among different regions within states): according to a report prepared for the European Commission, legal issues concerning this aspect are no different from those encountered in the exploration of conventional oil and gas reserves (Philippe & Partners 2011).[39]

A third factor that can hamper SF expansion regards the *availability of water resources*: As previously mentioned, fracturing requires a high level of water withdrawal. A recent evaluation by the IEA identified SG extraction as the one absorbing the greatest amount of water among a group of technological energy options (IEA 2012e). With the exception of the Scandinavian countries, the renewable water resources per capita in Europe are much fewer than in the United States: in particular in France and Poland water resources per inhabitant are respectively a third and a sixth of those recorded for the United States.[40]

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[37]Shale oil resources in the United States are twice the proven conventional oil reserves; in Europe the ratio drops to 1:1.

[38]One should also consider that the geology of Western Europe is also more problematic because many European countries are located on basins with more fractured formations (EASAC 2014).

[39]"Competent authorities and companies active in shale gas confirm that they do not experience significant differences between regular hydrocarbon procedures and procedures with a view to permitting/authorising shale gas activities. One concern may be that shale gas projects often start on a very small scale (the exploration phase), but develop into large-scale projects having a higher potential impact on the environment and on the population than originally foreseen/expected", p. 97.

[40]According to FAO Aquastat (www.fao.org/nr/water/aquastat/data/query/index.html), in 2011 per capita renewable water resources amounted to 9802 cubic meters in the United States, 3342 in France and 1608 in Poland.

The most substantial contrast between Europe and the US concerns the *environmental impact of fracking*: Europe is torn between a fear of losing a vital technological option to improve its energy security and the potential harmful effects of this choice on the environment, also in relation to the ambitious targets for greenhouse gas emission reduction in the Commission Roadmap to 2050.[41] This conflict is reflected in the different positions taken by various European institutions and Member States. It has increased the distance between the Industry, Research and Energy Committee of the European Parliament—which supports the adoption of fracking—and the DG Environment of the Commission, which expresses serious concern about its environmental effects. At the end of 2012, the European Parliament stated that decisions to allow the exploration of SG remain in the realm of Member States, and rejected a request for a European moratorium[42] like the ones implemented in France and Bulgaria. In contrast, the UK and Poland strongly support SG development.[43] The European Parliament has also constrained the use of hydraulic fracturing following the results of a web-based consultation process which started at the beginning of 2013.[44] The results of the survey showed that according to 38 % of the respondents unconventional fossil fuels should not be developed in Europe, while another 29 % think that they should only be exploited with proper health and environmental safeguards in place.[45]

The failure to find a common position on the subject can be ascribed to several factors. First, the European institutions consider phasing-out hydrocarbons a pillar of the "Europe 2020" strategy. Therefore, encouraging the adoption of a technique that postpones the eradication of fossil fuels (with serious side-effects on greenhouse gas emissions) weakens the commitment to focus on renewable energy and energy efficiency. In addition, strong opposition to the use of hydraulic fracturing emerged from a 2013 Eurobarometer survey: three-quarters of the respondents would be concerned (40 % very concerned) to live in areas in the vicinity of a SG play.[46]

[41]The European Roadmap to 2050 foresees an 80 % greenhouse gas emission reduction by 2050 (compared to 1990) differentiated by sector (electricity sector −95 %, industry −85 %, transport −61 %) (European Commission 2011).

[42]"Shale gas: member states need robust rules on fracking, say MEPs", http://tinyurl.com/l7dg4ch.

[43]Poland is considering issuing bonds to finance exploration by national companies. Euractive (2012), "Poland to issue special shale gas bonds", http://tinyurl.com/cmltaks.

[44]On 21 November 2012, Environment Commissioner Potočnik stated that "[…] It is clear that the future development of shale gas will depend on the extent of public acceptance of fracking. Addressing health and environmental risks will be of paramount importance for the industry to gain broad public acceptance and a 'public license to operate' in Europe"; http://europa.eu/rapid/press-release_MEMO-12-885_en.htm.

[45]The consultation (*Unconventional fossil fuels in Europe*) took place between 20 December 2012 and 23 March 2013. The Report is available at http://tinyurl.com/padwqvf.

[46]http://ec.europa.eu/public_opinion/flash/fl_360_sum_en.pdf.

What is missing from the debate is an assessment of how harnessing European SFs can help reduce the share of coal in power generation,[47] in particular to substitute the European nuclear capacity, which will be shut down in the next decade, without increasing greenhouse gas emissions.[48]

Finally, as a further obstacle to the emergence of a "golden age of gas" in Europe the IEA identifies a feeble demand for natural gas, which will remain below 2010 levels until 2035 (IEA 2012e, 2014). There are three reasons: weak economic growth, which thwarts industrial gas demand; high prices for the next few years; and a crowding out of gas consumption in power generation and in the heating sector because of the increasing penetration of renewables (IEA 2012d).

7 Conclusions

The shale revolution shows that shifts in the technology frontier allow physical constraints to be overcome. The availability of SFs has widened the set of energy options, improving energy security and reducing foreign dependency. Nevertheless the fortunate conditions that prevailed in the US—high energy prices combined with favourable legislation and "light" environmental regulation—are hard to replicate elsewhere, and in the long run even to maintain in the US. It is very unlikely that SF developments will occur in Europe because of the different structural features of the two regions (e.g. higher population density and scarcer water resources in Europe) and for political reasons: SF exploitation would be at odds with the EU decarbonizing strategy, which envisages a drastic reduction in hydrocarbon use.

These findings are consistent with the IEA scenarios, which show that in the next twenty years the production of SFs will only reach significant levels in the US, China and Canada, while it will remain marginal in Europe (IEA 2013). According to the most optimistic IEA scenarios (where it is assumed the optimal policies—"the golden rules"—are adopted), unconventional gas may provide a contribution from a third to a quarter of total gas production within a period of about two decades. However, the effective contribution of SFs to total supply must be assessed in the light of their lower EROI and the faster decline in the recovery rate of reserves, which implies that the amount of resources actually available is subject to important revisions.

Furthermore, a growing production of SFs would not mechanically lower oil and gas prices, as asserted by many observers (see for example European Commission 2014) but may affect the price of SF substitutes (such as coal). Over the medium

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[47]In Europe, coal still has an important role in power generation: in the EU-27 average it accounts for over a quarter of the electricity produced, a figure that rises to over 45 % in Germany and to 84 % in Poland.

[48]Germany has planned to stop its nuclear power plants (which at the moment generate just under a quarter of German electricity) by 2022 and Belgium (where nuclear accounts for more than half of the domestic generation) is planning a similar phasing out between 2015 and 2025.

term, unless further technological innovations occur, SF prices are tied to higher production and transportation costs because of their lower density and quality (in terms of EROI). An excessive decline in prices would make SF extraction uneconomical; at the same time the reduction in gas prices in the US has so far promoted a switch from coal to gas in power generation, depressing international coal prices.

Lastly, many environmental impacts of SFs remain incompletely addressed: locally, there is evidence that fracking affects water withdrawals and water pollution; globally, there is the risk that gas flaring increases greenhouse effects because of the higher GWP of natural gas. On the other hand, SFs also provide beneficial effects—in terms of lower carbon emissions and energy efficiency—through the reduction in coal-fired power generation induced by the switch to gas.

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Does the Trade-off Between Energy Security and Climate Change Protection Matter? The Canadian Tar Sands Case

Laura Castellucci

Abstract Energy security may have different meanings. In addressing the energy security question from an economic perspective, a standard definition "as reliable and adequate supply of energy at reasonable prices" may be accepted once the meaning of "reasonable prices" is given. Since the problem concerns the society as a whole (be it a single nation or the European Community or the OECD countries), *prices* to be considered are those for the society as a whole. This is to say that external costs have to be added to the market prices and that they are represented by the negative impacts on climate change, i.e. GHG emissions. The Canadian tar sands are analyzed as a case study to investigate how each viable energy mix for Europe performs with respect to both energy security and climate change. The minimization of the risk of supply disruption and of GHG emissions being the optimum target. Needless to say, those choices that produce positive impacts on both are preferred ones while choices having opposite impacts need a comparison among their economic costs and benefits.

1 Introduction

Energy security may have different meanings. In addressing the energy security question from an economic perspective, we may adopt the standard definition of a "reliable and adequate supply of energy at reasonable prices", provided we add "for society".[1] This is to say that external costs in terms of gas emissions need to be

[1]For a good review of definitions, see Winzer (2012). Winzer proposes narrowing the concept of energy security to the concept of energy supply continuity. In either case, we think the reference to prices is necessary.

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added to the market prices. The reason for this is to be found in the effects that such emissions produce in terms of climate change. The question is therefore whether there is climate change; and if there is, whether it has anthropogenic causes. To answer these questions we need a scientific basis, which can be the recent contribution of the IPCC Working Group I to the fifth Assessment Report (AR5, December 2013). The contribution considers new evidence on climate change which is based "on many independent scientific analyses from observations of the climate system, paleoclimate archives, theoretical studies of climate processes and simulations using climate models":

> Observations of the climate system are based on direct measurements and remote sensing from satellites and other platforms. Global-scale observations from the instrumental era began in the mid-19th century for temperature and other variables, with more comprehensive and diverse sets of observations available for the period 1950 onwards. Warming of the climate system is unequivocal, and since the 1950s, many of the observed changes are unprecedented over decades to millennia. The atmosphere and ocean have warmed, the amounts of snow and ice have diminished, sea level has risen, and the concentrations of greenhouse gases have increased.[2]

The point now is to detect the drivers behind the warming of the climate system and to assess whether human activity has some responsibility. In fact, any

> natural and anthropogenic substances and processes that alter the Earth's energy budget are drivers of climate change. Radiative Forcing (RF) quantifies the change in energy fluxes caused by changes in these drivers for 2011 relative to 1750. Positive RF leads to surface warming, negative RF leads to surface cooling. Total radiative forcing is positive and has led to an uptake of energy by the climate system. The largest contribution to total radiative forcing is caused by the increase in the atmospheric concentration of CO_2 since 1750 (p. 13).

As shown in Fig. 1 (produced by the same WG I of the IPCC), which reports radiative forcing by emissions and drivers, the anthropogenic RF in 2011 (relative to 1750) was almost double with respect to 1980, which in turn was more than double with respect to 1950. Notice the good confidence level of the estimates in the last column of the figure.

The scientific message is so clear as to leave little room for doubt. Nevertheless, it is not uncommon to find contrasting or sceptical positions in the general debate, which short-sighted politicians and greedy managers/CEOs can thrive on. In fact, while estimations of climate system disruption by human activity become more and more reliable with improvements in methods of estimation and increases in data availability, they also become more pessimistic in the sense of showing greater human responsibility and larger effects.[3] Thus, it may appear redundant to recall the scientific basis of climate change—it should be clear and accepted—but unfortunately this is not always the case. In our commercial society, science and culture do not enjoy the undisputed reputation that they did in the past and, moreover, there are attempts to subtract these specific issues from the realm of science and present

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[2]IPCC, WGI (2013). p. 4, 13 and 14.

[3]For those interested in the economics of climate change, see Tol (2014).

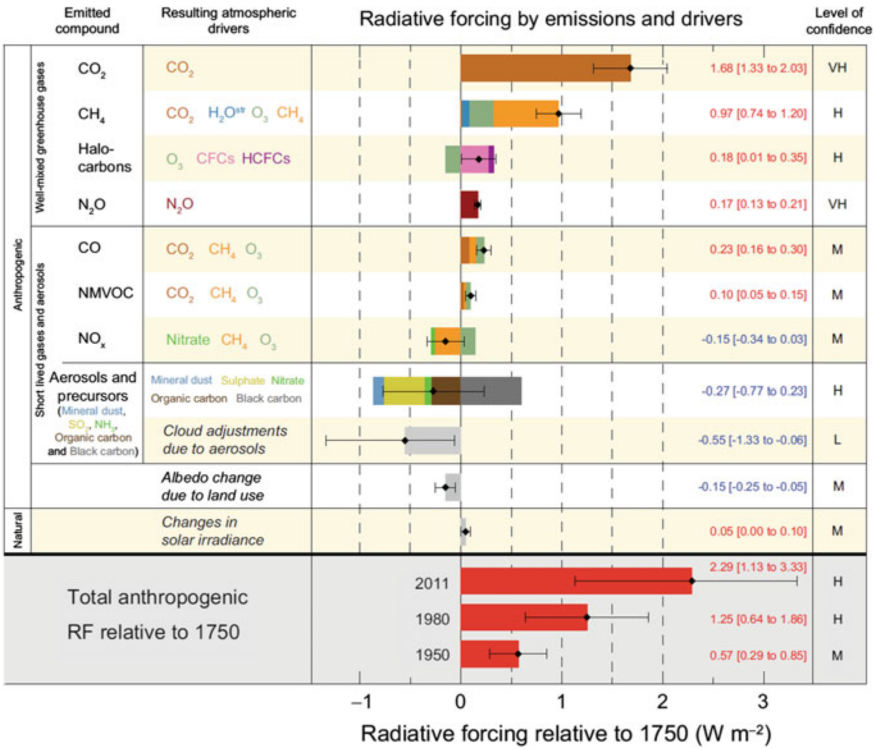


Fig. 1 Radiative forcing estimates in 2011 relative to 1750 and aggregated uncertainties for the main drivers of climate change. Values are global average radiative forcing (RF14), partitioned according to the emitted compounds or processes that result in a combination of drivers. The best estimates of the net radiative forcing are shown as black diamonds with corresponding uncertainty intervals; the numerical values are provided on the right of the figure, together with the confidence level in the net forcing (*VH* very high, *H* high, *M* medium, *L* low, *VL* very low). Albedo forcing due to black carbon on snow and ice is included in the black carbon aerosol bar. Small forcings due to contrails (0.05 W m–2, including contrail induced cirrus), and HFCs, PFCs and SF6 (total 0.03 W m–2) are not shown. Concentration-based RFs for gases can be obtained by summing the like-coloured bars. Volcanic forcing is not included as its episodic nature makes is difficult to compare to other forcing mechanisms. Total anthropogenic radiative forcing is provided for three different years relative to 1750. *Source* IPCC (2013)

them as opinions. For this reason, here we underline once more the few important facts which the IPCC Group I calls attention to and which constitute the basis for any discourse on climate policy[4]:

1. The influence of human activities on warming in the atmosphere and the ocean, on reductions in snow and ice, on global mean sea level rises, on changes in the global water cycle, etc. has been detected.

[4]IPCC, WGI, (2013), p. 17.

2. The evidence for this influence of human activity has grown since the previous report (AR4).
3. It is *extremely likely* that human influence has been the dominant cause of the observed warming since the mid-20th century.
4. Continued emissions of greenhouse gases will cause further warming and changes in all components of the climate system.
5. Limiting climate change will require substantial and sustained reductions of greenhouse gas emissions.

Within the anthropogenic causes of climate warming, the energy sector has played the prominent role and is still the main driver, although the transportation sector is catching up. As is well known, it was energy production coming from the burning of first wood and fossil fuels soon afterwards which empowered humanity with the industrial revolution and gave rise to very high and prolonged positive economic rates of GDP growth. It is now also clear that all this came with a 'cost' to society as a whole: climate change. What we need to do and will be able to do will be crucial, not simply for the rate of growth of GDP but for the very existence of human beings. To be more specific, it is still the energy sector, broadly defined, which deserves our greatest attention, since the economic system is completely dependent on energy availability. In terms of trade-offs, the well-known one between growth and climate change largely coincides with that between energy security and climate change.

With these reference points in mind, we address the question of whether we are doing anything to move away from our energy model and switch to one more compatible with climate policy. As we shall see, notwithstanding our knowledge and technological progress, in very recent years the global community has been going backwards in terms of climate change protection (shale gas and tar sands speak for themselves), showing no practical concerns but merely producing rhetoric.

This chapter is organised as follows. To address the trade-off between energy security and climate protection, we start by introducing the issue of decoupling, because if it were possible to decouple economic growth from the use of natural resources we would not even face the trade-off. In other words, an absolute decoupling at the global level could make growth sustainable. In Sect. 2 we argue that while decoupling is possible in principle, it is not being realised in practice. The reasons are linked to the evolution of technical progress. When this process is left to the market, it responds to the market prices of resources and does not adjust to resource availability and environmental deterioration. Sections 3, 4 and 5 are therefore devoted respectively to policy instruments, to future energy prices, and to the evolution of technical progress. It appears that not only is technical progress in energy production driven by a search for increases in resource productivity which are not always environmentally friendly, but it is driven by market prices, which are increasingly sensitive to financial speculation. Basically, oil prices only partially reflect the demand and supply conditions in the energy market, as they are also increasingly affected, among other things, by speculation (increasing volatility). The need for an active government policy is undeniable. Section 6 confirms the story with a case study, that of Canadian tar sands (bitumen). If one takes Canada as a representative country in terms of climate change policy in the 21st century, the answer to the question of whether the trade-off matters is absolutely negative. Finally, Sect. 7 is dedicated to European energy security within the context of energy policy. It shows what cooperation among countries can and should do in terms of policy targets, but also how Europe badly needs to stay firm in its energy policy. While it is to be hoped that Europe will be able to defend its position of entrusting certain decisions to governments rather than to the market, we underline the threats represented by the increasing pressure from North America (US and Canada) to import unconventional oils. Section 8 offers some concluding remarks.

2 Growth Versus Environmental Protection: The Trade-off and Possible Decoupling

When it comes to the problem of a trade-off between growth and environment protection, or growth and species conservation, or even growth and health risks, the winner is always growth. Needless to say, growth and energy security go hand in hand (Sect. 2.1 addresses directly energy security). For this reason, decoupling attempts have enjoyed great popularity since their early formulations. Several reports by the European Commission and by the EEA, the IEA, the OECD and other think tanks concentrate on the possibilities of decoupling growth from the use of natural resources and from negative environmental impacts. In 2002, the OECD proposed a set of indicators to measure the decoupling of environmental pressure from economic growth, and in 2005 the European Commission commissioned from a group of research institutes[5] a Policy Review on Decoupling to assess progress made towards decoupling in the EU-25 and AC-3 countries.[6] Being the first assessment of its type, the study had to start by building comparable data sets for each country considered and then choose or construct indicators for resource consumption. While economic indicators such as Gross Domestic Product (GDP) are well known and available for each country, the problem of resource/environment indicators is more controversial and more complicated because as yet we lack an aggregate indicator of environmental performance.[7] The pioneering 2005 report proposes considering

[5]Institute of Environmental Sciences (Leiden University), Wuppertal Institute for Climate, Environment and Energy, and CE Solutions for Environment, Economy and Technology.

[6]OECD (2002), Institute of Environmental Sciences (CML), Wuppertal Institute for Climate, CE Solutions for Environment, Economy and Technology (2005). The OECD has to be credited for being the first international body to have adopted the concept of resource decoupling and for having considered it as one of the main objectives in their policy paper, Environment Strategy for the First Decade of the 21st Century, 2001. According to their definition, decoupling consists in breaking the links between economic goods and environmental bads.

[7]Probably the 'ecological footprint' could be considered a good approximation or a good candidate for such an aggregate indicator, although it has several problems, including the subjectivity of the

Domestic Material Consumption over GDP (DMC/euros) as an indirect measure of environmental pressure. The materials considered include fossil fuels, biomass, construction materials, industrial minerals, ore and metals. To adjust these quantitative material consumption flows for their different qualitative environmental impacts, it proposes using Environment-weighted Material Consumption (EMC) and a land use indicator. The conclusions are not optimistic. In the words of the report,

> the absolute amount of direct materials consumed has not decreased but even slightly increased over the 1990s indicating that absolute decoupling of material use from economic growth has not been achieved but (only) relative decoupling. A contribution to this process of relative decoupling came from a slight absolute reduction of the direct materials consumption of fossil fuel (favoured by a substitution of low-energy coal by high-energy gas); [on the] contrary, biomass has increased; construction materials have increased even more, etc.[8]

A few years later, in 2011, another and more elaborate attempt was made to assess decoupling of the use of natural resources and environmental impacts, this time from human wellbeing rather than from GDP growth. The Green Economy Initiative of the UNEP and IRP[9] focuses on the theoretical and practical possibilities of breaking the link between human wellbeing—which is not simply measured by economic growth, although it is included—and the consumption of natural resources. The importance of finding ways of doing this strictly follows from a recognition of the physical limits of the availability of natural resources, and therefore of the consequence that growth in GDP cannot be sustainable in the future if it comes with a growing rate of use of natural resources. Comparisons between growth as measured by GDP and the rate of natural resource consumption (and/or measures of environmental impact) are at the heart of the problem.

Decoupling has been given two definitions, depending on whether GDP growth is greater than the rate of growth in resource consumption—when they are both positive—or whether instead the first is positive while the second is negative. In the first case we are in the presence of a 'relative' decoupling, while in the second one an 'absolute' decoupling is at work. Figure 2 represents these two cases by separating what may be called 'resource decoupling' from 'impact decoupling' according to the indicator used.

As is shown in the 2005 Report, while relative decoupling seems relatively common,[10] absolute reductions in resource use are rare and they can only occur when growth in resource productivity exceeds the growth rate of the economy.[11] It is

(Footnote 7 continued)

parameters. However the concept is gaining momentum and with respect to water resources, for example, the water footprint is now widely used even at the stage of policy design. The idea was firstly elaborated by Wackernagel and Rees (1996).

[8]Policy Review on Decoupling (2005), p. 6.

[9]The Green Economy Initiative, UNEP and International Resource Panel (IRP) (2011).

[10]This is true for the European Union. See Fig. 4 in Sect. 6. Obviously, the figure shows a 'local' decoupling while it does not say anything about a 'global' decoupling.

[11]Steger and Bleischwitz (2011).

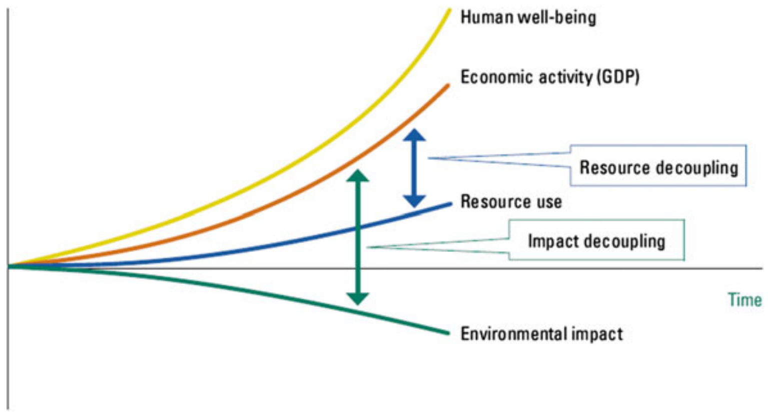


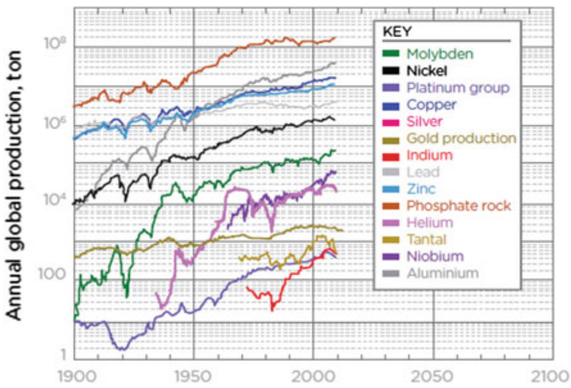
Fig. 2 Decoupling Effects. *Source* UNEP (2014)

interesting to note that according to the Report even in the two countries which have made the most explicit efforts towards decoupling—Japan and Germany—and where domestic resource consumption shows stabilisation if not a modest decline, a deepening of the analysis shows that many goods contain parts that have been produced abroad using large amounts of energy, water and minerals. The result is extremely important because it uncovers a widespread problem stemming from international trade between developed and less developed countries: most advanced countries are managing the problem of high resource intensity by exporting it elsewhere. The Report observes that trade generally increases energy use and resource flows, and thus, overall, impedes rather than promotes decoupling. The growing amount of international trade therefore raises another strong concern about the practical possibility of decoupling, as it appears to contribute in the wrong direction.

This rather discomforting picture in 2011 did not change in 2014, when the Decoupling 2 Report appeared.[12] Notwithstanding the fact that decoupling appears to be possible, because technologies that deliver significant resource productivity increases are already commercially available, it does not take place on the global scale. Something is holding back decoupling and this needs to be investigated. The core of the problem is **technological progress**. Two important aspects must be singled out: the autonomous development of technological progress; and the lock-in effect. Leaving technological development and adoption to market choices produces the unpleasant results repeatedly assessed by the Reports and by any other study on the subject, at least qualitatively, because the market does not adjust to changes in natural resource availability or to environmental deterioration by promoting an increase in resource productivity and better environmental quality. This requires active government policy, which would not necessarily be greatly intrusive but should be credible and well designed. Without it, the use of resources will continue to increase, as shown

[12]UNEP-International Resource Panel (2014).

Fig. 3 The exponential growth in the extraction of many metals since 1900 (the scale of the y-axis is logarithmic). *Source* UNEP (2014)



in Fig. 3, and the environment will become more polluted. The Report states that there is a need for policymakers to respond by 'intentionally' boosting resource productivity and not to count on spontaneous technical progress. Except for single special cases and/or temporary impacts, society has to face the trade-off between growth and environmental protection and cannot avoid choosing between them.

2.1 *Energy Security Versus Environmental Protection*

The same is true if one considers the even more specific trade-off between energy security and other policy objectives, such as the fight against climate change. No automatic reconciliation can be expected unless the energy policy choices happen to be of a given type. If such choices were in favour of boosting clean renewable sources, energy security could go hand in hand with climate protection. In European energy policy, the true pillar seemed to be the boosting of renewables, which therefore ushered in an optimistic view of the trade-off disappearing. Unfortunately, according to the most recent documents on energy security[13] this is not the case, as the definition of energy security appears to be closer to what Winzer (2012) calls an "umbrella term" rather than to an objective and precise one. With no claim to offer the best definition, we simply underline the fact that to provide for energy security must include reducing the risk of disruption of energy supply and this in turn implies knowing the nature of the risk. A geopolitical risk is quite different from a technical risk, which is mainly linked to infrastructure (such as transmission lines, communication networks, etc.), and from human risks such as fluctuations in demand or the underinvestment of the past, but it is common knowledge that to differentiate sources, decisions and actors etc. is the best way to

[13]EC (2014c), European Energy Security Strategy, EC (2014), In-depth study of European energy security.

reduce risk. As we shall see in Sect. 7, while the reduction of the risk of disruption may be welcome, the way this reduction is obtained is not immaterial to the total risk to society, which includes the risk of climate change disruption.

Of course, not depending on a single country for imports is a wise decision in absolute terms, but other decisions are not so simple, and in fact various inconsistencies emerge from recent documents which appear not to consider the risk of aggravating climate change. The winner is always energy security, even if the "total" risk to society is higher. The reason for this can be found in differences in time impact. While reducing the disruption risk by fracking in Europe (see Sect. 7) will have the immediate effect of increasing CO_2 emissions, their impact on climate change will be certain but delayed (see IPCC WGI). Society may face a reduced risk of energy disruption thanks to having another energy source, but will face an increased risk of floods or droughts—i.e. extreme events to which Europe is particularly exposed given its high population density and urbanisation—in the near future, and eventually even a disruption in energy supply.

3 Policy Intervention: A Profile

When it comes to the choice of instruments to be used to protect the environment, a textbook distinction is made among those which are demand-oriented, like price changes through taxation or emission permits, and those which are supply-oriented, like bans on owners of a resource extracting more than certain quantities. Since demand-oriented policies have different characteristics and effects to supply-oriented ones, it is obvious to expect the best policy to be an optimal mix of instruments depending on the circumstances and the ultimate policy targets. For this reason the best policy mix should be designed to directly address specific and urgent technological problems. The first of these is how to overcome the lock-in effect; the second is how to make the market deploy the environmentally beneficial technology already available; and the third is how to influence investment in innovation to enhance resource productivity and climate protection in the long run.

If, for instance, we are locked into using a dirty technology and/or we are not switching to a cleaner one because of market prices and costs, the use of both demand- and supply-oriented instruments will be optimal as they can reinforce each other. The optimal policy mix will be contingent on the specific conditions but it has to be targeted at the development and adoption of clean technologies in the long-run: **technology is indeed at the core of climate policy**.

Some countries, for instance the USA, instead of ratifying the Kyoto protocol, arguing that bigger emitters such as China, India and Brazil were not included in the binding commitment, declared they relied on clean technology to contribute to GHG emission reduction. Deeply market-oriented countries, such as the U.S. and others, could in principle achieve emission reductions through technology, which is associated with less public intervention, but they would need to overcome the problem of the market evolution of technologies. We can share their view that the best way of mitigating climate warming is through "clean" technology, both by deploying ones already developed—such as Carbon Capture and Storage (CCS)—and by investing in R&D to develop new ones, but how this view translates into practice remains to be seen.

Unfortunately, and judging by the facts so far, although the oil sector actually makes investments in R&D, they are not motivated by a search for cleaner technology but rather by the interest in increasing profits, which matches with the government target of increasing the domestic supply to reduce imports (energy security often coincides with import reduction).

The truth is that the 'new' breakthrough in technology is horizontal drilling and fracking, and it is now a fact that fracking technology is making the US less dependent on foreign imports, irrespective of the price of climate warming. Even the U.S. Energy Information Administration has proudly confirmed that

> total U.S. net imports of energy as a share of energy consumption fell to their lowest level in 29 years for the first six months of 2014. Total energy consumption in the first six months of 2014 was 3 % above consumption during the first six months of 2013, but consumption growth was outpaced by increases in total energy production.[14]

An analogous case, that of Canadian tar sands, will be addressed at some length in Sect. 6 of this chapter, while the US shale gas case has been addressed in two other chapters of this volume. Here, we can only sadly acknowledge that in the name of energy security now not even Europe is against fracking, and it is also not doing all it can to overcome the locked-in dirty coal technology. A crystal clear policy mix would have been to put a price on CO_2 as a demand management instrument and to ban fracking and the comeback of coal as supply-oriented policy. A reform of the EU Emissions Trading System is actually responding to the first requirement, while supply is drifting Europe away from its traditional position towards unconventional oils.

4 Future Scarcity and Future Prices

Unless policymakers respond with intentional resource productivity increases, the most likely scenario is that represented in Fig. 3, i.e. the annual extraction of ores and minerals will continue to grow (indeed the extraction of many materials has grown exponentially since 1990).

In terms of a global economy, it is crystal clear that such a path is unsustainable. In other words, the current high consumption of natural resources will at some point in time reach the natural physical limits. Before this point, resources will become progressively scarcer and this will have several consequences, among which price increases are to be expected. However, the real world is more complicated than this and the market prices of minerals, and especially of fossil fuels, do not reflect their

[14]EIA 10 October, 2014.

scarcity, and nor do they include external effects such as GHG emissions. Not surprisingly, they have fluctuated instead of steadily increasing with depletion and emissions, and are now decreasing. Of course technical progress has counteracted the scarcity effect on prices by making the extraction of more resources, in deeper layers or of less quality, possible. In a sense, the depletion effect has been totally or partially offset by the learning effect. This may appear a positive result for society, but the appearance is deceptive because emissions are not included in the prices.

Within this line of thought—i.e. prices reflect scarcity of supply—the peak oil argument is one of the most popular. There is a vast literature on peak oil and different estimates are produced in terms of 'when' it will happen, but 2030 generally seems to be the year on which there is the most agreement. Thus, every time the oil price goes up there are people claiming that it is because the peak has been reached. In my view, peak oil is not that important because if we continue to burn it and we do not really adopt a plan to reduce its use and at some point stop burning oil, the climate will be out of control. However, the attitude of "leave peak oil do" is not at all reassuring because it is another argument in favour of leaving the choice of energy sources to the market. It will stop using fossil fuels when their scarcity makes them non-economically viable, with no consideration whatsoever of the consequences for climate warming of reaching such a point. As Gerlagh[15] has clearly pointed out, the problem is "too much oil" and not too little: some of it has to be left un-extracted if we really do care about climate change and therefore about the cumulative GHG emitted. Van der Ploeg has gone further and has estimated that "one trillion tons of carbon must be either left unused or be sequestrated".[16]

To aggravate things further, the unconventional oil reserves recently discovered are as large as the conventional ones and this means that either substituting the un-conventional for conventional oil (as is the case with the US reduction in oil imports following the expansion of shale gas) or adding to the conventional oil will greatly aggravate climate warming, since unconventional oils are uncontroversially known to be more polluting than the conventional ones.[17] Once again, we cannot adopt a policy of wait-and-see and react to market signals (prices), because they are flawed. We have already seen that they do not capture future scarcity and do not include external costs; otherwise, they would show an upward trend (in monetary and/or real terms) while they are now decreasing.

We now add the impact of 'virtual oil' trading. Even the most true believer in the market will agree that oil prices are not good economic signals for many reasons, and that in recent years they have become even less reliable. To cite just one feature of the general debate on the energy markets, let us consider the arguments that

[15]Gerlagh (2011).

[16]Van der Ploeg (2013). Van der Ploeg and Withagen (2013).

[17]CERA 2009 estimated that they emit about 5–15 % more carbon dioxide than conventional oil, while in the same year the IEA produced a much higher estimate of 20 %. The US Government reported in 2005 that, with the technology in place, conventional oil produces around 40 kg of carbon dioxide per barrel against the 80–115 kg for unconventional oil . According to Brandt (2011), the amount is 22 %.

sustain public complaints when the oil price increases and when it decreases. In the first case, many say that economic recovery is at risk because high oil prices choke recovery (despite increasing evidence that even the first oil shock of the 70 s was less responsible than thought in slowing down the economies of the US and other OECD countries[18]). In the second case, many say that investors will stop their activity for fear of not recuperating costs. When the West Texas Intermediate oil price, one of the two dominant oil reference prices,[19] went down to less than 90$ a barrel last October, the lowest level in 17 months, oil market observers said that investors were 'panicking' and inclined to no longer invest in the sector, preventing innovation. However, few, if any, would have expected the fall to continue. But it did, making the fear of not recuperating costs become a reality since the price nose-dived down to even cutting the threshold of $50 a barrel (it is now—January 2015—less than $47). The decrease in the oil price should have ushered in different but equally bad effects in terms of stopping innovation. It follows that only price stability could avoid choking the recovery and stopping innovation.

Looking deeper into oil price setting (see for instance Fattouh 2011), we see that there are several driving forces behind price movements. It is therefore very hard, if not completely misleading, to interpret changes only in terms of the economics of demand and supply, as it is to predict future movements on the basis of pure economics. The price volatility which has been increasingly observed in recent years cannot really be understood or explained without considering the changes our society has experienced in terms of financial markets. Innovations in these markets combined with fewer government regulations, due to a changed vision of the working in the market of the private and public sectors, and also to greater vulnerability to capital owners, has produced a disconnection between the real economy and the financial one. The second has so far prevailed, producing a great variety of effects.

Among these effects is the *financialisation* of the economy, which has produced a shortening of the time horizon, and financial speculation entering the commodities market, in which financial institutions previously did not operate. In the current oil market, the relationship between the "pure seller" and the "pure buyer" is broken by the existence of operators who are not interested in physical oil. The possibility of using *futures options* and other *paper trading instruments* has made room for an increasing number of operators. With the growing number of transactions coming from operators not linked with the oil industry, the price of crude has been increasingly affected by the decisions of these operators, who buy the virtual commodity cheaply and sell it at a high price to make profits.

Quantifying the impact of financial speculation on the oil price is obviously not easy and in fact the literature is growing,[20] but it is indeed very difficult, if not

[18]Hamilton (2005), Cunado and Perez de Gracia (2003), Jemenez-Rodriguez and Sanchez (2005), Barsky and Kilian (2004).

[19]Fattouh (2011).

[20]In 2013, The Energy Journal published a Special Issue on Financial Speculation in the Oil Markets and the Determinants of the Price of Oil, vol 34, n. 3.

impossible, to explain the 2008 price spike up to $145 from $34 in 2004 and its going back to $34 at the end of the same year without considering the working of financial speculation. After all, in the short run oil demand is practically inelastic and the supply was not disrupted by such external shocks as war or political instability that year.

Finally, it is probably worth mentioning an assertive view, according to which speculative activities are very much in control of prices as financial speculators thrive when prices fluctuate. In the case of high prices consumers are hit, while in the case of low prices the producers are. According to this view, it is therefore necessary to establish an organisation meant to "regulate those prices in the market which are agreed between the actual supplier and the true receiver. There must be eliminated conditions when these two players of the market are hurt by high or low prices of oil set up by virtual commodity traders in major stock exchanges".[21]

5 The Role of Technological Progress

During the 200 years since the start of the industrial revolution some lessons have been learned, and the first and most important one is that the West thrived on very cheap oil for many years. During these years of very low oil prices and positive GDP growth for the industrialised countries, other things also seemed to be moving in the right direction. Among these, technological progress was helping humanity to solve its problems. Driven by the price shocks of 1973 and 1979, it contributed to enhancing energy efficiency, energy saving, and above all to moving away from less efficient sources to more efficient ones, which happened to also be more environmentally friendly, i.e. less polluting per unit of energy produced. The story of energy of these years is easily told; the first source was wood, then coal, oil and gas plus (traditionally) hydroelectric and (more recently) nuclear. At the end of the 20th century the energy model was clear and long-standing: 80 % of energy was produced from fossil fuels while all the other sources, nuclear included, provided the remaining 20 %.

Meanwhile, and in particular around the 1990s, the problem of climate change due to CO_2 emissions gained momentum and the energy sector was found to bear the greatest responsibility. Once again, technological progress appeared to be the answer to the concerns of governments by making the production of energy from clean renewables such as the sun and wind commercially possible. While renewable sources were making their appearance in the market (showing a fast decline in unit costs as producers followed the learning curve, and with no depletion effect to offset this decline), and some countries were making efforts to 'correct' energy prices by

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[21]Ibrahimov and Azizov (2011), "Oil market structure and pricing. Crude oil and oil products marketing and pricing: what is the price of crude oil?", IPEDR vol 22 (2011), IACSIT Press, Singapore, p. 59.

including external costs through carbon taxes and/or emission permits to accelerate the transition to an energy model more compatible with climate change, the oil industry continued to invest in drilling new wells at deeper levels, under the sea and under the thinner ice layers, etc.

Although the investments by the oil industry were signalling that technological lock-in effects were strongly in place, the growing importance of renewable in combination with the phasing out of 'dirty' coal seemed to be ushering the transition to a new and sustainable energy pattern departing from fossil fuels and moving towards clean energy. Unfortunately this was not the case.

First, dirty but widely abundant coal is coming back in a surprisingly big way, and rather than being a fuel of the past it seems to be one of the future, completely contradicting any reasonable prediction, at least with respect to Europe, where the coal phase-out was declared to have practically concluded in the first decade of this century (indeed, it was clearly noted even earlier that "the trend in many of the OECD countries is away from coal"[22]). Instead, in 2014 the International Energy Agency (IEA) had to note that the

> continued increase in coal use counteracts emission reduction from recent progress in the development of renewable, underlining the need to improve coal plant efficiency and scale up carbon capture and storage. Growth in coal-fired generation since 2010 has been greater than that of all non-fossil sources combined, continuing a 20-year trend.[23]

Needless to say, the return of coal is totally incompatible with climate policy, and therefore governments should mandate the adoption of Carbon Capture and Storage (CCS) technology.[24]

Second, the role of gas needs to be carefully investigated, particularly after the return of coal. In a sense, the role of gas is very interesting and peculiar, since it has changed in the last five years or so. It definitely used to be seen as a transitional source to be used in the short and medium run to facilitate the transformation of the energy pattern into a more environmentally friendly one, but it is now being replaced by dirtier coal. Its role as a transitional source was so clearly established that if there were precautions to be considered, they were those of avoiding the risk of becoming locked-into gas use in the long run. An interesting paper analysing the UK case for gas, for instance, uncovers the lock-in effect or inertia of investing in gas power stations just by considering the sunk costs and not simply the capital repayment conditions.[25] In the long term, the effect of using gas power stations was considered to be so negative that it was capable of neutralising the European long-run decarbonisation target. The unpredictable crowding out of gas by dirtier coal is an important scenario change. The entry of LNG (liquefied natural gas) in this scenario challenges the energy pattern even further.

[22]Grubb (2001).

[23]IEA, Energy Technology Perspectives 2014.

[24]However, if the price of carbon were around 40/50 euros, CCS would be adopted automatically.

[25]Chignell and Gross (2012).

Thus, on the one hand we are trapped into the lock-in effects of the oil and coal industries, and on the other hand the evolution of technical change is not environmental friendly (and with no market price corrections for scarcity and externalities, the result could not be expected to be different). In fact, except for the development of CCS technologies, which unfortunately lack actual deployment, all recent developments have been incompatible with environmental protection.

To cite just some of these developments, let us consider the type of investments made by the oil industry with great success, meaning good returns to investors. According to Oil & Energy Insider Investment Opportunities & Strategic Energy Intelligence, in 2013 there was a 'super boom' in subsea infrastructure investment, which was five times that in 2012. The innovation consisted in a subsea processing system which replaces the drilling of sea wells and the subsequent transportation of oil or gas to a production platform by processing oil and gas on the sea floor:

> Basically subsea systems cut out an entire layer of traditional production simply by doing everything down on the seafloor. That translates into lower production costs so it saves money and increases the profit margin on each well.[26]

As we see, any consideration of the impacts of processing on the sea floor is completely absent. All that counts is making profits and attracting private investment. The predictions for the future are frightening enough: while now only 30 % of oil and gas extracted in the world is from off-shore production (and 91 % comes from shallow water wells) using standard processing methods with a platform, in the next 15/20 years off-shore oil and gas production based on subsea systems is expected to equal on-shore production.

Moreover, the oil companies have invested in research and development to increase the present average extraction rate of around 25 % of the oil in a well. A technology named the Lazarus Process, a commercially viable process, allows up to 75 % of a well's oil to be recovered. It is said that this is equivalent to "rediscovering every oil field twice". Such R&D investments by the market are simply motivated by profits and do not help to alleviate climate change. **While we should leave a huge amount of oil unburned we are instead eager to extract more and more.**

What is in fact changing the landscape is American shale oil and gas production and the fact that large fields of such oil and gas are being discovered in many other countries from China to Argentina, from Russia to Brazil, from the U.K. to Australia, Poland, Libya, Algeria, India etc. <u>Contrary to what was happening during the 90s, technological progress is now evolving against the environment.</u> Just as we

[26]Oil and Energy Insider. Investment Opportunities and Strategic Energy Intelligence. https://oilprice.com/premium. An idea of the mood in the oil industry in the field of undersea technologies can be gleaned from the fact that last October the 15th annual exhibition for the oil and gas industry held in Bergen was called Off-Shore Technology Day (OTD).

had to conclude that there is not a decoupling of growth from the use of natural resources at the global level, we also must admit that technological progress is not solving the problem of climate change but is instead aggravating it.

6 A Case Study: The Canadian Tar Sands

Before the approval of the Kyoto Protocol in 1997, Canada was among the countries most active in the negotiations which led to the signing of the important agreement. It is somewhat surprising that Canada is the only country to 'repudiate' it (in 2012). In fact, the protocol did not have an easy life from the start and it took several years to enter into force because some countries were slow to ratify it and some, like the U.S., never ratified it.[27] Nevertheless, the Canadian repudiation is unique. Understanding the reasons why this country arrived at its drastic decision is outside the scope of this study, but it gives an indication of the chances of such an agreement, which is needed to mitigate the global climate bad, being enforced, or if instead there is no way of expecting countries to cooperate for the provision of a global public good.

Canada is an interesting case study: it is a rich developed country, a democracy with a well-educated population on average. Its educational system relies on science as in other western economies and Canada enjoys a good reputation among the club of developed countries and so how it arrived at the repudiation is hard to say (as well as being beyond our scope), but two features emerge. First, it soon became clear that Canada was not on track with respect to the binding target of reducing emissions by 6 % by 2012 with respect to the base year 1990. Second, complaints were raised almost immediately about the little flexibility the agreement allowed. Consequently, the standard argument (in addition to the one that big emitters such as China and India were not included) began to circulate: investments to enhance energy efficiency, a low-carbon energy infrastructure and new[28] technologies would be the only way of making the energy system more environmentally sustainable.

Obviously, politics is the most significant explanatory variable and the change of Canadian government cannot be ignored, but no politicians actually denied the scientific basis of climate change and the responsibility of human activity. They simply wanted, or so they asserted, to adopt different instruments—namely clean technologies—to reduce emissions. In fact, it is now evident that Canada never reduced its emissions. On the contrary, GHG emissions have increased both in total and per capita terms and the country performs particularly badly in any ranking of developed countries.[29]

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[27]To enter into force, ratification was needed by at least 55 % of the signatory countries with their emissions amounting to 55 % of total emissions. The ratification by Russia at the end of 2004 allowed the Protocol to enter into force in 2005.

[28]However, as we argue in Sect. 4, innovation is not necessarily low-carbon.

[29]According to the Conference Board of Canada, in a ranking of 17 OECD countries with respect to GHG emissions per capita, Canada in 2010 held the 15th position and scored a "D" grade on a

Although both the official repudiation and the great leap in oil sand production have happened in the last two years, a brief look at the history of the development of the tar sand market will reveal the importance of the economics of the oil industry and the oil price trend in the repudiation decision. The possibility of extracting oil from bitumen already existed at the beginning of the 20th century, when a patent was granted for a hot water separation process. In fact, the Sun Oil Company opened its first mine in 1967 (producing just 30,000 barrels per day, compared with the current production of 1.9 million barrels per day according to the UK Tar Sands Network), but world oil prices were low and falling and so the industry did not develop. A second mine, operated by Syncrude Consortium, only came into operation in 1978, which is after the 1973 energy crisis. This crisis, known as the first oil shock, sent a signal to the oil industry that the price could in fact increase, after being incredibly low and stable for many years. With the 1979 energy crisis oil prices peaked again, but declined again during the 80s to such low levels that the oil industry seemed to be in retrenchment. At the end of the century, oil sands production started to take off, but total unit production costs were too high with respect to oil prices and they had to be subsidised. For several years, no other mines were opened and the third one, operated by Shell Canada, appeared only in 2003. In fact 2003 was very important for the development of the bitumen industry because the price of oil started to increase, rising to the famous $145 per barrel in January 2008, to make the industry very profitable. In 2008, Canada was not only not on track with its commitment to reduce its emissions by 2012, but it was actually knowingly increasing them, given the great expansion of bitumen production. Indeed the greenhouse gas emission intensity of bitumen and synthetic crude oil production is three times that of conventional oil. In fact, in 2012 Canadian oil sand production of crude bitumen and synthetic crude oil had increased by 30 % with respect to 2002, with the related emissions consequences thanks to hydraulic fracking technology. Despite differences in data estimation, all the sources that have estimated emissions show that oil sands are much greater GHG emitters than conventional oil processes (from a minimum of 5 % more up to

(Footnote 29 continued)

scale from A to D. www.conferenceboard.ca/. In a ranking of 140 countries with respect to GHG emissions per capita in 2000 for the World Resources Institute, Canada's were the 7th highest. www.wri.org/. Another report by Michelle Mech in 2011 states that Canada is in the top ten of the world's GHG emitters and is the second on a per capita basis. Moreover, in the same report it appears that "Canada's GHG emissions in 2008 were 24 % higher than in 1990 and 30 % higher than the country's Kyoto commitments. While many other industrialised countries have committed to emissions reductions of 20–40 % below 1990 levels by 2020, the Canadian government's current target—17 % below 2005 levels by 2020—translates to 2.5 % above 1990 levels. ….. Canada does not have a low carbon growth plan. Out of 57 countries that together are responsible for over 90 % of global energy-related CO2, Canada ranks 2nd last in climate protection". In "A Comprehensive Guide to the Alberta Oil Sands. Understanding the Environmental and Human Impacts, Export Implications, and Political, Economic and Industry Influences", p. 7/8. www.greenparty.ca.

20 or 22 %—see footnote 13). The facts show, therefore, that Canada pursued the opposite of its commitment (i.e. emissions reduction).

Moreover, at the beginning of 2008 oil prices were high enough to make it very profitable to extract from tar sands. The retrenchment of the oil industry was over; shale gas in the USA, and deep sea floor production in Brazil were doing well. However, at the end of 2008 the price again collapsed to $34, ending the trend of growth since 2001 and especially since 2003 when it accelerated.[30] In fact, the great stability of oil prices up to the middle of the 70s was over. In 2011 the price again reached levels around $100 and then fell back to less than $90, and later to around $49 where it is now (January 2015). Of course, the Canadian oil industry is not happy with the fall in the oil price, above all because the repudiation of the protocol in 2012 removed any inhibition linked to emissions reduction on further developing oil sands, freeing it completely to reap market profits at the expense of the climate. Only a falling oil price can represent an obstacle to this, and in particular if it comes from overproduction as seems to be the case now. In fact, Canada's energy policy, which is dominated by the interests of the oil industry, has the aim of gaining a secure larger share of the global demand for its oil sands: "oil sands development drives steady Canadian oil production growth to 2030".[31]

This clearly emerges from the relations Canada has been entertaining over recent years with the neighbouring US, with other countries where large reserves of oil sands have been discovered, such as Venezuela and China, and with the European Union. Regarding the relationship with the US, it suffices to mention the long debate over the construction of the Keystone XL pipeline, connecting Alberta, the Canadian state where most of the reserves are situated and where the tar sands business is most developed, to Texas and the refineries on the gulf coast. The lobbying of the US government to get it approved is known and well-documented[32]; without a complete pipeline from Alberta to Texas, both the high cost of transportation and the great uncertainty over American imports would make extraction unprofitable.

Regarding countries where large reserves of tar sands have been discovered, such as Venezuela, Canada is trying to stipulate bilateral agreements to avoid future competition and to export its technology.

Finally, Canada's relations with the EU are very strained. This started with the issuing of Europe's Fuel Quality Directive in 2009,[33] through which the European Union aimed to reduce vehicle emissions and support its energy policy targeting the decarbonisation of energy production. The Commission mentioned findings that the intensity of oil sand GHG emissions was higher than that of conventional oils.

[30]It is practically impossible to explain the price movements between 2003 and 2008 without considering the role of speculation. As is well known, the demand for oil is practically inelastic in the short run. See Sect. 3.

[31]Canadian Association of Petroleum Producers, 9 June 2014, www.capp.ca.

[32]Many observers consider approval to be more probable after the mid-term election results that saw the Republican party gain the majority in the Senate and increase its majority in the House.

[33]Fuel Quality Directive 2009/30/EC.

In the labelling of fuel sources mandated by the Directive, oil sands would be labelled as very polluting. In the same year, Canada responded by establishing a body named the Pan-European Oil Sands Team, which was composed of European diplomats, members of ministries of the environment and of oil companies, and of course representatives of the Alberta government, to shape the debate on oil sands. While to several members of the body it appeared that the debate was intentionally conducted in a way to serve Canadian interests, in 2011 the Union commissioned a study from a scientist at Stanford University to assess the GHG intensity of Canadian oil sands and of European feedstock.[34] The study examines and compares previous estimates; it scrupulously underlines the reasons why estimates from different models do not coincide; it explains how processes of extraction and upgrading may differ, and produces 'low', 'high' and 'most likely' estimates 'from well to wheel' of the GHG emissions of oil sand oil. To synthesise the finding in a number, an intensity is associated with oil sands that is 22 % higher than with conventional fuels used in Europe.[35]

In 2012, a Canadian think tank, the Pembina Institute, commented positively on the European proposal to assign a default emission value to oil sand higher than that of conventional oil, recognising the higher emissions resulting from the production and upgrading of oil sands. According to the Institute report, "emission per unit energy from well to wheel of oil sands ranges from 12 to 40 % higher than the average intensity of conventional fuels used by Europeans … Given this clear distinction, the treatment of 'natural bitumen' as a separate feedstock is well justified".[36] The 'battle' went on for 5 years and it seemed that the European Union was firm in its position. Unfortunately, things were to change, and last October the Commission seemed to abandon its plans to label tar sands as highly polluting. The proposal has yet to be approved and signed off by the European Parliament, but the Commission has removed an obstacle for Canada to export tar sands oil to Europe. Moreover, as at the end of September the first cargo of Canada tar sands oil was loaded onto the Minerva Gloria, an oil tanker under a Greek flag with the Italian refinery at Sarroch in Sardinia as its destination,[37] the situation seems to be evolving in favour of easing exports.

Many observers agree on interpreting this move as a result of five years' pressure on the European Commission from big oil companies and the Canadian government. By coincidence, in September the negotiations about a bilateral trade agreement between the EU and Canada, which were launched in 2009, finally

[34]Brandt (2011). Available on the web.

[35]The lowest intensity oil sand process is less GHG intensive than the most intensive conventional fuel (as noted in recent reports by HIS-CERA, Jacob Consultancy and others). Importantly though, the most likely industry-average GHG emissions from oil sands are significantly higher than the most likely industry-average emissions from conventional fuels.

[36]The Pembina Institute (2012) www.pembina.org/.

[37]The news appeared in several sites on the net and also in the national Italian newspaper Il Sole 24 Ore, 27 September 2014, under the title "Arriva in Italia il primo carico di petrolio "made in Canada".

ended. The agreement, Comprehensive Economic and Trade Agreement (CETA), still to be approved by the Council and the European Parliament, is said to remove 99 % of tariffs between the two economies and to create new market opportunities in services and investment. The fact that the Directorate-General for Trade of the European Commission while presenting the benefits of the agreement found it necessary to guarantee that the "economic gains do not come at the expense of democracy, environment or consumers' health and safety" may raise some concerns.[38]

Canada is indeed an emblematic example of how countries do not want to cooperate to provide for a common global good (climate mitigation), can change position with respect to important international issues when domestic profits come into conflict with the principles underlying international treaties that they have signed, and can activate their diplomacy to support their industry interests no matter how costly they are for the global common (climate) good. Moreover, the example shows that countries may not even care about 'local' external effects or negative impacts on their own territory, people and fauna. As is now known, the impact of the Alberta tar sands business on local communities, such as First Nations and others, is devastating; the drastic reduction in the population of caribou which is taking place has been found to be due to the segmentation and the disappearance of their habitat, namely the forests, resulting from tar sand extraction. Moreover, the hydraulic fracking technology intrudes and pollutes the groundwater, and the tailing ponds are even a concern for the same oil companies. Finally, the Athabasca river is being increasingly polluted, and the benefits to the state of Alberta in terms of economic growth have not been weighed against the cost in terms of the deterioration of the river basin.

The lesson we learn from the case of contemporary Canada is that if a rich country can change its position with respect to climate policy on the basis of domestic profits and not on the basis of science, then it is not a question of finding more flexible instruments which may suit countries better. Canada is a proof that the trade-off does not matter, cooperation does not exist, and even reputation among the global community has no value.

7 European Energy Security in the Context of European Energy Policy

In this discomforting scenario it is all the more necessary that the European Union stands firm in its position of leader in environmental protection. The EU, which happened to evolve from the 1952 European Coal and Steel Community (CECA), has an important role to play in the global scenario. Europe can show that it is possible to get the prices right by internalising the costs of emissions through

[38] http://ec.europa.eu/trade/policy/in-focus/ceta.

emission taxes and/or tradable permits and also that it is possible to move away from the current unsustainable energy pattern (80 % fossil fuels) to a decarbonised one where clean renewable provide a much greater share of energy. The way to the transition is clear and quite simple. First, externalities have to be internalised, which simply requires extending and improving the emission trading system introduced in 2005. Second, structural investments need to be made to better connect the various sources of energy across countries. Third, R&D investments in the specific field of energy storage technologies need to be supported. These technologies may be very important in moving towards a low-carbon society. Electricity storage systems can correct load imbalances, and systems capable of storing solar power for use at night or even storing summer heat to warm homes in the cold months can increase the reliability of supply and facilitate the expansion of renewable energy sources.[39] Obviously, it should ban technologies such as hydraulic fracking and even the return to coal power unless CCS becomes compulsory. Europe could show the world that, notwithstanding the fact that it contributes only 10 % of total emissions (in 2012), it is seriously committed to playing its role in the reduction of these threatening GHG emissions for the benefit of future generations.

Furthermore, Europe's commitment to climate policy could represent a common cause for the countries in the area to once again strengthen their ties. After all, the views on many important features of a civil society held in the European countries are closer to each other than to the American one. The European Union has its identity and its *weltanshauung* to preserve, instead of passively complying with the most untamed financial capitalism and myopic consumerism. An EU energy policy unambiguously meeting the demand for climate protection could also galvanise fresh efforts to strengthen the union.

So far, the European energy policy can be judged positively both looking backwards—what has been achieved in terms of Kyoto and the 2020 strategy[40]—and forwards—in terms of the new targets and new policies.[41] At present, the union is on track to achieve its Kyoto targets. For the first commitment period, 2008–2012, the EU-28 Member States overachieved their targets, while for the second commitment period, 2013–2020, emissions are expected to decrease by 23 % with respect to the base year, which equally satisfies the commitment. The same is true for the targets of the Climate and Energy Package, as current projections give an emissions reduction of 21 % in 2020 with respect to 1990 for the European Union as a whole, although some countries need additional efforts. Finally, during the period 1990–2012 the EU reached a decoupling between GHG emissions and GDP growth as is shown in Fig. 4.

[39]In one of its latest publications, the International Energy Agency addresses energy storage technologies. It also presents a decarbonised electricity scenario making use of electricity storage. "Technology Roadmap: Energy Storage", 2014. www.iea.org.

[40]See European Commission, COM (2014a) 689 final, "Progress towards achieving the Kyoto and the EU 2020 objectives".

[41]See European Commission Climate Action 2030 framework for climate and energy policies and Roadmap for moving to a low-carbon economy in 2050.

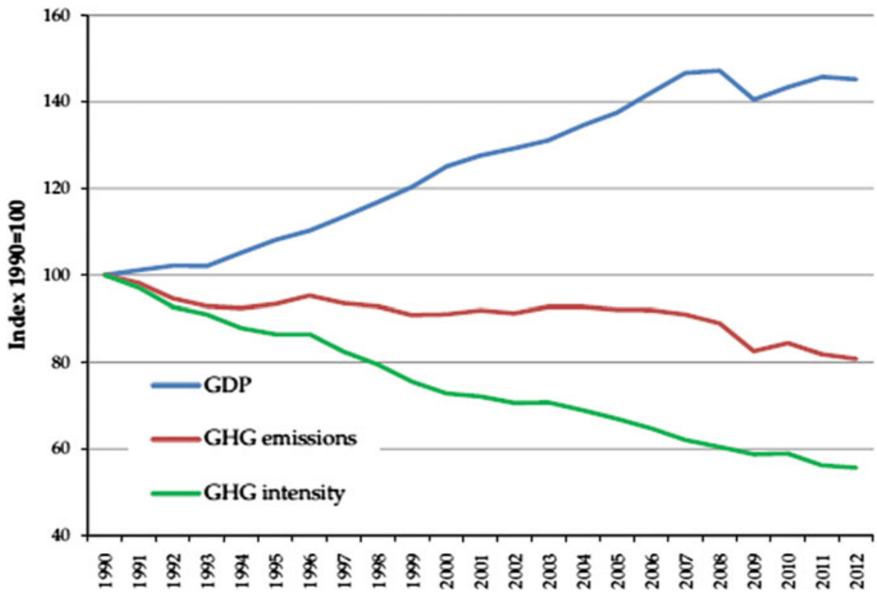

Fig. 4 Evolution of GDP (in real terms), GHG emissions and emission intensity (i.e. ratio of greenhouse gas emissions to GDP).1990 = 100. *Source* EC (2014a, b, c)

It is most important to notice that, according to the European Environment Agency,[42] the drivers behind emission reductions have been primarily the structural climate and energy policies implemented by the community, while the economic crisis was responsible for less than half of the emission reduction registered in the years 2008–2012. The EEA analysis decomposes the impact of the factors affecting GHG emissions as (1) per capita GDP, (2) population, (3) primary energy intensity, and (4) carbon intensity of primary energy. Reduced primary energy intensity due to energy efficiency improvements was an important factor, as was the reduction in the carbon intensity of primary energy due to the development of renewable. The effect of the positive rate of growth of GDP during 2005–2008 was to reduce the impact of the two factors while the negative rate of growth during 2008–2012 reinforced this.

The Union position is also consistent with the choices of the past in terms of new targets and new policies envisaged for 2030 and 2050, which is most important for climate protection. Briefly, as short-term objectives the EU has chosen: a binding target for 2030[43] of (at least) a 40 % reduction in emissions below the 1990 level; a share of renewable energy of (at least) 27 % by 2030; an increase in energy efficiency of around the same 27 %, to be reached mainly through improvements in

[42]EEA (2014), http://www.eea.europa.eu/publications/why-are-greenhouse-gases-decreasing.

[43]Notice that the EU 2020 commitment of a 20 % reduction could become 30 % in the case that other economies agree to participate in the global reduction effort.

the building and industrial sectors; and a reform of the EU trading system to get the price of carbon right.

The introduction of a Market Stability Reserve and of a single EU-wide cap on emission permits instead of the current national ones could be the right provisions to introduce. Currently, there are too many permits in circulation, which is the reason for the low price of carbon.[44] The reform is important because the EU trading system has to get the price right for the various sources of energy, and the revenue it produces can also be a way of financing investment in new clean technologies. As the European Commission states in its 2014 Progress Report, this new source of revenue amounted to 3.6 billion euros in 2013, which Member States plan to invest in a low-carbon society.

As the long-run target is a low-carbon society, it is important to look for cost-efficient ways of reducing energy consumption and of becoming even more climate-friendly. These ways can only come from clean technologies, and innovations, not only in renewable sources of energy but also in energy-efficient materials for the building sector, in hybrid and electric cars, smart grids, low carbon power generation, and carbon capture and storage technologies.

Finally, the European Commission is also multiplying its efforts towards a single European electricity market. An integrated market is an ambitious goal with many benefits (despite some difficulties in reaching it). Among these, efficiency gains in the use of cross-border transmission infrastructure and power generating plants are the most important. Furthermore, given the choice to make clean renewable the pillar of the electricity system, an integrated market facilitates the expansion of these resources as renewable electricity can flow among EU countries, better matching the demand and the supply.

To complete the profile of the energy policy, there are initiatives with respect to the emissions stemming from sectors not included in the EU ETS, which are more than half of the total emissions. For these sectors, namely housing, agriculture, waste and transport (excluding aviation), Member States have taken on "binding" national annual targets (differentiated according to the wealth of the state) and agreed to report on their emissions. Consistent with this policy scenario is the Fuel Quality Directive mentioned above as a source of conflict with Canada. To reduce emissions from the transport sector the quality of fuels is crucial. Thus Europe should resist the attempts by Canada (and the US) to export oil and gas obtained from unconventional sources. Europe has to make it very clear that it will not be a consumer of such sources because of their incompatibility with the climate policy it has pursued in the past and is determined to continue to pursue and possibly strengthen in the long run. To become an importer of such dirty oils would be too strong a contradiction. In addition, the EU should also consider that increasing imports may damage energy security by crowding out domestic resources (sun and

[44]The large number of permits in circulation, given the unforeseen prolonged crisis and perhaps the underestimated effect of a growing share of renewable in total production, are pushing the carbon price down to less than 6/7 euros.

wind) and clean technology. Resisting the pressure would be a win-win solution for Europe, resulting in neither increases in imports nor in emissions. Europe would retain its leadership in climate protection and show the world that frequently when a country declares that its environmental policy is based on technology and innovation it is in fact cheating the other countries. Technological progress and innovation are not environmentally friendly, since in responding to market prices they are driven by profit. 'Clean' technologies and 'clean' innovations are environmentally friendly but the question is how they can develop if prices give wrong signals and governments are too weak to enforce a climate policy.

Although the European energy policy is clear, the way Europe wants to provide for energy security is less so, and in fact its strategy appears rather confused at the moment as it "may need to evolve due to changing circumstances".[45] While adjustment to changing circumstances is obvious, the lack of a long-run strategy is a sign of weakness. A credible strategy is extremely important, both for geopolitical reasons and for economic ones, as market investments, including in R&D, respond to government decisions.

The following issues summarise our concerns. Sharing the view that the present confused position has its roots in last May's annexation of Ukraine by Russia, we understand that Europe has to diversify away from Russian gas and possibly from gas itself (after all, gas was considered a transition source) for security reasons. However we have to admit that Europe was not credible with respect to Gazprom's pricing behaviour: no common sale price was insisted on as European competition law would require (each country got a different price and conditions) and restrictions on resale were accepted, which equally contradict European competition law. Why this was the case will not be investigated here, but it shows that to 'adjust' to contingent situations—the deals were made against a background of rising oil and gas prices—is not always rewarding and can be simply dangerous. A lesson has been learned, and from now on Europe will be speaking with one voice in external energy policy.

Apart from this positive impact, all the other consequences are very worrying. First, the risk reduction by differentiating energy sources is prevailing over pursuing decarbonisation targets, as the replacement of energy may come from the use of European shale gas, the return of dirty coal and from Mediterranean oil. In the case of shale gas, even the controversial—to say the least—fracking technique is not ruled out, notwithstanding the French moratorium until 2017 and the UK temporary stop to better understand its impacts and effects. In the case of coal, no decision has been taken towards making CCS compulsory. Even more astonishingly, licenses to drill for oil in the Adriatic sea (Croazia and ENI) seem to have already been granted. This is not simply a question of decarbonisation but one of not knowing the impact on climate change of drilling in a closed and already compromised sea like the Adriatic. What we do under the sea may be more important for the climate than what we do on land.

[45]EC (2014b), p. 3.

Second, a streamlined administration procedure has been announced through an amendment to the Directive on the assessment of the effects of certain public and private projects on the environment. We are all happy when a shortening of bureaucratic/administrative procedure is possible, but when it comes at the expense of the environment this is no longer the case. The philosophy of the amendment is clear: the legal requirement to carry out an environmental impact assessment will be limited to cases where there is evidence of environmental damage. Deciding when to applying the legal requirement coincides with an a priori decision in favour of development. Does oil drilling in the Adriatic or fracking in Poland or Germany require an environmental impact assessment?

Third, as is known, the huge development in un-conventional oils was made possible by high and rising oil prices. Last June, $100 a barrel could be considered the bottom level of the oil price for years to come and even a production cost of around $80 could be recovered. In fact, American and Canadian enterprises widely invested in the sector. Then, the oil price went down to around $50, several shale wells became exhausted much earlier than expected, and rumours about environmental damage started to spread. In less than one year a full turn in the scenario has come about. At the moment, several American shale oil companies seem in real trouble and there are signs of them asking for government help. If the government rescue materialises, the story of harmful energy subsidies will continue. In the end, the taxpayer will be worse off: he will pay to subject himself to a greater risk of climate change.

Finally, Europe is now demonstrating that it relies more on what the general public wants through the launching of public consultations. Public consultation may be useful, but with respect to the problem of energy security it is not difficult to unmask a tangle. The general public cannot have all the scientific information about the immediate and future effects of taking certain decisions but it will easily declare it is in favour of energy security.

8 Concluding Remarks

If the global community really wanted to proceed with the decarbonisation of the economic system of production and consumption starting with the sector more responsible for the GHGs accumulated—i.e. the energy sector—there would be affordable solutions, as several clean sources for energy production are now available and clean technology development is allowing emissions from dirty sources such as coal (CCS) to be reduced.

However, obstacles are deeply rooted in our present commercial society, and the most important of them are the following. First, there is a lack of a long-run view when taking economic decisions at all levels, from the general public to firms/multinationals to governments. Second, there is a delink between the real economy and the financial one, particularly evident in the oil industry, which has happened mainly in the 21st century. Third, governments are vulnerable to capital owners. In addition, one must remember how difficult it has always been to internalise externalities and to provide for public goods. These objective difficulties are even greater nowadays when *free riding* seems an accepted way of getting richer, and governments seem to have lost their will and power to correct externalities and provide public goods at the domestic level, and are inclined to adopt *free riding* behaviour at the international level.

For a climate policy to be effective, several preconditions have to be satisfied. Among these, governments have to assume a long-run view, direct technological development in the direction of policy targets, and recompose the link between the real and financial economies by regulating financial speculation. In the case of the oil price, the increasing fluctuations of which are due (at least partially) to financial speculation and disrupt the real market, why not ban non-oil-related operators from entering the market? The most convinced defenders of the market mechanism—of the ability of supply and demand to bring about the best result—would have to explain how allowing 'virtual' demand to enter the oil market can improve the performance of the real economy.

Briefly, what we need to do is to take a long-run view and actively manage a transformation of the energy system. In doing this we have to be aware that the "long-term view is regularly challenged by developments that have lasting and transformative impacts like the shale gas revolution in North America". In addition, we must depart from the past attitude of "continuing to respond to the energy system as it evolves rather than actively managing its transformation towards the aim of achieving a clean, secure and economic energy supply".[46] To meet the targets of affordable, secure and low-carbon energy, Europe only has to believe in its energy policy and to consolidate it by taking the following steps.

First, Europe has a role to play, which is to show the world that climate change is a real threat and to convince the global community that a quantity of oil should therefore be left un-extracted. This argument is the reverse of the peak oil issue. If the global community went on burning the current reserves, the GHG emissions would be incompatible with the target of global temperature increase it wants to meet. Second, the transition to renewable needs to be accelerated, both by getting the price of carbon right (through a reform of the ETS) and by incentivizing R&D investment expenditure. Third, Europe should pay particular attention to technological development. As technological progress is at the core of climate change mitigation, how it evolves cannot be left to the market but must be directed towards policy targets. It is therefore necessary to make the adoption of CCS mandatory for all coal power stations. This has become urgent given the unexpected return of coal. Furthermore, Europe should encourage any development in energy storage technologies, which greatly facilitate the adoption of clean renewable, enhance energy security, and thus help in decarbonising the economy. Fourth, regarding policy instruments, a combination of demand- and supply-oriented policies could be the fastest and most efficient way to reach a specific target (a carbon price combined

[46]IEA (2014) p. 4.

with a ban on unconventional oil could speed up the transition to a cleaner energy pattern). Fifth, efforts to establish a single European market for electricity should be reinvigorated, while the role of gas as a transitional resource towards a new clean energy pattern should be confirmed, and it is therefore necessary to stop the replacement of gas by coal. Finally, Europe should highlight the fact that when countries do not want to commit to GHG reduction through specific agreed instruments, it is because they are free riding, and when they mention energy security as the reason they cannot agree to cooperate, it is because energy security has no precise meaning but nevertheless appears to be a national priority. In the global arena of facts, little space is given to the practical implementation of a climate policy, while the media gives increasing space to hot air.

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Part III
Public Policies as a Tool to Strengthen European Energy and Climate Security

Rationales for a Revisited European Energy Technology Policy

Sophia Ruester

Abstract If the EU wants to meet its 2050 climate objectives, i.e. reducing greenhouse gas emissions to 80–95 % below 1990 levels, while at the same time ensuring the secure supply of energy, the future energy mix will have to rely on a significantly increased share of low-carbon electricity generation. A diverse portfolio of clean technologies has to be employed at a large scale. However, many of those technologies are not yet competitive, or even not technically proven, and substantial additional research, development and demonstration (RD&D) activities are required. The present EU energy technology policy supporting such RD&D needs to be revisited. Market actors and the European public demand new, transparent and lasting policy commitments, not only because the current technology policy framework is running out in 2020, but also because of increasing global competitive pressure in the low-carbon technology sectors. We, therefore, discuss rationales for (a) (revisited) (European) energy technology policy, asking (1) why there is any need for an energy technology policy, (2) why there is a need for some coordinated intervention on the European level, and (3) why there is a need to revise the already implemented policy measures.

1 Background

In 2009, the European Council agreed to reduce greenhouse gas emissions inside the European Union to 80–95 % below 1990 levels by 2050. Given that a certain level of emissions in non-energy sectors (such as agriculture) is not avoidable, the electricity sector has—as illustrated in Fig. 1—to be decarbonized by an even higher degree. At the same time, the electrification of other sectors such as trans-

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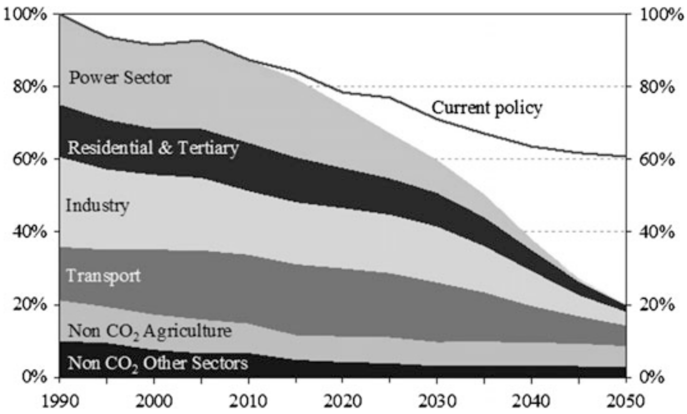

Fig. 1 EU greenhouse gas emissions towards an 80 % domestic reduction (100 % = 1990). *Source* European Commission—A Roadmap for moving to a competitive low carbon economy in 2050. COM(2011) 112 final

portation or heating and cooling, even though pace and extent are uncertain, will result in an increased role of electricity in final energy consumption.

If the EU wants to meet this long-term climate objective, while at the same time ensuring the secure supply of energy, the future energy mix will have to rely on a significantly increased share of low-carbon electricity generation. While the EU is making good progress towards meeting its climate and energy targets for 2020,[1] an integrated policy framework for the period beyond 2020 is now urgently needed to ensure regulatory certainty for investors and innovators. A diverse portfolio of clean technologies has to be employed at a large scale (see also e.g. Eurelectric 2011; IEA 2012).

However, many of those technologies are not yet competitive, or even not technically proven, and substantial additional research, development and demonstration (RD&D) activities have to be undertaken. A non-negligible financing gap between historic spendings and future funding needs has been identified (see e.g. European Commission 2009b). Moreover, the current period of austerity following the financial and economic crises imposed tight constraints on national budgets and forced governments to rethink fiscal policies, including support to research, innovation and demonstration projects. Some Member States have recently abandoned several expensive national funding programs, mostly those promoting clean energy technologies.

Moreover, there are doubts that the mix of currently implemented policy measures can deliver cost-efficient decarbonization. With the exception of the EU

[1]These targets, known as the "20-20-20 targets", set three key objectives for the year 2020: a 20 % reduction in EU greenhouse gas emissions as compared to 1990 levels; raising the share of EU primary energy consumption produced from renewable energy sources to 20 %; and a 20 % improvement in energy efficiency.

Emission Trading Scheme, most policy instruments—as for instance various means to support renewable energy sources or existing financial support to innovation—are designed unilaterally and implemented at national levels. The Strategic Energy Technology Plan, generally perceived as the "technology pillar" of the EU energy and climate policy, offers a first instrument and attempt to explicitly target a common European energy technology policy. However, it expires by 2020. Limitations regarding existing policies' efficiency and effectiveness are costly, as the scope of energy technology policy is large. More than EUR 5 billion per year are currently spent for low-carbon energy technology RD&D activities across the EU.

The EU commitment to achieve an almost entirely decarbonized economy by 2050 requires a stable long-term policy framework. As also emphasized in a recent Communication by the European Commission, there is a "need to provide regulatory certainty as early as possible for investors in low-carbon technologies, to spur research, development and innovation" (EC 2014). To this end, we discuss rationales for (a) (revisited) (European) energy technology policy, asking (1) why there is any need for an energy technology policy, (2) why there is a need for some coordinated intervention on the European level, and (3) why there is a need to revise the already implemented policy measures.

2 Rationales for an Energy Technology Policy

Why do we need any policy intervention in terms of supporting RD&D of low-carbon energy technologies? In what follows, we argue that there are at least four kinds of reasons for such policy intervention, including (i) the environmental externality, (ii) innovation externalities, (iii) capital market imperfections, and (iv) increasing global competition in green-tech sectors. Policy intervention, hence, can be motivated by market failures on the one hand, as well as by strategic industry and trade policy considerations on the other.

2.1 The Environmental Externality

The emission of greenhouse gases involves a negative externality.[2] Emitters cause climate change and, thus, impose costs not only on themselves but on the whole population and future generations. The reduction of emissions, consequently, is a global public good and unless such reduction is adequately rewarded, or the damaging emissions properly charged, the incentive to develop and deploy low-carbon technologies will be too low.

[2]See e.g. IPCC (2014) for further elaborations thereon.

From a global perspective, a common, comprehensive carbon price would be the economically efficient instrument, inducing emission reductions wherever they are cheapest and minimizing abatement costs across all sectors (Stern 2006).[3] However, in the absence of an adequate internalization of environmental externalities, as is the case with the existing EU emission trading scheme, covering only a subset of emissions and suffering from a surplus in emission allowances which is reflected in a very low price, further policy intervention in matters of energy technology support is needed.

2.2 Innovation Externalities

Many low-carbon technologies are not yet competitive.[4] All fundamental and a part of applied knowledge gained from research activities is a public good—without a very restrictive access regime, innovating firms cannot fully appropriate the returns from their RD&D activities due to existing social, market and network spillover effects. Marginal social returns can be significantly higher than the marginal private return to the innovator. Jaffe (1996) gives an excellent account of various market and technological spillovers arising from private innovation activities. Martin and Scott (2000) and Foxon (2003) explicitly discuss market failures of low-carbon innovation.

Furthermore, there is a tension between the need to encourage private sector RD&D, which, companies argue, requires strong enforcement of intellectual property rights, with the public desire to make the resulting discoveries as widely available as possible so that they can be deployed at large scale. Reaching ambitious climate objectives requires the wide use of clean technologies, also in developing countries, as well as achieving a high enough rate of knowledge diffusion that allows building on existing knowledge. Authorities and funding institutions must, therefore, aim to implement effective mechanisms to encourage the participation of private parties in innovation while delivering a high and fast enough technology transfer. An example of good practice in solving this trade-off has been implemented for instance by the UK Energy Technologies Institute (ETI 2010).[5]

[3]For a discussion of the relative merits of different carbon pricing schemes see also Grubb and Newbery (2007), or Goulder and Parry (2008). For an extensive overview on experiences with the implemented European Emission Trading Scheme see Ellerman et al. (2010, 2014), Zaklan (2013).

[4]For a detailed overview on the state of development and technological maturity of different low-carbon technologies see the “Technology Mapping” in the European Commission’s “Strategic Energy Technology Information System” (http://setis.ec.europa.eu/setis-deliverables/technology-mapping).

[5]The ETI has set up a flexible system to manage intellectual property resulting from the RD&D activities it (co-)finances. The intellectual property (including patents) is owned and managed by a member of the research consortium. Industrial members of the ETI and program associates, though, have free access to it. Third parties do not have access to generated knowledge for a certain period (normally seven years); hence, a “club of funders” is created. After the exclusive

Without further public support, the level and timing of private investments in the development of new clean energy technologies will be socially suboptimal (see e.g. Acemoglu 2010). Private companies will tend to focus on innovations leading to more rapid or more secure pay-offs, even though an optimal innovation portfolio, from a societal point of view, might also include innovation projects that yield positive cash-flows only in the very long-term or with a lower profitability. While the potential market for green technologies is huge, the margins to be earned, even with an adequate carbon price, will likely be modest, as energy prices are limited by existing well-developed conventional fossil fuel options. Consequently, public support in the energy field will be far more important than for other sectors, where products do not fear close substitutes. There are, thus, good economic reasons for a technology policy that addresses the full spectrum from basic research and development to first commercial-scale demonstration and early deployment.

2.3 Capital Market Imperfections

Assuming a perfect capital market, financial resources would be allocated to their most profitable uses. The accuracy of this allocation depends on two factors, the availability of information, and the ability to interpret this information properly (Peneder 2008). In real-world settings, however, economic actors face market imperfections of adverse selection (the innovator has better information about expected net benefits of a project than the investor who finances it) and moral hazard (the innovator may change his behavior after the financing decision has been taken, e.g. increase the risk profile of the project).

Moreover, innovations in clean energy technologies often pair very high capital requirements with substantial economic, technical and regulatory uncertainties—a situation that hampers access to finance. Many investors are constrained in (equity as well as debt) capital, not only due to the limited availability of funds as a result of the financial crisis, but also since certain actors face difficulties to raise *available* funds. There is empirical evidence that especially small firms and new market entrants suffer from higher cost of capital than their larger, incumbent competitors (Hyytinen and Toivanen 2005). Moreover, transaction costs can be very (and actually too) high relative to the required financing volume. And also the timing of returns can be an issue. From an investor perspective it might take too long until any benefits are monetized, given also potential uncertainty regarding future adaptations of the policy framework. This is further reinforced by the phenomenon that the private sector often tends to use a too high discount rate when evaluating RD&D projects (Cohen and Noll 1991). Hence, there are again good economic

(Footnote 5 continued)

access period, third party access to intellectual property is granted subject to the payment of a limited royalty.

Fig. 2 Rationales for an energy technology policy

reasons for policy intervention to reduce uncertainties, relax credit constraints and remove investment and financing barriers.

2.4 *Increasing Global Competition*

Besides future energy supply security, a major challenge Europe is facing today is "to remain at the forefront of the booming international market for energy technology" (EC 2010, p. 15), at a time when Member States curtail public spending. If decarbonization has no alternative but real potential gains from decreasing energy production- and supply costs only occur in the longer-run, growth effects stemming from the competitive production and profitable trade of low-carbon technologies on the world market are key to enhance growth in the shorter- to medium-term. Regarding wind energy, for instance, top-European turbine manufacturers such as Vestas or Siemens saw a continuous reduction in their global market share. Though, predominantly European manufacturers are active in the offshore wind market today, and there could be an argument to use this advantage of being a pioneer, and to benefit from domestic technology adoption as well as from exporting the technology to non-European markets. Similarly, for solar PV, China has become the dominant manufacturer. Manufacturing of cells and modules is a labor-intensive process, and the quality of Chinese products is comparable to European ones. Though, European firms still have a strong position in solar PV manufacturing equipment, high-tech products being sold to Asian manufacturers, too (Fig. 2).

3 Rationales for a European Energy Technology Policy

Policy intervention can be governed by European bodies (e.g. European Commission, Agency for the Cooperation of Energy Regulators), on a regional level jointly coordinated among a group of stakeholders (e.g. voluntary regional cooperations), or by individual Member States who seek to intervene mainly on their home market. The challenges accompanying the transition to a low-carbon, high-reliability power system at acceptable social costs are clearly European, and to rely only on individual Member State action is likely to lead to sub-optimal, inefficient outcomes. From an institutional perspective, European Treaties define shared competences between Member States and the EU regarding the achievement of the European environmental- and energy policy goals (Art. 192 and 194, Treaty of the Functioning of the EU) as well as related to the competitiveness of the European industry (Art. 173). It is thus necessary to investigate whether for the development of clean energy technologies substantial economic benefits can be gained from a renewed EU involvement, but at the same time to set those benefits into relation to the costs of pooling public regulatory power at this highest political level.

Benefits from EU intervention can be expected from the coordination of national policies.[6] The currently implemented bottom-up approach, with energy- and climate policy targets[7] being specified in EU Directives that have to be implemented into national laws, however, resulted in a wide set of diverse national policy designs. Ecofys (2014) provides an extensive overview on the various price- and quantity-based national renewable support schemes implemented during the last decade. CEER (2012) discusses implications of these non-harmonized unilateral policy instruments. In a similar vein, Glachant and Ruester (2014) see the risk of a definitive fragmentation of the European electricity market due to uncoordinated national policy initiatives.

Moreover, technology push initiated at the European level can avoid an unnecessary duplication of national or regional initiatives which is especially relevant for technologies in the ‘valley of death’, where substantial funding for commercial-scale demonstration and early deployment is needed, but projects are not yet viable in the short-term (Grubb 2004). Furthermore, most of the Member States simply are too small to implement certain instruments or to compete on a global scale with economies such as the US or China; and when joint action is taken, technology-, but also industry- and trade policies are more credible towards world market competitors, while also being more credible for attracting foreign investment. A common EU funding scheme can also avoid that Member States would only fund technologies that are produced within their own borders and free-ride on third countries to push other technologies. European co-funding can leverage additional national and private funds. And also for overcoming the economic downturn and relaxing funding constraints, the EU has to play its role, as the financial and economic crises clearly are a European issue asking for European solutions.

Following the principles of subsidiarity and proportionality, EU action, however, shall only be taken when it is more effective than actions at national, regional, or local level. Potential drawbacks of EU involvement and harmonization might be the

[6]For more details see also Ruester et al. (2012).

[7]See Footnote 2. This policy has been confirmed in 2014 with EU leaders agreeing on similar targets for 2030, i.e. a 40 % greenhouse gas reduction, a 27 % share of renewable energy sources and 27 % energy savings.

disregard of national specificities, the reduction of institutional competition between alternative policy approaches, and the loss of decentralized 'willingness to do more'. Considering the above arguments in favor of EU intervention, it becomes clear that they outweigh their costs for some policy areas where strong coordination is needed (such as the pricing of carbon emissions). However, at the same time, when EU regulations become themselves complex and alien to national habits, also transaction costs increase and might outweigh the benefits of EU intervention. Nonetheless, the above arguments indicate that no energy technology policy can work properly without a certain degree of coordinated, supra-national governance.

4 Rationales for a New European Energy Technology Policy

In what follows, we discuss the need to re-think currently implemented policies. We consider limitations of the existing instruments that aim at correcting (i) the environmental and (ii) innovation externalities; and illustrate drawbacks in reacting to (iii) capital market imperfections, the financial and economic crises and institutional frictions, and (iv) to increasing global competition.

4.1 Limitations of Existing Policies Addressing the Environmental Externality

The major instrument to address the environmental externality is carbon pricing. Accordingly, an **EU-wide cap and trade system** was introduced in 2005. The 2009 climate and energy policy package strengthened legislation and extended the coverage of the EU Emission Trading Scheme (EU ETS) substantially. Accordingly, Directive 2009/29/EC considers a single EU-wide cap on emission allowances from 2013 on, the stepwise replacement of the free allocation by auctioning, and an enlarged list of activities and greenhouse gases covered. However, as illustrated in Fig. 3, the EU ETS does not yet deliver an adequate price signal (see also Ellerman et al. 2010; Schmidt et al. 2012; Martin et al. 2012, for further discussions thereon). Prices are neither at a sufficiently high level nor reliable, but instead are argued to be too low and far from being predictable in the long-term. This hampers incentives to invest and innovate. As a response, the UK Government in 2011 unilaterally introduced a price floor of GBP 16/ton, following a linear path up to GBP 30/ton by 2020.

At the start of the 3rd trading phase (2013–2020), there was a surplus of almost two billion allowances, caused by the economic downturn on the one hand and high imports of international credits on the other. By the end of 2013, this surplus had grown even further to over 2.1 billion allowances. As a short-term measure, the

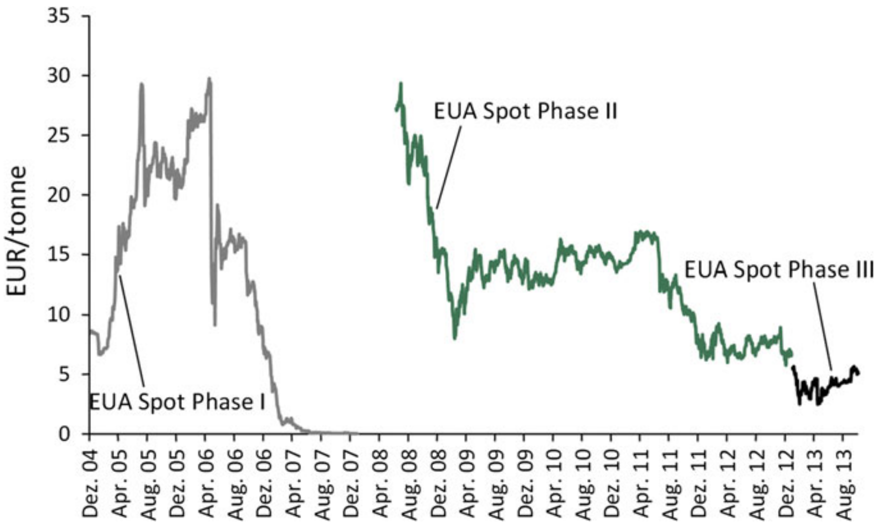

Fig. 3 Price development of EU emission allowances

Commission is postponing the auctioning of 900 million allowances until 2019–2020 (so called "back-loading") in order to allow demand to pick up.[8] As back-loading is only a temporary measure, a sustainable solution to the imbalance between supply and demand will require structural changes to the EU ETS. The Commission, therefore, proposed to establish a "market stability reserve" with the next trading period starting in 2021. Moreover, the linear reduction factor determining the emission cap could be decreased from currently 1.74 % to 2.2 % per year. But the EU ETS is still a new instrument. Stern (2006), in this vein, argues that the first two decades of its implementation will "be a period of transition" before "carbon pricing is universal and automatically factored into decision making" (p. xix).

Regarding **non-ETS sectors**, carbon emission reduction targets have been centrally set within the Effort Sharing Agreement (EC 2009a, b). The decision on which policy instruments to implement to achieve these targets has been left to the Member States, though carbon taxes might play a major role. The proposal of a new Energy Taxation Directive provides a framework for the adoption of a tax comprising both an energy- and a greenhouse gas emission component. Minimum carbon tax levels of EUR 20/t CO_2 have been proposed for several energy products. Apart from this, a few European countries have already imposed specific taxes on the CO_2 content of energy products. Finland and Sweden, for instance, introduced a

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[8]This back-loading does not reduce the overall number of allowances to be auctioned during the trading phase, but does only alter the distribution of auctions over time. In 2014, the auction volume will be reduced by 400 million allowances, in 2015, by 300 million, and in 2016, by 200 million allowances, respectively.

special tax in the 1990s. After a long debate in 2009, Ireland introduced a carbon tax as a component of a general package of fiscal consolidation. Thus, there is wide heterogeneity among national policies; some Member States even have certain contra-productive fossil fuel subsidies in place due to various political reasons and national implicit tax rates on energy differ substantially (Pazienza et al. 2011).

Besides carbon pricing, Directive 2009/28/EC on the **promotion of renewable energy sources** (RES) sets binding national targets for the share of RES in gross final energy consumption by 2020. Member States have full autonomy in developing their national action plans and in the choice of policy measures. Implemented support instruments include (a) feed-in tariff schemes which guarantee a certain price for a specific period of time or predetermined amount of production; (b) feed-in premiums guaranteeing a certain add-on to the market price; or (c) quota obligations with tradable green certificates, a quantity-based instrument where either producers or suppliers of energy are obliged to have a specific share of RES in their portfolio. Besides, tenders may be used in combination with the above instruments, such as tenders for a fixed feed-in tariff where potential investors bid the required support level.

Several studies assess the performance of alternative policy instruments (e.g. Jacobsson et al. 2009 or Ragwitz et al. 2011 and references therein). Ecofys et al. (2011) provide a detailed overview on implemented RES support policies in Europe. Price-control schemes with guaranteed access to the grid seem to be a prominent and effective tool. Furthermore, countries typically have implemented a whole set of instruments, differentiating among technology types and installation sizes and being adapted regularly. A complete re-orientation of policy schemes, as happened in Italy where in 2002 a green certificate scheme has substituted a feed-in tariff policy, is rather an exception than the rule.[9] Kitzing et al. (2012) find indications for a bottom-up convergence of policy choice. Indeed, the Commission expressed lately that "a greater convergence of national support schemes to facilitate trade and move towards a more pan-European approach to development of renewable energy sources must be pursued" (EC 2011b, p. 11).[10] In any case, Directive 2009/28/EC has been designed to ensure the achievement of the 2020 RES target. However, this may not in itself promote the necessary long-term investments to also achieve the long-term decarbonization objective.

Regarding **energy efficiency**, the third column of the EU energy and climate policy package, a new Energy Efficiency Directive came into force in 2012.

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[9]In 2005, a feed-in tariff scheme for solar electricity called "conto energia" was launched again in Italy and had been revised several times until the 5th conto energia in 2012.

[10]Evaluating responses to a public consultation on the implications of non-harmonized RES support schemes, CEER (2012) presents opinions on that issue as well. Proponents of harmonized support schemes argue that harmonization would avoid distortions in competition and instead create a level-playing field allocating RES production to areas "with best available and most cost-efficient resources and grid connection" (p. 14) whereas other stakeholders point on the key advantage of a decentralized approach of allowing individual Member States to tailor support schemes to their specific conditions.

Member States agreed on an indicative target of 20 % energy savings and to several binding measures. These include amongst others that energy companies are requested to reduce their energy sales to industry and residential sector by at least 1.5 % p.a.; a 3 % renovation rate for public buildings; and an obligation to develop national roadmaps on how to make the entire buildings sector more energy efficient. Besides, other relevant pieces of legislation imposing various standards and obligations include Directive 2010/31/EC on the energy performance of buildings, the Energy Labelling Directive 2010/30/EC and Directive 2009/125/EC establishing a framework for the setting of ecodesign requirements for energy-related products.

4.2 Limitations of Existing Policies Addressing Innovation Externalities

The EU's **Strategic Energy Technology (SET) Plan** has been adopted in 2008 as the so called "technology pillar" of the EU energy and climate policy that aims at accelerating the development and deployment of low-carbon technologies. Its implementation started with the establishment of the *European Industrial Initiatives* which bring together industry, the research community, Member States and the Commission. Within these Initiatives, strategic objectives have been formulated based on *Technology Roadmaps* that identify priority actions for the decade from 2010 to 2020. More specific *Implementation Plans*, containing more detailed descriptions of proposed RD&D activities, as well as suggestions about potential funding sources, are developed regularly for three-year periods. Comparing the past level of expenditures with the one necessary to deliver the identified priority actions

Table 1 Funding and estimated financing needs for key SET Plan technologies (million EUR—yearly average)

Sector	Public EU funding	Total funding (public and private)	Financing need identified in SET Plan
Wind	11	380	550
Solar (PV and CSP)	32	470	1600
Bioenergy	13	350	850
Carbon capture and storage	17	290	1050–1650
Hydrogen and fuel cells	70	620	500
Nuclear fusion	204	485	n.a.
Nuclear fission—generation IV	5	460	500–1000
Smart grids	14	270	200
Smart cities	n.a.	n.a.	1000–1200

Source European Commission (2009b)

up to 2020, a financing gap of EUR 47–60 billion has been estimated (Table 1) for key SET Plan technologies.

With the SET Plan, R&D investments across the EU increased from EUR 3.2–5.4 billion per year. For the 2014–2020 period, the EU is further ramping up investments in energy and climate related RD&D. Under the Horizon 2020 program, close to EUR 6 billion will be dedicated to energy efficiency, to low-carbon technologies and to smart cities and communities. Increased funds will also be available for various financial instruments, public private partnerships and projects undertaken by small and medium-sized companies.

The SET Plan has been a successful initiative with respect to (i) information exchange by providing a common platform for industry, academia, and policy makers from both the Member States and the EC; (ii) more coordinated planning by identifying priorities and action plans within Industrial Initiatives and Technology Platforms; and (iii) the joining of forces between private and public sectors and research community as well as between different Member States and stakeholders, within for instance the European Energy Research Alliance. Now, this instrument has to proof to be helpful also in successfully *implementing* formulated research and innovation plans.

However, the SET Plan in its current formulation—with the objective to "support the achievement of 2020 goals" has a limited time horizon. In addition, it is based on a within-sector approach regarding planning and priority setting (Ruester et al. 2014). Hence, this current policy does not necessarily support an optimal, cost-efficient portfolio of low-carbon technologies, i.e. decarbonization at least cost. Furthermore, a sustainable energy technology policy will need to react to the new context given the EU and financial crises, renewed concerns about future energy security and increasing global competition in green-tech markets.

Technology push in the form of **direct support to RD&D** can involve a whole set of financing instruments, such as research grants and direct subsidies, tax incentives, low-interest loans and loan guarantees, or technology prizes. Such instruments can be understood as policy instruments (Olmos et al. 2012). In addition to their function of closing the gap between the cost of innovation and funds private parties are willing to contribute, they (i) might be able to target specific technologies (e.g. public loans/guarantees, public equity, subsidies in the form of technology prizes); (ii) show a certain flexibility in (re-) directing funds to alternative innovation projects (e.g. lower for public loans than for subsidies in the form of benefits related to RD&D investments); and (iii) typically are suited to support certain types of innovating entities (in terms of their size, governance, etc.).

As illustrated in the 'Carvalho Report' (European Parliament 2010), the EU Framework Programmes have been a powerful mechanism for catalyzing innovation and accelerating the development, demonstration and deployment of low-carbon technologies, and to implement the SET Plan. Nevertheless, many stakeholders criticize that FP7 is, "despite the improvements made in relation to FP6, still characterized by excessive bureaucracy […] and undue delays" (p. 4). The report, moreover, complains about a lack of global orientation and recommends a further internationalization through active cooperation with non-European countries.

Current practice also shows that subsidies in the form of grants and contracts—the most attractive form of support from the innovators' perspective, but also the most expensive one for public authorities—are, by far, the preferred policy instrument to fund clean energy innovation of any type (Olmos et al. 2012). Even though there is an increasing interest from (private and public) venture capital investors in green technologies, their role will probably remain a minor one also in the future (Lester and Hart 2012). Venture capital funds typically do not exceed a few hundred million EUR, and an individual project investment does not exceed about EUR 10 million which is quite low for energy (especially demonstration) projects. Besides, equity investors tend to exit after a period of about 10 years and a market with exit options, therefore, would be an important precondition.

Box 1: EU funding to energy RD&D and innovation

Annual EU budgets are prepared in the context of multi-annual financial frameworks. Research funding until recently has been organized through *Framework Programmes*. For the most recent FP7, the total budget increased substantially to EUR 50 billion compared to 18 billion for FP6, with certain funding dedicated to energy (2.35 billion), environment (1.89 billion) and Euratom (2.7 billion). These numbers show a clear nominal increase over past budgets, but in relative terms the share of energy did continuously decrease over time.

The *Intelligent Energy Europe* facility, launched in 2003 and running until 2013, aimed at promoting energy efficiency and RES with a total budget of EUR 727 million during its second phase covering 2007–2013. The major part of the fund was made available through annual calls. Moreover, EUR 9 billion were distributed as part of *cohesion policy*. The *European Investment Bank* and the European Bank for Reconstruction and Development provide low-interest loans.

The *European Energy Programme for Recovery* was a short-term measure set up in 2009 as a response to the financial crisis. With a budget of EUR 4 billion it aimed at co-financing projects in the areas of gas and electricity infrastructure (2.3 billion), offshore wind (565 million) and CCS (1 billion), which without such additional EU funding likely would be delayed, downsized or even cancelled. Funds that had not been used by 31.12.2010 have been transferred into the *European Energy Efficiency Fund* (EUR 125 million—complemented by 75 million from the EIB, 60 million from Cassa Depositi e Prestiti and 5 million from Deutsche Bank) that offers different types of debt and equity instruments.

A new source of EU funds has been the *NER300*. Within the EU ETS, 300 million emission allowances are set aside in the New Entrants' Reserve. The instrument is managed jointly by the EC, the EIB and Member States. Projects developers apply to the Member State in which the project would be situated. Each Member State selects a set of projects from the applications and passes it to the EIB, where proposals then are evaluated and selected.

Horizon 2020 is the new EU funding program for research and innovation running from 2014 to 2020 with a total budget of EUR 80 billion. It combines all existing funding through Framework Programmes and the innovation-related activities of the Competitiveness and Innovation Framework Programme and the European Institute of Innovation and Technology. EU funding during the period 2014–2020 furthermore is available under the *European Structural and Investment Funds*, where a certain amount has been ring-fenced for the "shift to a low-carbon economy". This represents a significant increase in EU support for renewables, energy efficiency, low-carbon urban transport and smart grids solutions as compared to previous years.

4.3 Limitations of Existing Policies Addressing the EU Financial Crisis and Market Liquidity

The **EU and financial crises** had severe consequences on the ability to mobilize private (both company internal and external) and especially also public funds. As a consequence of the recent developments in credit markets and regulatory measures that have been implemented accordingly,[11] it has become increasingly difficult to access long-term financing, especially for projects with a high investment volume, as is the case for many energy innovation and demonstration projects. In addition, the current period of austerity has imposed tight fiscal constraints on national budgets and forces governments to re-think public spendings. Policy makers are reconsidering what their countries can afford in terms of low-carbon energy technology support. Different countries, such as Greece, France or the UK, have cut renewable subsidies substantially (Gilder-Cooke 2012).

The crises have affected all Member States, but not all in the same way and to the same extent, which exposes the EU to the danger of braking into new informal zones. Less affected countries, mostly in northern Europe, have an entirely different starting position for decarbonization policies than more affected Member States, mostly in southern Europe. Hence, on the one hand, there are a few countries, such as Germany or the Netherlands, which can benefit from relatively low financing cost, public funding opportunities and a quite high consumer willingness to pay for energy policy. On the other hand, there are countries that suffer from extremely

[11] Basel III as a global regulatory standard on bank capital adequacy, stress testing and market liquidity strengthens capital requirements and introduces new regulatory requirements on liquidity and leverage. EU Directive 2009/138/EC codifies and harmonizes EU insurance regulation and amongst others sets standards regarding the amount of capital that insurance companies must hold to reduce the risk of insolvency.

high financing cost, highly limited public funds, and consumers not willing, or able, to afford low-carbon technology support.

A first policy response to these challenges has been the European Energy Programme for Recovery, a EUR 4 billion program set up in 2009 to boost Europe's economic recovery by "stimulating economic activity and promoting growth and job creation" (EC 2012b, p. 2; see Box 1). However, given the complexity and magnitude of the crises, much more action is needed to keep low-carbon innovation on track towards 2020 and beyond.

4.4 Limitations of Existing Policies Addressing Increased Global Competition

Europe must not be regarded as an isolated system. In the recent past, third countries could build strong positions in RD&D, but also in the manufacturing of different low-carbon technologies. European companies suffer from substantially reduced market shares in e.g. the solar PV or onshore wind turbine sectors. As also highlighted in the EC's Competitiveness Report (EC 2011a, b), global competition has become much tougher and the need to remain competitive on the world market is becoming ever more important. For Europe to be a beneficiary in the low-carbon market, rather than just a consumer of technologies developed elsewhere, there seems to be no alternative to putting innovation at the heart of its growth strategy.

At one extreme of an industrial policy stands the proactive state, on the other extreme, authorities that minimize public intervention but trust in competition and free trade. Changing conditions on the world market for clean technologies might provide further justifications for policy measures that strengthen the power of European players in order to keep a competitive advantage, build industrial leadership and attract foreign capital. There are different arguments backing government intervention under certain circumstances. For instance, the presence of increasing returns to scale and imperfect competition in a sector can provide a rationale for supporting the domestic industry to raise national welfare (Krugman 1987).

Europe strongly values open markets and free competition. In the recent past, however, some voices call for actions supporting European players in keeping pace with its international competitors. In a recent Communication (EC 2012a, b), six "Key Enabling Technologies" (KETs, e.g. advanced materials or advanced manufacturing technologies) have been identified which is a first step towards explicitly focusing and prioritizing specific industrial sectors. These KETs have been recognized as cross-cutting technologies, feeding into many different industrial value chains and enabling a wide range of product applications, including those related to the transition towards a low-carbon economy. However, the need for trade and industry policy intervention in the energy sector and at European level has to be discussed with care and in recognition of current trade legislations.

5 Conclusion

The present EU energy technology policy supporting the development of low-carbon alternatives needs to be revisited. Market actors and the European public demand new, transparent and lasting policy commitments, not only because the current technology policy framework is running out in 2020, but also because of increasing global competitive pressure in green-tech sectors. Moreover, technological innovation, measured via RD&D expenditures, EU patents, and the competitive situation on technologies compared to third countries, are considered to be an important indicator for improving energy security (EC 2014).

There is a *need for public support* to correct for market failures originating from the environmental- and innovation externalities, to account for capital market imperfections and to fully exploit international trade opportunities in clean technologies. There further is a *need for EU involvement* to coordinate market failure corrections between Member States and to bundle national forces. And there is a *need to re-think current policies* to correct for limitations of existing policy measures, to give a clear and stable vision for the post-2020 period, and at the same time to reinforce European competitiveness in the global market.

However, current trade disputes related to clean technologies illustrate the complexity of industry and trade policies, as recent plans by the EU to place tariffs on Chinese solar manufacturers showed, see Bloomberg (2013). There is a fine line between supporting technologies and subsidizing industries. Any industrial or trade policy favoring European players, therefore, must be debated and designed with care and rationales for introducing such measures should only relate to environmental or innovation externalities.

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German Energiewende - quo vadis?

Ulrike Lehr and Christian Lutz

Abstract Under the impression of the Fukushima events in 2011, the German Government decided to immediately close down the seven oldest German nuclear power plants (built before 1980) and one younger plant, which had been under scrutiny due to several incidents. To secure energy supply, a set of measures concerning renewable energy deployment and the increase in energy efficiency has been established, together with nuclear phase out, which are often referred to as the "Energiewende". After more than two years into this transition, the challenges and opportunities of the Energiewende become measurable. The contribution reports findings from the monitoring process. One focus of the contribution is the analysis of the economic effects of the Energiewende thus far and in the near future. With the help of a macro-econometric model, two different paths of development are compared with respect to their effects on GDP, employment, and investment and value-added in different economic sectors.

1 Introduction

Renewable energy and energy efficiency had been already high on the agenda in Germany, when the Government decided in the aftermath of the Fukushima events in 2011 to abandon its earlier plans from 2010 for nuclear as a bridging technology and return to the decisions to phase out nuclear, as agreed at the beginning of the 21st century. Moreover, the decision extended to an immediate shut down of the seven oldest nuclear power plants and one younger plant, which had come to attention by several irregularities and out of operation for most of the time anyway. Renewable energy and energy efficiency therefore play an important role in what the world has come to know as the German Energiewende, the transformation of the energy system towards a less polluting, safer and secure energy supply.

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This decision has received much attention from scholars and the public in Europe and around the world. Germany as one of the leading industrialized countries in terms of industrial production and exports has few resources and has to provide energy to an 80 million population and an industrial sector, coined by large energy consumers. The literature ranges from “Germany’s gamble” (Buchanan 2012) to the question of “Green Revolution or Germany’s Nightmare?” (DW 2013).

Part of the Energiewende is an evaluation and monitoring process. Three years into this process, ex post analysis becomes more and more reliable. This contribution is based on a study for the German Federal Ministry for Economic Affairs and Energy, which did a back cast and a forecast for the next years to evaluate the economic effects of the Energiewende.

To do so, we employed PANTA RHEI, a macro-econometric model for Germany and simulated the economic indicators for two scenarios: an Energiewende scenario, which shows what has been reached in the process thus far and what will be reached in the near future, and a counterfactual scenario to compare with. By this, we can show, which effects can be attributed to the Energiewende. The remainder of this chapter is organized as follows. Section 2 gives an overview of earlier efforts and measures, which set the path towards the Energiewende, and shows earlier evaluation results from the literature. Section 3 defines the modelling framework. It introduces the macro-econometric environmental model PANTA RHEI and reflects upon recent applications and results. Section 4 defines the relevant scenarios in detail. It identifies the drivers of the economic effects and shows the most important characteristics of the respective scenario in terms of investment, the energy mix, prices and energy demand and supply. Next to the differences between the two scenarios, the section also presents the common set of framework data for both scenarios. Section 5 describes the simulation results and puts it into perspective, Sect. 6 concludes.

2 Germany’s Way to the Energiewende—Beyond the Nuclear Discussion

The Energiewende was decided against the background of already existing regulation regarding the efficient use of energy and the generation of heat and electricity from renewable energy sources. As far back as the 1970s in response to the first oil crises, Germany started regulating residential heat demand through ordinances on the buildings’ heat required and on age, consumption and maintenance of the heating system. The first energy savings act dates back to 1976. Latest since 2002, the idea that regulation of the buildings’ envelope and their heating systems are related gained ground and the two strands of regulation merged into the energy saving ordinance.

Compared to this, renewable energy support started rather late. The first “Law on Feeding Electricity from Renewable Energy Sources to the Public Grid”

(Stromeinspeisungsgesetz 1990) had been drafted by a conservative and a green member of parliament and was submitted by the conservative CDU/CSU parliamentary group. It passed parliament in 1991 and was the first step towards what became the EEG, the Renewable Energy Act in 2000. The support was available for systems with a maximum capacity of five MW and the then still monopolistic utility companies could add the paid support to the electricity bill for all consumers. The central elements of the 1990 law were the existence of tariffs and the obligation to buy all generated electricity. Even after the liberalization of the electricity market in consequence of the European Electricity Directive in 1998, the need to regulate access to the grid persisted. Therefore, the new EEG decreed that electricity from renewable energy source gained priority access.

The 1000-roofs program between 1991 and 1995 supported photovoltaic (PV) installations (GIZ 2012). The objective of this capital grant promotional program was the “evaluation of the already achieved level of technology” and “evaluation of the required development need for small grid connected installations”. It supported grid connected PV installation with a capacity between one and five kWp on rooftops of residential homes. The grant covered 70 % of the investment and mounting costs and a quota regulated the number of permissible installation per federal state, partly since the federal states paid for a share of the grant. From 1999 until 2003, the 100,000-roofs program supported solar PV. The target was an installed capacity of 300 MW and the support consisted of soft loans on a reduced rate. The late nineties and early 2000s were a period of high interest rates on loans; therefore, a reduction by more than 60 % was an attractive incentive.

The individual efforts in energy conservation and renewable energy use were bundled into the integrated energy and climate package in 2007 (IEKP 2007). The measures range from combined heat and power (CHP) support to buildings’ efficiency, increasing efficiency in industry, support of renewables to transport measures for the introduction of biofuels and increasing efficiency of vehicles. Lutz and Meyer (2008) estimate the economic effects of partial measures of the IEKP such as the efficiency program for buildings, and other measures and find slightly higher growth and a positive impact on employment.

Lehr et al. (2012a, b, c) report findings from two studies, with a focus on efficiency measures in different economic sectors and the other one on the impacts of renewable energy increases. Energy efficiency measures are modelled bottom-up for each sector, i.e. for transport, residential building, efficient appliances and households and in industry as well as cross sectional technologies. Only technologies with payback periods from energy savings smaller than the equipment’s lifetime are included in the analysis, which is based on Ifeu, Fraunhofer ISI, Prognos, GWS et al. (2011). In addition, export increases for energy efficient appliances contribute to the overall positive economic effects. For renewable energy, a higher growth path and more additional employment also strongly depend on the export assumptions. Germany’s economy relies heavily on its position on global markets, also its wind and solar industry does. The media coverage of the integrated energy and climate package supported Germany’s role as a pioneer in climate change mitigation and the transition towards an energy system based on renewables. First mover advantages pay in terms of higher shares on global markets. Further studies support these findings: economic effects of efficiency measures are analyzed by Blazejczak et al. (2014a, b). They focus on the improvement of buildings' efficiency and assume twice as high an effort in this sector. This leads to investment between 7.4 billion EUR (2020) and 14 billion EUR (2050) and annual saved energy costs of 3.8 billion EUR (2020) and up to 32 billion EUR (2050). Economic effects from these measures are positive. Compared to a reference without the respective measures (see the next section on the definition of counter factual scenarios) GDP is up to 1 % higher and additional employment ranges at 340,000. Böhringer et al. (2012) analyze the economic effects of the renewable energy support mechanisms. Applying a general equilibrium model, they find positive employment effects for some parameter choices, depending on the design of the respective support mechanism. Frondel et al. (2009) have repeatedly doubted positive employment effects and pointed at the high costs of the renewable energy support mechanism. However, their calculations stop at the cumulated costs.

IHS Global Insights (Wiegert and Hounsell 2013) find negative impacts, assuming high prices for energy intensive sectors and a termination of the exemptions of the energy intensive industries from surcharges for renewables. In November 2014, the EU Commission has declared the exemptions to be almost completely in line with EU legislation. The EEG amendment in summer 2014 has already been drafted in close cooperation with the Commission to ensure further exemptions. The analysis by the German Economic Institute (DIW) shows positive effects of renewable energy expansion (Blazejczak et al. 2014a, b). Finally, an analysis of the energy and climate policy measures since 1995 shows positive effects, due to accumulated energy savings (Lehr et al. 2013). Accordingly, the macroeconomic effects throughout the 2010–2012 period turn out to be positive.

The IEKP was an important step towards a more sustainable economy. However, it fell short of providing a pathway for a transition of the energy system until 2050, which is compatible with international climate change targets.

Therefore, the German government developed the energy concept, which is a continuation of the IEKP with detailed targets until 2050. It is at the core of the Energiewende framework of 2011, ironically partly to underpin life time extension of nuclear power plants in 2010. Table 1 gives an overview of the respective targets. Detailed pathways show the transition from today's shares of renewables, in final energy consumption and in electricity generation, from today's GHG emissions to an 80 % reduction by 2050; primary energy use shall decrease by 50 % by 2050 and electricity consumption by 25 %. The latter represents a steeper increase in efficiency than it may seem at first glance, because the number of electric appliances will further grow in the future as will electro mobility.

The energy concept further suggests measures to reach these targets and provides a framework of monitoring the success in reaching the suggested targets. The analysis on the economic effects of the Energiewende presented below is a small building bloc in the first comprehensive progress report (BMWi 2014).

And nuclear? The so-called nuclear consensus from 2001 had set dates for the phase out of nuclear energy. Any nuclear power plant received a lifespan of

Table 1 Targets of the energy concept

		2011 (%)	2012 (%)	2020 (%)	2030 (%)	2040 (%)	2050 (%)
Renewable energy	GHG reduction	25.6	24.7	At least 40	At least 55	At least 70	At least 80
	In electricity	20.4	23.6	At least 35	At least 50	At least 65	At least 80
	In final energy	11.5	12.4	18	30	45	60
Efficiency	Primary energy	−5.4	−4.3	−20			−50
	Electricity	1.8	−10				−25
	Production	Increase in energy productivity (=output/energy input) by 2 % per annum					
	Buildings	2 % of buildings modernized each year = all buildings in 50 years					

Source BMWI, own table

32 years and the amount of electricity it could generate until its end of operation. Two nuclear power plants were switched off immediately; four more should have followed in 2010 and 2011. After a brief reconsideration of the phase out schedule by the German Government, the Fukushima events in March 2011 led to the current state, where nuclear will be phased out by 2021. Figure 1 shows the path as it is set in the Amendment to the Law on Atomic Energy of 2011 (AtG 2011). It also shows the electricity generation from nuclear power plants according to the nuclear consensus from 2002 and the Energiewende scenario from 2011. A major challenge will be the shutdown of the remaining nuclear power plants between 2020 and 2022.

A large decrease in capacity took place immediately after the decision to return to nuclear phase out in March 2011. Eight out of 17 operating nuclear power plants were switched off; the decrease in operating capacity was 8.8 GW. 12.7 GW remained in operation. The reduction of installed nuclear capacity by more than one third went without disruption of the electricity supply in Germany. Studies on price impacts show only small increases in electricity wholesale prices, partly due to current overcapacity on the electricity market and merit-order effects.[1]

The energy mix, investment in new power plants, operation of the existing power generation as well as the multitude of other factors related to the above outlined goals impact the economy. Apart from individual cost-benefit-assessments for instance in support of the decision for or against the installation of a solar home

[1]The electricity supply curve can be thought of as ordered according to power plants‘ generation costs. This is called the merit order. The more electricity from renewable energy enters the market, the more generation at zero generation costs is in the market and spot market prices drop.

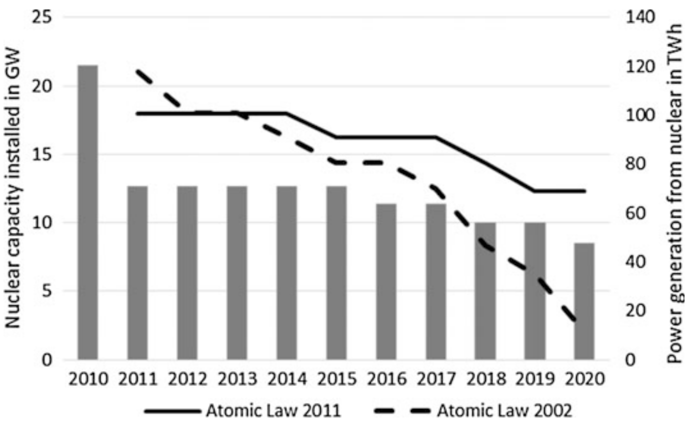

Fig. 1 Phase out path for nuclear energy as decided in the Law on Atomic Energy AtG 2011, 2010–2020, in GW. *Source* GWS, Prognos, EWI (2014), Sachverständigenrat Wirtschaft (2012)

system, the macro effects of the transition to a cleaner and safer energy system are important.

To determine the macroeconomic effects of the energy transition a macroeconomic model analysis can illustrate feedbacks between the energy system and the overall economy and determine gross effects at the macroeconomic and sectoral levels. Scenario analysis is the established technique to evaluate the effects of a political instrument or a bundle of instruments such as the Energiewende. Economic quantities from a scenario, which includes all the measures, are compared with the results of a scenario without the measures—the so-called counterfactual. The comparison shows in which scenario the economic performance will be better. Typical indicators are GDP, both level and growth rates, employment, consumption, the trade balance and others.

Figure 2 depicts the different steps of the evaluation. The scenarios describe possible specifications of the future energy system for Germany. Bottom-up models help to translate the scenarios into a set of monetary stimuli. Investment in energy efficiency or renewable energy technologies, price changes due to different heat and power generation costs or savings from reduced energy costs due to increased efficiency are the monetary effects of a change in the energy system. These monetary stimuli trigger many effects in the overall economy: relative price changes induce behavioral changes, investment leads to additional employment and demand for the respective goods in the short run and will increase depreciation in the longer term, energy savings shift demand to other goods than energy.

The comparison of the results becomes more difficult once different references, combinations of measures and design of the macroeconomic models are chosen. In this context, the key is the definition of the energy transition and a clear description of the measures that are necessary for its achievement compared to an appropriate reference trend.

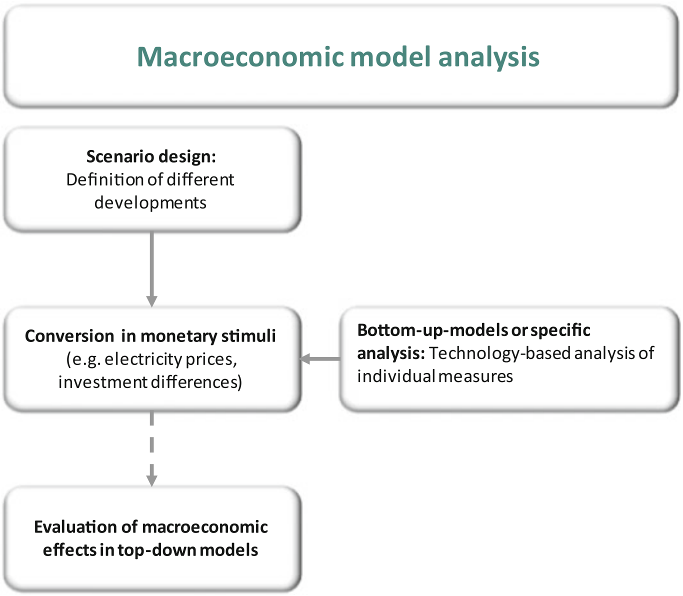

Fig. 2 Macroeconomic model analysis. *Source* GWS/Prognos/EWI (2014)

The next section briefly explores the modelling tool and explains the relevant links. We then turn to the scenarios and explain the main drivers for each of the two scenarios considered.

3 Model PANTA RHEI

The economic effects of the German Energiewende are determined using the environmental economic model PANTA RHEI. PANTA RHEI (Lutz et al. 2005; Lehr et al. 2008; Meyer et al. 2012) is an environmentally extended version of the econometric simulation and forecasting model INFORGE (Ahlert et al. 2009; Meyer et al. 2007). A detailed description of the economic part of the model is presented in Maier et al. (2013, 2015). For more details of the extended model, see Lutz (2011). PANTA RHEI has been used to answer several questions on the economic effects of environmental policy instruments. The support of energy efficiency and renewable energy, which has been outlined in Chapter "The EEC Commission and European Energy Policy: A Historical Appraisal", has been evaluated with the help of PANTA RHEI. In 2010, economic effects of different energy scenarios were compared to each other, which were the basis for the German energy concept (Prognos, EWI, GWS (2010); Nagl et al. 2011). Recent applications include an evaluation of green ICT (Welfens and Lutz 2012), employment effects of the increase of renewable energy (Lehr et al. 2012a, b, c), and economic evaluation of climate protection measures in Germany (Lutz et al. 2014a, b). In a recent IEA (2014, p. 57) overview the model is classified as "input-output", but it is rather "econometric" plus "input-output", as parameters are econometrically estimated and input-output structures flexible (West 1995). The overall approach is based on the INFORUM philosophy (Almon 1991). More detail can be found in the chapter of Douglas Meade, who applies the US LIFT model to study the impact of shale gas in the US.

The behavioral equations reflect bounded rationality rather than optimizing behavior of agents. All parameters are estimated econometrically from time series data from 1991 to 2010. Producer prices are the result of mark-up calculations of firms. Output decisions follow observable historic developments, including observed inefficiencies rather than optimal choices. The use of econometrically estimated equations means that agents have only myopic expectations. They follow routines developed in the past. This implies in contrast to optimization models that markets will not necessarily be in an optimum and non-market (energy) policy interventions can have positive economic impacts.

The model is empirically evaluated: the parameters of the structural equations are econometrically estimated. In the model-specification stage various sets of competing theoretical hypotheses are empirically tested. As the resulting structure is characterized by highly nonlinear and interdependent dynamics the economic core of the model has furthermore been tested in dynamic ex-post simulations. The model is solved by an iterative procedure year by year.

Structural equations are modeled on the 59 sector level (according to the European 2 digit NACE classification of economic activities) of the input-output accounting framework of the official system of national accounts (SNA) and the corresponding macro variables are then endogenously calculated by explicit aggregation. In that sense the model has a bottom-up structure. The input-output part is consistently integrated into the SNA accounts, which fully reflect the circular flow of generation, distribution, redistribution and use of income.

The core of PANTA RHEI is the economic module, which calculates final demand (consumption, investment, exports) and intermediate demand (domestic and imported) for goods, capital stocks, and employment, wages, unit costs and producer as well as consumer prices in deep disaggregation of 59 industries. The disaggregated system also calculates taxes on goods and taxes on production. The corresponding equations are integrated into the balance equations of the input-output system.

Another important outcome of the macro SNA system is net savings and governmental debt as its stock. Both are important indicators for the evaluation of policies. The demand side of the labor market is modeled in deep industry disaggregation. Wages per head are explained using Philips curve specifications. The aggregate labor supply is driven by demographic developments.

The energy module describes the interrelations between economic developments, energy consumption and related emissions. The relations are interdependent. Economic activity such as gross production of industries or final consumer demand influence respective energy demand. Vice versa, the expenditures for energy consumption have a direct influence on economic variables.

The energy module contains the full energy balance with primary energy input, transformation and final energy consumption for 20 energy consumption sectors, 27 fossil energy carriers and the satellite balance for renewable energy (AGEB 2013). All together, the balances divide energy consumption into 30 energy carriers. Prices, also in Euros per energy unit, are modeled for different energy users such as industry, services and private households for all energy carriers. The energy module is fully integrated into the economic part of the model.

Final energy consumption of industries is explained by sector output, the relation of the aggregate energy price—an average of the different carrier prices weighted with their shares in the energy consumption of that sector—and the sector price and time trends, which mirror exogenous technological progress.

For services, the number of employees turned out to be a better proxy for economic activity than gross output. Average temperatures also play a role for the energy consumption of the service sector. For private households, consumption by purpose as heating or by fuels is already calculated in the economic part of the model in monetary terms. Additional information can be taken from stock models for transport and heating from the specific modules, as only new investments in cars, houses or appliances, or expensive insulation measures will gradually change average efficiency parameters over time.

Final demand of each energy carrier for industries can be calculated by definition, multiplying the share of the carrier with overall final energy demand of the sector. For the shares, the influence of relative prices, the price of the energy carrier in relation to the weighted price of all energy inputs of the sector, and of time trends are econometrically tested.

Energy carrier prices depend on exogenous world market prices for coal, oil and gas and specific other price components such as tax rates and margins. For electricity different cost components such as the assignment of the feed-in-tariff for electricity are explicitly modeled. For services, households and transport specific prices are calculated, as for example tax rates partly differ between end users.

For energy-related carbon emissions, fix carbon emission factors from the German reporting (Federal Environmental Agency 2013) to the United Nations Framework Convention on Climate Change (UNFCCC) are applied. Multiplication with final energy demand gives sector and energy carrier specific emissions. All detailed information in the energy balance for 30 energy carriers is consistently aggregated and linked to the corresponding four industries of the IO table.

4 Scenarios and Framework Conditions

The scenario definition centers on one principle: basic macroeconomic parameters, e.g., population, economic development and international energy prices, which are available either from historical values or from medium-term forecasts, are assumed the same in both scenarios. They correspond to the current Energy Reference Forecast (Prognos, EWI, GWS 2014, see Lutz et al. 2014a, b for an overview in English). The German government commissions an energy reference forecast in a 5 year frequency. It projects the most likely development, given the current policy framework. Projections for international energy prices and the global population development stem from or are closely related to the respective publications such as the IEA's World Energy Outlook. The projection of the global economic development, of the energy system in Europe and in Germany and of the German economic development result from the combination of several macro models, energy system models and electricity market models.

Three years after the Energiewende has been decided, it makes sense to ask, what has been reached thus far and what were the economic effects of the Energiewende until today? To answer these questions, the analysis in the next sections takes the energy system as we find it in 2013 and compares it with an ex-post counterfactual. For the ex-ante analysis, both, the counterfactual and the Energiewende scenario are forward projected.

4.1 Framework Data

Framework data, as mentioned above, are not in the realm of being affected by the energy transition, such as international energy prices for fossil fuels or the population development in Germany. The population is decreasing during the observation period from 80.3 million in 2009 to 79.4 million in 2020 (−1.1 %). This leads to a 1.5 % drop of labor force compared to 2009.

Real GDP has increased during the ex post period by an average of 2.1 % p.a. In the ex-ante period, the average growth rate is 1.2 % p.a. However, the scenarios change GDP growth rates and GDP will differ between the scenarios (see Sect. 5). Together with the population's decrease, this leads to an increase of average real per capita income by about 9 % by 2013 and 19 % by 2020.

Consumer prices for petroleum products, natural gas, and coal result from global market prices and exchange rates, as well as from associated taxes and fees. CO_2 prices will have an effect on relative prices of fossil fuels. The underlying assumption is that businesses not participating in emissions trading and private residences will pay a CO_2 surcharge in line with CO_2 certificate prices and the specific CO_2 content of the energy sources from 2020 onwards.

The price for natural gas for heating and other residential use has dropped in the ex-post period by 5 %; the price for light heating oil has risen by almost 50 % (Fig. 3). The projection for fossil fuel prices is based on Prognos, EWI, GWS (2014). In 2020, natural gas price will be 7 % higher than 2009 and heating oil will be 73 % compared to 2009. Although current price turmoil of crude oil seems to signal low prices, the analysis of the economic effects of the German Energiewende bases its price assumptions on the latest available IEA World Energy Outlook (IEA 2013). Brent oil prices will grow between 2011 and 2020 from 108 USD2011/bbl in

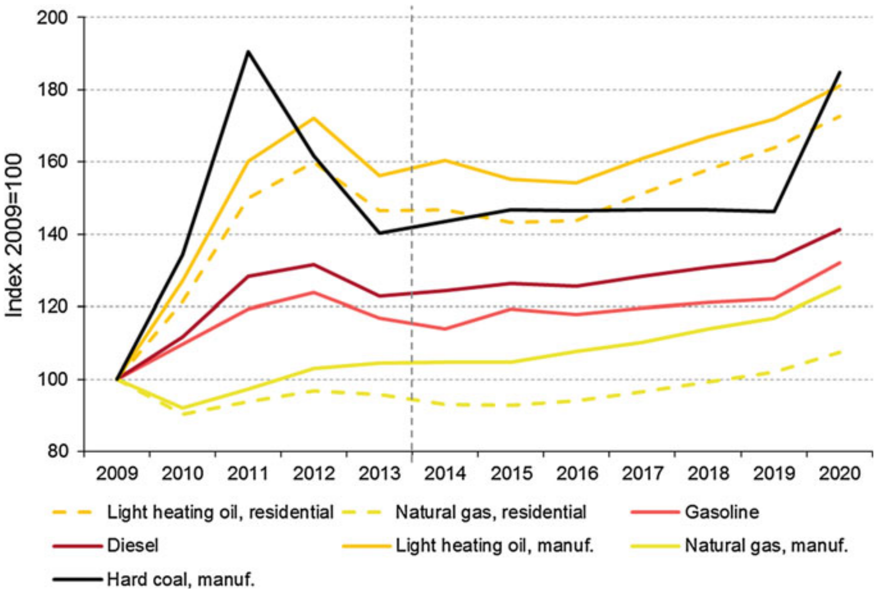

Fig. 3 Consumer prices for petroleum products and natural gas, household prices with VAT, manufacturing prices without VAT, 2009–2020, Index 2009 = 100. *Source* GWS/Prognos/EWI (2014)

2011 to 117 USD2011/bbl in 2020. As taxes and other charges for fossil fuels are assumed to remain constant until 2020, consumer price increases are driven by import price changes. In 2020, a CO_2 surcharge is introduced for all carbon emissions outside the EU-ETS. Industrial prices are assumed to show stronger increases.

The base year for the following analysis is 2009, because as has been pointed out above the Energiewende started in 2010 with the decisions laid down in the German energy concept. Therefore, the scenarios bifurcate in 2010 and 2009 is the last year with a shared data set.

Against this general framework, the Energiewende scenario and the counterfactual are developed. For the ex-post analysis, data for the Energiewende scenario are observable, the actual development of the energy mix, of prices and quantities supplied and demanded are contained in the most recent energy statistics. The counterfactual, however, is based on assumptions for the past development without the Energiewende policies. To stay consistent with the literature outlined above, we chose the development projected in Prognos, EWI, GWS (2010) as a proxy for the counterfactual, ex-post as well as ex ante.

4.2 The Energiewende Scenario

The Energiewende scenario, as mentioned above, contains the actual development prior to 2013. This can be seen as the implementation of the energy transition. For the years 2014–2020, the development follows the 2014 Energy Reference Forecast, because it reflects all measures from the Energiewende package. This does not necessarily mean that all Energiewende targets are met in this scenario. It rather describes the development under the Energiewende decisions from 2011, as they are described in Sect. 2.

Assumptions for exogenous variables such as international energy prices, carbon prices in the EU ETS or demographical development are taken from Prognos, EWI, GWS (2014). A brief overview in English can be found in Lutz et al. (2014a, b). For the electricity market, the Energiewende scenario draws fuel and CO_2 prices, the phase-out of nuclear power and the expansion of renewable energy from the 2014 Energy Reference Forecast.

Table 2 shows overall performance with regard to the targets of the energy concept for the year 2011 and 2012, and as expected in the Energiewende scenario (EW).

Table 2 Comparison of selected results of the EW scenario with targets of the German energy concept

	2011 (%)	2012 (%)	2020 (%)
Greenhouse gas emissions			
Greenhouse gas emissions compared to 1990	−25.6	−24.7	**−40**
Result ET-Scenario			−36
Efficiency			
Primary energy consumption compared to 2008	−5.4	−4.3	**−20**
Result ET-Scenario			−18
Energy productivity TFEC	1.7 (2008–2011)	1.1 (2008–2012)	**2.1** (2008–2050)
Result ET-Scenario			1.9 (2008–2020)
Gross electricity consumption compared to 2008	−1.8	−1.9	**−10**
Result ET-Scenario			−7
CHP			
CHP share in electricity generation	17.0	17.3	**25**
Result ET-Scenario			16
Renewable energy			
RE share in gross electricity consumption	20.4	23.6	**At least 35**
Result ET-Scenario			40.4
RE share in gross final energy consumption	11.5	12.4	**18**
Result ET-Scenario			21.8

Targets of the German Government in bold
Source GWS/Prognos/EWI (2014)

The Energiewende scenario fulfills the objectives of the Energy Concept with respect to renewable energy. The share of renewable energy in gross electricity consumption in 2020 will be 40.4 % (targeted value: 35–40 %). Lower coal prices would not change this increase, as a sensitivity analysis shows. The share of renewable energy in gross final energy consumption increased to 12.4 % in 2012. It will reach 21.8 % in 2020, exceeding the target of 18 %. Fossil fuels still provide the basis of energy supply with more than 75 % in 2020.

4.3 The Counterfactual Scenario

What is the counterfactual development to the Energiewende scenario? Although nuclear phase out received a lot of attention, it is *not* the main characteristic of the Energiewende implied changes in the system. On the contrary, as sketched in Sect. 2 nuclear phase out was mainly a reiteration of agreements from 10 years earlier. The core of the Energiewende scenario is in the perspective for a long-term transition of the energy system towards a cleaner and safer provision of energy. The definition of the counterfactual therefore contains the regulation and measures before 2010, without the long-term targets. The counterfactual scenario (CF) is based on a scenario developed before the Energiewende in 2010. It includes the assumptions of the reference scenario given in the "Energy Scenarios 2010" (Prognos, EWI, GWS 2010) and describes the development without the energy transition based on expectations from the beginning of 2010. The scenario assumptions are central to the macroeconomic effects of the thus defined energy transition.

4.4 Scenario Comparison

Differences in the economic results of the two simulation runs are driven by the differences in the two scenarios. Primary energy consumption is reduced in the Energiewende (EW) scenario by 2.5 % points more) than in the counterfactual (CF) scenario by 2020. Furthermore, the share of renewable energy in the EW scenario is higher than in the CF scenario. However, fossil fuels constitute the basis of energy supply (share >75 %).

In the EW scenario, primary energy consumption under increasing GDP shows a 1 % decrease by 2013 and a 13 % decrease by 2020 compared to 2009 values. In the CF scenario, the decrease is about 10 % by 2020. The additional savings of about 2.5 % points in the EW scenario correspond to a reduction of about 344 PJ. Figure 4 shows the relative changes in the energy mix.

Fossil fuels lose market shares but still dominate the energy mix in both scenarios in 2020, with shares of 76 % (EW scenario) and 79 % (CF scenario). Hard coal is used much less in the Energiewende scenario due to merit-order effects, the

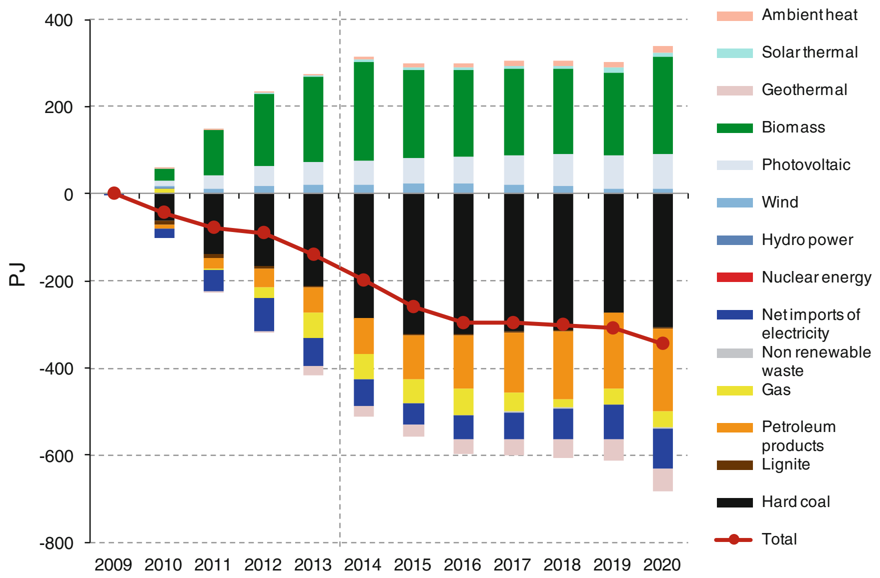

Fig. 4 Difference in primary energy consumption between the scenarios by energy source, 2009–2020, in PJ. *Source* GWS/Prognos/EWI (2014)

use of hard coal carries the largest part of the difference in fossil fuel use. Biomass and PV on the other hand carry the largest part of the additional increase in renewable energy. The increase in the contribution of renewables to primary energy demand in 2020 is 19 % for the EW scenario and 16 % for the CF scenario. Compared to the 9 % in 2011, renewables will be growing strongly. With a falling energy consumption, the need for RE growth is not as large as without it. The installed capacity of offshore wind energy will increase by the largest amount and more than quadruple compared to 2013. Onshore wind energy will mainly face replacement installation; PV will increase by 50 %.

Additional electricity generation from renewable energy in the EW scenario leads to lower electricity generation from hard coal- and gas-fired power stations than in the CF scenario (Fig. 5). Electricity exports in the EW scenario are significantly higher than in the CF scenario.

To balance volatile electricity production from renewables, fossil fuel based capacity is needed as back-up capacity. This leads to larger electricity exports when both capacities –back-up and renewables—feed into the grid. As can already be observed today, excess electricity production is exported to the European markets. However, European generation will also meet the respective targets and forecasts for generation from renewables will improve, so that imports and exports become more and more planned and lead to decreasing costs. Additional grid capacity and storage option improve this outcome. Renewable energy in Germany will contribute

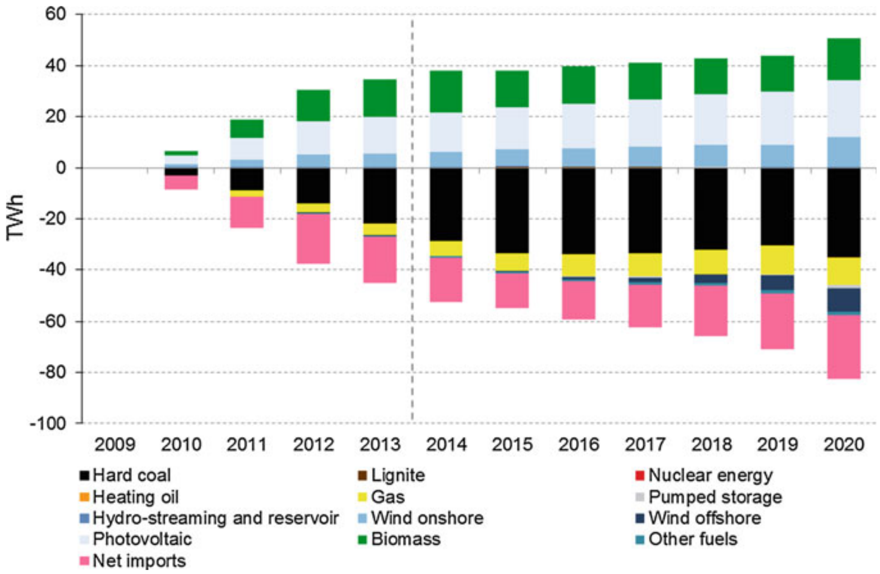

Fig. 5 Difference in gross electricity production between EW scenario and CF scenario by energy source, 2010–2020, in TWh. *Source* GWS/Prognos/EWI (2014)

40 % to electricity production by 2020 and thus meet the Energiewende target of a larger than 35 % share by far. The counterfactual scenario misses the target.

Renewable energy increase comes with large additional investment, which needs to be refinanced. The refinancing mechanism in Germany is based on the Renewable Energy Act as described in Sect. 2. Grid operators buy electricity from renewable generation at fixed tariffs and sell it at the power exchange at market price. If the difference between the turnover at the market and all tariffs paid is negative, this difference is added to the electricity bills of all consumers in a burden sharing process. Some large consumers are exempt. This burden sharing process has two flaws, which have been discussed in the literature and the public at great length in 2013/2014: firstly, the more renewables enter the market at the same time, the more the market prices fall, because renewables produce at zero generation costs. This is good news for all consumers buying their electricity at the market, but given the refinancing mechanism actually drives up additional costs for renewables, because falling market prices increase the gap between a fixed tariff and the market price. Secondly, though the exemption of additional costs for energy intensive industries, which compete on international markets, has just recently passed the European jurisdictions, which are critical towards favorable distortions, it decreases the denominator of the formula which determines the surcharge. This leads to unfavorable price increases for consumers that are not exempt. These price increases will cause negative effects in the economic model and in the economy.

The surcharge jumped with the large PV installations of more than 7 GW in 2010 and 2011 (Fig. 6). The increase in 2012 was at much lower cost, because the

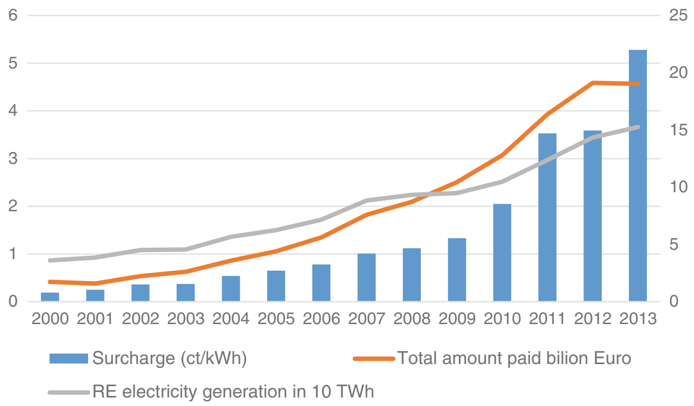

Fig. 6 Development of the surcharge, electricity generation from RE and total amount paid

price of PV modules in 2012 was less than 50 % of what it had been in 2010. The jump of the surcharge from 3.59 ct/kWh (2012) to 5.28 ct/kWh (2013) stems from a miscalculation of the surcharge and a deficit in 2012. In 2014, the surcharge again rose to 6.24 ct/kWh. The year 2015 will be the first year for the surcharge to slightly decrease to 6.17 ct/kWh.

The share of electricity to be exempt from paying the surcharge rose from 18.4 % in 2011 to 22.6 % in 2014 (Mayer and Burger 2014). The increase is due to business cycle activities of the respective industries and changes in the regulation for eligibility for the exemption. Electricity intensive industries have to apply for exemptions on the level of facilities. The design of the exemptions can be roughly compared to the carbon leakage list of the EU ETS, but does not focus on industry classifications, but on single facilities.

The EEG surcharge in the EW scenario has to be higher than in the CF scenario, because of higher shares of renewable energy. Households, trade and commerce as well as industrial customers face higher final consumption prices in the EW scenario. The wholesale price in the Energiewende scenario is slightly lower than in the CF scenario because of the merit-order effect. In brief, the merit-order effect shifts the marginal cost curve to the right, because electricity generation from renewable energy has priority access at zero marginal cost. Fossil fuel based price setting generation starts only to cover demand which has not been covered by renewables. Market prices decrease. Electricity prices for the energy-intensive industries also benefit from this effect, and are lower than those in the CF scenario due to the exemption from EEG surcharge and the lower wholesale price in the EW scenario.

For the other pillar of the Energiewende, i.e. for energy efficiency, the outlook is not quite as promising. Final energy consumption for instance, increased during the ex post period by about 2 % in the EW scenario and 3 % in the CF scenario. This is partly due to economic recovery and sinking energy prices compared to the 2008 price highs. The future development foresees a turnaround of this trend (Fig. 7).

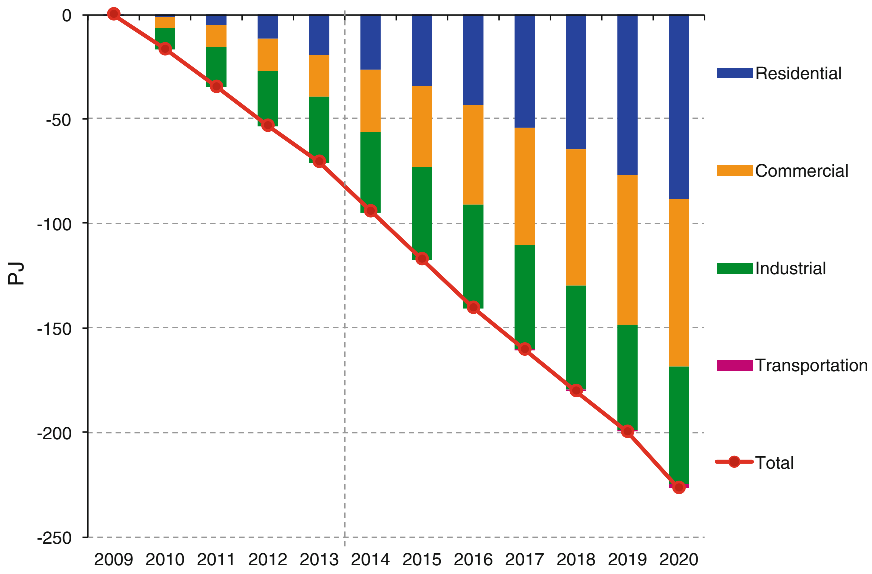

Fig. 7 Additional saved final energy in EW scenario by sector, 2009–2020, in PJ. *Source* GWS/Prognos/EWI (2014)

Already in the counterfactual final energy consumption declines by almost 6 % between 2013 and 2020, the EW scenario with its additional efforts to improve energy efficiency reaches a more than 8 % decline. All sectors contribute to this decline, but the industrial sector starts the increase of efficiency later than for instance the residential sector. However, from 2011 onwards, consumption also begins to decline in the industrial sector.

The additional reduction in the EW scenario seen in 2020 is due to a large extent to the residential (39 %) and commercial (35 %) sectors. The share of the industrial sector in additional savings is 25 %. The additional savings in the transportation sector are low (1 %). Apart from the increasing energy demand for process heat, cooling, ventilation and building automation, less total energy is required for all other purposes in 2020 compared to 2009. In the EW scenario, consumption by space heating and mechanical energy drops more significantly than in the CF scenario. The additional reduction is 82 PJ for space heating and 68 PJ for mechanical energy.

Energy efficiency has mostly positive economic effects, especially if it pays back the necessary investment during its lifetime or even before. The savings free money for other purposes and free the consumer from the dependence on fossil fuel price changes.

The Energiewende catalogue also contains emission targets for 2020 and beyond. Energy-related GHG emissions decrease between 2009 and 2020 by about 15 % in the EW scenario and 9 % in the CF scenario. The additional reduction in the EW scenario of about 45 million t CO_2 equivalents mainly stem from the trends in the energy sector. The transition towards more renewables decreases emissions.

Between 2009 and 2013, the energy-related GHG emissions rise in the EW scenario by about 2 % (CF scenario: +5.5 %). During the ex-ante period, emissions decrease in the EW scenario and in the CF scenario. In the EW scenario, the emissions in 2020 are about 15 % lower than in the base year 2009, the CF shows a reduction of nine percent.

The economic effect of this development hinges on the development of the carbon price mainly through the European emission trading system (ETS). In the ex-post analysis period, the price fell steadily and was between 4 and 7 Euro this year. To calculate avoided environmental damages from the emission reduction, Breitschopf et al. (2014) follow Federal Environmental Agency [Umweltbundesamt] (2012) and assume 80 €/t CO_2 as the price for full internalization of external costs. With this price, the authors calculate avoided damages from CO_2 mitigation. They call this estimate a gross calculation, because it does not include partial internalization from the existing emission trading system and existing emission prices.

Figure 8 depicts the increase in avoided damages from GHG reductions since 2008, following Breitschopf et al. (2014). Actual savings from avoided emissions will also increase with increasing CO_2 prices, because each avoided unit is worth more. The projection assumes CO_2 prices to rise to 10 $Euro_{2011}$ in 2020.

Additional emissions reductions in the EW scenario result from a combination of two factors: the steeper decline in primary energy consumption and the increasing role of low- or non-CO_2 emitting energy sources, especially in electricity generation (Fig. 9). About 60 % of the additional reduction in 2020 result from the energy sector. The transportation sector does not contribute significantly to additional reductions.

The scenario exhibits more reductions in its first phase until 2015/16. Most reduction in the energy sector occur in this phase and the largest reductions occur in

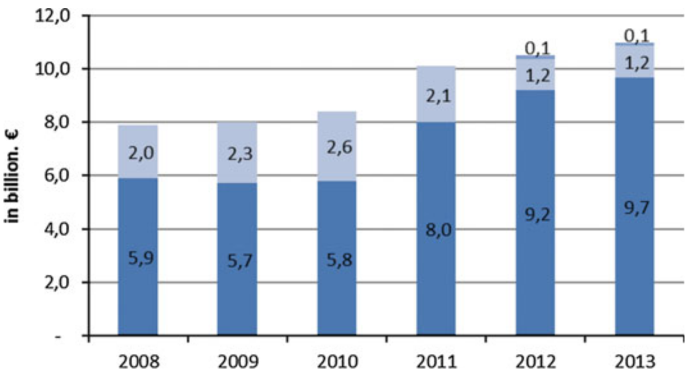

Fig. 8 Avoided damage costs from CO_2 reduction in electricity generation (*dark*), heat generation (*light*) and transport (*medium*), billion Euro. *Source* Breitschopf et al. (2014) and the sources therein

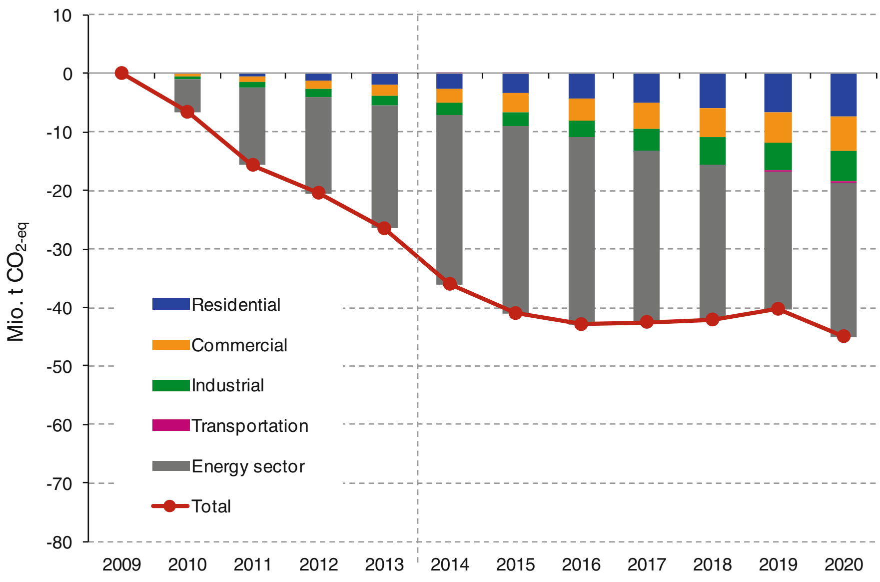

Fig. 9 Additional greenhouse gas emissions avoided in EW scenario by sector, 2009–2020, in million t CO_2 equivalents. *Source* GWS/Prognos/EWI (2014)

the energy sector. Industry and the residential sector pick up energy saving activities in the second phase until 2020. Furthermore, the contributions of the sectors change over time. During the second phase, the contribution of the energy sector slightly drops, whereas the contributions of the industrial, commercial and residential sectors become increasingly significant.

Final energy consumption decreases between 2009 and 2020 by 6 % in the EW scenario and by 3 % in the CF scenario. Fossil fuels decrease and the share of renewable energy increases. Additional savings in the EW scenario in the second half of the observation period mainly falls to the commercial and residential sectors as well as to the use of space heating and mechanical energy.

5 Results—The Economic Effects of the Energiewende in Germany

From the sections above, one can summarize the different impacts on the economic system as price effects, investment effects and long-term cost reductions from energy savings. They differ in their relative quantity over time and yield several economic adjustment processes on the macro level and the sector level. This section will firstly describe the investment effect, because it is the most important direct effect. Additional investment induces additional employment and additional demand for intermediary goods and imports. Secondly, we turn to the overall macro effects and show the changes in GDP. To better understand the different drivers, a sensitivity analysis decomposes the macro effect in the third part of this section.

5.1 Direct Investment Effects

The EW scenario and CF scenario, as has been pointed out above, are based on identical socio-economic assumptions on central quantities, such as international economic development, international energy prices and demography. They differ with respect to electricity generation and the resulting electricity prices as well as the additional investments that are necessary (in the EW scenario) to increase energy efficiency and enhance the expansion of renewable energy.

Especially differences in investment drive economic results. Figure 10 shows the monetary stimulus from energy efficiency investment, concentrating especially on buildings for the residential and the commercial sectors. According to the IEA (2014, p. 47) these investment effects are main drivers for the macroeconomic impacts.

Investment in the energy system mainly differs in the ex-post analysis (Fig. 11). Especially high investment in PV, as mentioned above, drove the additional investment in RE: 15.5 billion Euro in 2010 and 17.5 billion Euro in 2011 reflects

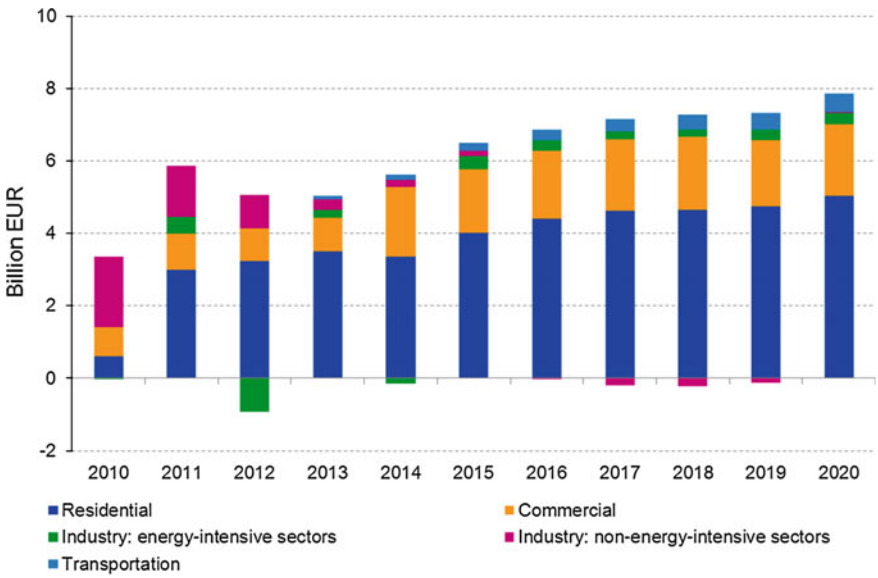

Fig. 10 Differences in investments in the demand sectors of the EW scenario compared to the CF scenario, 2010–2020, in billion EUR. *Source* GWS/Prognos/EWI (2014)

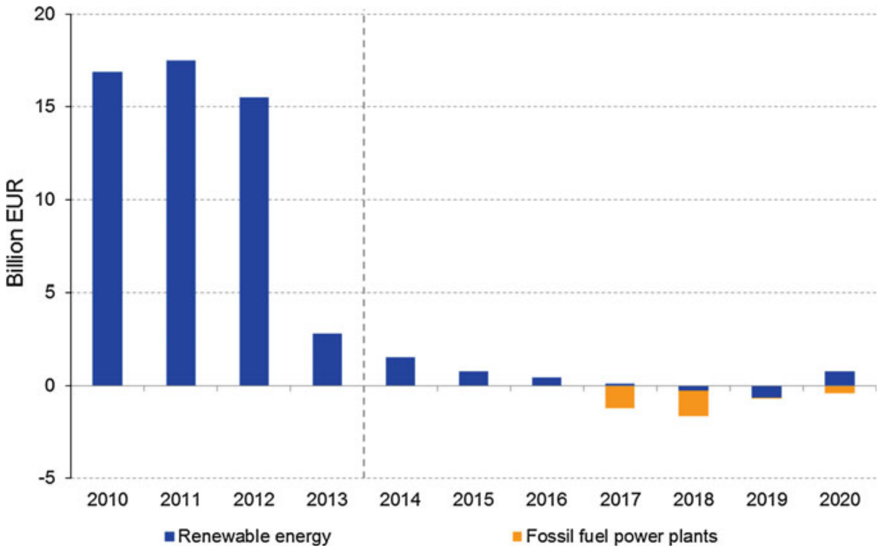

Fig. 11 Differences in investments in the electricity market in the Energiewende scenario compared to the Counter-Factual scenario, 2010–2020, in billion EUR. *Source* GWS/Prognos/EWI (2014)

the average increase of PV capacity by 7 GW in each of these years. In 2012, for instance, PV investment was at 11.2 billion Euro and wind investment reached 3.7 billion Euro (O'Sullivan et al. 2013). In terms of employment, we see a decrease of jobs in photovoltaic module production due to increasing imports from Asia. However, installation is more labor intensive and leads to domestic employment and only the ceiling on installations led to a severe decrease in employment.

The feed-in tariffs are set for 20 years from the start of operation of a renewable energy system. This distributes the refinance of the investment costs of a certain year over the next twenty years, and leads to cumulative effects when several high investment years occur after one another. Therefore, in 2011, electricity prices in the EW scenario are only slightly higher than those in the CF scenario are. The maximum price difference is not achieved until 2019 and is equal to about 2.1 ct/kWh (1.8 ct/kWh without VAT). By 2020, the price difference is still 1.4 ct/kWh for residential customers.

5.2 Macroeconomic Impacts

The economy responds to the different stimuli from the two scenarios differently and the economic quantities reflect this. Roughly speaking, we observe two phases. Ex post, until the year 2012, the expansion of renewable energy dominates, driven

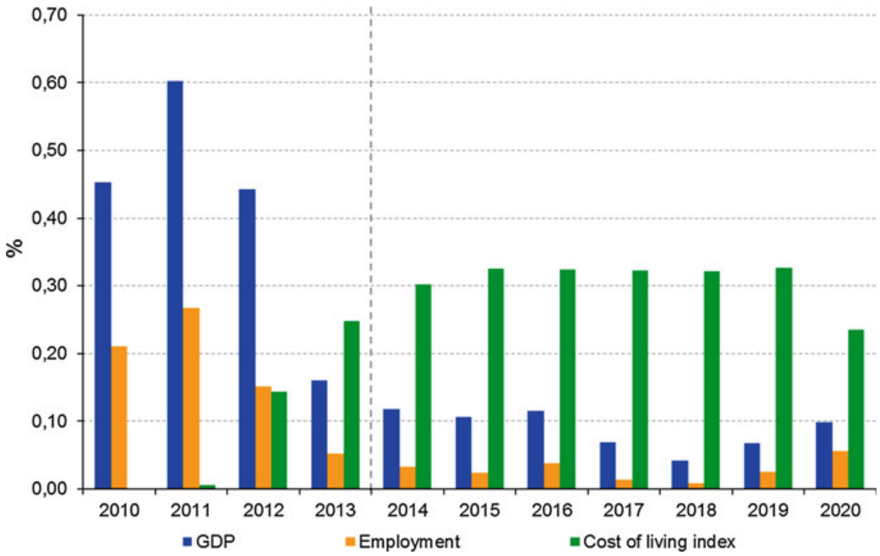

Fig. 12 Deviations of GDP (price-adjusted), employment and the cost of living index in the EW Scenario from those in the CF scenario, 2010–2020, in %. *Source* GWS/Prognos/EWI (2014)

by, in monetary variables, the expansion of photovoltaics. From the ex-ante perspective from about 2015 in the EW scenario, energy efficiency measures as well as increased electricity prices primarily drive the macroeconomic effects.

Especially through the significant investments made in the renewable energy sector from 2010 to 2012, the effects on the GDP are markedly positive (Fig. 12). Nevertheless, long-term financing via the EEG leads to increased electricity prices in subsequent years for all consumer groups, except for the electricity-intensive industries who are able to slightly benefit from the reduction of wholesale prices. The price index of the cost of living rises significantly up to 2014 because of higher electricity prices (Fig. 12; Table 3). Production prices are also higher in the EW scenario than in the CF scenario.

High activities in renewable energy increases leads to additional employment from installation and production of the respective systems. Therefore, employment from 2010 to 2012 is higher than in the counterfactual scenario, the difference between the scenarios shows additional employment of 0.28 %, which translates into more than 100,000 additional jobs.

However, increasing prices, rising wages and decreasing investment dynamics, slow the employment effects over time. Investments in the building sector create additional demand for construction activities and play an important role in the macroeconomic effects. In addition, the commercial sector contributes significantly with additional investments in efficiency measures—especially in the building sector. Again, this supports the construction sector and leads to noticeable (cumulated) effects in subsequent years in the form of lower energy costs.

Table 3 Differences between selected macroeconomic variables in the EW scenario and the CF scenario, 2010–2020, in absolute terms

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	Ex post				Ex ante						
Components of price-adjusted GDP (differences in billion EUR)											
Gross domestic product	10.7	14.7	10.9	4.0	3.0	2.7	3.0	1.8	1.1	1.8	2.7
Private consumption	0.0	2.7	1.9	0.4	−1.2	−2.0	−2.5	−3.4	−4.4	−5.1	−5.3
Government consumption	0.0	−0.3	−0.1	0.0	−0.1	−0.1	−0.1	−0.1	−0.1	0.0	0.0
Machinery and equipment	9.5	10.1	6.8	1.8	0.7	0.6	0.3	−0.8	−1.2	−0.5	0.2
Construction	4.5	6.2	5.6	2.8	3.7	3.9	4.7	4.4	4.4	4.8	5.1
Exports	0.4	0.1	−0.5	−0.9	−1.0	−1.0	−1.0	−0.9	−0.8	−0.6	−0.2
Imports	3.2	3.5	2.3	−0.5	−1.7	−2.1	−2.4	−3.3	−4.0	−4.1	−3.6
Government budget in current prices (differences in billion EUR)											
Net borrowing/net lending	0.7	3.8	0.3	−0.3	0.3	0.7	1.1	0.5	0.5	0.9	1.3
Price indices (differences in percentage points)											
Cost of living	0.00	0.01	0.16	0.29	0.35	0.38	0.38	0.39	0.39	0.40	0.29
Production	0.01	0.05	0.23	0.34	0.39	0.40	0.39	0.38	0.36	0.34	0.23
Imports	−0.03	−0.11	−0.10	−0.06	−0.09	−0.10	−0.12	−0.15	−0.18	−0.21	−0.27
Labor market (differences in 1.000)											
Employment	85.1	108.8	61.9	21.6	13.6	9.5	15.2	5.5	3.5	9.8	22.2
Unemployed persons	−54.4	−65.8	−36.8	−12.0	−7.0	−4.5	−8.0	−2.0	−0.8	−4.7	−12.3

Source: GWS/Prognos/EWI (2014)

In detail, Table 3 provides selected macroeconomic quantities. Private consumption is lower than in the CF scenario, mainly because expenditures for the increase of efficiency in buildings displace private consumption. Investment in construction increases in this scenario and consumption of other goods is cut back. However, we do not assume full crowding out, because energy efficiency investment is supported with the respective governmental programs.

Not only investment in buildings is larger in the EW scenario, also investment in renewable energy is slightly higher. This is counterbalanced by lower investment in conventional energy (see the discussion on investment in Sect. 5.1). This is reflected in the row titled "Machinery and Equipment". GDP is higher in the EW scenario than in the CF scenario. Even the price level, which reacts delayed due to the design of the EEG surcharge, remains consistently higher in the EW scenario than in the CF scenario because of the higher EEG surcharge.

The effects on the international competitiveness of German companies and on their exports are extremely low because of the vast exemptions for electricity-intensive industries. Higher energy efficiency and ambitious renewable energy expansion lead to a smaller demand for fossil fuel imports. This results in a decline of 534 PJ and corresponds to about 3.2 billion EUR in avoided import costs by 2020.

Employment was particularly higher in the early years of the Energiewende as the ex-post analysis shows. This is mainly due to the increases in renewable energy, notably in PV. PV installations to a large extend are rooftop installed and thus rather labor intensive. Unemployment does not decrease by the same amount as employment increase. This is mainly for statistical reasons: not all additional employment is recruited from unemployed workforce and employment also includes the self-employed, which are not eligible for unemployment benefit and thus not included in the data on unemployment.

5.3 Sensitivity Analyses to Decompose Major Drivers

What are the drivers of these results? Stimuli come from the energy demand side and from the energy supply side. The following sensitivity analysis helps to identify the main triggers.

Important inputs from the bottom-up electricity market model for the macroeconomic analysis include investments (especially in renewable energy), electricity prices per consumer group and net electricity imports. The demand stimuli are broken down into investments in energy efficiency for the residential, commercial, industry and transportation sectors.

Figure 13 shows the time profile of the main impacts. In the ex-post period, almost the whole impact came from the increase in renewable energy, here denoted as electricity sector. However, the main investors were private households and farmers in the case of PV and private investor groups in the case of wind energy, farmers also invested massively in biogas based electricity generation. Commercial

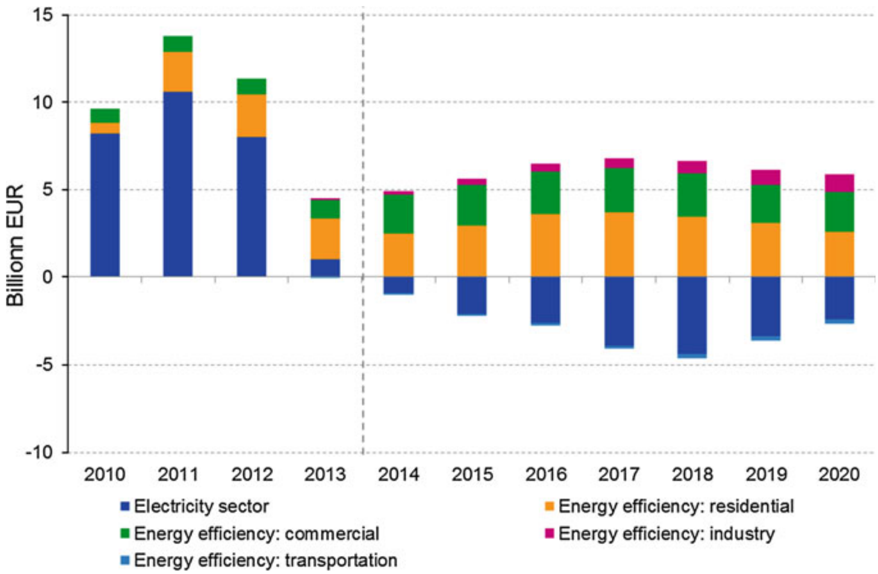

Fig. 13 Breakdown of GDP effects, 2010–2020, in billion EUR. *Source* GWS/Prognos/EWI (2014)

and residential efficiency investment drives additional GDP in the future. The negative impact on GDP in the future period results from increased prices from the refinancing mechanisms of the EEG surcharge for RE. In this context, higher energy efficiency constitutes an efficient means to limit energy costs for households and businesses. Small and medium-sized enterprises represent a large share of the commercial sector. Energy efficiency measures are an important tool for them to bring down their energy bills.

6 Conclusions, Discussion and Outlook

Given the attention and media coverage it received, the results for the economic effects of the Energiewende seem small. Does that mean it is a disappointment? The answer is a twofold no. Firstly, several years ago, economic literature discussed if the distortions from environmental regulation could be small (Jacob et al. 2005) at all. Most authors acted surprised to see that environmental regulation did not cause the end of economic growth. Small but positive effects would have been hailed a couple of years ago. Secondly, the Energiewende is aimed at the change of the energy system. The target of environmental regulation is the environment, although this tends to be forgotten on times of tight budgets, slow growth in parts of Europe and austerity programs as the cure for all.

Is the Energiewende good news for all economic agents? This question goes beyond the macro indicators presented above, which evens economic distribution effects. Price increases for households' electricity consumption, for instance, will have regressive effects. Lower income households are more affected by these price increases and have fewer opportunities for burden decreasing measures such as investing in energy efficient appliances (Lehr and Drosdowski 2014). Households' electricity costs differ annually by more than 500 Euro in 2012. The assumed increases until 2015 according to the latest estimate of electricity prices is 3 % for white collar workers and 3.1 % for blue collar workers, but 3.5 % for pensioners. Supporting redistributive measures range from transfers to lower income groups to cover for the difference in the electricity bill to loans for more efficient appliances.

Some measures, although rewarding from an individual economic point of view face other barriers, which are hard to overcome with economic incentives. A large share of the owners of the building stock is in their retirement age and has very little inclination to take on investments with a 30-year payback period. Soft loans with lower than market rates are not creating strong incentives at the current levels of market rates either. Building ordinances are seen as a large burden with these owners.

Industries differ with respect to their energy needs and their possibilities to buy electricity on the spot market and benefit from lower prices. As long as the exemption from additional charges holds, energy intensive industries rather benefit from decreasing market prices. SMEs, on the other hand, are not exempt as often as other enterprises and in the case of small enterprises often lack time and resources to invest in increasing energy efficiency. The government supports SMEs in particular through tailored information and consulting programs regarding energy efficiency.

Conventional utility companies suffer the largest losses in the short to medium run. Detailed analysis for the largest federal state, North-Rhine Westphalia (Prognos, Energynautics, GWS 2014) estimates job losses in this sectors with up to 5 % until 2030. The current debate on the oldest coal fired power plants adds to the apprehension of this industry.

Several authors have suggested that renewable energy and energy efficiency increases lead to a better position on world markets (for renewable energy e.g. Lehr et al. 2012a, b, c, for energy efficiency see BMU 2012). The logic goes that better domestic environmental regulation results in the establishment of a lead market and more exports. Gehrke et al. (2014) tried to find empirical evidence for this for renewable energy technologies. However, data are only available for wind and PV and both markets changed tremendously in recent years. Trade data do not allow conclusions for other technologies or for production machinery.

To monitor the progress of the Energiewende, data collection therefore remains an important issue. Empirical based models such as the PANTA RHEI model rely on the availability of data. Timely updates and consistency in the data improve the simulations' quality.

How about oil prices? The recent decline of the oil price has led to the question if renewables and efficiency become less attractive in the face of "cheap oil".

However, markets have changed and renewable energy expansion does not react to each decrease of fossil fuel prices as heavily as 20 years ago. Firstly, renewables only compete to oil in very few applications. Today's renewable energy increases mostly focus on electricity generation and apart from small scale diesel generators, oil does not figure largely in this energy sector. Secondly, in electricity generation, renewables are often competitive in generation costs as IRENA (2015) show. And thirdly, low oil prices may free money for other investments—in renewables and energy efficiency among other things.

Facing volatile prices is also an issue of energy security. Thus, renewables with the long-term calculable risk may increase energy security. Moreover, Lehr et al. (2015) have shown that an increase in renewable energy leads to improved energy security, using different versions of diversity indicators. They also include different risk assessment factors for imported fossil fuels and difference costs for renewables. The results are unanimously pointing towards an improvement of energy security from domestic renewables replacing risky imports.

The Energiewende is a long-term transformation of the German energy system. Though the overall economic results are better than expected by many, undoubtedly mistakes have been made, and crucial decisions will have to be taken in the near future. Overshooting PV installations from 2010 to 2012 have increased the EEG surcharge unnecessarily and reduced the space for future balanced development of renewables in the electricity market, while keeping international competitiveness of respective German companies. The EEG amendment (EEG 2.0) from summer 2014 has brought back reliability and reduced future cost increases.

Future design of the German electricity market will have to be decided in the next years, before the remaining nuclear power plants will be shut in the early 2020s. Difficult questions, whether energy-only markets will suffice or capacity markets are needed, have to be answered.

The Energiewende is a process of trial and error. As a frontrunner, Germany moves into unknown land. With the future prospects for more energy efficiency, renewable energy and all associated engineering, technical and legislative solutions being bright, and even brighter with a success of the climate summit in Paris in December 2015, the future benefits seem to outweigh the costs.

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Taxing Energy Use: Patterns and Incoherencies in Energy Taxation in Europe and the OECD

Michelle Harding, Chiara Martini and Alastair Thomas

Abstract This article compares effective tax rates, in energy and carbon terms, on the full spectrum of energy use in 21 European Union countries and across all OECD countries. The analysis highlights the different tax rates that apply to energy in both groups, with higher and more consistent taxation of energy being observed in the EU-21 countries than in the OECD as a whole. Nonetheless, differences in the taxation of fuels used for similar purposes, or between users of fuels are observed across and within all countries examined. From an environmental policy perspective differences of particular note include the common tax preference provided to diesel relative to gasoline for road use and the low tax rates applied to many fuels employed for heating and process use, and particularly to coal. The analysis suggests that countries are not fully harnessing the full power of taxes on energy use for environmental purposes and that realignment of energy taxes could help to ensure that countries pursue their environmental, social and economic goals as effectively as possible.

1 Introduction

Energy use is a critical component of modern economies. It is a central ingredient in industrial and commercial production and in private consumption. Many forms of energy use, however, also contribute to significant environmental problems, such as climate change and air pollution. Taxation is one of the major policy levers

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available to governments to influence energy use patterns. In this chapter we extend recent OECD work (see OECD 2013a) to examine how energy use is taxed in the 21 European Union member countries that are also OECD member countries (EU-21)[1] as compared to the 34 countries that form the OECD area as a whole.

This chapter examines energy taxes as they apply to the full spectrum of energy use (including both fossil fuel and renewable sources of energy) following a consistent methodology that enables cross-country comparison of results. Given the centrality of energy to the economy and the environment, such an understanding is critical to consideration of how governments can best use the policy tools available to them to support green growth (OECD 2011).

The analysis shows substantial differences, both across and within countries, in the tax treatment of different forms, uses and users of energy. For the EU-21 area as a whole, the simple average of country-wide average effective tax rates on energy use is EUR 3.9 per GJ and EUR 59 per tonne of CO_2, whereas in the broader OECD area it is lower at EUR 3.3 per GJ and EUR 52 per tonne of CO_2. Across EU-21 countries, average effective tax rates range from EUR 2.13 per GJ and EUR 26 per tonne of CO_2 to EUR 6.58 per GJ and EUR 94 per tonne of CO_2 in the EU-21. Across the broader OECD area they range from just EUR 0.18 per GJ and EUR 2.80 per tonne of CO_2 to EUR 6.58 per GJ and EUR 107.28 per tonne of CO_2. Within countries, effective tax rates on energy use are highest in the transport sector, but vary significantly within sectors—even when used for similar purposes. For example, effective tax rates on diesel for road use are typically lower than the comparable rates on gasoline. Across all sectors, oil products tend to be taxed more heavily than natural gas, coal and other energy products. Such variations, and the low levels of taxation on energy products with substantive environmental impacts, suggest ample opportunities for reform of energy tax systems to achieve countries' environmental, economic and social policy goals more effectively and cost-efficiently.

The chapter is structured as follows: Sect. 2 discusses in detail why countries tax energy use as background to the analysis to follow. Section 3 outlines the methodology used to analyse the use and taxation of energy. Sections 4, 5, 6 then present the results. First, Sect. 4 presents a short overview of energy use and taxation in European OECD countries and the broader OECD, before providing graphical profiles of energy use and taxation across European OECD countries and OECD countries as a whole. Section 5 then considers in more detail effective tax rates on transport use, heating and process use, and electricity generation, before Sect. 6 presents economy-wide effective tax rates on energy use in each OECD country. Section 7 concludes.

[1]The 21 EU countries which are also members of the OECD are Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Luxembourg, Netherlands, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden and the United Kingdom.

2 Policy Rationale for Energy Taxation

In reviewing energy tax policy settings it is important to understand the varying rationales for taxing energy use that influence these settings. There are a range of reasons for which governments may tax energy products. Energy taxes may be intended to internalise the external costs of energy use, notably their contributions to climate change, local air pollution, or congestion. Energy taxes may also be motivated by a desire to raise revenue efficiently, to fund specific projects (as a form of user charge), or to promote energy efficiency or alter relative energy prices to favour a particular energy mix for energy security reasons.

Energy taxes may be used to internalise in prices some portion of the social cost or externalities that result from energy use, such as the damage caused by emissions of CO_2 and local air pollutants (Pigou 1920). Such "Pigouvian" taxes should be imposed at a rate equal to the marginal social cost of the pollution damage. However, determining the marginal damage can be difficult. For example, the social cost of carbon has been variously estimated in the range USD 10 to USD 350 per tonne of CO_2 emitted (Yohe et al. 2007). Nevertheless, a Pigouvian tax that is slightly too high or slightly too low, is still likely to provide significant welfare gains compared to the absence of a tax (Heine et al. 2012).

Further complicating the design of a Pigouvian tax, while externalities that have a global impact (like greenhouse gases) may impose a uniform damage cost, local air pollutants (like those that cause smog) will result in the damage cost varying from one location to another. Marginal damages can also differ between stock pollutants like greenhouse gases, the effect of which is mostly a function of their accumulation, and flow pollutants, the effect of which are more closely tied to current emissions. Whether or not a tax on a good that causes external costs is explicitly intended to internalise some of those costs, it will send price signals that implicitly have that effect.

In some cases, an energy product may be taxed simply because it is an essential product the demand for which is relatively inelastic, minimising the efficiency cost of raising revenue. Such a product is also an attractive tax target because demand and thus government revenue is relatively stable. Ramsey (1927) showed that in order to raise a given amount of revenue at the lowest cost (in terms of distortions to consumption decisions), higher tax rates should be imposed on goods for which demand is not very sensitive (inelastic) to price increases, with relatively lower tax rates on goods for which demand is more sensitive (elastic) to price increases (the so-called "Ramsey rule"). In the context of taxes on energy products, for which demand is often less sensitive to price changes than other products (see OECD 2006, for a review of empirical literature), this implies that tax rates above Pigouvian levels may be justified for the purpose of raising revenue. One weakness, however, in applying this approach is the need for reliable and up to date elasticity estimates for all goods. Furthermore, if cross-price elasticities are non-zero then Ramsey taxation could actually increase, rather than decrease, distortions to consumption decisions. Finally, as many inelastic goods (e.g. food and energy) may represent a large proportion of consumption by low-income families, implementing the rule may create equity concerns and require off-setting measures.[2]

A third rationale for energy taxes is to fund particular projects or as a form of user charge. For example, revenues from taxes on road fuels are often devoted to maintenance of highway systems. In some cases like this, excise taxes may be viewed as a type of user charge (albeit one based on some measure of average rather than marginal cost).

In practice, governments often tax energy with more than one of these objectives in mind. Reflecting these different reasons for taxes on energy, the design and magnitude of energy taxes varies considerably across countries both in Europe and in the broader OECD area. These variations may also reflect different approaches to distributional and competitiveness concerns, as well as the use of other policy instruments, such as regulation, to address environmental concerns.[3] Regardless of the purpose for which countries tax energy, taxes change the relative prices of different forms of energy and thus patterns of energy use, with important economic and environmental consequences (OECD 2010). In this sense, taxes may influence and orient the energy mix, an effect that is particularly relevant for the EU where energy security is a key policy issue. Through their impact in increasing energy prices, taxes on energy also promote energy efficiency which can contribute to addressing both environmental and energy security concerns.

3 Development of Cross-Country Analysis and Graphical Profiles

The analysis considers all final use of energy in each country, including the net energy used in energy transmission and in the transformation of energy from one form to another (e.g., crude oil to gasoline, or the production of electricity). This energy use is disaggregated by a range of different users (for example, different forms of industry, household use, and transport use) and sources of energy (such as different types of coal, oil products, natural gas, and renewables). Each different source of energy is converted into common units of energy (terajoules) and carbon emissions (tonnes of CO_2 from combustion), using standard conversion factors.

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[2]An additional complication is the need to take account of the impact of commodity taxes on the labour market. Commodity taxes push up commodity prices and thereby reduce the consumption value of wages, tending to discourage labour effort. A solution is to tax goods that are complements with leisure more heavily than other goods in order to make leisure less attractive (Corlett and Hague 1953; Diamond and Mirrlees 1971; Crawford et al. 2010). Due to the difficulties of implementing this kind of differential taxation, Crawford et al. (2010) concluded that, externality issues aside, there is a strong pragmatic case for uniformity in commodity taxation.

[3]OECD (2006) discuses in more detail the different approaches to environmental taxation taken in OECD countries and the related political economy challenges.

Taxes included in the analysis are all those levied directly on a unit of energy product when consumed (for example, excise taxes or carbon taxes levied on the basis of volume, mass or energy content). Other taxes on energy—such as taxes on the production of energy, vehicle taxes and value-added taxes—are not included.

Tax rates, which are typically set in monetary units per physical quantity of fuel (e.g., litres, kilograms, kilowatt-hours, etc.) are re-calculated as effective tax rates in a common currency, alternately per gigajoule of energy and per tonne of CO_2 emissions, using standard conversion factors for each fuel. For federal countries, tax rates from sub-national levels were not included, primarily due to the lack of data which would allow the separation of energy consumption by state or province.[4] Rates for selected subnational jurisdictions are shown on the graphical profiles where relevant.

The OECD-EU countries place an implicit tax on carbon emissions from some sectors through the European Union Emission Trading Scheme (EU ETS), although the price signal provided by the EU ETS was relatively modest across the time period considered in the analysis. The impact of the EU ETS is not included in the cross-OECD analysis due to difficulties in reconciling data on emission sources with the dataset on fuels and users. Similarly, the SO_2 cap-and-trade scheme in the United States is not included.

Data on energy use is taken from the *Extended World Energy Balances* (IEA 2011). Tax information was gathered from publicly available national sources and through contact with national officials, as well as from OECD (2013c) and European Union (2012). The tax rates have been "mapped" to each of the sources and uses of energy from the *Extended World Energy Balances* to generate a standardised OECD-wide database for a common disaggregation of fuels and fuel uses, by, alternately, energy content and carbon emissions. This database allows cross-country comparisons across a wide range of aggregations of fuels and users.

Using this database, we have prepared graphical profiles of energy use and taxation in the EU-21 countries as well as in the OECD as a whole. In these graphical profiles, the horizontal axis shows all final use of energy by businesses and individuals in the group of countries considered, including the net energy used in energy transmission and in the transformation of energy. Energy use has been grouped into three broad categories: transport; heating and process use; and electricity. Within these three broad categories, energy use has been further disaggregated by major fuel types. On the vertical axis, the graphical profiles show the average tax rates (weighted by the amount of fuel subject to each rate) that apply to energy use in these groups of countries. The area of the bar for each subcategory is therefore an estimate of revenue. The graphical profile in carbon terms for EU countries shows the interaction of tax systems with the EU ETS by noting [ETS-A]

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[4]These sub-national taxes can be significant, and are often set at higher levels than federal ones. For example, state diesel and gasoline excise rates in the United States are often similar to or higher than federal excise rates and Canadian provincial rates are generally higher than federal rates (although combined rates are still low in both countries relative to most other OECD countries). Other sub-national measures, such as the California cap-and-trade programme and the carbon tax in British Columbia, also add to the effective tax burden.

against categories of energy use that are fully or largely covered by the EU ETS and [ETS-P] for categories that are only partially covered. The graphical profile also shows the average market price for ETS credits for 2010–11 on the vertical axis.

In the figures below, tax rates are as of 1 April 2012 (except for Australia, which is as of 1 July 2012). Energy use data is for 2009, which was the most recently available data in disaggregated form when the analysis was undertaken. It is used as a proxy for 2012 consumption. The overall tax rates on energy presented below are the weighted average of each tax rate in energy terms (including non-taxed energy) by the volume of energy subject to that rate. Similarly, overall tax rates on carbon emissions from energy use are the weighted average of effective tax rates on carbon and the amount of carbon produced by each energy source.

4 Energy Use and Taxation in the OECD and OECD-EU Member Countries

Energy use patterns vary significantly across both Europe and the OECD. This section considers energy use, and the taxation of energy use, first in European OECD countries, and then across all OECD countries.

4.1 Patterns of Energy Use in Europe and the OECD

Table 1 compares the shares of total energy and carbon emissions (by use and by fuel) in the 21 European Union member countries that are also OECD member countries (the "EU-21" countries), and in all 34 OECD member countries. Considering first the EU-21 countries, on a simple average basis they use around 24 % of energy for transport purposes, a further 42 % for industrial processes and heating, and the remaining 34 % for electricity generation. When considered in terms of carbon emissions from energy use, the proportion of emissions from electricity is considerably lower (at 26 %) due to the larger share of (hydro and non-hydro) renewables and nuclear in electricity generation than in transport or heating and process use. Similarly, a higher use of coal in industrial processes and heat generation increases the share of emissions from these uses to 48 %. The remaining 26 % of carbon emissions from energy use derive from transport energy, which is almost entirely (96 %) generated from oil products. There are significant variations around these averages within individual countries.

Across the EU-21 countries, oil products are the single largest source of energy consumption (36 % of energy on a simple average basis) and are particularly dominant as a source of energy used for transport. Natural gas, coal and peat, and renewable and nuclear energy, account for more moderate (13–22 %) proportions of total energy use, on a simple average basis, while biomass and waste accounts for just 9 % of energy use on this basis. Renewable sources of energy are primarily used in electricity generation.

Table 1 Shares of energy use by user and by fuel for EU-21 and all OECD countries (simple average)

		% of base by user			% of base by fuel				
		Transport (%)	Heating and process (%)	Electricity (%)	Coal and peat (%)	Oil products (%)	Natural gas (%)	Biomass and waste (%)	Renewables and nuclear (%)
TJ	EU-21	24	42	34	18	36	23	9	13
	OECD	23	39	38	18	36	22	8	16
CO_2	EU-21	26	48	26	26	39	20	15	–
	OECD	27	46	27	26	42	19	13	–

Source Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a, European Commission 2012). Tax rates are as of 1 April 2012 (except 1 July 2012 for Australia); energy use data is for 2009 from IEA (2011). Figures for Canada and the United States include only federal taxes

These results show the wide range of fuels relied on by Europe for their energy mix, although the mix of fuels within each EU country varies considerably from these averages. In many countries, certain fuels are not sourced domestically. Natural gas, for example, is a large part of the European energy mix that is imported from outside the EU but is also seen as critical to the transition to a low-carbon economy, making it a core issue in the EU energy strategy, as stated recently by the EU representatives at the 7th Set Plan Conference (Joint Research Centre 2014).

Turning to all OECD country results, these are very similar to those for the EU-21 countries. The largest difference is the higher share of energy used in electricity generation in the OECD as compared to the EU-21 (38 % compared to 34 %), although in terms of carbon emissions the difference is just one percentage point—as a result of a higher share of renewables and nuclear being used in electricity generation in the OECD than in the EU-21 (16 % rather than 13 %).

As in the EU-21, oil products are the single largest source of energy consumption in the OECD, and are again particularly dominant as a source of energy used for transport. Natural gas, coal and peat, and renewable and nuclear energy, account for similar (16–22 %) proportions of total energy use, while biomass and waste accounts for only 8 % of energy use on this basis.

4.2 Taxation of Energy Use in Europe and the OECD

While energy use, on average, is very similar between the EU-21 and OECD country groups, the taxation of that energy use varies more substantially. In large part, this is due to the EU-21 countries being bound by the 2003 EU Energy Tax Directive which sets out common rules for the taxation of energy products in member states.[5]

The first attempt to introduce a common framework for EU carbon and energy taxation occurred as far back as 1992 (COM/92/226), but neither it nor its amended proposal achieved significant success. According to the 1992 proposal, excise rates should reflect both carbon and energy content of the taxed fuels. In 1997 such an approach was abandoned and the draft directive called for a staggered introduction of minimum tax rates on all energy products (COM/97/30). Policy guidelines also specified exemptions, reductions and tax refunds for specific sectors and uses. Still, the

[5]The European Commission proposed a new Energy Taxation Directive in 2011 (see European Commission 2011). The proposed rules aim to promote energy efficiency and consumption of more environmentally friendly products and to avoid distortions of competition in the Single Market. Under the revised directive, taxes on energy would have two components: a single minimum rate for CO_2 emissions (EUR 20 per tonne of CO_2) for all sectors that are not part of the EU ETS; and minimum rates based on the energy content of the fuel, which will be more uniform across types of fuel. These components would be combined to produce the overall minimum tax rate at which fuel products would be taxed. Countries would be able to choose to exceed one or both minimum rates, although the same rate would then apply to all fuels used for the same purpose. Transitional periods would apply for certain fuels to allow government and industry to adapt, with full implementation intended from 2023. In addition, certain country-specific transition periods are proposed.

proposal faced hard opposition, and no consensus could be reached, due—among others—to concerns about potential adverse impacts on EU industrial competitiveness.

After no major progress in 1999 and 2000, an agreement on EU-wide minimum energy tax levels was scheduled to be reached by the end of 2002. Conflicting opinions from a number of countries caused a series of postponements. Finally, in October 2003 the agreement on the text of a directive was achieved. The "Directive restructuring the Community framework for the taxation of energy products and electricity" replaced its 1992 predecessor which dealt just with mineral oils.

The Directive 2003/96/EC set minimum rates for all energy products, including natural gas and solid fuels, as well as electricity. The Directive is intended to reduce distortions of competition, both between Member States created by divergent rates of tax on energy products, and between mineral oils and the other energy products. It is also intended to increase incentives to use energy more efficiently. The Directive sets common taxation rules for a range of fuels, including many oil products, coal and natural gas, and for electricity consumption. For each, it sets a minimum level of tax expressed in terms of the volume, weight, or energy content of the fuel. The directive also sets out transitional measures and permitted derogations (both general and country-specific) from the minimum levels, such as exemptions for particular sectors. The current minimum tax rates under the Directive are set out in Table 2.

The taxation of energy across the EU-21, measured in effective tax rates per GJ of energy, and per tonne of CO_2, is illustrated in Figs. 1 and 2 below. These figures present a graphical profile of the weighted average tax rates for different fuels used for transport purposes, heating and process use, and electricity generation. The striking contrast between the relatively high taxation in the transport category and the relatively low taxation in the heating and process and electricity categories is evident from both graphical profiles as is the variation in tax rates on different fuels. For example, coal used in electricity generation is taxed, on average, at a lower rate than other fossil fuels used to generate electricity, both on an energy and CO_2 basis. Likewise, coal and natural gas used for heating and process purposes are often taxed at lower rates than oil products.[6] In many cases these low rates do not seem to reflect the external costs associated with the use of these fuels, such as their contributions to climate change and local air pollution. However, governments often have a range of competing policy choices in setting taxes on energy, including concerns about energy security, competitiveness and distribution.

A similar pattern emerges in Figs. 3 and 4 which present the same graphical profiles, but this time for all OECD countries. Once again there is a striking contrast between the high average level of taxation on transport fuels as compared to fuels used in heating and process and electricity generation. There is also variation in the taxation of different fuels used for the same purpose. However, across all fuels and uses, the average effective tax rates in the OECD are significantly lower than for the

[6] *Taxing Energy Use* (OECD 2013a, c) presents more detailed graphical profiles for each OECD country, showing more precisely the different tax rates applying to energy products and users in each country.

Table 2 Minimum rates under the 2003 EU energy tax directive

Fuel		Minimum tax rate (EUR)	Unit	EUR/GJ equivalent	EUR/tonne of CO_2 equivalent
Gasoline	Leaded	421	1000 l	12.69	183.07
	Unleaded	359	1000 l	10.82	156.11
Gas oil	Propellant use	330	1000 l	9.19	123.99
	Heating and process use	21	1000 l	0.58	7.89
Kerosene	Propellant use	330	1000 l	9.19	129.41
	Heating and process use	21	1000 l	0.59	8.24
Heavy fuel oil	Heating	15	1000 kg	0.37	4.82
LPG	Propellant use	125	1000 kg	2.64	41.88
	Process use	41	1000 kg	0.87	13.74
	Heating	0	1000 kg	0	0
Natural gas	Propellant use	2.6	1 GJ	2.60	46.35
	Process use and non-business heating	0.3	1 GJ	0.30	5.35
	Business heating	0.15	1 GJ	0.15	2.67
Coal	Non-business heating	0.3	1 GJ	0.30	3.17
	Business heating	0.15	1 GJ	0.15	1.59
Electricity consumption	Business	0.5	1 MWh	0.14	2.29
	Non-business	1	1 MWh	0.28	4.57

Energy content and CO_2 equivalents have been calculated based on the conversion factors described in Annex 1 of OECD (OECD 2013a)
Source Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a).Tax rates are as of 1 April 2012 (except 1 July 2012 for Australia); energy use data is for 2009 from IEA (2011). Figures for Canada and the United States include only federal taxes

EU-21. For example, the weighted average effective tax rate on oil products used in transport in the entire OECD is EUR 6 per GJ, whereas it is EUR 14 per GJ in the EU-21. This difference reflects the relatively low effective tax rates of some of the largest countries in the OECD (e.g. the United States, Japan and Canada). Given the global nature of the negative externalities created by carbon emissions, this emphasises the particular importance, from a global perspective, of the climate consequences of the policy choices made by large energy users.

Within each of the EU-21 countries' economies, different fuels and users of fuels face different tax rates. Transport use of fuel is, in almost every country, taxed at significantly higher rates than other uses of fuel. On a simple average basis, transport bears a very high level of taxation, at more than EUR13 per GJ in energy terms and EUR 185 per tonne of CO_2. Tax rates on energy for heating and process use and electricity generation are well under a tenth of the rates applied to transport

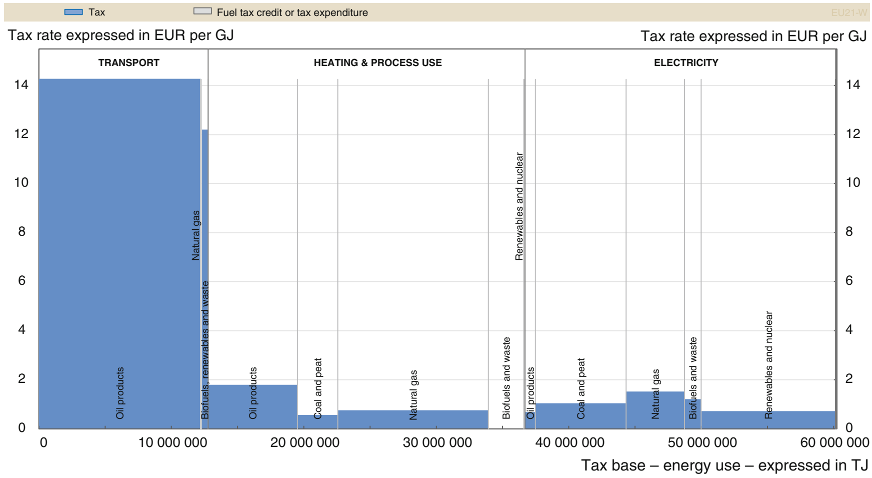

Fig. 1 Taxation of energy in the EU-21 area on an energy content basis. *Source* Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a). Tax rates are as of 1 April 2012 (except 1 July 2012 for Australia); energy use data is for 2009 from IEA (2011). Figures for Canada and the United States include only federal taxes

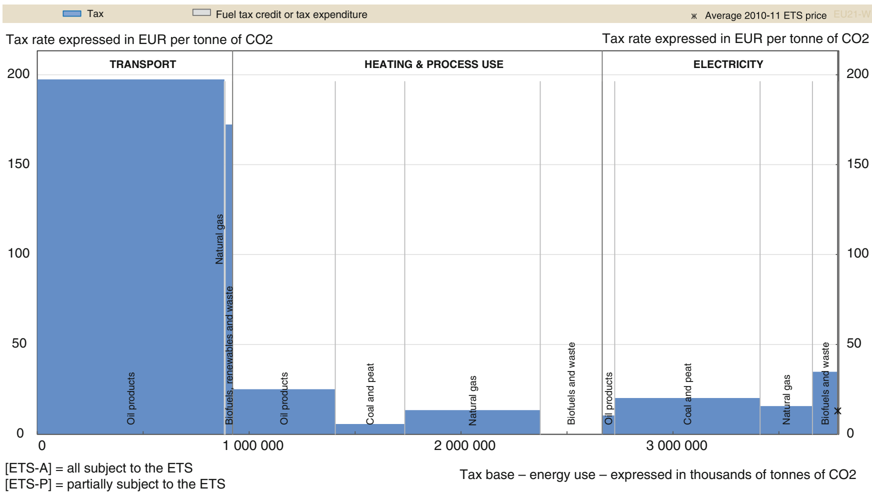

Fig. 2 Taxation of energy in the EU-21 area on a carbon content basis. *Source* Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a).Tax rates are as of 1 April 2012 (except 1 July 2012 for Australia); energy use data is for 2009 from IEA (2011). Figures for Canada and the United States include only federal taxes

energy. Similarly, within most of the EU-21 countries, oil is taxed at higher rates than other fuels—even when transport use of oil is excluded. Within the heating and process and electricity categories, natural gas is taxed at higher rates than coal in

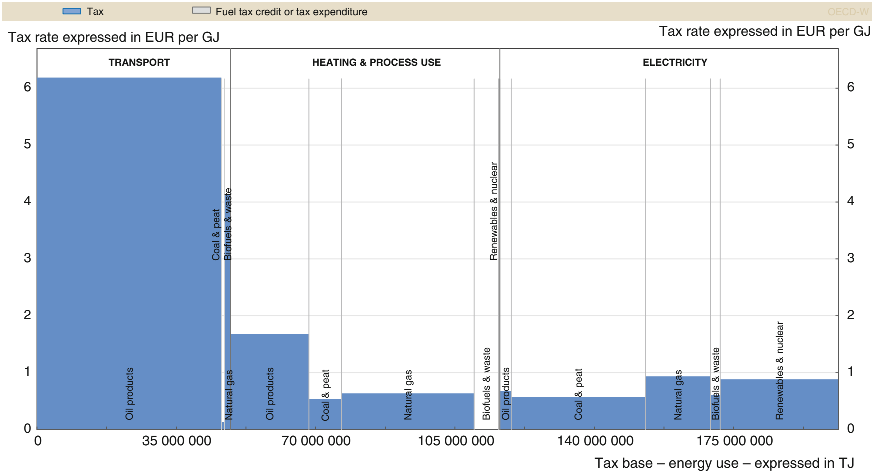

Fig. 3 Taxation of energy in the OECD on an energy content basis. *Source* Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a). Tax rates are as of 1 April 2012 (except 1 July 2012 for Australia); energy use data is for 2009 from IEA (2011). Figures for Canada and the United States include only federal taxes

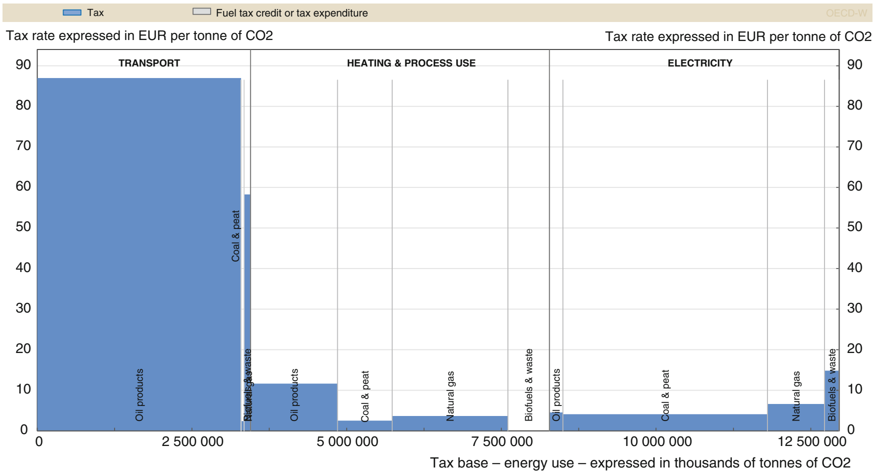

Fig. 4 Taxation of energy in the OECD on a carbon content basis. *Source* Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a).Tax rates are as of 1 April 2012 (except 1 July 2012 for Australia); energy use data is for 2009 from IEA (2011). Figures for Canada and the United States include only federal taxes

energy terms, and the difference is greater still when considered in carbon terms. The simple average rates for the EU countries are shown in Table 3.

These patterns are also observed when the simple average rates in all OECD countries are considered, as shown in Table 4. Transport fuels again face the highest

Table 3 EU-21 simple average of overall effective tax rates by energy type and use

Energy use		Energy type					
		Oil products	Coal and peat	Natural gas	Biofuels and waste	Renewables and nuclear	All fuels
Transport	EUR/GJ	13.4	0.0	0.5	6.8	0.0	13.0
	EUR/tonne CO_2	185	0	10	97	–	181
Heating and process	EUR/GJ	2.1	0.7	1.0	0.0	0.0	1.1
	EUR/tonne CO_2	29	7	18	0	–	14
Electricity generation	EUR/GJ	1.1	1.1	1.5	1.0	1.5	1.2
	EUR/tonne CO_2	19	31	19	26	–	26
All uses	EUR/GJ	9.3	1.1	1.2	1.2	1.5	3.9
	EUR/tonne CO_2	129	18	18	17	–	59

Source Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a).Tax rates are as of 1 April 2012 (except 1 July 2012 for Australia); energy use data is for 2009 from IEA (2011). Figures for Canada and the United States include only federal taxes. A "–" indicates no tax base exists; a "0.0" implies either no taxation or very low taxation such that it does not show when rounded to 1 decimal place

Table 4 OECD simple average of overall effective tax rates by energy type and use

Energy use		Energy type					
		Oil products	Coal and peat	Natural gas	Biofuels and waste	Renewables and nuclear	All fuels
Transport	EUR/GJ	11.8	0.0	0.6	5.0	0.0	11.5
	EUR/tonne CO_2	164	0	11	71	–	161
Heating and process	EUR/GJ	1.7	0.5	0.7	0.0	0.0	0.9
	EUR/tonne CO_2	24	5	13	0	–	12
Electricity generation	EUR/GJ	0.9	0.7	1.2	0.7	1.1	0.9
	EUR/tonne CO_2	11	14	14	13	–	13
All uses	EUR/GJ	7.9	0.8	0.8	0.8	1.0	3.3
	EUR/tonne CO_2	110	14	15	31	–	52

Source Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a).Tax rates are as of 1 April 2012 (except 1 July 2012 for Australia); energy use data is for 2009 from IEA (2011). Figures for Canada and the United States include only federal taxes. A "–" indicates no tax base exists; a "0.0" implies either no taxation or very low taxation such that it does not show when rounded to 1 decimal place rates, driven largely by the higher tax rates applied to oil products for transport use, although on a simple average basis, the rates applied to transport fuels are lower than those applied on average among the EU-21 countries. Across the OECD as a whole, transport tax rates are also more than ten times as high as rates on electricity or heating and process use of energy. Oil products remain the most commonly and heavily taxed fuel when the group of OECD countries is considered together. By comparison, natural gas and coal have similar (when expressed in energy terms) and substantially lower rates, with coal taxed at lower rates than natural gas in carbon terms due to its higher carbon intensity.

Comparing the EU-21 average with the whole group of OECD shows that tax rates are higher on all fuels in the EU-21 countries than in the OECD as a whole. On a group-wide basis, the simple average is 20 % higher when measured in energy terms and 13 % higher when measured in energy terms, due to the relative carbon intensities of the two groups of countries.

5 Patterns and Taxation of Energy by Type of Use

Given the different levels of taxation observed for different uses of energy in the OECD-EU countries and more broadly within the OECD, this section considers, in turn, the taxation of energy used in transport, heating and process, and electricity production within each country.

5.1 Taxation of Energy Used in Transport

Energy used in transport includes energy for road transport and that used for other modes of transport such as rail, marine and air, although road transport is by far the most significant use of transport energy. In the European OECD countries, transport energy generates 80 %, on average, of excise tax revenues from energy products in OECD countries despite accounting for only 24 % of energy use on average, due to the higher tax rates that are applied to road fuels. Within the broader OECD this ratio is even higher, with transport generating on average 85 % of excise tax revenues on 23 % of energy use.

Transport energy is taxed at higher rates than other forms of energy both on an OECD wide basis, as discussed above, and also within almost all OECD countries. Within the EU-21 countries, effective tax rates on transport energy (Fig. 5, left panel) range from EUR 9.22 in Spain to EUR 18.9 per GJ in the United Kingdom. Effective tax rates on carbon from transport energy range from EUR 126 per GJ to EUR 263 per tonne of CO_2 within the same two countries (Fig. 5, right panel). Within the EU-21 countries, the simple average is EUR 13.03 per GJ, but the weighted average is in fact higher, at EUR 14.12 per GJ, due to the presence of

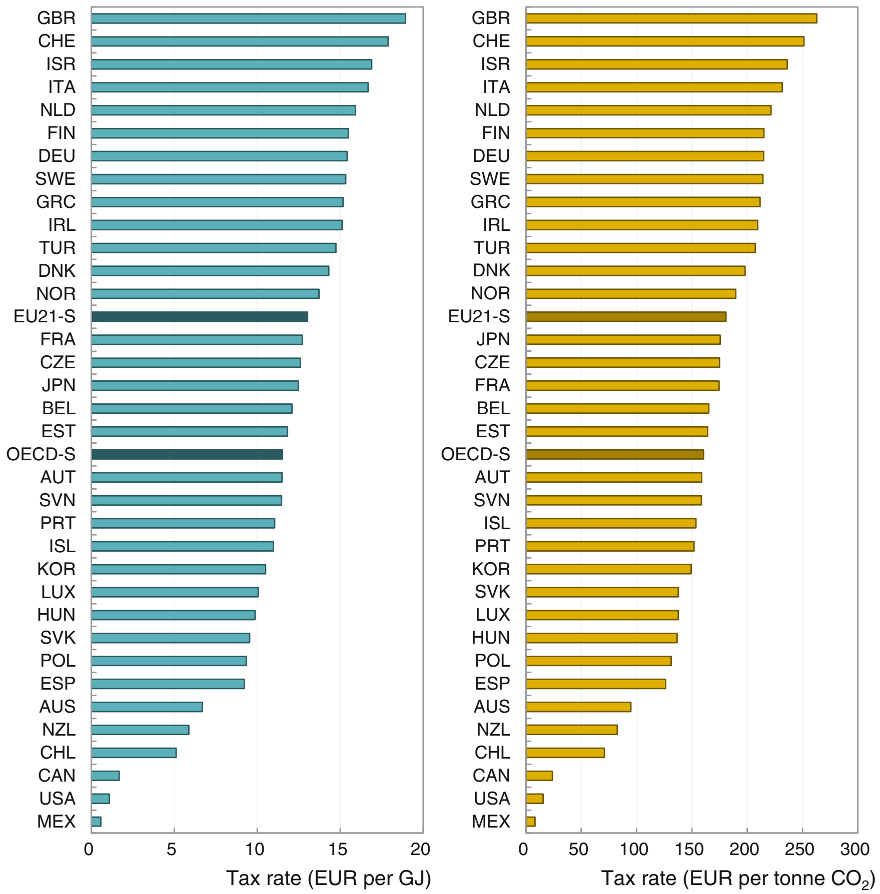

Fig. 5 Effective tax rates on transport energy (*left*) and CO_2 emissions (*right*) in OECD countries *Source* Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a). Tax rates are as of 1 April 2012 (except 1 July 2012 for Australia); energy use data is for 2009 from IEA (2011). Figures for Canada and the United States include only federal taxes. OECD-S is the simple mean for all OECD countries. EU-21-S is the simple mean for all OECD EU-member countries. A "–" indicates no tax base exists; a "0.0" implies either no taxation or very low taxation such that it does not show when rounded to 1 decimal place

larger EU energy users at the higher end of the distribution, notably the United Kingdom, Germany and Italy.

The simple average tax rate on transport energy is slightly lower when all OECD countries are considered, at EUR 11.53 per GJ. However, there is considerably more diversity in tax rates applied across the OECD, ranging from EUR 0.57 per GJ in Mexico to EUR 18.9 per GJ in the United Kingdom, with the highest non-EU country rate to be found in Switzerland, at EUR 17.89 per GJ. Effective tax rates on carbon range from EUR 8 to EUR 263 per tonne of CO_2 in the same two countries.

The presence of larger OECD economies at the lower end of the distribution means that on a weighted average basis the average is much lower (EUR 6.05 per GJ).

While effective tax rates on transport energy vary between countries, they also vary considerably within each country. Road fuel is taxed at much higher rates than fuel used for other modes of transport, in terms of both energy and CO_2 content. This is perhaps explained by the broader range of policy goals that governments may be seeking to address with the former. Fuel use in road transport contributes to other externalities such as congestion, traffic accidents and noise.[7] . In the absence of road pricing, road fuel consumption, which is correlated (though not evenly for different vehicles) with distance travelled, may be a rough proxy for these other external costs (Parry et al. 2007). In addition, a number of countries formally or informally earmark road fuel taxes to fund road infrastructure costs (construction and maintenance), as a kind of loose user charge.

Even within road transport fuels, there is a high variance among tax rates in both energy and carbon terms. Gasoline and diesel face the highest tax rates: by contrast, natural gas, also a fossil fuel, on average is taxed at a very low rate in both energy and carbon terms and is entirely untaxed in many countries, although it accounts for only 2 % of transport energy. LPG on average is taxed at somewhere near one quarter of the rates on gasoline and diesel; biofuels (mostly ethanol and biodiesel) are taxed at around one-third of the rates applying to gasoline and diesel. See Table 5 for the average effective rates on different transport fuels in the EU-21.

These patterns are also seen within the OECD as a whole, with slightly lower rates applying to all fuels except gasoline for non-road use and natural gas for road use (see Table 6).

However, the patterns of energy use differ considerably between the two groups. Within both groups, oil products, namely gasoline and diesel, are the most significant fuel used. However, within the EU-21 countries, diesel accounts for 60 % of transport fuels and gasoline for another 31 %. Within the OECD as a whole, the pattern is reversed: gasoline is the dominant fuel (56 %) of all transport fuels, with diesel accounting for a further 34 %.

As shown in Tables 5 and 6, gasoline for road use is taxed at higher rates than diesel used for the same purpose—on average almost 45 % higher in energy terms in the EU-21 countries. With the exception of the United States, all OECD countries also tax diesel at a lower rate than gasoline on both an energy and carbon basis. Even when considered on a per litre basis, only Australia, Switzerland, the United Kingdom and the United States tax diesel at or above the gasoline tax rate. Tax rates on gasoline and diesel, in energy terms, are shown for all countries in Fig. 6.

Although diesel and gasoline are used for the same purpose, the two fuels have different energy and emission characteristics. A litre of diesel has roughly 10 %

[7]Since these social costs generally vary by location and traffic conditions, kilometre-based charges would be a much more direct and efficient way of addressing them (e.g., kilometre-based charges on busy roads that progressively rise and fall during the course of the rush hour to reduce congestion). Innovations in transport pricing that allowed increased use of distance-based or congestion charges would reduce the level of fuel taxes required to address these external costs.

Table 5 EU-21 simple average of effective tax rates on transport energy by energy type and use

Energy use		Energy type						
		Gasoline	Diesel	LPG	Aviation fuels	Biofuels	Natural gas	All fuels
Road	EUR/GJ	17.4	12.0	3.8	0.0	6.9	0.4	13.6
	EUR/tonne CO_2	251	162	60	0	97	6	189
Non-road	EUR/GJ	0.6	5.1	0.4	2.5	0.0	0.4	3.7
	EUR/tonne CO_2	8	69	6	35	0	7	52
All transport	EUR/GJ	17.3	11.8	4.0	2.5	6.9	0.5	13.0
	EUR/tonne CO_2	250	159	63	35	97	10	181

Source Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a). Tax rates are as of 1 April 2012 (except 1 July 2012 for Australia); energy use data is for 2009 from IEA (2011). Figures for Canada and the United States include only federal taxes. A "–" indicates no tax base exists; a "0.0" implies either no taxation or very low taxation such that it does not show when rounded to 1 decimal place

Table 6 OECD simple average of effective tax rates on transport energy by energy type and use

Energy use		Energy type						
		Gasoline	Diesel	LPG	Aviation fuels	Biofuels	Natural gas	All fuels
Road	EUR/GJ	15.5	10.5	3.4	–	5.0	0.7	12.2
	EUR/tonne CO_2	224	142	54	–	71	12	170
Non-road	EUR/GJ	1.0	4.4	0.3	1.7	0.0	0.3	2.9
	EUR/tonne CO_2	15	60	4	23	0	5	40
All transport	EUR/GJ	15.5	10.2	3.6	1.7	5.0	0.6	11.5
	EUR/tonne CO_2	223	157	56	23	71	11	161

Source Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a).Tax rates are as of 1 April 2012 (except 1 July 2012 for Australia); energy use data is for 2009 from IEA (2011). Figures for Canada and the United States include only federal taxes. A "–" indicates no tax base exists; a "0.0" implies either no taxation or very low taxation such that it does not show when rounded to 1 decimal place

more combustion energy content and produces roughly 18 % more CO_2 emissions than a litre of gasoline.[8] As a result, equal treatment of gasoline and diesel on either an energy basis or a carbon basis would require a higher tax rate per litre on diesel. Similarly, diesel is associated with higher levels of emissions of air pollutants per

[8]A litre of diesel is also typically associated with higher emissions of local air pollutants, but these are not taken into account in the analysis.

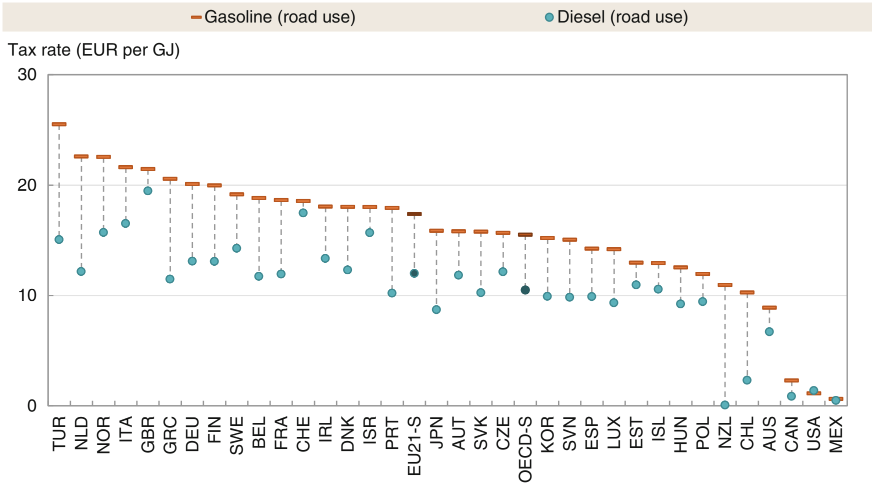

Fig. 6 Tax rate differentials between gasoline and diesel per litre, per GJ and per tonne of CO_2. *Source* Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a). Tax rates are as of 1 April 2012 (except 1 July 2012 for Australia). Figures for Canada and the United States include only federal taxes. The figure for New Zealand excludes road-user charges which apply to diesel vehicles per kilometre travelled

litre, notably particulate matter. The higher levels of both carbon dioxide and harmful air pollutants from the combustion of diesel imply that, from an environmental perspective, the current tax preference given to diesel is unwarranted.

The higher fuel efficiency of diesel cars compared to their gasoline counterparts on a model to model basis also does not warrant lower tax rates on diesel fuel. In setting tax rates per litre of fuel, the appropriate comparison between fuels is the environmental cost per litre of fuel use, which is greater for diesel vehicles. Increased fuel efficiency will itself result in lower fuel (and tax) costs over time, a benefit which is entirely captured by the owner. Therefore, there is no environmental policy need to use taxes to encourage the purchase of more efficient vehicles (Harding 2014).

The lower taxation of diesel may reflect concerns about industrial competitiveness, given the traditional reliance of commercial and industrial vehicles on diesel fuel. Such competitiveness concerns could be addressed in more targeted ways such as through the provision of direct assistance or rebates for particular users (for example, Australia provides a partial rebate for the use of diesel by vehicles weighing over 4.5 tonnes). Further, diesel can no longer be regarded as primarily a commercial fuel. The share of diesel-powered passenger cars has increased substantially in many countries, likely at least in part in response to the tax advantage enjoyed by diesel.

Removing the differential between diesel and gasoline tax rates would have a significant revenue impact. Across the EU 21 countries, if the tax rate on diesel was raised to the gasoline tax rate in energy terms, the total revenue raised could be up to EUR 40 billion, on a static estimate. More broadly, if the rate was increased in all OECD countries excluding the United States (where the diesel rate is already set above the gasoline tax rate), the tax expenditure associated with the lower rate of taxation on diesel is approximately EUR 56 billion (approximately 0.25 % of the total GDP of these countries in 2012) on a static estimate.[9] Although behavioural changes from any increase in tax rates would reduce this revenue, incorporating behavioural elasticities into the analysis indicates that this impact would be slight.

The estimated revenue from increasing tax rates on diesel to the same level as tax rates on gasoline in energy terms is shown in Fig. 7. Figure 7 shows for each country the amount of revenue from the increase as a percentage of the total revenue that would be raised from diesel under the increased rate. The numbers in each bar reflect the estimate, in EUR billion, for that country.

5.2 Taxation of Heating and Process Use of Energy

Effective tax rates on energy used for heating and process purposes (primarily natural gas, fuel oil and coal) are lower than those for energy used for transport in all of the EU-21 countries. Again, there is significant variation between effective rates applying to this energy across the OECD-EU countries. Effective tax rates range from EUR 2.61 per GJ in Ireland to EUR 0.16 in Hungary. The degree of variation between countries is also greater than in the transport sector.

Among the wider OECD, the variation in heating and process rates is again greater than within the EU-21 countries, with heating and process energy being untaxed (at the federal level) in the United States and slightly negative (a subsidy of EUR 0.01 per GJ) in Chile as a result of a petroleum price stabilisation scheme. In terms of carbon, effective tax rates range from EUR 42.25 per tonne of CO_2 in Israel, to zero in the United States and a subsidy of EUR 0.10 per tonne of CO_2 in Chile.

The EU countries have among the highest rates observed in OECD countries. Among the top half of the rates applied in the OECD, EU countries occupy all but 2 places (which go to Israel and Switzerland).

Average tax rates on heating and process fuels in the EU-21 countries are EUR 1.07 per GJ and EUR 14.07 per tonne of CO_2. Among the OECD as a whole the average rates are lower, at 0.85 EUR per GJ in energy terms and 11.7 EUR per tonne of CO_2 in carbon terms. Average effective tax rates for all countries are shown in Fig. 8.

[9]The above calculation is based on a static analysis. In considering revenue from increases in diesel tax rates, it is important to consider the behavioural impacts of such an increase in reducing the consumption of diesel fuel (possibly together with increases in consumption of gasoline or other road fuels). Dahl (2012) estimates the median price elasticity for diesel as −0.16, although estimates vary considerably across OECD countries, from −0.01 in the Netherlands to −0.74 in Canada.

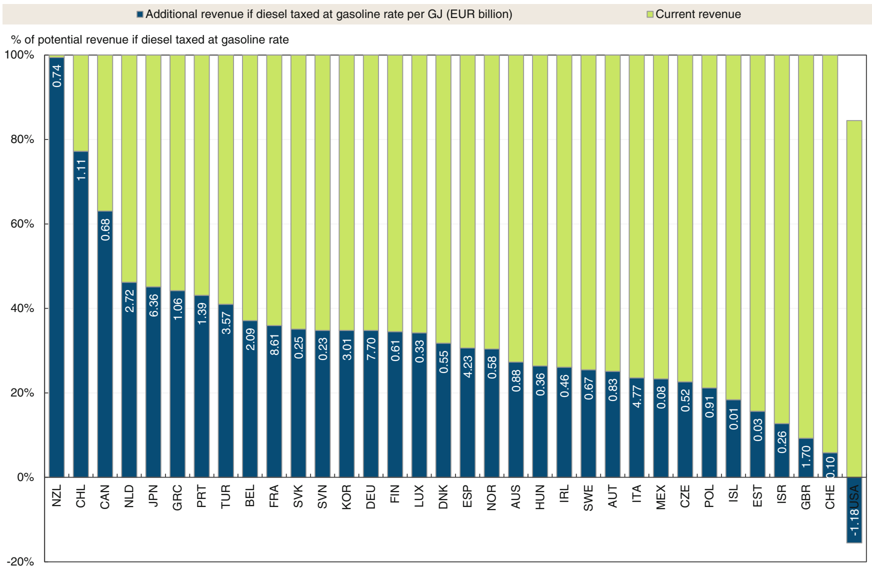

Fig. 7 Revenue potential from increasing tax rates on diesel to gasoline rate per GJ in OECD countries. *Source* Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a). The height of the *darker grey* bars indicates the percentage increase in motor fuel tax revenue, as a proportion of the total revenue that would be raised, if diesel were taxed at the gasoline rate. The figure within the bars indicates the upper limit of revenue gain from such an increase (in billions of Euros) on a static analysis

However, the figures shown above do not show the impact of the EU ETS, which applies to the EU-21 countries as well as to Iceland and Norway. The EU ETS sends price signals similar to a carbon tax, and would have the impact of increasing the effective tax rate on carbon by the price of the permits, although this was typically modest over the period considered. It is possible that the lower rates on heating and process use observed in the EU-21 countries, Iceland and Norway, relative to transport fuels in these countries, reflects to some extent the fact that most large industrial emitters in these countries are subject to the EU emission trading scheme.

Within countries, effective tax rates also vary substantially by both fuel type and use. For the purposes of cross-country analysis, fuel use has been disaggregated into residential and commercial use on one hand, and industrial use and energy transformation (e.g., oil refineries) on the other.

Among the EU-21 countries, diesel faces the highest average effective rate on energy, followed by fuel oil and natural gas, with lower rates applying to coal, peat and other oil products. Coal and natural gas taxed at lower rates, with coal having the lowest rate in energy terms. No significant amounts of biofuels, waste or renewables are used for heating and process purposes. Diesel also faces the highest effective tax rate in terms of CO_2 emissions, followed by other oil products, natural gas and fuel oil. Coal and peat face even lower effective tax rates in CO_2 terms than

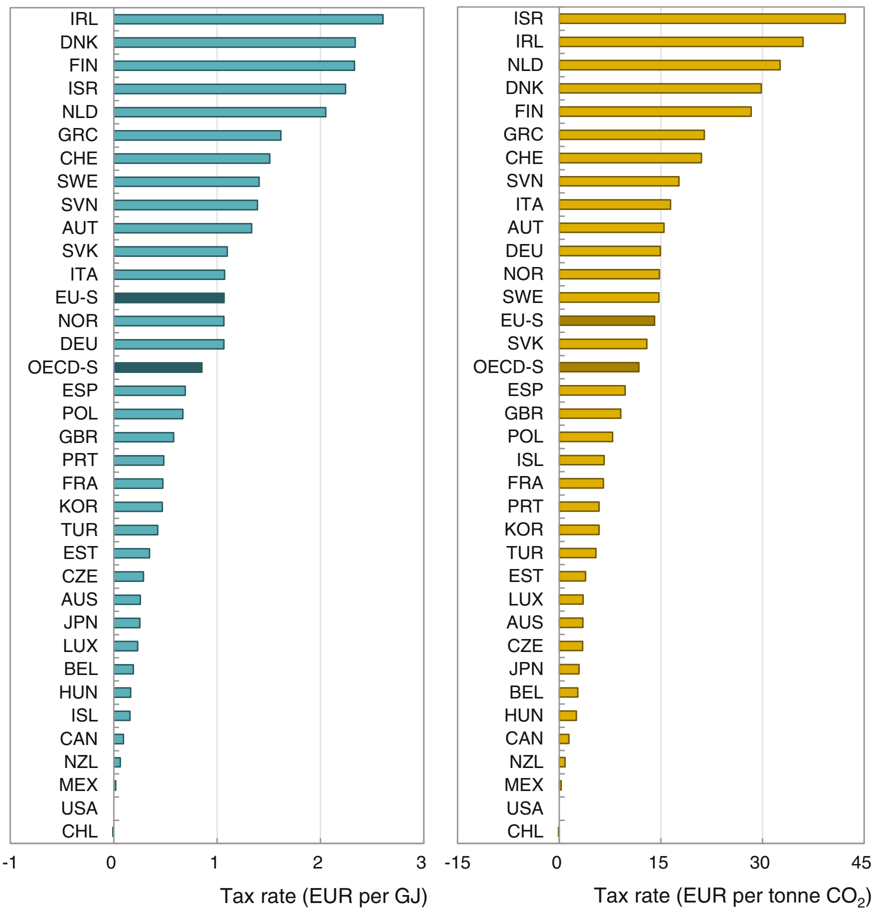

Fig. 8 Effective tax rates on heating and process energy (*left*) and CO_2 (*right*) in OECD countries. *Source* Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a). Tax rates are as of 1 April 2012 (except 1 July 2012 for Australia); energy use data is for 2009 from IEA (2011). Figures for Canada and the United States include only federal taxes. Differences in the order of countries are due to the differing mix of fuels used for heating and process purposes in each country which affects its carbon intensity

in energy terms as they generate more CO_2 emissions per TJ of energy than the other fuel types. Effective tax rates applying to heating and process fuels in the EU-21 are shown in Table 7.

Similar patterns are observed across the OECD as a whole, at generally lower rates. Coal and natural gas are not taxed at all in a number of countries, although on a simple average basis face comparable rates to those applied in the EU-21 countries. The rates applying to the OECD as a whole on average are shown in Table 8.

The different rates applied to heating and process energy may partially be explained by the different users of fuel, although from an environmental perspective

Table 7 EU-21 simple average of effective tax rates on heating and process energy by energy type and use

Energy use		Energy type					
		Coal	Natural gas	Diesel	Fuel oil	Other oil	All fuels
Residential and commercial	EUR/GJ	0.3	1.6	4.3	2.9	2.4	1.5
	EUR/tonne CO_2	3	29	58	38	36	20
Industrial and energy transformation	EUR/GJ	0.8	0.9	4.2	1.9	0.6	1.0
	EUR/tonne CO_2	7	15	56	24	9	13
All heating and process use	EUR/GJ	0.8	1.0	4.3	2.0	0.7	1.1
	EUR/tonne CO_2	7	18	58	25	10	14

Source Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a). Tax rates per tonne of CO_2 exclude three outliers: Iceland, Norway and Sweden. Tax rates are as of 1 April 2012 (except 1 July 2012 for Australia); energy use data is for 2009 from IEA (2011). Figures for Canada and the United States include only federal taxes

Table 8 OECD simple average of effective tax rates on heating and process energy by energy type and use

Energy use		Energy type					
		Coal	Natural gas	Diesel	Fuel oil	Other oil	All fuels
Residential and commercial	EUR/GJ	0.3	1.1	3.1	1.9	1.8	1.2
	EUR/tonne CO_2	3	20	42	24	27	17
Industrial & energy transformation	EUR/GJ	0.6	0.6	3.3	1.3	0.5	0.8
	EUR/tonne CO_2	5	10	45	17	7	10
All heating and process use	EUR/GJ	0.6	0.7	3.4	1.3	0.7	0.9
	EUR/tonne CO_2	5	13	46	17	11	12

Source Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a). Tax rates per tonne of CO_2 exclude three outliers: Iceland, Norway and Sweden. Tax rates are as of 1 April 2012 (except 1 July 2012 for Australia); energy use data is for 2009 from IEA (2011). Figures for Canada and the United States include only federal taxes

there is little basis for taxing the same fuel differently depending on the end user of the fuel. Differences may also result from the use of other policy measures in different countries—notably the EU ETS—to reduce or internalise some of the costs of fuel use in these sectors. Across the OECD, oil products and natural gas used for residential and commercial purposes (mostly space heating) are taxed more heavily in both energy and carbon terms than when used for industrial use or energy transformation. On the other hand, coal and peat are on average taxed more highly when used in industry and energy transformation than in residential and commercial use (although the use of coal in the latter sector is quite small).

Countries differ when the overall effective tax rates on energy used by these two main user groups are considered. In energy terms, 18 countries impose a clearly higher tax on residential and commercial fuel use than on industrial and energy transformation use. In Sweden, Denmark and the Netherlands the difference is substantial. In contrast, 10 countries impose a clearly higher effective tax rate on industrial use and energy transformation, with Ireland imposing substantially higher effective rates on industrial and energy transformation use. Meanwhile, in six countries there is minimal difference between the two fuel use groups. The pattern is similar if the rates are considered in carbon terms. These tax rates are shown in Fig. 9.

The generally low tax rates on heating and process fuels, together with the large variation in rates between different uses, may be partly explained by distributional and competitiveness concerns. For example, lower effective tax rates on industrial energy use may seek to address competiveness concerns, particularly for energy-intensive heavy industries that are subject to strong international competition, such as iron and steel, petrochemicals and mineral smelting. On the other hand, in EU countries, the lower rates may to some extent reflect the application of the EU ETS to many large industrial emitters.

In contrast, countries that impose lower rates on residential fuel use may place greater weight on concerns regarding the ability of low-income families to afford heating fuels, or because of greater need for heating (for example in Sweden, where consumers in the northern part of the country pay a reduced rate on electricity).

While concerns about industrial competitiveness and impacts on low-income households are valid policy concerns, providing relief from environmentally related taxes such as taxes on fuel blunts the price signal (e.g. in terms of the cost of carbon emissions) that could otherwise be sent to such sectors. This results in loss of an opportunity to help shift production and consumer decisions toward a lower carbon path and is an inefficient and untargeted way to provide relief to affected households or industrial sectors. It is generally preferable to assist such sectors in a way not linked to energy costs, so as to ensure an incentive to change behaviour (OECD 2006).

Another possible explanation for the different rates applied to the different users of heating and process energy is that the rates result from the extent to which different fuels are used by each group. For example, coal and oil products are used more heavily in industrial processes than in domestic or commercial use. Conversely, natural gas is the most common residential and commercial heating fuel, together with biomass (primarily wood). The different tax rates that apply to these fuels may therefore result in different effective tax rates, rather than any deliberate policy choice to prefer on sector over another. This is particularly likely to be the case when the difference in the rates is small.

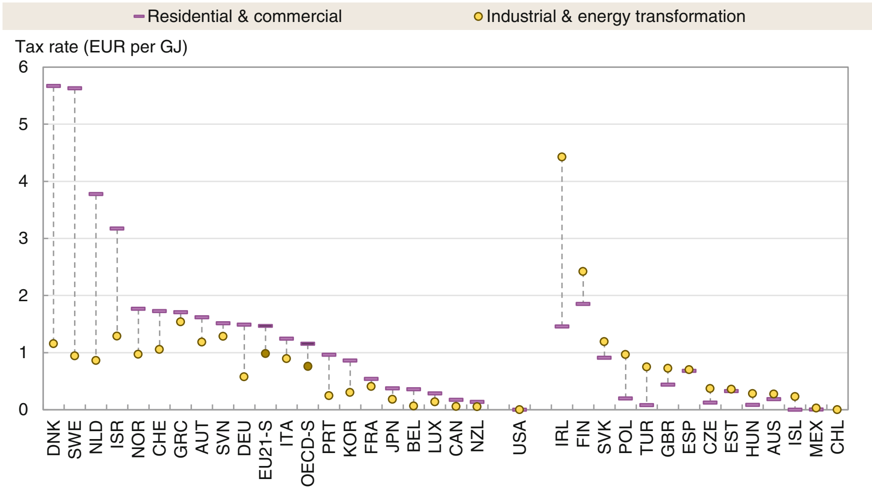

Fig. 9 Effective tax rates on residential and commercial energy use versus industrial use and energy transformation. *Source* Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a). Tax rates are as of 1 April 2012 (except 1 July 2012 for Australia); energy use data is for 2009 from IEA (2011). Figures for Canada and the United States include only federal taxes

5.3 Taxation of Energy Used to Produce Electricity

Energy used to produce electricity can be taxed directly through excise taxes levied on the fuels used to generate electricity, or indirectly, through the taxation of the consumption of electricity. Under the Energy Tax Directive, EU countries should tax the consumption of electricity. In addition, 4 OECD-EU countries also tax fuels used to generate electricity. More broadly among the OECD, electricity consumption is taxed in a further 5 countries, of which three also tax generation fuels. Two countries tax only the fuels used to generate electricity. Electricity consumption and generation are untaxed in the remaining 6 countries, none of whom are EU member countries. It is worth mentioning that taxes applied directly to fuels used to generate electricity are likely to have a greater influence on the energy mix and therefore provide clearer environmental signals than taxes on electricity consumption, which is more likely to promote electricity efficiency, lowering electricity consumption (to an extent that depends on the value of the electricity own-price elasticity). Through both mechanisms, taxes on energy can therefore contribute to energy security goals.

Where taxes are levied directly on the fuels used to generate electricity, these are included in the analysis in the same way as taxes on other fuels. Where taxes are levied on the consumption of electricity, these have been "looked through" to determine the effective tax rate on each underlying energy source (e.g. coal, natural gas, hydro etc.), based on the efficiency of electricity production and the carbon content of each fuel. Where a country taxes both fuels used to produce electricity and electricity consumption, both levels of taxation are taken into account in calculating the effective tax rate on each primary energy source.

As with the other energy uses considered, effective tax rates on the fuels used to generate electricity vary considerably across fuel types. Table 9 shows the simple average for OECD-EU countries of the effective tax rates in energy and CO_2 terms for different fuels used in electricity generation. These take into account both taxes on fuel used to generate electricity (inputs), and taxes on electricity (the output). Again, oil products, together with renewables (excluding hydro and nuclear) face the highest tax rates, with coal and natural gas facing lower rates.

Reflecting the higher use of consumption taxes on electricity in EU countries, the OECD average tax rates are both lower and more varied by fuel. Natural gas faces the highest rate of any fossil fuel, with coal facing the lowest rate. From an environmental perspective—as described in Sect. 2 of this chapter—such a pattern is certainly in contrast with the use of taxes to internalise environmental externalities. Taxes that internalised the cost of carbon from fuel use would be even when considered in carbon terms, which would imply a higher rate in energy terms for those fuels which are more carbon intensive, such as coal. Further, air pollution costs are likely to be higher in respect of coal, although the impact of air pollution will differ by location and technologies used. This too would imply a higher tax rate on coal relative to other energy sources. The apparent incoherency in rates may be partially explained by other considerations such as competitiveness or energy security concerns, although in many cases they may not result from deliberate policy choices. The simple average rates on fuels used to generate electricity across the OECD are shown in Table 10.

Since the methodology looks through taxes on electricity consumption to the underlying fuels, a tax on electricity consumption will result in a lower effective tax rate on generation sources that are less efficient in transforming fuel into electricity (since the tax on electricity used is attributed to a greater amount of underlying fuel). A tax on electricity may encourage conservation of electricity generally. However, unlike differential taxation of the fuels used to generate electricity, taxation of electricity consumption itself provides no incentive to favour higher-efficiency generation sources since it effectively ignores energy lost as a result of inefficiencies in the generation process.

Table 9 EU-21 simple average of effective tax rates on energy used to generate electricity

	Energy type								
	Coal	Biofuels	Waste	Natural gas	Oil	Renewables	Hydro	Nuclear	All fuels
EUR/GJ	1.1	0.9	1.5	1.1	2.2	2.2	0.4	1.2	1.1
EUR/tonne CO_2	21	20	18	16	14	–	–	–	19

Source Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a). Tax rates are as of 1 April 2012 (except 1 July 2012 for Australia); energy use data is for 2009 from IEA (2011). Figures for Canada and the United States include only federal taxes. A "–" indicates no tax base exists; a "0.0" implies either no taxation or very low taxation such that it does not show when rounded to 1 decimal place

Table 10 OECD simple average of effective tax rates on energy used to generate electricity

	Energy type								
	Coal	Biofuels	Waste	Natural gas	Oil	Renewables	Hydro	Nuclear	All fuels
EUR/GJ	0.7	0.8	0.6	1.2	0.9	1.5	1.5	0.3	0.9
EUR/tonne CO_2	14	13	12	14	11	–	–	–	13

Source Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a).Tax rates are as of 1 April 2012 (except 1 July 2012 for Australia); energy use data is for 2009 from IEA (2011). Figures for Canada and the United States include only federal taxes. A "–" indicates no tax base exists; a "0.0" implies either no taxation or very low taxation such that it does not show when rounded to 1 decimal place

Tables 9 and 10 also shows the implicit tax rates on carbon that are calculated by taking into account explicit taxes on carbon fuels and treating taxes on electricity consumption as if they were an indirect tax on the average carbon content of that country's electricity. Where a significant share of electricity is generated from non-carbon sources (e.g. renewables and nuclear), the calculated tax burden on the smaller carbon generation sources will be quite large. An undifferentiated tax on electricity regardless of generation source therefore creates no incentive to favour less carbon-intensive sources.

6 Economy-Wide Tax Rates on Energy in the EU-21 and OECD Countries

Economy-wide tax rates on energy in each country are the result of these different patterns of taxation for different sources and uses of energy, on a weighted average basis. At an economy-wide level, there are significant differences in the overall level of energy taxation across the OECD area when all taxes on energy are taken into account, whether tax rates on energy are considered as effective tax rates per unit of energy or per unit of carbon emissions (see Fig. 10). On a simple average basis, OECD countries tax energy use at EUR 3.28 per GJ and at EUR 52.04 per tonne of CO_2. The influence of larger energy users within the OECD, particularly the United States, lowers the weighted average effective tax rates to 1.77 per GJ and EUR 27.12 per tonne of CO_2. The range of country averages, however, is very wide: from EUR 0.18 per GJ in Mexico (where petroleum is subsidised) to EUR 6.58 per GJ in Luxembourg (where the high proportion of energy used in transport increases the overall average tax rate on energy) when tax rates are considered as effective tax rates in terms of energy content, and from EUR 2.80 per tonne in Mexico to EUR 107.28 per tonne in Switzerland when considered in terms of carbon emissions.

The highest overall tax rates on carbon tend to be in European countries. Many countries with the highest effective taxes have explicit carbon taxes (e.g. Denmark, Iceland, Ireland, Norway, Sweden and Switzerland). Explicit carbon taxes generally

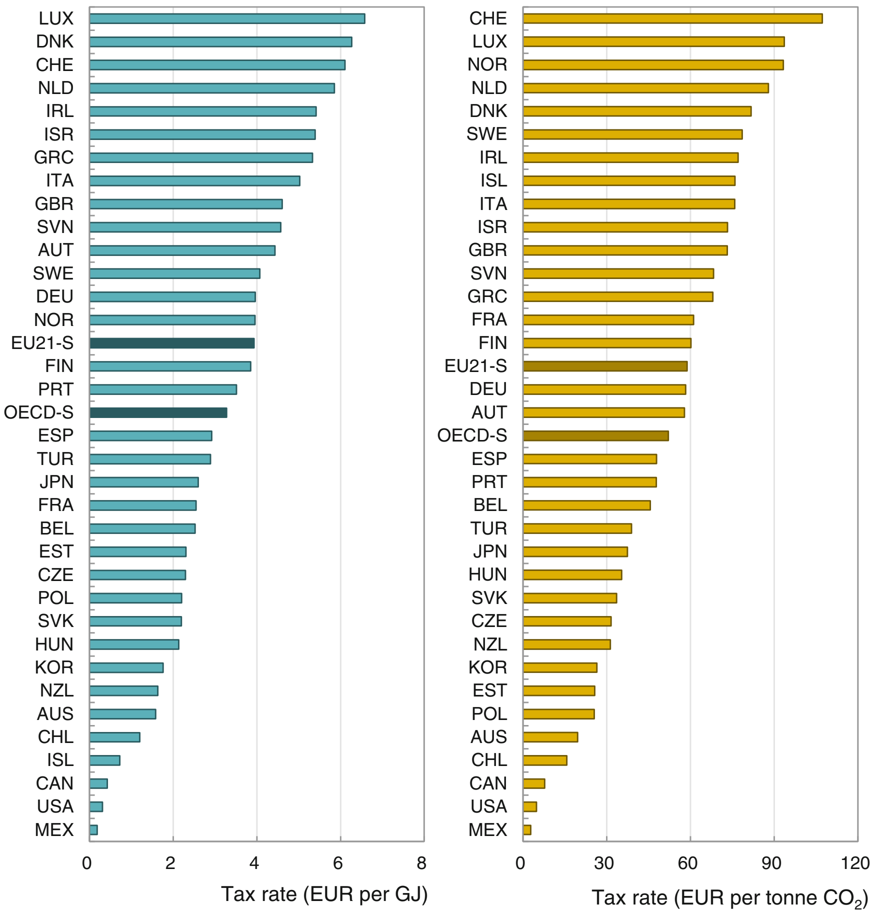

Fig. 10 Average effective tax rates on energy (*left*) and CO_2 from energy use (*right*) in OECD countries. *Source* Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a). Tax rates are as of 1 April 2012 (except 1 July 2012 for Australia); energy use data is for 2009 from IEA (2011). Figures for Canada and the United States include only federal taxes

exist alongside other taxes on energy products, which are sometimes based on the energy content of different fuels. These countries also tend to tax a broad range of energy products and have generally higher and more consistent rates across different fuels and uses, particularly among fuels used for heating and process purposes.

Australasia and the Americas have the lowest effective tax rates on an economy-wide basis. These countries typically only tax fuels used in transport use (though generally at lower rates than the OECD average) and tend not to tax energy in non-transport uses (an exception being at the provincial level in Canada).

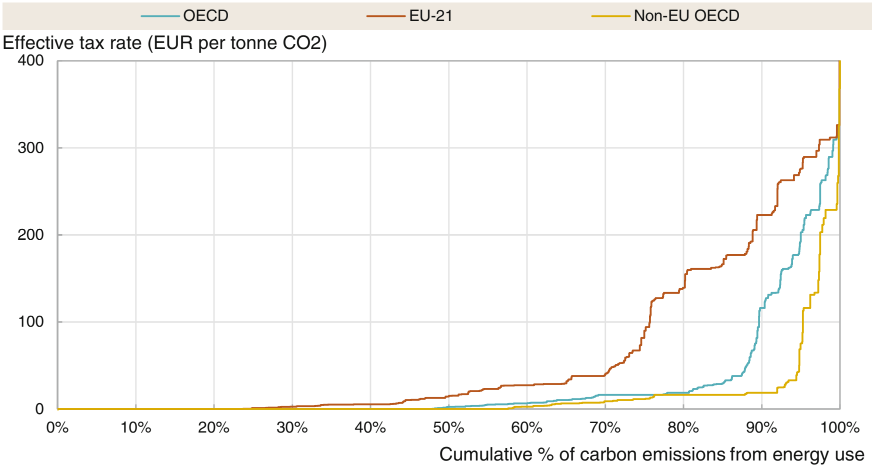

Fig. 11 Tax rates on cumulative percentage of CO_2 from energy use in EU-21, non-EU, and OECD countries. *Source* Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a). Tax rates are as of 1 April 2012 (except 1 July 2012 for Australia); energy use data is for 2009 from IEA (2011). Figures for Canada and the United States include only federal taxes

When the totality of energy use in both groups is considered, there are very different patterns in energy taxation between the EU and non-EU OECD countries. With a few exceptions, the EU-21 countries tend to have higher tax rates, both on an economy-wide basis and across the whole range of energy use. This is shown in Fig. 11 which shows on the horizontal axis the cumulative percentage of energy use in the OECD-EU countries, the non-EU OECD countries, and the OECD as a whole. Energy use has been ranked from the lowest to the highest taxed in each group.

Figure 11 shows that among EU OECD countries, around 75 % is taxed, with 25 % being taxed at EUR 100 per tonne of CO_2 or higher. Among non-EU OECD countries, just over 40 % is taxed and only 4 % at more than EUR 100 per tonne of CO_2.

Empirical evidence shows that the imposition of energy taxes does affect energy consumption behaviour. For example, OECD (2006)—which summarises various earlier studies—finds relatively low short-run energy elasticities (ranging from −0.13 to −0.26) but larger long-run elasticities (−0.37 to −0.46).[10] Consistent with this, it is interesting to note that a simple scatter plot of OECD countries in Fig. 12 shows that countries with a higher average effective tax rates on CO_2 tend to have lower carbon emissions per unit of GDP (i.e. have less carbon intensive economies). This arises either because these economies are more energy efficient, or because they use a less carbon-intensive fuel mix, or a combination of the two.

[10]See also, for example, Fell et al. (2010), Goodwin et al. (2004) and the United Kingdom Energy Research Centre (2007).

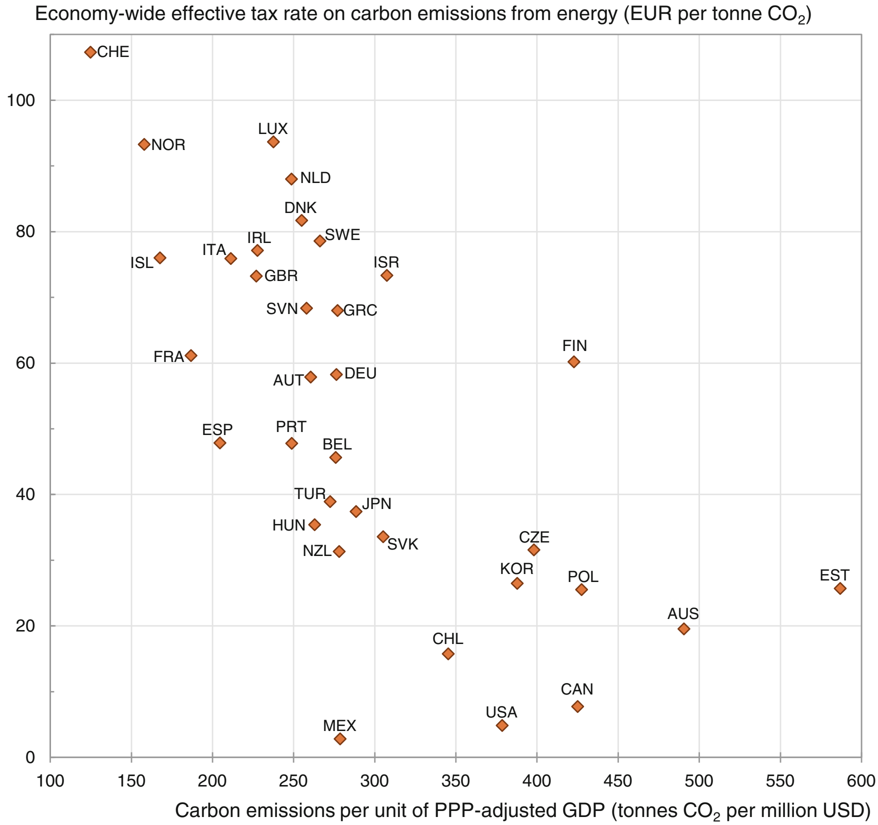

Fig. 12 Overall effective tax rates on CO_2 from energy use and carbon efficiency in OECD countries. *Source* Authors' calculations based on data from *Taxing Energy Use* (OECD 2013a) and the World Bank Development Indicators (2014). Tax rates are as of 1 April 2012 (except 1 July 2012 for Australia); energy use data is for 2009 from IEA (2011). Figures for Canada and the United States include only federal taxes

While this correlation does not imply causation, it suggests that there may be a linkage between the rate of taxation applied to carbon and the extent of carbon usage within an economy.

7 Conclusions

Energy use is a key part of modern economies as an input to industrial production, in transport, and as a contributor to household living standards. At the same time, energy use also contributes to a range of significant environmental problems, such as climate change and local air pollution. The taxation of energy is an important policy instrument that, whether intended or not, has a significant impact on energy prices, energy usage and the resulting environmental impacts. Taxation can influence both the level and composition of energy usage, affecting the amount and shares of different sources in the energy mix. It therefore has implications for energy security goals. By incorporating the external costs of energy use into prices, energy taxes can promote efficient use of energy, lowering environmental impacts and the economy's demand for energy. It can also have the impact of shifting the energy mix which raises energy security issues although this is likely to depend on the maturity of alternative energy technologies which are the main drivers of substitution possibilities. Finally, energy taxes raise a significant amount of revenue: across the EU-OECD countries, they raise on average 2.5 % of GDP on a simple average basis.

The EU-21 countries tax energy within the framework provided by the EU's Energy Tax Directive, which mandates minimum tax rates across a wide range of energy products. However, there remain wide variations in the effective tax rates applied to energy use across and within the EU-21 countries. These differences, both in tax bases and rates, are greater when all 34 OECD countries are considered. These uneven price signals with respect to different energy products, and low rates and exemptions on some of them, result in wide differences (and often considerable weakness) in the tax disincentives to emit carbon dioxide (CO_2). Since CO_2 has broadly the same impact on atmospheric greenhouse gas concentrations however and wherever it is emitted, these differences underline the fragmentation in current efforts to mitigate climate change.

While in some cases there may be good justifications for variations in effective tax rates on carbon (e.g., where motor fuels are taxed as a proxy for other social costs of vehicle use), in many other cases the reasons are not at all obvious. Furthermore, some rates may not be reflective of the external costs associated with different forms of energy and energy use. This may suggest that many countries have not given great weight in their tax policy design to environmental damage from fuel use, such as that caused by carbon emissions. Many differentials may simply have arisen out of the piecemeal design and introduction of taxes on different energy products over a period of time.

The significant differences noted across countries suggest that reappraisal of tax settings is needed. Some of the main incoherencies in the taxation of energy include:

- The effective tax rate on diesel for road use in terms of both energy and carbon content is typically lower than the comparable rate on gasoline, despite the higher emissions of carbon and local air pollutants associated with diesel per unit of energy.
- Among transport and heating and process fuels, oil products (predominantly gasoline and diesel) tend to be taxed significantly more heavily and more frequently than other energy products, such as natural gas and coal.

- There is often a very low (or zero) tax rate on coal, despite its significant negative environmental impacts, particularly considering its greater contribution to greenhouse gas emissions and other air pollutants per unit of energy.
- Fuel used in agriculture, fishing and forestry is often exempt from tax, providing no signal with respect to external costs, thereby encouraging over-use.
- Among fuels which are used for electricity generation, coal, which is widely used, is often taxed at a lower rate than natural gas and biofuels and waste; and taxes on the consumption of electricity provide no signals in terms of the differing environmental impact of the various primary energy sources from which electricity may be generated.

These uneven price signals with respect to different energy products, and low rates and exemptions on some of them, suggest that countries are not fully harnessing the power of energy taxes to pursue their environmental objectives and that some of the lowest-cost opportunities to reduce carbon emissions are being foregone. In many countries, a reappraisal is warranted to ensure that advantage is being taken of the lowest-cost opportunities to reduce carbon emissions and to explicitly determine whether current energy tax settings can be realigned to most efficiently meet countries' environmental, social and economic goals.

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Public Policies and the Energy Mix in Italy: Where Do We Stand?

Rossella Bardazzi and Maria Grazia Pazienza

Abstract Given the almost complete energy dependency and the consequently high sensitiveness to energy security in Italy, energy efficiency and a significant renewable share in the national energy mix are key goals of energy policy. Although the energy intensity of the Italian economy is among the lowest in western countries, there is room for further improvements pursuing economic growth without increasing the energy use (decoupling). Indeed the high Italian energy efficiency has been stimulated by import dependence and relatively high energy prices, because the economic system proved to be very reactive to selective price incentives towards energy products. Notwithstanding these premises, the general coherence and efficacy of the current framework—a bundle of excise taxes, direct subsidies, feed-in tariffs and tax expenditure together with the launch of an auction-based ETS phase—is highly questionable. Therefore, a progressive evolution of support mechanisms for renewable and energy efficiency to a more cost-effective and market-based system is strongly encouraged. This chapter outlines the current complex incentive system, highlighting incoherencies and successes, and discusses a proposal for a general reform that includes, in accordance with the European Commission proposal, a carbon taxation.

1 Introduction

Given Italy's almost complete energy dependency and its consequent high sensitivity to energy security, energy efficiency and a significant share of renewable in the national energy mix are key goals of the national energy policy. Although the

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energy intensity of the Italian economy is among the lowest among western countries, there is room for further improvements to pursue economic growth without increasing energy use (decoupling). Electricity generation with renewable sources, on the other hand, has recently experienced a sharp increase, but solar and wind energy are still far from their potential.

Indeed, the Italian high energy efficiency has been stimulated by import dependence and relatively high energy prices. However, public policies have fluctuated among energy efficiency, climate protection, the geographical diversification of resources and measures to mitigate the adverse effects of high energy prices. These policy interventions have been overlapping in the past two decades. They have not been well coordinated and have been repeatedly changed with no clear economic rationale, also creating some uncertainty in the markets. As a result, the general coherence and efficacy of the current framework—a bundle of excise taxes, direct subsidies, feed-in tariffs and tax expenditure, together with the launch of an auction-based ETS phase—is highly questionable.

Moreover, within the European framework, member states need to examine their different national practices on energy policy levies and tax components with the objective of minimising negative consequences for energy prices. At the same time, a progressive evolution of support mechanisms for renewables to a more cost-effective and market-based system and more convergence of national support schemes is being strongly encouraged.

This chapter aims to outline the current complex policy framework in Italy, highlighting incoherencies and successes, and discusses a proposal for a general reform that includes, in accordance with the European Commission proposal, carbon taxation. After a discussion of the Italian position in terms of energy security and energy efficiency targets, we focus on measuring the performance of the national energy system using indicators related to the energy and carbon efficiency of users and sectors (Sect. 2). The effects of public policies on these trends are highlighted, together with their influence on fuel price dynamics. Section 3 focuses on an analysis of the main economic instruments and carbon price policies used at the national level to highlight the efficacy and the limits of the current structure of energy/environmental policy measures. The chapter concludes with a discussion of a future direction to reform this policy structure according to the international framework (Sect. 4).

2 Energy Security and Energy Efficiency in Italy

Energy security is concerned with risks arising from three broad sources: technical (linked to infrastructure failures), human (mainly demand fluctuations, but also geopolitical instability and the strategic management of supplies) and natural (resource depletion and intermittency) (Winzer 2012). Different conceptualizations of energy security result from variation in different stakeholders' perceptions of what security means, but, according to Månsson et al. (2014), two specific dimensions can be distinguished which are both related to energy security for consumers: a physical and an economic dimension. The first relates to the availability and accessibility of energy supply, while the second refers to price volatility and affordability: prices should give a signal to indicate a situation of scarcity or oversupply. Both dimensions are included in the EU Commission energy security strategy, and this in turn is defined as 'inseparable' from the 2030 Framework for climate and energy (EC 2014a), which aims to deliver a competitive and low-carbon economy by exploiting renewable and indigenous sources of energy. In May 2014, the European Commission approved the Communication on Energy Security (EC 2014b) to reduce EU energy dependence and to promote resilience to shocks and to energy supply disruptions. This communication has now been complemented by the EC Communication on Energy Union (February 2015), which is based on five integrated dimensions: energy security; the internal energy market; energy efficiency as a contribution to demand moderation; decarbonisation of the economic system through renewable energy; and research and innovation. Finally, regarding energy efficiency, several European Directives have been implemented since the early 1990s concerning labelling, the efficiency of buildings, and eco-design.

Within this European policy framework, Italy is committed to the implementation of energy efficiency measures and to all strategies for ensuring improving energy security through diversifying the energy mix and energy suppliers. According to the latest draft of the National Energy Strategy (2013), energy efficiency is one of the main priorities defined for the medium-long term: enhancing efficiency is a way to contribute to reducing energy costs for households and industries, to reducing polluting emissions and to improving supply security with a lower dependence on energy imports. On the other hand, security is mainly perceived in terms of security of supply because Italy is highly dependent on energy imports, and therefore households and industry are exposed to international price volatility and to geopolitical crises, as witnessed in recent years.

Italy, along with other EU member states, saw a peak in energy consumption in 2005 and then a decrease, probably driven by a combination of weak demand and improved energy efficiency (Fig. 1). Natural gas and oil cover almost the same share of demand—around 35 %—because of an above-average decline in oil consumption, at least partly due to refinery closures.[1] Renewables represent the third energy source, with a share of 15 %, which is approaching the target of 17 % set for Italy by the EU 20-20-20 strategy.

Italy's import dependence is among the highest in the EU. 87 % of the country's energy needs were covered by imports in 2012 and this rate has been fairly constant over the past ten years (Fig. 2).[2] The National Energy Strategy (NES) aims to reduce this rate to 67 %, thanks to increased renewable production, lower electricity imports, increased production of national resources and energy efficiency.

[1]Since 2011, 3 out of 15 refineries have been shut down in Italy. In 2014, the available refining capacity was around 91 million tons, with a drop of 15 % compared to 2011.

[2]The graph shows the contribution of different fuels to total energy import dependency. The sum of the relative shares of the net imports of the total demand represents the total import dependency.

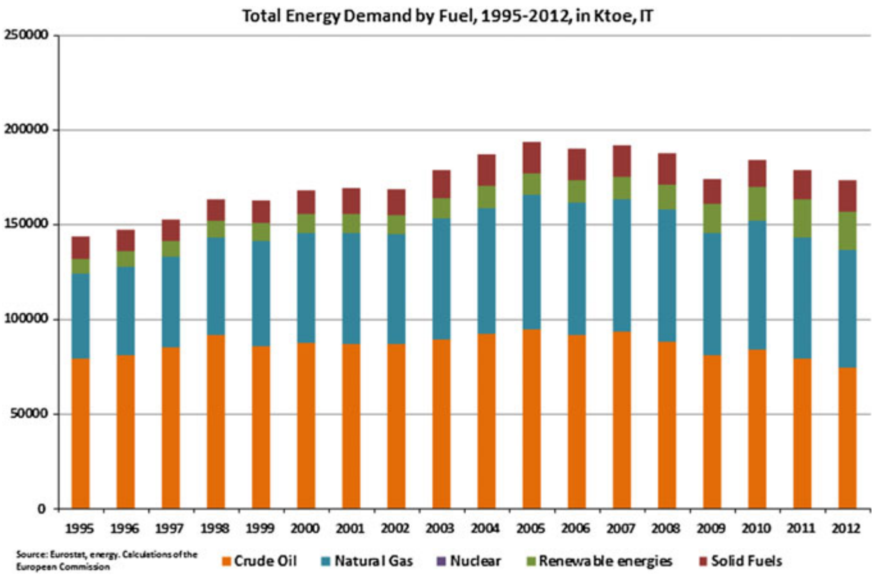


Fig. 1 Total Energy demand by fuel—Italy. *Source* EC Staff (2014)

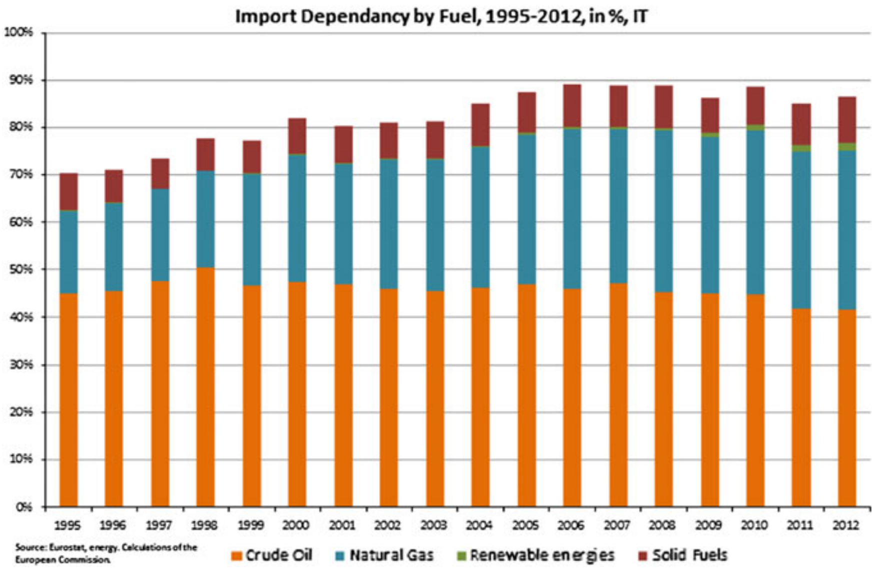


Fig. 2 Import dependency—Italy. *Source* EC Staff (2014)

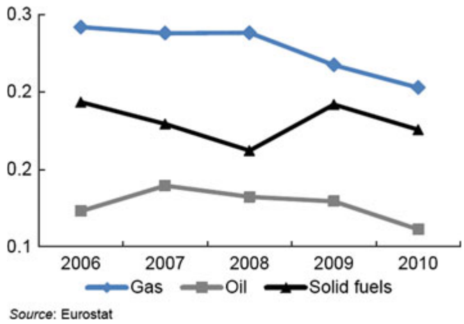


Fig. 3 HHI index energy imports, Italy. *Source* EC (2013)

Despite this characteristic, the country enjoys a number of mitigating factors: a composite energy mix and a well-diversified range of trading partners. Indeed, the Herfindahl-Hirschmann Index (HHI), used to measure diversification, shows that the import sources are fairly diversified, particularly for gas (Fig. 3). In the case of oil, Italy relies mostly on non-European countries, such as Libya, Azerbaijan, Saudi Arabia, Russia and Iraq, among others. Therefore, geopolitical risks can generate price fluctuations, which could affect the economy. On the other hand, its gas supply mainly comes from two countries, Algeria and Russia, which account for more than 60 % of total imports, but also from intra-EU flows. The country-specific concentration index computed by the European Commission for natural gas ranks Italy in a very good position,[3] with a value of 16 out of 100, close to Germany (15.3) but worse than France (4.2). However, security of supply suffers from a lack of infrastructure, with only two regasification terminals and incomplete integration with the gas pipelines from the north of Europe. Therefore, most imported gas is still based on long-term 'take-or-pay' contracts, which still depend mainly on oil indexation and they are not yet aligned with spot market prices. Natural gas is of crucial importance for electricity generation. Indeed, the energy mix for electricity is based mainly on gas (38 % of net generation in 2013) and renewable (34 %) and it differs greatly from the average EU mix because of the absence of nuclear power and the low share of coal (14 %).[4] The rapid increase in installed renewable capacity happened in a few years. As shown in Table 1, the change was mainly due to the solar source: in 2013 the installed photovoltaic capacity was almost equal to that of traditional renewable hydro power, while the number of plants tripled (passing from 155,977 to 591,029). The strong growth of biogas (+173 %) and bioliquid (+73 %) explain the increase in the installed bioenergy capacity.

Italy also imports some of its power from other European member states—about 15 % in 2013, according to Terna (2013). However, a country-specific

[3]The country-specific supplier concentration index is computed as the sum of the squares of the ratio between the net positive imports from a partner and the gross inland consumption in the importing country (EC Staff 2014). The index takes values between 0 (no imports) and 100 (the entire supply of a fuel comes from a single supplier).

[4]Data are from the Italian electricity budget (2013). See Terna (2013).

Table 1 Renewable sources in Italy (2010–2013)

	Installed capacity (MW)				% variation 2013 versus 2010
	2010	2011	2012	2013	
Hydro	17,876	18,092	18,232	18,366	3
Wind	5,814	6,936	8,120	8,561	47
Photovoltaic	3,470	12,773	16,690	18,053	420
Geothermal	772	772	772	772	0
Biomasses and wastes	2,352	2,825	3,802	4,033	71

Source authors' calculation on GSE Statistical Report, various years

diversification index cannot be applied in this case because import flows between different markets can change direction more frequently than fossil fuels. From a supply security point of view, electricity generation can be investigated according to its production fuels, and from this perspective it is more sensitive to natural gas than to solid fuels, particularly in the Italian case. Indeed, import dependency is lower for coal in the EU than for natural gas and import sources are more diversified globally, meaning that power generation is more resilient to external coal supply disruptions than to natural gas shortages (EC Staff 2014).

Finally, solid fuels represent the fourth source of Italian energy consumption with a lower share (9 % in 2012) than the EU average (16 %). The country-specific supplier concentration index for solid fuels is relatively low (18), thus confirming that coal imports are much more diversified than other fossil fuels.

The main structural features of the Italian energy system are a high import dependence along with a wide range of trading partners and a fairly diversified mix of energy sources. As regards security of supply, the development of renewable sources and the appropriate infrastructure to diversify energy suppliers is of crucial importance. Indeed the NES has set these as primary goals, along with a reduction of energy prices to improve Italian industrial competitiveness and family budgets, and a reduction of carbon emissions. In order to reach these goals, energy efficiency plays a key role in meeting all the established targets.

2.1 Measuring Energy Efficiency and Italy's Performance

Energy efficiency is related to a better use of energy in energy-consuming devices. In general, end-use appliances are not very efficient, therefore implying losses, a higher demand for fuels, and environmental costs. Energy efficiency is defined in terms of energy services provided by unit of input. For instance, in the residential sector the indicator is energy input per square metre, for the transport sector energy input per kilometre is used, while for industrial activity energy input per unit of output is the common indicator. Energy intensity is also used as a measure of energy efficiency because it is readily available at the aggregate level as the ratio of the total primary energy supply (TPES) to the gross domestic product (GDP) of each country. However, energy intensity is not only determined by energy efficiency because it is affected by the structure of the economic system (industrial vs. service activities), by climate conditions and by the size of the country (especially for transport).[5] Therefore, energy efficiency can be measured through a set of additional disaggregated indicators to understand the key drivers of energy consumption and to provide policy-relevant analysis of how to influence these trends. Efficiency indicators have been published by IEA since 1997 according to a methodology as presented in IEA (2014). For the 28 European countries, information on the energy efficiency indicators is maintained in the ODYSSEE database provided by the Enerdata Research Service on behalf of all the EU Energy Agencies and the European Commission.[6]

In energy efficiency terms, Italy already performs very well compared to other European countries (Fig. 4). At the aggregate level, Italy has traditionally had a low final energy intensity, but while this indicator has constantly fallen at the EU level, progress in Italy has slowed down. This trend is simply due to the already low level of energy intensity which has been achieved at the aggregate economic level, although there is a potential for further improvement to be exploited through policy measures. This low energy intensity can be attributed to a number of factors, including the structure of economic activities, the share of energy-intensive sectors, specific public policies and high energy prices. In order to limit high energy vulnerability, the public authorities have tried to implement a wide and complex range of policies and programmes to diversify energy sources and energy partners, and to introduce financial incentives aimed at developing renewable sources and energy efficiency standards, and market-based instruments—more specifically taxes—to discourage energy-intensive devices (see Sect. 3).

ODEX is the index used by the ODYSSEE-MURE project to measure energy efficiency gains by sector (industry, transport, households) and for the whole economy (all final consumers). For each sector, the index is calculated as a weighted average of sub-sectoral indices of energy efficiency progress; the sub-sectors are industrial or service sectors or end-users for households and transport. The sub-sectoral indices are calculated from variations in unit energy consumption indicators, measured in physical units and selected to provide the best "proxy" for energy efficiency progress, from a policy evaluation viewpoint.[7] The ODEX index is represented in relation to the base year by weighting the energy efficiency gains of each sector between the year t and the year 2000 (Fig. 5). Over the period 1990–2012, final energy efficiency increased by 25 % in the EU28 countries at an annual average rate of 1.3 %. All sectors contributed to this

[5] Moreover, several issues related to its measurement may arise. See Bhattacharyya (2011), Chap. 3.

[6] See the website http://www.odyssee-mure.eu/.

[7] For instance for households kWh/appliance, koe/m2, toe/dwelling; for transport: toe/passenger for air transport, goe/passenger -km for rail, goe/t-km for the transport of goods by rail and water, toe per vehicle for motorcycles and buses. For the index specification of other sectors, see www.odyssee-mure.eu

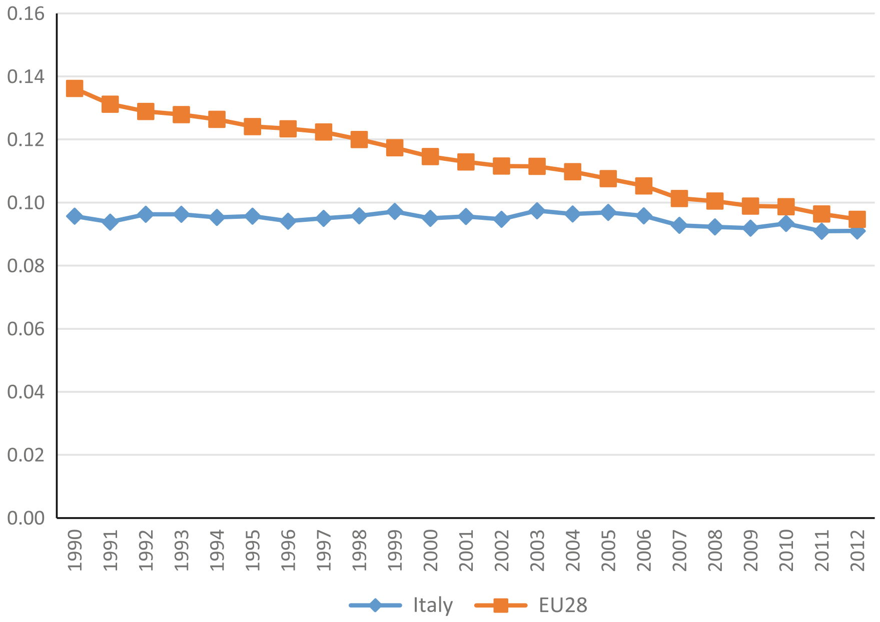


Fig. 4 Final energy intensity at purchasing power parities (ppp, koe/€2005p) with climatic corrections. *Source* Odyssee database

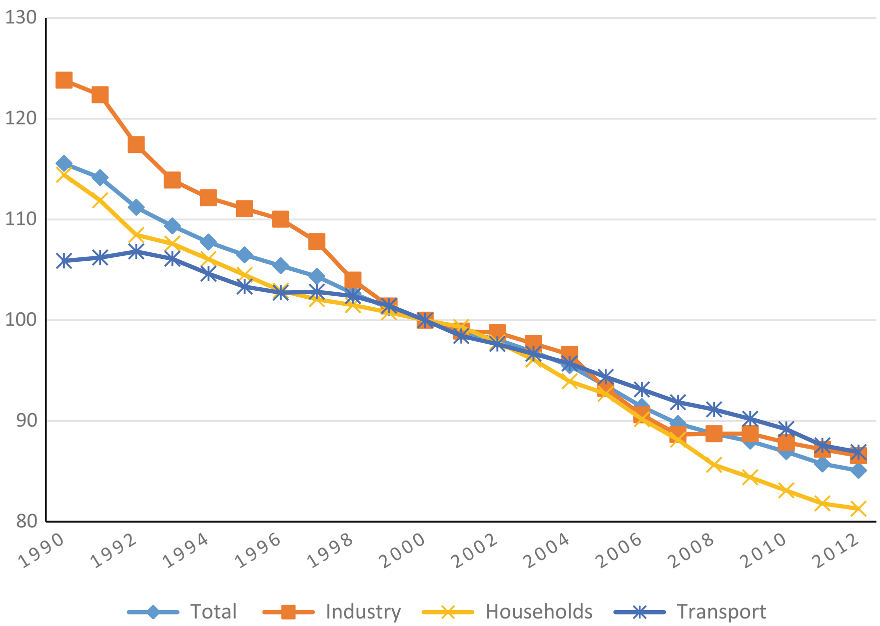


Fig. 5 Odyssee energy efficiency index (ODEX), EU28 (base 2000 = 100). *Source* Odyssee Database

improvement, particularly the industrial sector (1.7 % per year) and households (1.5 % per year).

In the manufacturing sector, the four most energy-intensive industries (chemicals, steel, paper and cement), which represented around 55 % of industrial energy consumption in 2012, reduced their energy consumption per unit of output until 2008—by around 2.1 % per year (chemicals and steel) and 0.7 (paper and cement) —while they increased their specific consumption during the crisis because firms were operating below full capacity so their energy efficiency index worsened. Most of the progress in the residential sector has been due to energy efficiency improvements in heating buildings (improvements both in construction and in heating appliances), which has been partially offset by an increase in the number of appliances and larger homes.

The extremely good energy efficiency of Italian final consumers further improved by 14 % over the period 1990–2012, against the 26 % EU average (Fig. 6). This relatively slow progress was due to the industry and transport sectors, while households improved their energy efficiency thanks to policy measures (subsidies for solar panel installation, substitution with high-efficiency appliances, new building requirements), but also to high energy prices, which induced energy savings (see Sect. 2.2). These high energy costs have also worsened the phenomenon of 'fuel poverty'—when a family cannot afford to keep adequately warm at a reasonable cost, given its disposable income. According to an indicator proposed by Faiella and Lavecchia (2014), 'low income high costs'—corrected to also include vulnerable households with zero heating expenditure—in the period 1997–2012 the share of Italian families constrained in energy consumption was around 8 %.

For transport, energy efficiency is differentiated by transport mode. While cars and rail have gained in efficiency, trucks and light vehicles have worsened their performance. According to the 2014 Scoreboard published by the American Council for an Energy-Efficient Economy (ACEEE),[8] the Italian transport sector ranked the highest among all the countries analysed. This result is largely due to advances in passenger vehicle energy efficiency: the national government has provided incentives to encourage consumers to replace old vehicles with new clean vehicles and has invested in the rail network both in terms of high-speed trains and improvements in goods transport.

Under the EU's Energy Efficiency Directive (2012/27/EU), Italy is committed to reducing national energy consumption by 15 megatonnes of oil equivalent by 2020. Indeed, energy efficiency measures have the potential to reduce energy consumption and the volumes imported. The most recent National Energy Efficiency Action Plan (NEEAP 2014) has a time horizon of 2016 set by EC Directive 2006/32, but it has set targets to 2020 which are consistent with the National Energy Strategy. This plan sets expected energy savings by 2020 for all sectors: the largest saving is expected from transport (−5.50 Mtoe per year), then from industry (−5.10), while households should contribute with savings of 3.67 Mtoe per year and the service sector with −1.23. This

[8]See Young et al. (2014).

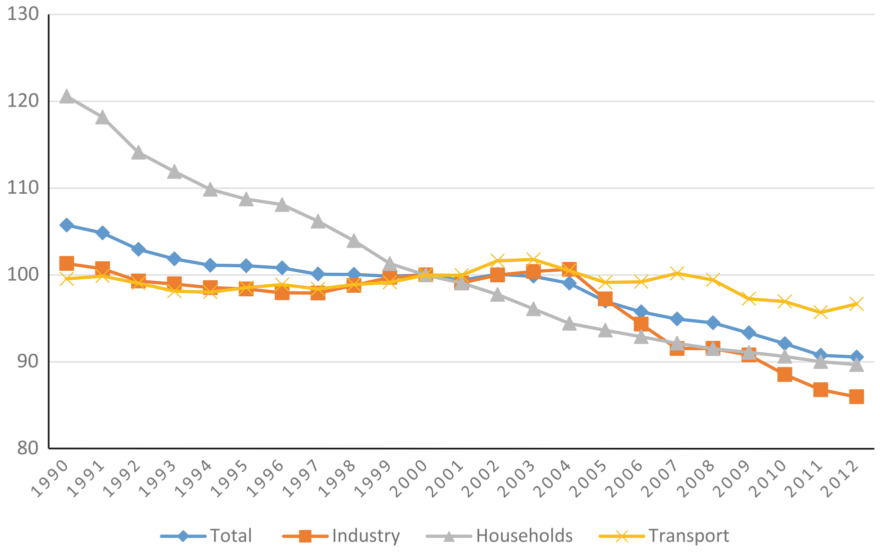


Fig. 6 ODEX, Italy (base 2000 = 100). *Source* Odyssee Database

energy efficiency improvement should be achieved with the implementation of policy measures already in place and new measures for promoting the energy efficiency of buildings—with new standards and tax rebates for the private residential sector and a special focus on public buildings, as required by EU directive 2012/27/UE.[9]

Another indicator to evaluate the trend of energy efficiency is the content of carbon emissions per unit of output, that is, carbon intensity (Fig. 7). This measure for the Italian economy is in line with the EU average and it has been stable since 2006. However, as is clear from the graph, carbon intensity has followed the same dynamics as energy intensity previously shown in Fig. 4. Italy's strategy for climate mitigation has relied heavily on promoting renewable through economic incentives, which in turn contributes to energy independence. These incentive support schemes have not been well coordinated and have been repeatedly changed, which has created some uncertainty in the markets, as will be explained in detail in Sect. 3.

When we look in more detail, some important insights can be collected. The left-hand graph of Fig. 8 shows CO_2 emissions for energy-intensive sectors. In Italy, carbon intensity per unit of output is lower than the European average for steel production, while some environmental improvements could be obtained for paper and cement production. Turning to the CO_2 intensity for private buildings (for lighting, heating and cooking), we notice that the household sector has performed well in terms of emissions per dwelling. However, despite the relatively good results the improvements have been slower than in the European Union overall.

[9]Article 5 of this directive establishes that the heating, lighting and thermal insulation of at least 3 % of total public buildings must be upgraded every year.

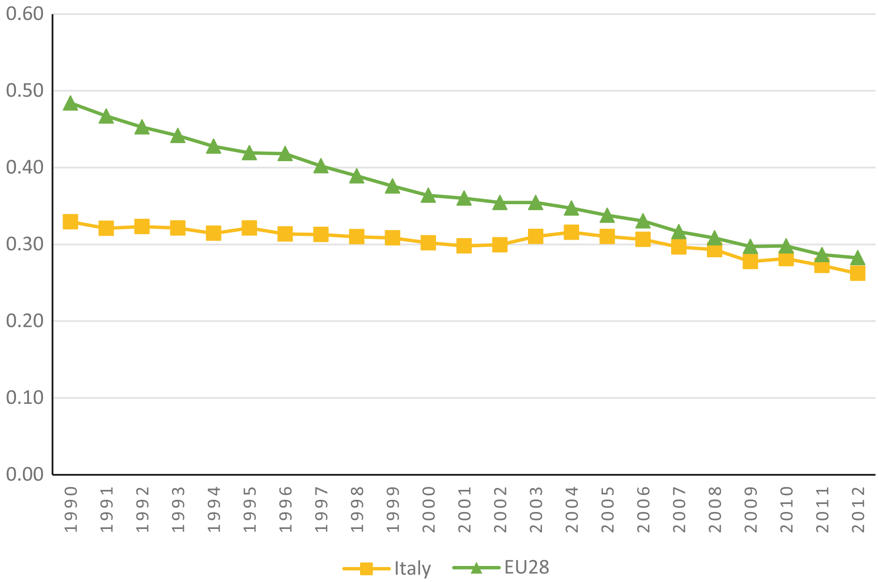


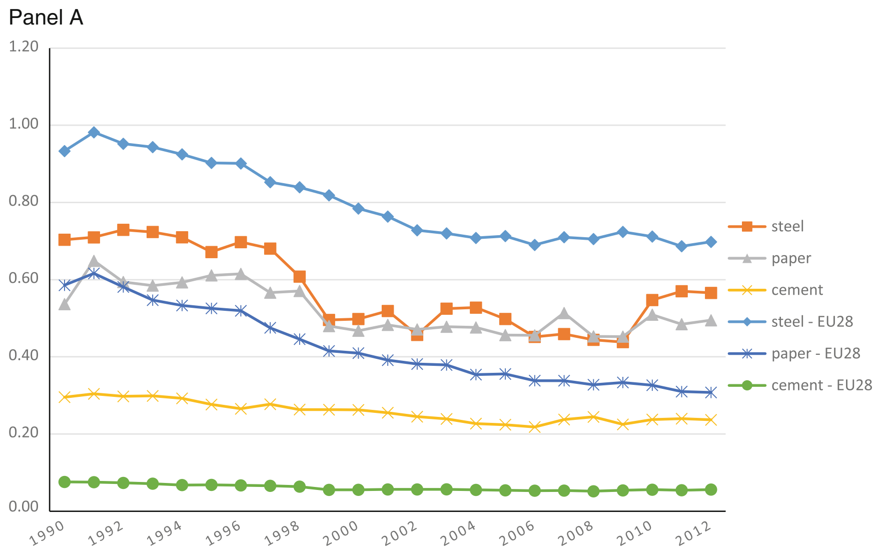
Fig. 7 CO_2 intensity 1990–2012 (including electricity and climatic corrections) (kCO2/€2005). *Source* Odyssee Database

2.2 *Energy Prices*

High energy prices have been a cost disadvantage for Italian companies and a significant burden for household consumption budgets. Italian gas prices are higher than the EU average, particularly for household consumers. This in turn also affects electricity prices because natural gas is the main fuel for thermal production. As shown in Fig. 9, prices are much higher for households than for industrial customers in all the major EU economies but the difference is larger in the Italian case, where the fiscal component of the price is particularly significant. Whereas electricity prices for Italian industrial firms are above the European average, gas prices are in line with other EU countries. This difference makes it worthwhile to switch from electricity to gas in industrial processes if there are no technological constraints.

Renewables cover an increasing share of total energy consumption in Italy and play a key role in electricity generation. In 2012 they accounted for 28 % of total production, with a jump to a share of 34 % in 2013 (Terna 2013).[10] A very complex mix of policy measures has supported this progress toward the EU 2020 target (see Sect. 3.3). The effect of this generous support scheme is twofold: on the one hand electricity prices are affected because charges are included in consumers' final bills;

[10]This increase is due to a growth in wind (+11 %), photovoltaic (+14.5 %), hydroelectric (+25 %) and biomass and waste (+36.9 %) electricity production.



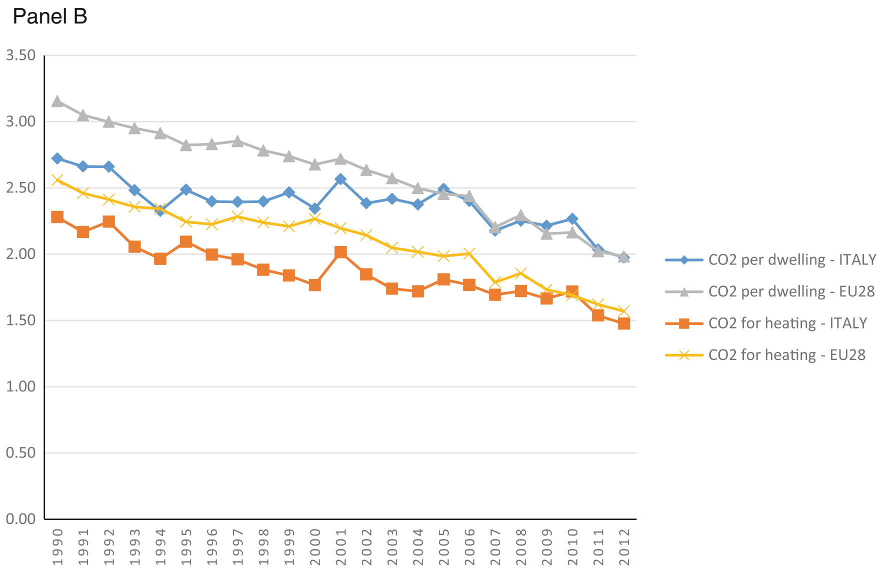


Fig. 8 CO_2 emissions for selected products (tCO_2/t) Panel A and for dwellings (tCO_2/dw) Panel B. *Source* Odyssee Database

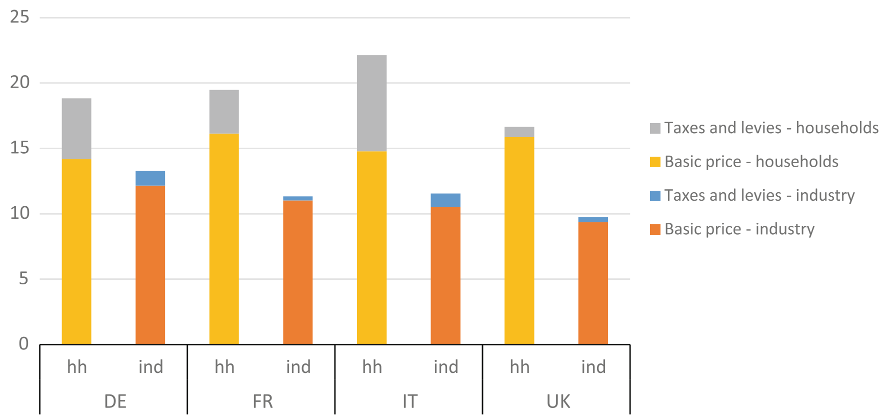


Fig. 9 Natural gas prices for selected EU countries, 2014 (Eur/GJ). *Source* Eurostat dataset

on the other, the increased supply has recently pushed down the basic price before tax. However, final electricity prices are higher than the EU average for both households and firms. In Table 2, electricity prices for domestic consumers are compared between the EU-28 and Italy.

It can be noticed that Italian unit prices are similar to the European average for low consumption levels (below 2,500 Kwh),[11] while they are higher and with a growing dynamic in the central brackets, where the bulk of electricity consumption volumes is located.

Electricity prices are also of paramount importance for international competitiveness. Indeed, in 2013 industrial companies absorbed about 40 % of the total electricity consumption, and electricity represented the second most-used fuel in industrial processes.[12] As shown in Fig. 10, Italy ranks only behind Cyprus and Malta in terms of electricity prices for industrial consumers, with a large component of the price represented by taxes (about 38 % of the price, while the fiscal component accounts for almost half of the price in Germany). This high cost hampers the competitiveness of Italian firms in international markets, as estimated interfuel elasticities show that the electricity demand of Italian manufacturing firms is less elastic to price changes compared to other energy sources, and substitution with other fuels is more limited.[13]

[11]The lowest bracket with very low consumption volumes covers second-home owners. This explains the higher unit price both in the EU and in Italy.

[12]According to the Italian Energy Balance (2013) published by the Ministry of Economic Development, the most important energy inputs for industrial firms are natural gas (43 % of total energy consumption), electricity (33 %), and oil and oil products (13 %). See http://dgerm.sviluppoeconomico.gov.it/dgerm/ben.asp.

[13]Bardazzi et al. (2015) estimate own and cross-price elasticities for energy sources for Italian manufacturing firms. The estimated parameters are lower for the two main energy inputs (−0.46 for electricity and −0.82 for natural gas) than for diesel (−0.90) and fuel oil (−1.44).

Table 2 Electricity prices for domestic consumers, taxes included (euro per Kwh) 2008–2014

	2008	2009	2010	2011	2012	2013	2014
Consumption < 1,000 kWh							
EU 28	0.249	0.249	0.264	0.272	0.277	0.299	0.315
Italy	0.276	0.294	0.283	0.265	0.257	0.279	0.294
1,000 kWh < Consumption < 2,500 kWh							
EU 28	0.169	0.174	0.179	0.191	0.201	0.213	0.219
Italy	0.158	0.171	0.163	0.164	0.186	0.196	0.211
2,500 kWh < Consumption < 5,000 kWh							
EU 28	0.158	0.164	0.167	0.180	0.188	0.199	0.205
Italy	0.203	0.210	0.197	0.199	0.213	0.229	0.245
5,000 kWh < Consumption < 15,000 kWh							
EU 28	0.149	0.157	0.160	0.171	0.179	0.191	0.196
Italy	0.231	0.261	0.249	0.243	0.264	0.285	0.301
Consumption > 15,000 kWh							
EU 28	0.141	0.153	0.154	0.165	0.172	0.182	0.186
Italy	0.217	0.293	0.280	0.287	0.295	0.320	0.328

Source Eurostat

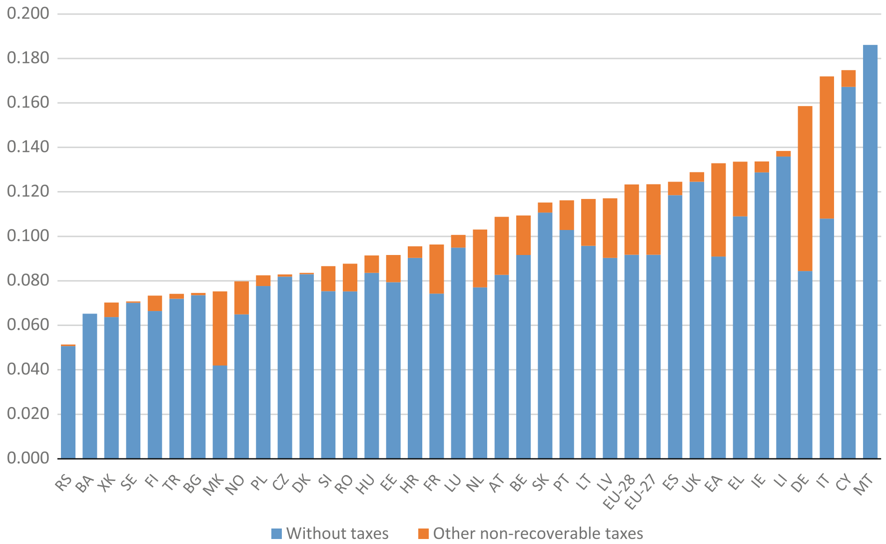


Fig. 10 Electricity prices for industrial consumers, 2014 (euro/kWh). *Source* Eurostat

Finally, the prices of petrol and other fuels affect commercial and private transport costs. As shown in Fig. 11, the consumer prices of petrol and diesel are higher in Italy than in the European Union generally, and this has always been the case in recent decades. The fiscal component is the main difference between the

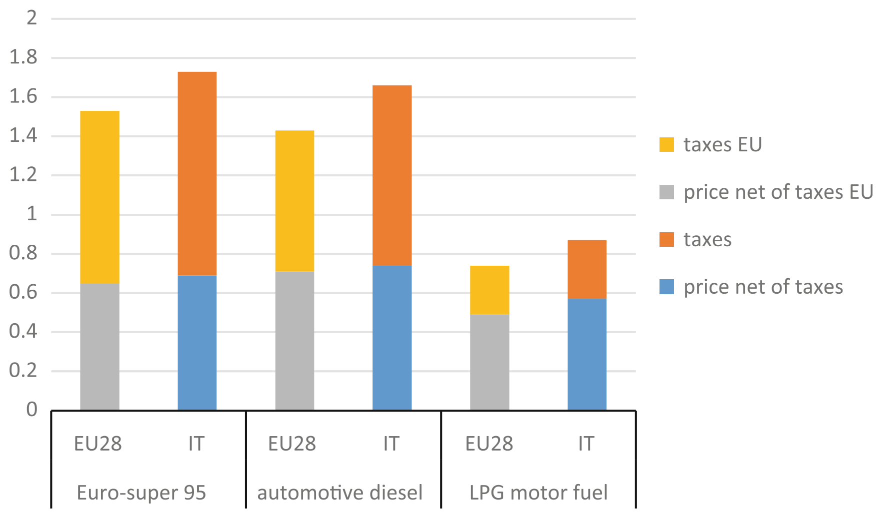


Fig. 11 Consumer prices of selected petroleum products 2013, (euros per litre). *Source* Oil Bulletin, Directorate-General for Energy, European Commission

national prices and the European average for all petroleum products. A study commissioned and reported in UPI (2014) assesses that fuel demand in Italy is highly elastic to fuel prices, particularly after the crisis that began in 2008. The rising taxes in the years 2011–2013 (+29 % for petrol, +46 % for diesel) increased pump prices and contributed to a collapse in fuel demand, especially along motorways. Obviously, the high incidence of excise taxes on petrol and diesel decreased the kilometres travelled per capita and improved efficiency.

3 Overview of Market-Based Instruments for Energy in Italy

The analysis of energy prices in the previous paragraph highlighted the role of the fiscal component in making Italian energy prices among the highest in the EU. Excise taxes on energy are one of the main pillars of market-based instruments, which the economic literature considers the most effective kind of instrument for reaching policy targets at the lowest cost, if properly designed. A very broad and well-known classification of policy instruments devoted to reducing energy intensity and to improving environment-related effects divides them into "market-based" and "command and control" (or non-market-based) instruments.[14] In the case of command and control (such as technology standards, non-marketable quotas, fixed

[14]On the characteristics of energy and environmental instruments, see Perman et al. (2013).

targets, prohibition or even moral suasion) the policy target is generally well specified and it is pursued by imposing mandatory obligations or restrictions on the behaviour of agents. On the contrary, market-based instruments (subsidies, taxes, fees, marketable quotas, liability systems) operate by creating incentives to change behaviour since they modify the relative prices that consumers and firms face, but do not specify how agents should behave to comply with the policy target. Market-based (or incentive-based) instruments are generally suggested as the main policy tool to be used, due to their cost-effectiveness (the optimal solution is reached at a minimum total cost) and to their higher degree of neutrality regarding agent choices.

This section presents an overview of energy taxation and other market-based instruments with the aim of assessing their role in Italian energy and environmental policies.

3.1 Taxes, Subsidies and Tax Expenditure in Italy

3.1.1 The Rationale of Energy Taxation

Taxation of energy products is a very popular policy in all countries, although it is implemented with different strengths and for different purposes. First of all, energy products are taxed because of their attractiveness from a general public revenue perspective. As energy is an essential product, the demand for which is relatively inelastic, the tax base and government revenue are stable and relatively easy to estimate.[15] In a very limited number of cases, energy taxes are earmarked[16] for specific use (i.e. fuel taxes for road maintenance) and can be levied as a user charge. Moreover, energy security and climate change goals call for an ever-increasing efficient use of resources, and the price signal embedded in energy taxes is deemed to be one of the best policy instruments. Both energy security and climate change imply market failures, because they can be considered public goods, and because they both imply an externality issue.[17] The use of Pigouvian taxes is, therefore, highly recommended in the literature. Thus, fossil fuels are often taxed in order to internalize some of the damage caused by their use (emissions, but also other social costs imposed by vehicles, such as congestion and traffic accidents).

Due to this list of potentially conflicting goals (revenue and externalities), it is very difficult to assess an optimal tax rate level. It is evident that for the revenue-raising objective the quantity consumed should ideally be constant,

[15] Moreover, the low demand elasticity of energy products minimizes the excess burden and makes this policy instrument consistent with the so-called Ramsey rule for optimal commodity taxation.

[16] Earmarking conflicts with the principle of universality in public budgeting (total revenue in the budget must cover total expenditure). However, part of the economic literature stresses that earmarking enhances the public acceptability of taxes, and in particular of environmental taxes. On this topic, see OECD (2012) and Kallbekken and Sælen (2011).

[17] For a discussion of energy security and market failures, see Goldthau (2011).

whereas for energy security and climate change purposes an increase in energy efficiency—and therefore a reduction in energy consumed—is the key target. Even if pricing externalities were the only objective of taxation, it would be very difficult in practice to assess the marginal level of externality to be used as the optimal level for the tax rate, especially if climate is taken into account.

That said, energy taxes have significant income and welfare impacts, and the impact of rising energy prices on income distribution and firm competitiveness is a cause of great concern—especially in Italy, where energy tax rates are among the highest in the world.

Current Energy Taxes in Italy

Energy taxes have historically been a very important source of public funds in Italy, because the revenue-raising goal is absolutely in line with the aim of increasing energy security. Energy taxes have always constituted more than 2 % of GDP and accounted for over 75 % of all environmental taxes.

Figure 12 shows the implicit tax rate at nominal and deflated values for selected European countries. Looking at the histograms, it can be noticed that energy taxes in Italy were above 300 euros per ton of oil equivalent in 2012, a level among the highest in Europe in nominal values (blue bars). Indeed, Italy ranks in second place, after Denmark. Considering deflated values, however, Italy drops behind the United Kingdom. The difference between nominal and deflated values testifies to the difficulties in managing energy excises: excises are unit taxes, for which the tax base is a quantity and the tax rate is a money value, not directly influenced by price levels.

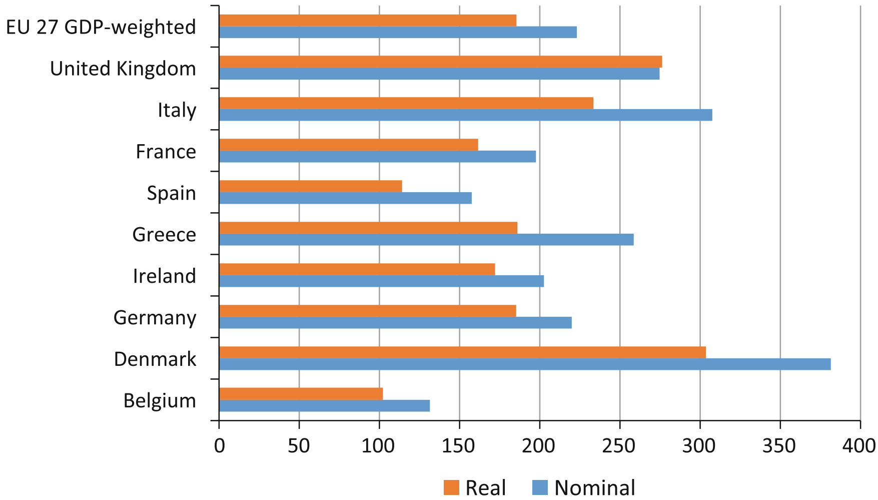


Fig. 12 Implicit tax rates on energy for selected EU countries (2012). The implicit tax rate is computed as energy taxes in euros per ton of oil equivalent (TOE). The real values are deflated (2000 = 100). *Source* Eurostat (2015)

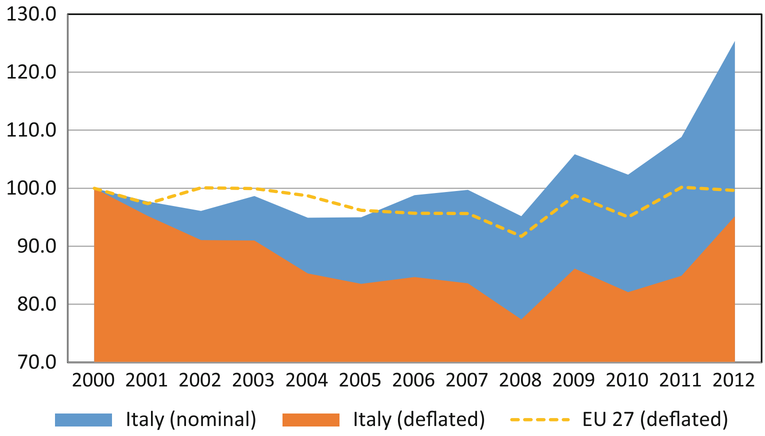


Fig. 13 Implicit tax rates on energy in Italy (indexed 2000 = 100). The implicit tax rate is computed as energy taxes in euros per ton of oil equivalent (TOE). *Source* Eurostat (2015)

Therefore, in order to obtain a steady real tax burden, policy makers should annually update nominal tax rates for inflation, but this updating process raises political costs and it is not performed as regularly as is theoretically needed.

In more detail, Fig. 13 shows how the difference between nominal and deflated values increased during the first part of the 2000s in Italy. The public budget problems which became evident in the aftermath of the financial crisis led to a manoeuvre on energy tax rates, as shown by the sharp rise in 2011–2012. Only after this last increase did the deflated value of the implicit tax rates approach the level reached in 2000. On the contrary, the deflated index for the EU exhibits a more stable path: the implicit tax rate fluctuates around the level reached in 2000 (100) throughout the period.

Households in Italy as well as in most European countries pay about 50 % of the total energy taxes (Fig. 14). The service sector accounts for a third of energy-related revenue, whereas industry reaches a share of 11 %. It is worth noting that industry has a smaller share of energy taxes than would be expected considering its role in the Italian economy. As discussed later, this is an indication of a large use of tax rebates to protect Italian industry against the adverse effects of market-based instruments.

A snapshot of the effective tax rates, classified according to fuel and energy use, is shown in Table 3. The effective tax rates have been computed by considering energy and CO_2 emission values in order to have a common basis for tax rates usually referring to different physical units (e.g. litres for car fuels, kwh for electricity). Being part of the European Union, Italy is constrained in regulating its energy tax rates by the minimum levels set by the EU Energy Taxation Directive (2003/96/EC), which were fixed without reference to the carbon content. However, not having been revised for more than a decade, the current tax rates on the main energy products in Italy have almost doubled the minimum Directive levels. Moreover, the table highlights that the energy tax rates are very far from

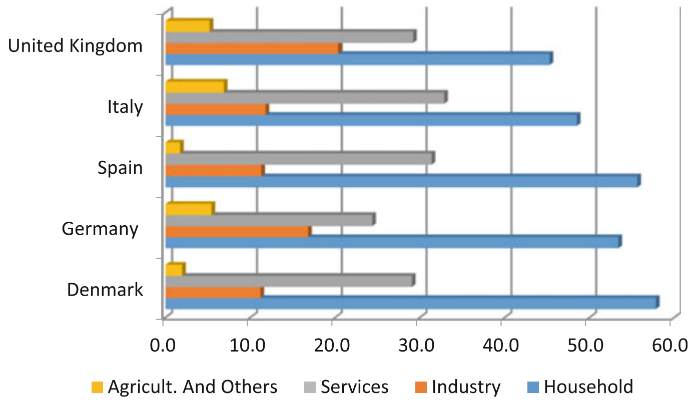


Fig. 14 Sector contributions to total energy tax revenue in selected countries (2011). *Source* Eurostat database

homogeneous when the energy content and carbon content of energy products are considered, and at the same time that Italian energy taxation is heavily concentrated on transport use, if compared to average OECD values.[18]

Although not shown in the table, it is important to stress that only road transport fuels are highly taxed, whereas the tax rates for aviation and marine use are much lower. This means that the highest share of the burden of energy taxation is directly on household shoulders, as previously shown in Fig. 14. The tax preference for non-household agents has also been historically evident in the difference between petrol and diesel tax rates, a characteristic common to the majority of OECD countries. Until the last decade, petrol consumption was prevalent in developed countries: private cars mainly used petrol whereas the commercial and industrial vehicle fuel was diesel. As a way to foster competitiveness, in Italy as in almost all developed countries the diesel tax rate was set at a lower level than the petrol one. The tax advantage—together with the higher energy efficiency of diesel vehicles—caused a noticeable shift towards diesel vehicles and subsequently an increase in the relative industrial price of diesel, which is now very close to the petrol price. Unfortunately, diesel fuel also has a higher CO_2 content and this means that the preferential tax treatment has encouraged more diesel use and relatively higher CO_2 emissions. Moreover, the current preferential tax treatment lacks a clear economic rationale because it is no longer clearly targeted at competitiveness protection. More generally, a clear rationale cannot be identified for Italian energy tax rates because it is the result of several ad hoc manoeuvres, almost completely caused by revenue-raising needs. A link between the tax rate and the energy content or the value of the externality caused by energy use is completely absent. However, in the

[18]The IEA data, used by the OECD to compute effective tax rates, collect all kinds of transportation under Transport Use, thus also including household energy use for private transport. Residential and commercial uses are therefore mainly energy use for heating purposes.

Table 3 Effective tax rates per fuel and energy use in Italy and OECD[a]

	Oil products	Coal and pet coke	Natural gas	Biofuels and waste	Renew. and nuclear	All fuels	OECD all fuels
EUR per GJ							
Transport use	16.8	0.0	0.1	21.5	0.0	16.7	11.5
Residential and commercial	8.1	0.0	0.1	0.0	0.0	1.2	1.2
Industrial and energy transformation	1.7	0.1	0.3	0.0	0.0	0.9	0.8
Electricity production	0.0	1.0	1.2	1.9	1.9	1.2	0.9
All uses	11.1	0.9	0.6	4.4	1.8	5.0	3.3
EUR per tonne CO2							
Transport use	232.5	0.0	1.5	303.8	–	231.8	161.0
Residential and commercial	116.0	0.0	1.9	0.0	–	20.2	17.0
Industrial and energy transformation	22.5	0.8	5.4	0.0	–	12.8	10.0
Electricity production	0.5	12.4	21.1	18.6	–	15.0	13.0
All uses	152.4	10.2	9.8	44.6	–	75.9	52.0

[a]OECD tax rates computed as simple averages
Source OECD (2013a)

late nineties, Italy tried to introduce an Environmental Tax Reform, with an attempt to redesign the tax system according to the climate protection goal, on the lines of a general carbon tax reform. This tax reform, which came into force in 1998 (law 448/98), is a clear example of the weakness of environmental policy in Italy. The policy started with a general and coherent design setting new tax rates to be annually increased, but was halted after only two years when a spike in international oil prices raised objections and protests from households and firms.[19]

3.1.2 Subsidies

According to economic theory, Pigouvian subsidies—like Pigouvian taxes—can be employed to encourage the use of energy-saving technologies or to discourage the use of fuels or appliances harming the environment. Unfortunately, as energy is a strategic input factor and a basic consumer need, subsidies are frequently set to

[19]For an appraisal of the effect of the full reform on the competitiveness of manufacturing firms, see Bardazzi et al. (2004).

target too many goals, leading to a system which encourages wasteful energy consumption and thus makes energy efficiency and climate policies ineffective. In the last decade this inconsistency has been highlighted by scholars and international organizations and the distinction between "good subsidies" (related to the development and deployment of renewable energy) and "bad subsidies" (directed at fossil fuels or at the general aim of lowering energy prices) is becoming more and more crucial. Phasing out fossil fuel subsidies has become one of the main policy lines to combat climate change.

In spite of their importance in the public debate and the international political agenda,[20] there is not yet a common agreed definition of what a "subsidy" is, particularly in the case of energy. Nonetheless, it is accepted that the definition should not only include potential direct financial transfers, but also "any government action that lowers the cost of energy production, raises the revenue of energy producers or lowers the price paid by energy consumers".[21] Based on this general characterization, subsidies can be classified as **on-budget subsidies**, covering measures affecting the general government budget, and **off-budget subsidies**, i.e. those measures not featuring in the public budget (tax expenditure or benefits originating from market regulation are the main categories).

On-budget Subsidies

A rough estimation at the European level of on-budget measures can be based on Eurostat's General government expenditure by function, which distinguishes among "Direct financial transfers," "Energy-related services provided directly"[22] and "Government energy related R&D Appropriations." The shares of GDP of overall on-budget energy-related expenditure for the EU 27 in 2008 are shown in Fig. 15. Although the role of on-budget subsidies is relatively small in the EU (on average 0.2 % of GDP or 0.5 % of total expenditure), the graph shows that several countries prefer the use of direct financial transfers rather than providing

[20]In the 2009 and 2013 G20 summits, a resolution to "rationalize and phase out over the medium term inefficient fossil fuel subsidies that encourage wasteful consumption" was agreed.

[21]See the IEA, OECD and World Bank report prepared for the 2010 G20, and OECD (2013a, b). Although difficult to estimate, other aspects such as the limitation of civil liability for nuclear accidents or a lack of measures aimed at internalizing external costs caused by producers should be taken into account.

[22]Using "*General government expenditure by function*", the entries '*Subsidies*' (D.3) and '*Capital Transfers*' (D.9) have been employed to estimate direct financial transfers from general government, while the entries '*Intermediate Consumption*' (P.2), '*Gross Capital Formation*' (P.5) and '*Compensation of Employees*' (D.1) have been utilized to estimate appropriations by general government to undertake energy-related services. For each of the entries above, only the (second level) entry '*Fuel and energy*' (04.3) under Economic Affairs (04) has been taken into account. R&D expenditure comes from the dataset "*Government Budget Appropriations or Outlays on R&D*" (*gba_nabsfin07*), entry '*Energy*' (05) in NABS (Nomenclature for the Analysis and Comparison of Scientific programmes and Budget).

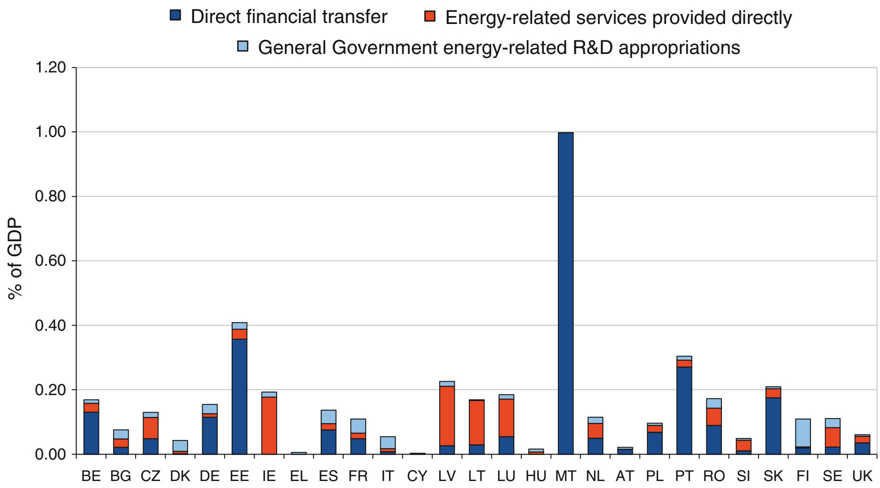


Fig. 15 Energy-related public expenditure (percentage of GDP). *Source* Eurostat database

energy-related services. Direct financial transfers are mainly concentrated on coal, currently the most important energy product recipient. On the contrary, an absence of primary energy resources reduces the level of direct support in highly energy-dependent economies like Italy. With the exception of the UK, data for R&D shows a higher correlation with the size of the economy, especially for the largest countries, which actually account for about the 90 % of the EU-27 expenditure on energy sector R&D. The negligible role of energy-related on-budget subsidies at EU level is obviously partially due to the general EU policy framework, which discourages the use of any subsidies considered harmful to the common market (state aid) and has committed member countries to very ambitious environmental goals. However, it is worth stressing that on-budget subsidies constitute only a part of public intervention in the energy sector, and relevant and generally non-transparent subsidies do not directly involve the general government budget.

Table 4 presents some further details on Italian energy-related public expenditure. The table shows a declining trend in this kind of expenditure—because of public budget stress—with the exception of "Other current Transfers".[23]

The dataset we have chosen does not allow us to identify the specific energy sector the support is addressed to (i.e. coal, oil, or nuclear energy decommissioning). In order to estimate these quotas, it is necessary to rely on findings from other studies, such as EEA (2004) or Ecofys (2014).

It is worth mentioning that outside the EU, on-budget subsidies are much more relevant: fossil fuel subsidies, which are usually consumer subsidies, are significant

[23]This item, appearing in the general government public budget but not in the central government budget, is the cost paid by electricity consumers to finance renewable subsidies. See Sect. 3.3 below.

Table 4 Energy-related public expenditure in Italy, general government (in million euros)

	Direct financial transfer	*Capital transfers, consolidated*	*Subsidies*	*Other current transfers, consolidated*	*General government energy-related R&D appropriations*
2000	**274.0**	*214.0*	*60.0*	*0.0*	**n.a.**
2005	**168.0**	*120.0*	*48.0*	*0.0*	**381.9**
2008	**170.0**	*139.0*	*29.0*	*2.0*	**589.3**
2010	**190.0**	*142.0*	*38.0*	*10.0*	**347.3**
2012	**180.0**	*141.0*	*26.0*	*13.0*	**327.3**

Source Authors' calculation on Eurostat database

as a percentage of GDP in Central Asia, South America and the Middle East. It has been estimated that maintaining diesel and petrol consumer prices below international levels implies a total fuel subsidy bill of around 10 % of GDP and leads to considerable public budget stress.[24]

Off-budget (Tax Expenditure)

As previously discussed, a relevant share of energy-related subsidies does not explicitly appear as public expenditure (off-budget). The great majority of this kind of intervention can be defined as tax expenditure, i.e. revenue foregone by the budget due to a reduction in the tax liabilities of particular household groups or sectors of activity. Indeed tax expenditure can be considered a deviation from the ordinary tax benchmark and it may take the form of tax exemptions, investment tax credits or preferential tax rates.

Regardless of the tax basis—energy content or pollutants—governments have often introduced exclusions or preferences to mitigate potentially adverse impacts of higher energy prices on household distribution or industrial competitiveness. It is increasingly recognized, however, that such preferences change the relative prices in the economy in ways that can harm the efficacy of the overall energy and environmental policy, or energy taxation in general. The use of tax subsidies has been widespread among oil and gas producer countries (such as Venezuela, Mexico and Iran) as a way of distributing to consumers and firms a sort of "dividend" from the export of these resources. Recently, the majority of producer countries have reconsidered this energy subsidy policy[25] because a number of analyses have shown a link between energy subsidies and inefficient energy uses, and particularly because producer country governments have realized how big the share of foregone revenue caused by energy subsidies is.

Needless to say, an exhaustive estimation of off-budget subsidies is particularly problematic. The IMF (2013) estimates them at 1.5 trillion dollars at world level,

[24]For a summary of the international organization estimates, see Overseas Development Institute (2013).

[25]In recent years, relevant fossil fuel tax expenditure reforms have been realized in Indonesia, Malaysia and Iran.

Table 5 Oil and natural gas related tax expenditure in Italy (in million euros)

Fossil fuel support to petroleum products and natural gas	2005	2008	2009	2010	2011p
Oil products					
Fuel-tax reduction for rail transport	10	5	1	1	2
Tax relief for trucking companies	69	148	144	144	346
Tax relief for public transport	24	14	14	16	25
Energy tax breaks for agriculture	860	807	816	817	908
Tax relief for ambulances	4	2	2	2	5
Fuel-tax exemption for shipping	570	548	488	492	547
Tax relief for users living in disadvantaged areas	62	62	233	231	231
Natural gas					
Tax relief for industrial users of natural gas	89	60	60	60	60

Source OECD (2013b)

more than 1.5 % of total GDP. The OECD has published a detailed inventory of energy-related tax expenditure (OECD 2013b), but the specific measures are so heterogeneous that averaging or comparing estimates among countries is very complicated. As a general finding, it can be noticed that the majority of fuel tax expenditure is devoted to oil and natural gas and this structure is also confirmed for Italy, as detailed in Table 5. The table shows that the most important recipient sectors are transport (all means of transport) and agriculture.

Several European countries set a reduced rate of VAT on the consumption of energy products. The difference between the standard rate and the special rate applied for certain specific uses and users (mainly households and agriculture) gives the magnitude of the implicit subsidy. In Italy too a reduced VAT rate (10 % instead of 22 %) is applied to selected electricity and natural gas users, but several other tax expenditure policies are also in force. As regards renewable, investments benefit from a rebate on VAT, and a general exemption from the payment of excise duties is established for green electricity produced and consumed directly by the producer. Moreover, a special tax regime is available for farmers producing and selling renewable energy: income coming from the renewable energy production is considered agricultural income and therefore taxed on a preferential lump-sum basis.[26] Finally, two tax rebates are provided for environmentally related investments and research and development activities. Law no. 296/06 grants a tax credit as a contribution to enterprises which carry out research and development activities (10 % of investment and innovation costs), whereas law no. 388/2000 (known as the Tremonti environment law) provides a tax allowance for investment in environment-related activities exceeding the average investment of the preceding

[26]More than 17,000 farmers registered renewable equipment in 2010, and around 3000 agricultural firms declared income from solar energy production. See the Istat Agricultural Census at www.istat.it.

five years. Italy has also used property taxes at the local level to promote green electricity: municipalities may establish lower rates for taxpayers installing a renewable energy plant to produce electricity.

3.2 Emission Trading Scheme

The European Emission Trading Scheme (EU ETS), introduced in 2003, is a cap-and-trade system set up to limit greenhouse emissions by selected large industrial installations in the EU.[27] Cap-and-trade systems involve the issuance of a limited number of allowances corresponding to the target size of CO_2 emissions. Typically, the cap decreases progressively from one period to another in order to reach a specific environmental target at a certain time horizon (e.g. in the current EU ETS the target is set to cut emissions by 20 % in 2020). After a trial phase, this market entered into force in 2008 together with the Kyoto protocol. Member States allocated allowances to the firms in the scheme (mainly for free, i.e. 'grandfathering') and these allowances were traded between market participants. After the end of the Kyoto protocol (December 2012), the ETS scheme run into a third phase in which the EU tried to introduce an amendment aiming to improve market stability: new economic activities were put under the ETS scheme and the grandfathering allocation, to a large extent, was replaced by auctioning.[28] From a theoretical point of view, Pigouvian taxes and ETS operate in the same way by sending a signal to the market: the true carbon price. If the marginal social costs are correctly estimated and the overall pollution target is optimally set, the permit price of a cap-and-trade system will equal the Pigouvian tax rate and both instruments will contribute to achieving the same environmental target, at the least total cost of abatement. However, in the real world these costs and the target are very difficult to estimate and the two instruments differ in efficacy and transaction and implementation costs. Indeed, building a new "artificial" market for CO_2 emissions proved to be harder than expected and the functioning of the market has almost always been unsatisfactory. In particular, since the surge of the financial crisis a surplus of allowances with respect to emissions has been observed (a surplus of over 2 billion allowances is estimated for 2014) and the market price, which represents the carbon signal, has plummeted below 5 euros per tonne. Apart from the policy initiatives

[27]The ETS sector includes power and heat generation, combustion plants, oil refineries, coke ovens, iron and steel plants, cement, glass, lime, bricks and ceramics.

[28]Although theoretically there is no difference between allocation by auction or grandfathering (provided that no market imperfections exist), they have different impacts on the budget: grandfathering of permits represents a transfer from society to polluters (foregone revenues), whereas auctioning represents revenue paid by polluters to society.

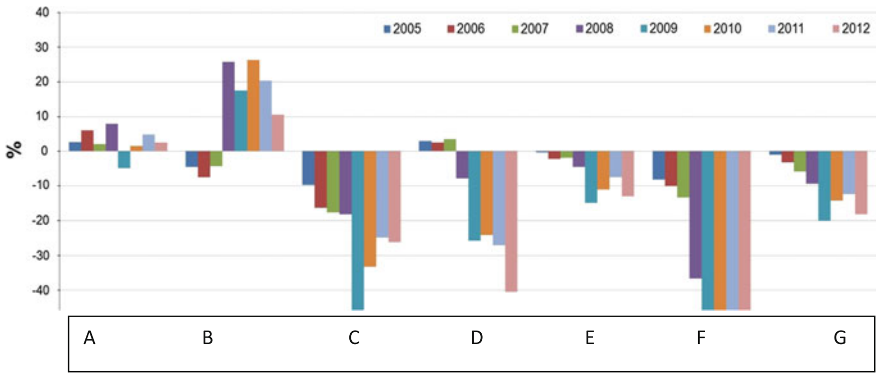


Fig. 16 Difference between emission permits and verified emission in Italy. *A* Power and Heat, *B* Refineries; *C* Iron & Steel, *D* Cement, *E* Glass, *F* Ceramic, *G* Pulp & Paper. *Source* Ispra database

currently taken by the EU commission to contrast this trend,[29] the general situation is inefficient because the carbon price signal from the ETS (principally directed towards energy-intensive sectors) is very different from that implicit in energy product taxation (for all sectors and consumers using energy products).

Italy has implemented the EU ETS regulation according to the EU legislation framework, but without a clear national *imprinting* or a real attempt to coordinate the EU ETS with the other instruments in force in Italy. Like many other member countries, in the first two phases Italy allocated more allowances than necessary. Obviously, this “national defensive choice” contributed to the aforementioned total surplus formation and weakened the signal to encourage firms to make more energy- and carbon-saving choices. Figure 16 illustrates the sectoral difference between allowances and verified emission during the first two phases of the EU ETS. With the partial exception of the power and refineries sectors, all the other sectors covered by the ETS framework exhibited a relevant surplus.

With the start of the third phase, auctioning replaced grandfathering (allocation for free) and the revenue collected in 2013 reached 386 million euros, more than 10 % of the total revenue at EU level (3625 million euros).[30]

[29]The EU commission is preparing a structural reform to improve the effectiveness of the market. A market stability reserve and a limitation on the use of international offsetting credits are the key elements of the proposed reform. See “Proposal for Decision Of The European Parliament and of The Council concerning the establishment and operation of a market stability reserve for the Union greenhouse gas emission trading scheme and amending Directive 2003/87/EC”, COM(2014) 20/2.

[30]The Italian government has declared that 50 % of this sum will be used for climate- and energy-related purposes, as set by the EU regulation.

3.3 Feed-in Tariffs

As discussed above, when defining subsidies all government policies which can alter market prices should be included, even those cases in which the government only sets a general regulation and revenue and expenditure are accrued and incurred by other agents. The most well-known example of such mandated transfers is the feed-in tariff (FIT), a fixed[31] payment made to households or businesses generating electricity from renewable energy sources (RES-E) proportional to the amount of power generated and implying a price higher than the market electricity price.[32] This premium on the market price is intended as compensation for the higher costs of the immature technology and must be financed. Although FIT schemes can be financed in a number of ways, the cost of this renewable incentive policy will ultimately be borne by consumers and firms. Italy, like the vast majority of EU member states supporting RES-E, finances the FIT scheme through a surcharge paid by electricity customers via their electricity bills (the so-called A3 component). This surcharge can be classified as a non-tax levy (or quasi-tax) because it is set annually and collected by national electricity regulators and does not feature in the budget of the central government.[33]

The Italian support system for RES-E is very complex because it is differentiated by source (wind and photovoltaic technologies, for example, are financed by different schemes) and because it has been repeatedly reformed and revised.[34] Nonetheless, it has proved to be one of the most generous in the world. Figure 17 shows that the average level of support in Italy—32 euros per MWh—is higher than in all other European countries.

However, this average level conceals a level of support highly differentiated according to technology: since the start of the new century, Italy has experienced a solar investment boom triggered by incentives much higher than the average (Table 6).[35]

Besides the investment boom, the generous Italian RES-E support scheme caused a rapid rise in support payments and, as a consequence, a considerable growth in the "A3 component" of electricity bills. This increase in electricity payments has progressively raised concerns about the distributional and competitiveness impacts on

[31]These contracts typically last between 15 and 20 years.

[32]In addition to FITs, there are also other mechanisms through which renewable energy sources are supported, for example, renewable energy certificates (Green Certificates), and other similar support schemes.

[33]In addition, a "priority access" to the power grid is generally granted to renewable electricity generators. This clause obviously imposes costs on some segments of the energy sector while conferring benefits on others.

[34]"CIP 6/92", Green Certificates, "Conto Energia" (with five different sub-regimes) and "Tariffa Onnicomprensiva" are the main support schemes that came in one after the other.

[35]Between 2000 and 2013 electricity power generation by RES more than doubled (from 50,990 to 112,008 GWh). 35 % of this increase is from solar installations.

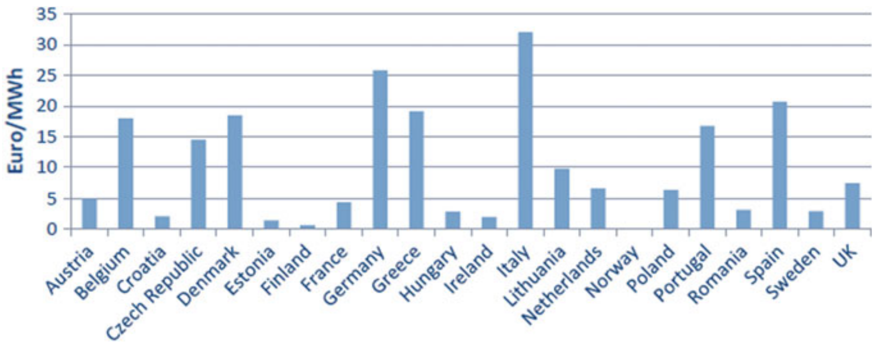


Fig. 17 RES-E support per unit of gross electricity produced in EU countries (2012). *Source* CEER (2015)

Table 6 Weighted average support level by technology (Euro per MWh 2012)

	Bio-energy	Geothermal	Hydro	Solar	Wind (on shore)	Total
Italy support	126.1	76.7	87.6	335.6	79.0	180.0
Minimum across 22 countries	14.5	8.0	3.5	14.5	7.0	13.5
Maximum across 22 countries	138.1	175.7	96.4	462.1	86.3	219.5
Weighted average across 22 countries						107.2

Source CEER (2015)

households and firms, as the revenue from the “A3 component” more than tripled between 2009 and 2013, reaching 12 billion in 2013.[36]

The Italian government has been forced to intervene to control this explosive trend, first by stopping the RES-E-related FIT schemes and, more recently, by introducing significant retroactive cuts to the guaranteed feed-in tariffs (FIT) and new taxes on self-consumed RES electricity.[37] Although the incentive system previously in force was too generous and therefore clearly unsustainable in the medium run, it is questionable whether the retroactive cuts are compatible with the Italian and European constitutional frameworks. After a decade of generous but unstable policy support schemes, the investment boom allowed early achievement

[36]A representative residential user is currently paying more than 20 % of the electricity price per Kwh to finance the A3 component. See Pazienza and Verde (2013) for further details.

[37]PV producers, which were granted incentives for a period of 20 years under the “Conto Energia” mechanism, now have to choose between three options that in any case result in a cut in the previously guaranteed FIT. See decree law 91/2014.

of the target set by the EU and national plans.[38] However, there are currently no incentives for new solar installations and very few in force for other technologies. Moreover, no clear policy scenario for the near future is available.

4 Which Direction for Energy and Climate Security Policy?

Important changes in the energy and climate framework at the national, European and world levels have characterized the last decade. Several geo-political tensions have increased the vulnerability of the energy-dependent European economies and exposed consumers and firms to abrupt increases in energy prices. This vulnerability called for an increase in the diversification of supplies and new energy-trading relations and pipeline projects have been planned. In the meanwhile, when the Kyoto Protocol became effective in 2005, the EU environmental policy gained new force in terms of energy-saving renewable and de-carbonization policies. A long phase of increasing oil and gas prices led to the US shale gas revolution.[39] This, together with the growing importance of LNG[40] and the renewable boom experienced in many countries, has lately driven oil and gas prices down.

This phase of increasing diversification of supplies and low fossil fuel prices can generally be considered positive from an energy security point of view; however low energy prices can also divert attention from energy-saving policies, causing a general "rebound effect" with adverse consequences for the decarbonisation goals. This is even more important in Italy, whose energy policy has frequently been driven more by urgencies than by sound long-term design.

In our opinion, this period of a relatively low national energy bill appears the appropriate time for a general reorganization of the field. After a very long gestation,[41] the National Energy Strategy set goals and programmes in coherence with the general European framework but the incongruity between extremely unstable energy markets (with profound changes in technology and infrastructure needs) and the very long period needed to write a policy strategy is evident. Not surprisingly, between the policy design and implementation phases various contradictions emerge. As discussed before, although Italy is one of the most energy-efficient countries, enhancing energy efficiency is still the first priority of the National

[38]The RES share of electricity consumption for 2013 is much higher than the level set by the National Action Plan for both 2013 and 2020. See GSE (2015) for further details.

[39]For a discussion of the US shale gas revolution, see Meade and Faiella Di Nino in this volume.

[40]The growing supply of LNG from the Middle East area pushes the natural gas price down as a result of increased competition, especially in those countries where regasification infrastructure is available.

[41]The National Energy Strategy was first sketched by the Prodi government, then formulated under the Berlusconi government, and finalized by the Monti government in March 2013. The Renzi government confirmed the Strategy in 2014.

Energy Strategy, as several sectors need to improve their performance. The aforementioned national plan for energy efficiency (NEEAP*)* is comprehensive and well structured. However, public funds needed to improve energy efficiency in public and private dwellings appear totally insufficient. At the same time, the recent decree law "*Sblocca Italia*" substantially encourages fossil fuel extraction, making drilling for oil and gas easier, especially in the Adriatic Sea and the south of Italy (Basilicata), where some of the largest unexploited Italian reserves are deemed to be located. Although it is evident that an increase in domestic fossil fuel supplies can be beneficial for energy security, it is also clear that focusing attention and monetary resources on oil and gas reserves—which in any case are estimated to be limited—can divert attention from long-term goals. Enhancing renewables and energy efficiency appears to be a much more reliable contribution to reducing the national energy bill.[42]

The main weakness of Italy's energy/environmental policy is, in other words, a lack of an integrated vision, which should build on national strengths and take into account diversification needs and new technology scenarios. It is beyond the aim of this chapter to discuss how the Italian energy strategy should prioritize its goals. However, we consider that a reliable use of market-based instruments based on a unique price signal as a basis for all sectoral implementation can help attain the maximum level of energy efficiency and, at the same time, the minimum level of carbon intensity.

As is widely known, carbon pricing policies are characterized by cost effectiveness because the price signal—if really unique—helps consumers and firms to choose goods, investments and technologies with the least carbon content. To reach the least carbon content, agents make both energy-saving and substitution choices, and consequently both goals can be reached. This view is coherent with the Commission proposal for a revision of the Energy Taxation Directive, which promotes the design of two separate components in common energy minimum tax rates: an energy content component and a carbon content component. In other words, taxing energy products can help in reaching the two goals.[43]

Although the price signal cannot be considered the only driver of environment-friendly behaviour, Italian consumers and firms have proven to be very reactive after energy price changes. A shift from leaded to unleaded petrol incentivized by different excise taxes and, more recently, an increasing use of natural gas and hybrid fuelled cars are notable examples of a very effective reaction by Italian households, which can contribute to explaining Italy's current historically low energy intensity (see Fig. 7). Regarding business, non-negligible own and cross-price elasticities attest to an overall flexibility in energy- and fuel-related

[42]This renewed opening towards fossil fuel extraction has also been challenged from environmental and landscape conservation perspectives. Several regions have gone to the Constitutional Court over the government decree.

[43]The Commission proposal, launched in 2011, is still under discussion because of strong resistance from some member countries.

choices.[44] However, the recent boom in photovoltaic and wind power investment, led by a very generous price signal (the FIT scheme), also shows that this kind of instrument can have many adverse effects if not embedded in a general strategy.[45]

The case of electricity taxation can constitute a good example of the lack of a coherent strategy in Italy. At least three different and uncoordinated policy signals affect the final electricity price, which, as shown before, is one of the highest both in Europe and the world. Excise taxes are levied both on energy products used to produce electricity and on electricity consumed by households and firms. Excises on energy inputs are levied with special tax rates (because of the double taxation) and are therefore different to those applied to other energy uses. In the consumption phase excise taxes and the aforementioned A3 component devoted to financing renewable subsidies (a quasi-tax) are levied. In addition, electricity producers are constrained by the EU Emission Trading Scheme and they currently have to buy allowances by auction. Unfortunately, there is no coordination mechanism between excise rates, subsidies and ETS prices because excises and subsidies have been frequently set more with the aim of balancing the public budget than of pursuing an energy or climate strategy. At the same time, the ETS market has proved to be very unstable and was deeply affected by the economic downturn. The ETS allowance price has varied between 30 and 1 euro since its implementation, making the signal absolutely unreliable and adding non-negligible compliance cost for firms. The overall result of these different signals is very high electricity prices, distributional and competitiveness concerns, no renewable support and different policy signals, apart from a general disincentive to consume electricity.

In our view, this fuzzy situation could be at least partially improved with the introduction of energy/carbon taxation able to produce a coherent price signal to economic agents by implementing the general rationale of the EU Commission proposal for amending the Energy Taxation Directive. All energy tax rates could be set according to an implicit cost of carbon, which could mirror either an internationally estimated cost or the EU ETS allowance price target, and to an energy content component, set to enhance energy-saving behaviour. As previously discussed, the current level of energy-related tax rates is among the highest internationally. This leaves enough room for tax rate reshaping without increasing the tax burden and with a likely relief of distributional and competitiveness concerns.

In this tax reorganization, preferential tax treatments, tax rebates and double taxation should be phased out, so firms constrained by the EU ETS should not pay excise taxes on energy products.[46] This tax revision could also be extended to

[44]As discussed in the previous paragraphs, the gas-electricity price differential has determined an important shift from electricity to gas use in industrial processes.

[45]This abrupt growth in the supply of renewable cannot show all the potential benefits because of the inadequacy of the Italian transmission network in absorbing this kind of supply. As discussed in Sect. 3.3, the incentive scheme led to high profits for renewable producers and a high burden on electricity consumers, both households and firms, thus forcing the Italian government to stop the programme.

[46]The need for an energy tax reorganization has also been identified by the OECD (2015).

complementary tax bases: transport taxes—for example—could also be reorganized to coherently reinforce the carbon and energy saving goals or to take other externalities into account, avoiding the pure double taxation of carbon or energy content tax bases. This appears even more important when considering that the Italian Action Plan for Energy Efficiency has assigned the most ambitious saving target (−5.50 out of 15 Mtoe) to the transport sector, which is highly heterogeneous in energy and carbon efficiency according to the mode of transport. If progress were made towards removing all the current discrepancies and overlapping between instruments, the effect would not necessarily be to achieve economic efficiency with environmental improvements at the cost of lower fiscal revenue; empirical studies (Vivid Economics 2012) have shown that carbon fiscal measures also have a potential role for fiscal consolidation in European countries.

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