The Next Generation of Economic Issues in Energy Policy in Europe

edited by Antonio Estache

Bernard Van Ommeslaghe Chair

CEPR Press

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In 2000, Bernard Van Ommeslaghe, Professor Emeritus from the Université Libre de Bruxelles (ULB) decided at the end of his very successful and innovative private sector career, to sponsor a Chair at his alma matter and to anchor it at the research center ECARES at ULB. The main purpose of the "Bernard Van Ommeslaghe Chair" is to support research, workshops, training activities and publications on market regulation and liberalization.

Overall the years, the Chair has supported events attended by some of the top European economists working in this field, including Emmanuelle Auriol, Estelle Cantillon, Claude Crampes, Mathias Dewatripont, Martin Hellwig, Elisabetta Iossa, Jean-Jacques Laffont, Ariane Lambert-Mogiliansky, Patrick Legros, David Martimort, David Newbery, Lars-Henrik Röller, Paul Seabright, Stephane Saussier, Giancarlo Spagnolo, Jean Tirole, Tommaso Valletti, Xavier Vives, Christian von Hirshhausen and Catherine Waddams. Since 2008, the beneficiary and organizer of the activities of the Chair is Antonio Estache.

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edited by

Antonio Estache
ECARES
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Acknowledgements

I am grateful to all the contributors to this book. My interactions with them has been a tremendous source of learning and much of this is reflected in the impressive quality of the chapters. I hope the readers will share this feeling as they go through the book. I am also grateful to the editors who helped us hide the fact that many of us are not native Anglophones: Steven Kennedy and Anil Shamdasani. And last but not least, I would like to thank Bernard Van Ommeslaghe for his continuous support to research on regulated industries and to the dissemination of frontier knowledge with direct policy relevance. Without his commitment, this book (and a lot of the research covered by the book) would not have been possible.

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Acronyms and Abbreviations

BRP	balancing responsible party
CEER	Council of European Energy Regulators
CER	certified emission reduction
CEPR	Centre for Economic Policy Research
CHP	combined heat power
CNE	*Comisión Nacional de Energía*
CPI	consumer price index
CRE	Comission de la régulation de l'énergie
CREG	Commission de Régulation de l'Électricité et du Gaz
CRS	constant return to scale
CSE	Sevillana de Electricidad
DEA	data envelopment analysis
DECC	Department of Energy and Climate Change
DG	Directorate-General
DMUs	decision-making units
DNOs	distribution network operators
DOJ	Department of Justice
DSR	demand-side response
ECARES	European Center for Advanced Research in Economics and Statistics
EC-JRC	European Commission Joint Research Centre
ENSG	Energy Networks Strategy Group
EPA	Environmental Protection Agency
EPE	Energy Policy for Europe
ERU	emissions reduction unit
ERZ	Eléctricas Reunidas de Zaragoza
ETS	Emissions Trading Scheme
EV	Eléctrica del Viesgo
FCC	Federal Communications Commission
FECSA	Fuerzas Eléctricas de Cataluña
FERC	Federal Energy Regulatory Commission
FITs	feed-in tariffs
FTC	Federal Trade Commission
GAV	gross added value
GDP	gross domestic product
GHG	greenhouse gas
GN-UNF	Gas Natural-Fenosa
GHh	gigawatt-hour
HC	Hidroeléctrica del Cantábrico
HDE	Hidroeléctrica Española

HECSA	Hidroeléctrica de Cataluña
IBE	Iberduero
IEA	International Energy Agency
ICT	information and communications technology
IME	input mix effect
IRG	Intergenerational Regulation Fund
kWh	kilowatt-hour
LCOE	levelised cost of electricity
LCP	large combustion plant
LSE	*Ley del Sector Eléctrico*
MLE	*Marco Legal Estable*
MO	market operator
MWh	megawatt-hour
NWh	negawatt-hour
NERC	North American Electric Reliability Corporation
NPV	net present value
OECD	Organisation for Economic Co-operation and Development
PUCs	Public Utility Commissions
PV	photovoltaic
R&D	research and development
RD&D	research, development and demonstration
RES	renewable energy sources
SEC	scale efficiency change
SGF	Smart Grids Forum
SMEs	small and medium enterprises
TCEQ	Texas Commission on Environmental Quality
tCO_2	tonne of CO_2
toe	tonnes of oil equivalent
TSO	transmission system operators
UNF	Unión Fenosa
WACC	weighted average cost of capital

Foreword

This book is one of the research products made possible during 2013 thanks to the support of the Chaire Bernard Van Ommeslaghe established at ECARES (the European Center for Advanced Research in Economics and Statistics) at the Université libre de Bruxelles. One of the goals of the Chair is to get academic researchers to stimulate policy debates and anticipate issues likely to emerge as a result of, first, policy mistakes or omissions, and second, changing economic or societal contexts. This is exactly what the various chapters deliver. They assess the multiple facets of the energy policy challenges the various European countries and Europe as a whole are likely to have to face in the foreseeable future. In doing so, they suggest that the scope for improvements in quantitative policy assessments is still large, notwithstanding the significant improvements achieved in recent years. They highlight a number of inconsistencies and coordination failures within and across countries. They also point to a number of possible options not yet explored in policy debates.

To those of us associated with the Chair, it is our hope that the chapters of this book will help in refining the research agenda for the sector and also the heated policy debates on energy policy that will no doubt continue as governments try to balance concerns for cheap energy (to support competitiveness and minimise fuel poverty) with the acceleration of the transformation of the sector (to boost energy independence and reduce environmental hazards).

Mathias Dewatripont
ECARES, Université libre de Bruxelles

January 2014

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Overview

Antonio Estache

Introduction

The main purpose of this book is to share the results of a series of policy-oriented think pieces on energy policy sponsored during 2013 by the Chaire Bernard Van Ommeslaghe of European Center for Advanced Research in Economics and Statistics (ECARES) of the Université Libre de Bruxelles in Brussels, and the Centre for Economic and Policy Research (CEPR) in London. The chapters deal with various facets of the energy policy challenges Europe as a region and European countries are likely to face in the foreseeable future.

Overall, the book confirms increasingly well-known concerns over the difficulties encountered by Europe in getting its energy policies right, but it also provides new insights on specific key difficulties encountered in defining both regional and national policies. While a number of these insights are known at least conceptually to many of the experts following the European energy debates, some more specific dimensions of their relevance are less familiar. It is clear from recurrent omissions and imprecisions in political speeches across Europe that many policymakers responsible for some of the central decisions in the sector tend to ignore or underestimate many of the subtle, essential drivers of success and failure for their political and policy commitments. It also seems clear that the scope for improvements in the quantification of choices is significant, as illustrated by some of the diagnostics illustrated in this book. Quantification is essential to be able to distinguish between cynicism and incompetence in policy, and this book contributes to the efforts to improve accountability for decisions in the sector by reducing the scope for decision-makers (and many users) to hide behind the veil of ignorance in the energy sector.

To ensure the broadest possible audience without underestimating some of the complex dimensions of the challenge, the book is written in such a way that the key messages come through as directly as possible without shying away from the technical dimensions. Indeed, these more technical dimensions are often part of the challenges or the reasons why some issues are underestimated and lessons from past mistakes ignored.

The broad context

A superficial reading of the evidence would blame many of the current energy policy challenges on politics, or at least on the inability or unwillingness of politicians to take decisions or to make the right ones. Not all energy problems are purely political, however. Politics matter of course, as illustrated in various chapters of this book, but they are not alone in explaining the slow rate at which energy policy is changing and adapting to tomorrow's needs. One of the lessons of the many books and articles that have been produced over the last 10 or 15 years is that energy policy is also becoming increasingly complex from an economics perspective. Poor internalisation of the analytical requirements of this increased complexity has now become part of the policy problem.

About 30 years ago, energy policy was relatively simple among the many policy areas government had to deal with. It was about ensuring that energy would be delivered smoothly regardless of provider, source, cost and competition. It then became somewhat more complex with the desire to reduce the role of the state as a provider and to increase competition to cut costs to users and taxpayers. With the growing concern for the greening of energy, the need to consider the choice of energy source more carefully became increasingly important as well. In the European context, the desire to ensure a minimum level of coordination across countries in the vision for the energy sector also further increased the complexity of its management, operation, financing and supervision.

Energy policy is clearly no longer simple, but its complexity seems to be increasing and this raises uncertainty in the sector. It also reduces the ability of key actors to decide upon and to deliver on increasingly reversible commitments that are made too early, too poorly informed and too incompletely analysed. There is a plethora of anecdotes across countries with striking similarities that point to recurrent themes and trade-offs. These reveal the high degree of complexity and the difficulty for policymakers to make the right decisions. The main themes can be categorised as follows:

i. the lasting unhappiness with the increasing gap in average industrial tariffs between the EU and its competitors, which is blamed (not totally adequately) for a reduction in the industrial competitiveness of Europe;

ii. the growing unhappiness with the increase in real residential tariffs across Europe in difficult economic times with growing shares of the population facing increasingly binding budget constraints;

iii. the exploding unhappiness of some producers and consumers with the reversal of national commitments to subsidise renewable energy and their inability to recover investments; and

iv. the underestimated unhappiness with the indecisiveness with respect to various technological options for the future of the sector (and which may explain changes of heart over nuclear power plants or carbon capture, for instance). Each has political costs, but each also has some significant costs for today's and tomorrow's users and taxpayers.

The different ways in which different countries and political parties tackle these challenges increases the uncertainty over the costs and benefits of various organisational structures for the sector at the national level. They also increase the difficulty of developing coordination mechanisms that deliver cost-effective integration of the European markets and, in particular, an honest vision of the investment requirements in transmission and in the added flexibility requirements imposed by the collective, dominating desire to rely more on renewable sources of energy.

This uncertainty is far from simply an intellectual curiosity for academics. It matters in an industry expecting to rely on private investors and operators taking a lead role in the delivery of an essential service with obvious social intergenerational impacts. Investors in this sector care as much about risks as in any other sector, and high uncertainty means higher risks. Higher risks mean higher expected return. Higher expected returns mean higher average tariffs. High expected average tariffs mean higher social damage from the national and supranational mismanagement of the sector.

This represents a change in the sector. Energy companies used to be so predictable that they were often seen as a safe haven for investors. The high proportion of pension funds willing to invest in energy over the last 15 years is a good indicator of this perception. This is changing rapidly. In Europe, investing in energy firms is no longer for the faint of heart and this can largely be blamed on the fact that policy has become unpredictable (one of the implicit lessons of Johan's Aldrecht chapter, for example). And the risk aversion with respect to investment in the sector is not expected to improve in the foreseeable future unless national and supranational policymakers sort out a growing number of concerns which are fuelling complexity, incoherence and uncertainty.

Policymakers are not insensitive to these concerns and many significant changes have taken place in energy policy in 2013 to try to improve the investment climate in the sector. However, many have also contributed to the confusion in the signals sent to operators and consumers rather than to a clarification of the institutional and financial mechanisms that will be adopted to deliver the promised convergence towards a greener common energy policy. Short-term national and supranational political pragmatism is indeed coming at the cost of increases in short- and long-term uncertainty. Some of this may be related to an underestimation of the scope of action available to governments to reduce residential and non-residential energy consumption, as illustrated in the chapter by Laurens Cherchye, Bram De Rock and Barnabé Walheer on the level of sectoral energy consumption inefficiency tolerated thanks to the misguided belief that it is needed to save jobs. It is also related to the occasional misreading of the scope for regulatory effectiveness, as illustrated by the Spanish case study presented in this book. When things go well, everyone takes the credit for success, including regulators. It is only when things don't work as well as they should that the various stakeholders try to identify who should have been doing what and failed to do so.

Ultimately, excessive short-term political and operational pragmatism rather than incompetence is probably to blame for many of the incoherencies and gaps in the current European design of energy policy. Central to these are the failure to create institutions with a clear mandate and well-established incentives to minimise incoherencies, and gaps in efforts to reconcile national sovereign concerns with the supranational concerns.

The most obvious institutional failure is that the assignment of responsibilities between the supranational and the national authorities in Europe is still incomplete (and probably confusing). This has left significant gaps in the accountability built into the current governance structures. Regulators across Europe have been (and continue to be) slow to react to evolving market conditions, but also to abuses allowed by cracks in the governance wall intended to protect users and taxpayers. This slow reaction time built into the institutional inadequacies of the system has allowed insidious, unjustifiable increases in market power. This then leads to incoherencies such as the failure to recognise that there is no need to define the social and environmental goals of the sector in terms of trade-off (i.e. cutting prices to protect today's users versus increasing today's prices to protect tomorrow's users and taxpayers), as too many recent political decisions imply. Reconciling regulatory, social and industrial policy objectives is possible, but the process seems to be turning a bit schizophrenic instead, as implied by Claude Crampes' discussion of the implementation challenges of the EU's 20-20-20 Vision.

A second obvious gap is the failure to reconstruct the planning ability for investments that was eliminated as a result of the desire to increase the role of the private sector and shrink the role of the public sector in energy over 15 years ago. It has been replaced by a planning process which generates bureaucratic red tape, easy politicising of technical and economic decisions, and uncertainty, rather than a process that sends a clear signal to investors from all boards. There is very little strategising possible for the implementation of politically defined visions without the discipline offered by simpler and clearer sector planning. Europe is seeing now what early reformers in Latin America discovered 15 years ago when they began to face the increased risks of rationing due to insufficient or uncoordinated investments in the sector resulting from the *tabla rasa* strategy adopted in the redesign of the governance structure of the sector. Operational planning is back in Latin America, it never disappeared in the key emerging economies of Asia (following Korea's lead), and it will have to return in Europe and many other OECD countries if investment has to adjust to the interests of both users and taxpayers.

A third gap is in the clarification of the definition of the real scope for coordination in Europe in view of the great variation in market and production structures across countries. In spite of these differences, the concerns across countries are largely similar but today's failures show that changes are needed and that in this context, pragmatism rather than idealism may be needed to ensure the political support at the national level of supranational commitments. The payoffs to improved coordination can be categorised into two broad groups: (i) more investment to implement the changes in production and market structures; and (ii) different regulations and regulatory frameworks to ensure the sustainability and the adaptability of the changes.

The changes observed in the production structures are largely driven by the need to increase the share of renewable energies among the various sources of energy relied upon (and in some countries, by the desire to cut the share of nuclear energy as well). The changes in the market structure emphasise improvements in the management of demand (i.e. improved energy efficiency) as well as continued improvements in competition in the industry, including more international competition. Changes on both the production and the demand side will require significant investments, as seen in the British and Belgian case studies covered in this book. Investments are indeed needed to integrate the new renewable sources as well as to improve the international mobility of energy. They are also needed to implement the technological changes that are needed to improve the efficiency of the sector. Systems to make energy require investments as well.

To ensure that the key actors in the sector have the right financial incentives to deliver the investment needed and to use these investments efficiently, changes in regulation are also needed. This will also require changes in the economic incentives faced by these actors. Social issues are serious, of course, and will have to be addressed, but this has to be done in an environment in which prices will have to reflect more accurately externalities. In many countries, this has been dealt with through short-term politically motivated decisions disregarding the longer-term consequences on investment and consumption incentives. Taxpayers' money has often been wasted supporting short-term solutions without regard to the longer-term consequences of these decisions. And yet our ability to design price structures that will protect those who need it without sending the wrong signals in terms of demand management is something relatively easy to do with the design of tariffs structures and/or through the targeting of subsidies, with relatively low administrative costs.

The European Commission is making notable efforts to reduce these uncertainties and incoherencies and to push for the search for more desirable policy interventions (European Commission, 2013a,b,c). It is doing this by attempting to clarify messages and commitments but, in the process, it sometimes also adds to the confusion. Consider the evolution of its views on the management of the sector in 2013. In May 2013, it issued a review of the energy challenges Europe will have to address over the short to medium run. To the recurring discussions of (i) the interactions between energy policies and concerns for climate change, and (ii) energy supply security, it added the need to work on the economic competitiveness and social impacts of the energy challenges.[1] This made sense and it then included a positive assessment of the role played by subsidies in stimulating the development of renewable sources of energy and an explicit discussion of the need to increase the use of prices to improve demand management. In early November 2013, less than 6 months later, it issued new guidelines to eventually end costly and controversial subsidies for renewable energy, but possibly opening the way for state-aid backing of gas or coal-fired electricity generation projects.[2] It also hinted that state aid to invest in nuclear energy was not desirable, less than a month after the British government decided to invest in a new nuclear price with a guaranteed price that will be hard to meet without some form of subsidy. It is indeed hard not to be confused.

In sum, the broad context in which energy policy is currently being designed is dominated by uncertainty with respect to the key drivers of optimal choices for the sector. And as we are all collectively learning, politicians and bureaucrats are all showing an impressive degree of (often well intended) political pragmatism. However, it turns out that this pragmatism is reaching the stage at which it may be hindering more than helping the transformation of the sector. It is thus essential to increase the transparency of the damage done by not figuring out the costs and benefits of the various options and by not recognising the costs of indecision or of reversing decisions based on intuition and political responsiveness rather than on facts. Increasing this transparency is one of the clearest roles of the following chapters.

The broad message of the book

Overall, the book is likely to leave the reader somewhat concerned. The main impression to emerge from the evidence reported by the various chapters is that the road to a sustainable and credible European policy is a long and increasingly winding one, which builds on national feeder roads that are not all in good shape. Some will actually lead nowhere unless key policy and implementation decisions are finally taken in credible ways. Many need significant rehabilitation if the energy vision for 2020 is to become a reality.

The book also provides some clear broad suggestions, in addition to the issue-specific recommendations that are made in each chapter. Collectively, the various authors have managed to accumulate convincing evidence that learning from the recent failures in energy policy is essential. This is because the recognition of the sources of, and the quantification of, their costs should make all actors in the

1 The most popular description of the targets to be achieved is the "20 20 20 by 2020", reflecting the idea that, by 2020, Europe wants to reduce CO_2 emissions by 20% compared to 1990 levels, to raise the share of renewable sources as part of the overall EU energy mix to 20% and to increase energy efficiency by 20%.

2 http://ec.europa.eu/energy/gas_electricity/doc/com_2013_public_intervention_en.pdf

sector more humble in self-assessments of the policy achievements in the recent past. Most of the chapters show clearly that improving clarity and reducing both innocence and excessive pragmatism in the design of policies could go a long way towards cutting increasingly unbearable costs in the sectors. An implementation strategy that would be physically, economically and politically viable is possible; it simply requires investing more in details at the institutional, policy and political level.

In this context, learning from the data is just as important as learning the conceptualisations of issues. Energy policy is no different from any other policy, and data and their analysis teaches lessons on the willingness to change, the willingness to pay for change and the ability to pay for change. It also allows for increasing transparency of the quantified revealed preferences of producers, consumers and politicians. This should be used to cut short many of the unsubstantiated debates on what works and what does not. It also provides key insights on where communication with users and voters on the costs and benefits of the various possible roads by the experts and the politicians is failing.

This may seem obvious to some, but the fact that key decisions are not taken or are often reversed in the context of energy policy is not without long-term consequences. The most obvious of these are environmental, but there are also many social and fiscal consequences. Many would argue that the failure to deliver on such a central policy is also likely to have brutal political consequences, as it redefines what is possible in terms of coordination of sectoral policies across Europe. Several other evaluations have made similar points with respect to the integration of energy markets since the European Commission issued its revised energy guidelines in May 2013.[3] However, few get into many of the details of specific trade-offs and specific national policy implementation efforts, as the contributors to this volume have been willing and able to do. And yet a broad range of more specific messages are possible, as seen in the individual chapters.

The specific contributions of each chapter

Claude Crampes reviews the economics of the 20-20-20 vision aiming at cleaning, greening and saving energy by 2020. He focuses on the competition and regulation dimensions of the implementation of the vision and the overall coherence of these policies with the sector's objectives. He points out that the European authorities are progressively abandoning the simple objective of enhancing competition. Indeed, he shows that with a combination of quantitative targets and penalties for non-compliance, member states are gradually moving towards somewhat ad hoc ex-post adjustment planning mechanisms where new corrections try to fix the negative consequences of former corrections without

3 To name just a few that are well worth reading in that they provide a large number of important insights on the current debates: Booz & Company (2013), Buchan (2013) Glachant and Reuster (2013), Vasconcelos (2013), Von Hirshhausen (2013), Waddams *et al.* (2013) and Zachman (2013).

much concern for the big picture. The final outcome of this process is the addition of layers of industrial policy to competition policy, combined with the uncoordinated addition of environmental policy to energy policy.

This chapter makes a large number of quite specific suggestions on various key dimensions of the sector at the European level. At a more general level, it emphasises the important role R&D should be playing, but cannot play, in the context of fiscal support to these activities shrinking as a result of the crisis. He also points to the need to turn the cheap talk on the political commitment to demand management into concrete actions, including the restoration of the economic signalling power of pricing across most activities in the sector. At a more subtle level, he points to the need to establish a clearer hierarchy of policies to ensure their coherence. At the institutional level, he points to the need to get the essence of the problem, which is simply the management of a common resource and the allocation of rights over this resource. In this context, he suggests the creation of an independent "Intergenerational Regulation Fund" with a clear mandate to define and enforce rules of the game in the best interests of both present and future generations.

Johan Aldrecht focuses on the investment needs associated with the new visions of the energy sector and on their financing requirements. He shows that in most European countries, electricity prices are currently too low to trigger new investments in efficient generation and network assets. Yet, these investments are essential to prepare the energy transition. The economic crisis resulted in a significant conventional overcapacity on European electricity markets while the low CO_2 emission price provides no incentive for ambitious mitigation investments. He argues that the current stalemate risks becoming structural. European climate policies combined technology-neutral instruments, like ETS, with supplementary technology-imposing targets, such as the RES, and energy efficiency targets by 2020. But the rigid supplementary measures to flank carbon pricing contributed to generation overcapacity and low CO_2 prices. The policies designed to achieve the long-term vision underestimated the short-run reactions of the market. Strategic banking of benefits (i.e. transfers of unused permits from one phase to the next) between ETS Phases, including in the later ones, will influence short-term market behaviour and CO_2 prices (i.e. between 2015 and 2020). It is rational to expect a significant increase in the demand for permits during that period and, hence, an increase in prices. But it is just as rational to expect that changes in goals (e.g. 30/30/30 rather than 20/20/20) would also impact demand and prices and distort the commitments to investment in renewables again. In a nutshell, the supplementary policies and the scope for their recurring changes increase the scope for strategic behaviour with respect to investment decisions and hence increase the level of uncertainty to be internalised by all actors in the sector, delaying the expected changes in the composition of generation in the sector in a very unpredictable way. And to a large extent, this is why there is a serious risk of underfinancing of the investment requirements of the clean sources.

Aldrecht points to many key structural reform needs in the sector to minimise the risks of its underfinancing and of mistargeting support. These include the need to reconsider the specific climate policy goals and the management of their evolution, the need to consider a reduction in the dependence on technology-imposing measures, changes in the definition and management of the ETS caps as of 2015, and changes in the organisational structure of specific markets such as the gas market to recognise the growing role shale gas has in determining the comparative advantage of gas producers. One of the main specific contributions to the reform agenda he argues for may be the identification of a mechanism that could reduce the risk of the crowding-out of energy transition investments by energy system expansion investments driven by economic fluctuations. In the last years, this has indeed been a key source of distortion in investment incentives in the sector. To minimise this risk, he argues that policy frameworks must commit to ensuring the continuous funding of high-energy R&D expenditures, irrespective of fluctuations; future recessions will always impact the CO_2 price in ETS. One way to do so would be to commit the allocation of carbon taxation revenues to energy R&D budgets.

Laurens Cherchye, Bram De Rock and Barnabé Walheer try to step back from the many debates on negative impact that the greening of energy is likely to have on the competitiveness of European economies and on jobs. To do so, they develop an efficiency assessment method specially tailored to address this issue. The method is used to conduct an efficiency analysis at the sector level (unbundled as Agriculture, Transport and Other industry). It allows a detailed assessment of the scope for improvements in efficiency available from using current assets. It allows them to measure the scope for reductions in input use and the scope for pollution reduction without having to cut employment, for instance, if that is the political preference supported by the voters. The chapter thus considers jobs as an output target just as the level of output (and hence growth). The results allow a fair degree of optimism, since they show that in many countries for many key economic activities, the scope for improvement is significant. As expected, there are large differences across countries but in their quantitative assessment, they manage to identify the specific activities in which the scope for improvement is largest. Unbundling their sectoral categories would allow for even more precise targeting of the activities with easy environmental payoffs at no political costs, because of no employment and output cost.

The implicit message from this chapter is thus that, in the short to medium run, energy efficiency should be a lot more central to the debate than is revealed by the current policy preferences observed in new laws and regulations for the sector. This is not a minor message in a European context in which a still popular view among politicians and key lobbies is that industrial policies should support the status quo or a very slow progression towards efficiency improvements. The evidence provided here suggests instead that this view underestimates the scope for improvements in the use of current technologies during the transition.

Sarah Deasley and her co-authors provide the first of three country case studies to show how countries deal with the challenges quite differently. They show that in the UK context, meeting the carbon budgets will require radical changes to the supply and demand of electricity in the next decades. Low-carbon generation is likely to be more intermittent and inflexible than today's mix, and the electrification of heat and transport will add significant new loads to the demand side. Accommodating the changes is likely to require major investment in networks. Smart grid investments may be able to reduce the costs of the transition to a low-carbon economy by facilitating more efficient use of existing infrastructure, thereby allowing the postponement of investment in new network capacity. But before investments are made, it is necessary to assess the costs and benefits of smart grid technologies compared with those of conventional alternatives. Smart grid technologies are less capital-intense, less 'lumpy' (i.e. they can come in smaller increments) and have shorter asset lives than conventional network technologies. These features may be an advantage in a world characterised by much uncertainty, as they allow greater flexibility to change strategy as new information emerges.

In addition to the specific messages applicable to the UK case and to the useful insights of the subtle dimensions of smart grid management and operation, the chapter offers a number of more general messages. The main one may be that the quantification of the challenges and options to address any policy can be real eye-opener as to what is possible and what it costs to change the design of an energy system. However, the chapter also shows that the methodology adopted to assess the options may have limits. They show, for instance, that the choice of network investments using a standard cost-benefit analysis technique will not take the option value associated with smart technologies into account, and may therefore underestimate their true net benefits. In other words, in this case, one of the most popular options has a built-in bias against a specific technology. Political decision-makers should not be expected to pick this up on their own, but experts and the policy advisors certainly should. But they often don't however.

Leticia Blázquez, Humberto Brea-Solís and Emili Griffel focus on Spain in analysing the extent to which the sector has been responsive to changes in policy in the past. They base their evaluation on an empirical analysis on the performance of the Spanish electricity distribution companies for the period from 1988 to 2010. During this period, two main different regulatory regimes were in force, and the changes resulted in a significant increase in the concentration of the sector, prompted by numerous mergers and acquisitions.

Their main message is that the ability to unbundle the sources of the changes observed in a sector can be a very pragmatic way of learning what works and what does not in reform. It can also be a way of replacing cheap talk with substantive talk in the assessment of the relative effectiveness of reform. For instance, they validate the idea that the package of changes in the organisation of the sector was associated with positive responses from the operators, since average productivity increased in the sector at an annual rate of 3.3% for a period that lasted 22 years. Most of the payoffs only came from technical improvements, however. The institutional changes did not manage to stimulate significant improvement in any of the other dimensions of efficiency change. In sum, what the chapter shows is that regulation can afford to be lax and nobody will complain as long at something improves. This somewhat cynical management of perceptions is unfortunately not only an issue but also certainly an essential dimension of any efforts to improve the accountability of operators, regulators and policymakers as Europe and European countries are pursuing their efforts to transform the sector. Cheap talk is easy and, as the Spanish example and the current debates on the future of the sector are showing, it is also quite costly in the long run.

Estelle Cantillon offers a case study of one of the emerging challenges for Belgium: dealing with electricity overcapacity in base load and tight capacity in peak load. Base load overcapacity is driven by the country's historical reliance on must-run technologies, such as nuclear power, and generous subsidies for electricity production from renewables. The increasing reliance on intermittent sources of energies (wind and solar) raises the need for flexible capacity, especially during peak times, but markets do not provide sufficient incentives for such flexible capacity provision. Belgium needs to fix this if it wants to guarantee security of supply. To do so at the lowest cost and to help the transition of the country's electricity system towards a world with more renewables, Cantillon suggests that Belgium, as any other country, would have to meet four general principles: neutrality between electricity demand and supply, technological neutrality, accountability, and price transparency. The solution she suggests meets these principles – she makes a preliminary proposal for a specific support mechanism for flexible capacity that Belgium could put in place to restore incentives for its provision and to ensure the country's supply security while supporting the presence of renewables.

In addition to the Belgium-specific cases, the more general contributions made by Estelle Cantillon are of two types. The first is a useful reminder that policy decisions need to be anchored in fairly general principles. Relying on a specific assessment of the effectiveness of a policy with respect to each of these principles may be the most effective way of identifying trade-offs and ensuring their transparency. It also has the advantage of serving as a revelation mechanism for any bias built into solutions championed by some stakeholders when they neglect to discuss key dimensions to avoid having to highlight a trade-off. This has happened in the energy debates a lot lately, as illustrated in the discussions of almost all the key dimensions reviewed in this book (the nuclear debates and the design of subsidies to users of renewable sources of energy are two obvious examples). Second is a more general discussion of the potential to expand the use of transmission system operators' (TSOs) tertiary reserves, including a discussion of a new mechanism for allocating and activating these reserves, and new cost-sharing rules. Her proposal ensures that security of supply is met at the lowest cost today and tomorrow by making the most of flexibility on both the supply and the demand side of the market. By the design of its cost-allocation rules, the proposal also restores the incentives to all participants to make the investments needed to cut the size of required reserves. While her proposal still requires some operational (including political) fine-tuning, it has the effect of getting the discussion rolling in Belgium. It also provides a potentially replicable idea for similar contexts in other countries.

Concluding comments

While the book touches upon many ideas, the sum of these ideas is only a small part of the set of issues that should be addressed by any encompassing assessment of the challenges ahead for the sector at the national and supranational levels. In the current social context, the most obvious gap that deserves further attention may be the discussion of the equity (i.e. distributional) effects of any changes in the sector.

While various chapters touch upon the social concerns that changes in average tariff levels may generate for some consumers, none really goes through a full assessment of their quantitative size, and even less so of the possible specific solutions considered in the various countries to minimise the social burden of the transformation of the energy sector. The social implications of the effects on the labour market induced by efforts to improve efficiency on the production side are touched upon in Chapter 4 – on pollution versus growth versus jobs trade-offs – but this is done at an aggregate level and does not allow for a complete assessment of the differences in impact across skills, for instance, which is important to track down any bias in the labour-market effects against low-income workers.

The answers to this dimension of the challenge, however, are central to the political viability of any further transformation of the sector. As mentioned earlier, politicians in Belgium, France or the UK, for instance, are *de facto* adopting price control decisions, in the interest of the protection of residential users, that are incompatible with their commitment to rely more effectively on demand management. Since demand management is so central to improvements in efficiency, and improvements in efficiency are so central to the sustainability of the transformation of the sector, these policy reversals are a major threat to the credibility of the changes committed to and, hence, to the incentives to invest further in the transformation of the sector. Because they are so fundamentally important for the future of the sector, these issues will be dealt with in a forthcoming collection of policy insights on the sector to be conducted by the Chaire Bernard Van Ommeslaghe.

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2

The EU's "Three 20s": Environmental or Industrial Policy?

Claude Crampes

With Directive 96/92/EC – "concerning common rules for the internal market in electricity"[4] – the EU launched in 1996 the unbundling of the electricity industry, thereby partially separating, on one hand, production and supply, where competition is allegedly sustainable, and on the other, transport and distribution, which are viewed as natural monopolies. It was expected that economic discipline would be guaranteed by industry-specific regulators for the latter and by competition authorities for the former. In this framework, state aid could be granted only in specific and infrequent circumstances, because such aid usually has the purpose or the effect of distorting competition.

The regulatory paradigm in which state aid was discouraged began to change in the spring of 2007, when the European Council called on member states and EU institutions to pursue actions to develop a sustainable, integrated European climate and energy policy. Energy Policy for Europe (EPE) was expected to pursue three objectives:

- increasing the security of supply,
- ensuring the competitiveness of European economies and the availability of affordable energy, and
- promoting environmental sustainability and combating climate change.

The new orientation necessitates the massive use of state aid, which is becoming the rule rather than the exception in the energy policy of member states. This

4 Repealed by Directive 2003/54/EC, later repealed in turn by Directive 2009/72/EC.

chapter is dedicated to one facet of the EPE, namely, the three-target commitment by the EU to:

- achieve at least a 20% reduction in greenhouse gas emissions by 2020 compared with 1990;
- increase energy efficiency so as to achieve the objective of saving 20% of the EU's energy consumption compared with projections for 2020; and
- achieve a binding target of a 20% share of renewable energies in overall EU energy consumption by 2020.

We discuss the tools used to reach these three quantitative targets and show that most are intrinsically bureaucratic. They create both a financial burden that cannot be sustained within the current institutional framework and a public commitment to constrain the future structure of the energy industry. Because of these effects, the role of competition in EPE will wither, and the rationale for managing the energy industry independently from environmental policy will disappear. The current combination of independent regulations intended to solve, separately, the problems of energy scarcity, environment protection, imperfect competition, and industry development is no longer sustainable. It is time to admit that if the central problem is global warming, all answers must turn on a pivotal institution endowed with the responsibility of managing common resources in a way that maximises the welfare of present and future generations.

In the first section below, we briefly present the conflicting objectives pursued by the European authorities as regards competition and environment protection. The three following sections are dedicated successively to the three pillars of the EPE: lower greenhouse gas emissions, more renewable energy sources, and lower energy consumption. The last section offers some brief concluding remarks.

Intergenerational regulation

Static efficiency versus environmental protection

Economic regulation, whether industry-specific (such as the regulation performed by national entities responsible for energy, telecoms, and water) or applicable to all industries (such as the regulation applied by competition authorities), has the objective of preventing individual firms and groups of firms from abusing their dominant position. Such regulation focuses on short-run structure and conduct and as such, it mainly results in actual or virtual price cuts or price caps imposed on or negotiated with producers. But lower prices entail higher levels of consumption. Consequently, in many industries (particularly in transport and energy), economic regulation has two negative side effects in the long run:

- Because production burns non-renewable resources (coal, gas, oil), more consumption means accelerating the depletion of fossil fuel stocks and increasing imports of primary fuel in some countries.

- Because production disseminates pollutants, more consumption means increasing damage to the environment.

Clearly, current practices designed to promote competition are at odds with stopping global warming and protecting the environment. In some places, they are at odds with the goal of assuring security of supply.

The source of the problem is that economic regulators are not formally responsible for environmental protection, which remains under the direct control of governments or is assigned to distinct independent entities. In the US, for example, concerns about abuse of dominant position and restrictions on access to essential facilities are managed by economic regulation authorities such as the FCC, FERC, DOJ, FTC and PUCs.[5] Independently, agencies like EPA, Cal/EPA, and TCEQ[6] are in charge of the risks of toxic emissions and damage to the environment caused by industrial plants. Similar institutional arrangements are in place in most developing countries.

The separation of tasks among several public entities can be motivated by the need for heterogeneous expertise, as well as by worries about the possibility of abuse of discretionary power. Whatever the reason, separation results in multiple agencies, each with a limited scope of responsibilities and each unable

5 The Federal Communications Commission is charged with regulating interstate and international communications by radio, television, wire, satellite, and cable (www.fcc.gov). The Federal Energy Regulatory Commission is an independent agency that regulates the interstate transmission of natural gas, oil, and electricity (www.ferc.gov). The Department of Justice has an antitrust division (www.usdoj.gov/atr) as well as a separate environment and natural resources division (www.usdoj.gov/enrd). The Federal Trade Commission has a Bureau of Competition to prevent monopolistic practices, attempts to monopolise, conspiracies to restrain trade, and anticompetitive mergers and acquisitions (www.ftc.gov). Public Utility Commissions are local or regional entities that are generally responsible for regulating electricity, gas, telephone, and water industries (see for example www.cpuc.ca.gov for California or www.puc.state.tx.us for Texas).

6 The Environmental Protection Agency is a federal body (www.epa.gov). Cal/EPA, the Californian Environmental Protection Agency (www.calepa.ca.gov) and TCEQ, the Texas Commission on Environmental Quality (www.tceq.state.tx.us), are state bodies.

to incorporate certain concerns that logically should be taken into account in the rules the agency promulgates.[7]

To tackle the problem of designing an overall regulation aimed at protecting both present and future generations is a matter of 'intergenerational regulation', which is best understood as a set of issues such as:

- *Standard setting*: What are the general features of constrained optimal intergenerational regulation? How should it balance instantaneous and dynamic efficiency, immediate and intergenerational rent-sharing?

- *Implementation*: Which part of the second-best intergenerational regulation can be implemented through market mechanisms and which part should be maintained under the supervision of a specific entity (or sector-specific entities)? How can one make 'cap-and-trade' and 'feed-in' mechanisms efficient components of the implementation of intergenerational regulation?

- *Regulation design*: Should regulators be responsible for both static and dynamic objectives? Under what circumstances can independent regulators tackling economic efficiency and environmental efficiency separately perform better than a single universal entity?

- *Regulation tools*: Except for the control of mergers, current regulation is mainly behavioural. Its toolbox basically contains controls and limits on prices, contractual provisions, and advertising content. Should discount rates and investment levels and types be added to the list? Should regulatory entities have structural prerogatives (divestment, number and size of firms)? What is the best way to tackle the problems of renegotiation and dynamic inconsistency?

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7 OECD (2006) identifies five key points concerning the potential conflicts and complementarities between competition and environmental regulations:

(1) Competition and environmental policies are complementary. They seek to correct market failures and enhance social welfare.

(2) Environmental regulations can, however, reduce competition in markets through various channels, raising prices for consumers. They may create barriers to entry into particular markets and increase concentration.

(3) Environmental regulation can also give rise to anticompetitive practices. They can be misused in predatory schemes to exclude or disadvantage rivals and also facilitate price-fixing and other collusive schemes.

(4) Competition authorities take environmental regulations into account in their everyday work but do not provide special consideration for environmental impacts or "environmental overrides."

(5) Environmental policies should be designed to achieve their aims without unnecessarily restraining competition. Competition authorities should help environmental agencies and legislatures find ways to achieve environmental objectives that are the least restrictive of competition.

- *Capture*: Regulatory bodies consist of individuals who pursue personal agendas. Is the risk of capture increased in the intergenerational framework? Are the risks higher in less-developed countries?

- *International coordination*: Given the globalisation process and the worldwide diffusion of some pollutants, would it be more efficient to organise intergenerational regulation on an international basis?

Setting up such institutions requires an economic analysis based on theoretical models of public economics and contract theory (Estache and Martimort, 1999; Laffont and Martimort, 1999; Laffont and Tirole, 1991; Martimort, 1999). That analysis must go beyond the standard conflict between prices and quantities as regulation devices (Hepburn, 2006; Weitzman, 1974) to explain how economic and environmental regulations interact (Fullerton et al., 1997; Gersbach and Requate, 2004; Haq et al., 2001). In particular, the imperfect competition features of most industries concerned by environmental regulation must be emphasised as well as the consequences of dynamic regulation in terms of industrial policy (OECD, 1996; Requate, 2006).

We address some of these questions by examining how the pro-competitive policy launched by the European authorities in the electricity industry at the end of the 1990s is now being distorted by the new environmental priorities resulting from the alarm over global warming. Before going through the details of EU environmental policy, we briefly comment on the role of state aid in environmental protection within the Union.

Are green electrons marketable?

In any microeconomics textbook, the first chapter tells us that perfect competition and perfect central planning are equivalent, so that pure market mechanisms lead to optimality. The second chapter details the hurdles that prevent competitive markets from implementing this 'first best' state of affairs. Among the usual suspects, one finds non-convex technologies and preferences, transaction costs, imperfect information, and externalities. The third chapter suggests how to mix market mechanisms and public intrusion to mitigate the nuisances caused by the aforementioned culprits. The discussion centres on the right mix of tight regulation (e.g., quotas and standards) and light regulation (e.g., taxes and regulated markets). In Brussels, no one has made it past the first chapter. They want competition everywhere all the time. France, by contrast, only read the second chapter. French politicians consider that since competition cannot bring about good outcomes, then central planning is certainly better than any form of market, never mind all the flaws of authoritarianism. The pragmatic English are perfectly indifferent to the first two chapters. They are concerned solely with the third.[8]

8 This paragraph is an adapted translation of Boiteux (2007).

This sketch of the views on market pros and cons is changing, at least with respect to EU policy. The Directorate-General for Competition (DG Comp) is gradually losing its preeminence in favour of other Directorates-General, in particular that for climate action and environment.[9] Also of note is the fact that energy is now an independent DG.[10] Because the present director general for energy (Philip Lowe) was formerly director general for competition, one may suspect that the energy industry remains highly constrained by the EU Treaty's Articles 101 on agreements, 102 on abuse, and 107 on state aid, plus the 2004 Regulation on mergers. Nevertheless, starting with the important publication of *20-20-20 by 2020* in the 2007 climate and energy package (ec.europa.eu/clima/policies/package/index_en.htm), the energy policy of the EU is drifting toward central planning and away from the free market.[11] Indeed, when the public authority is fixing quantitative targets (20% cleaning, 20% greening and 20% saving by 2020) combined with penalties for non-compliance, we are far from perfect competition, even though some *ex post* trade is still allowed like in the Emissions Trading System discussed later.

In the EU competition policy toolbox, the control of state aid plays an important role in limiting the potential distortions that governments can create when they support domestic actors by financial and nonfinancial means. The principle settled by Article 107 is simple: state aid is forbidden, except if….[12] Actually, environmental protection is one of the exceptions in Article 107. Now, when it comes to the '20-20-20' objective, the principle changes to: state aid is permitted, except if….[13]

Indeed, distortions of competition are necessary to reduce the negative externalities of industrial production and consumption;[14] absent public obligation, decision-makers do not internalise the environmental damages they

9 However, it remains true that the commissioner responsible for competition in 2013 (Joaquín Almunia) is a vice-president of the Commission, a title denied to the commissioners for climate, energy, and environment (ec.europa.eu/commission_2010-2014/index_en.htm).

10 The energy DG has been in operation since February 17, 2010. Formerly, Energy and Transport were one. On the same date, Climate Action was split from Environment.

11 Even so, the EC recurrently remembers its attachment to market mechanisms. See, for example, "Green Paper on market-based instruments for environment and related policy purposes," COM(2007) 140 final.

12 "Save as otherwise provided in the Treaties, any aid granted by a Member State or through State resources in any form whatsoever which distorts or threatens to distort competition by favouring certain undertakings or the production of certain goods shall, in so far as it affects trade between Member States, be incompatible with the internal market."

13 "The primary objective of State aid control in the field of environmental protection is to ensure that State aid measures will result in a higher level of environmental protection than would occur without the aid and to ensure that the positive effects of the aid outweigh its negative effects in terms of distortions of competition …" (clause 8 in "Community guidelines on State aid for environmental protection," 2008/C 82/01).

14 "State aid measures can sometimes be effective tools for achieving objectives of common interest. Under some conditions, State aid can correct market failures, thereby improving the functioning of markets and enhancing competitiveness. It can also help to promote sustainable development, irrespective of the correction of market failures." (State Aid Action Plan — Less and better targeted State aid: A roadmap for State aid reform 2005-2009 COM(2005) 107 final).

create, contrary to the 'polluter pays principle' established by Article 191 of the Treaty. Yet, in a non-regulated market system, decision-makers will *never* internalise environmental damage. In that case, the corrective scheme designed to implement polluter-pays must be installed for the long run.

Because of both their cost and intermittency, renewable energy sources (RES) cannot be developed without public intervention. The new frontier for electricity from RES is the so-called 'grid parity', which is the possibility for these sources to compete against fossil-fuel sources on a level field. It may be true that in the future, RES-electricity will have a MWh cost comparable to the cost of power generated in fossil-fuel powered plants. This will solve the cost problem, but not the intermittency feature. The guarantee to supply a given quantity of electrical power at a given date for a given duration will always be out of reach for intermittent sources such as wind and solar energy. Consequently, the development of RES-electricity creates a public commitment to constrain the future structure of the industry. The EU Green 20 actually authorises member states to set industrial policy in the energy sector.

Concerning energy saving, it is not the natural outcome of a competition policy that promotes price cuts. Increasing consumers' surplus while decreasing energy consumption requires huge investments in insulating buildings and high levels of R&D in the industries that manufacture electrical appliances. Again, a matter of industrial policy.

To satisfy the competition proclivities of the EU authorities, some tools for environmental regulation include pieces of market mechanisms. This is clearly the case for the trade half of the 'cap-and-trade' mechanism at the core of the Emission Trading System targeted at decreasing CO_2 emissions. Some possibilities of trade also exist for the promotion of renewables (green certificates) and for energy saving (white certificates). Basically, they all rely on the following structure:

- Obligated agents are designated, their duties defined and 'materialised' by certificates.
- A quantitative link is forged between the obligation and some technology that produces certificates.
- A commercial forum is created within which the obligated agents and the producers of certificates can trade.
- Performance is monitored; violators are sanctioned.

This mechanism is mainly working for the reduction of CO_2 emissions in the EU. It is not the main tool used for the two other environmental targets.

The Black 20

The target of decreasing greenhouse gas (GHG) emissions by 20% from the 1990 level is a sequel of the Kyoto Protocol of 1997. To meet the objective, EU member states in 2005 launched the EU Emissions Trading Scheme, a cap-and-trade system.[15] A mandatory target is imposed on almost 12,000 industrial plants all around Europe, plus airlines since 2012. They are the obligated parties. Every year, each obligated firm receives for free or buys an initial endowment. Along the year, the adjustment between the individual target and the initial endowment is reached, partly through technical investment to abate polluting emissions, and partly through spot and forward market exchanges. The market part of the mechanism generates a carbon price. Up to now, the price has apparently been driven by macroeconomic trends (e.g., the worldwide economic crisis) rather than by the microeconomic balancing of the benefits from pollution abatement and the expected emission costs. So far, the price per tonne of CO_2 (t CO_2 price) has remained well below the penalty for noncompliance; the latter being €40/t CO_2 during the first round (2005–07), and €100/t CO_2 during the second (2008–12) and third (2013–20).

There is a structural explanation for the discrepancy between the spot price of CO_2 (never above €30/t, around €3/t during spring 2013) and the estimate of what it could (or should?) be, say between €40/t and €100/t.[16] The explanation can be found in the basics of microeconomics. We know that:

- competition leads to optimality, as long as all competing agents neither emit nor are subjected to externalities (the first welfare theorem); and
- when externalities are present, a Pigouvian tax or a Coasian system of property rights restores optimality as long as the tax is fixed at the damage level and the rights can be sold and bought by all the concerned agents.

The problem is that, as regards global warming, the main concerned party is not present at the negotiating table because it hasn't yet been born. Governments, international organisations, and NGOs are in charge of speaking on behalf of our great-children. It could help to solve the problem if these representatives did not depend on the votes and financial resources of today's myopic citizens. Here is the source of the failure: entities mandated for five or ten years by egoistic and short-sighted agents, and intensively lobbied by industrial groups, are supposed to take conflicting decisions in favour of agents with unknown preferences and technologies living a century from now. Because of structural myopia,

15 The system is now backed by Directive 2009/29/EC of 23 April 2009 of the European Parliament and Council, amending Directive 2003/87/EC, to improve and extend the greenhouse gas emission allowance trading scheme of the Community. For the analysis of the comparative advantages of alternative tools, see Fischer and Newell (2008).

16 This is the interval commonly accepted for the cost of carbon capture and storage.

the quantity of permits given for free or auctioned (since January 2013 for all electricity producers) is too large. And excess supply means low carbon prices with almost no effect on industrial production and consumption. This in turn has weak effects on emission reduction, energy saving, and the encouragement of renewables. How can the dilemma be solved?

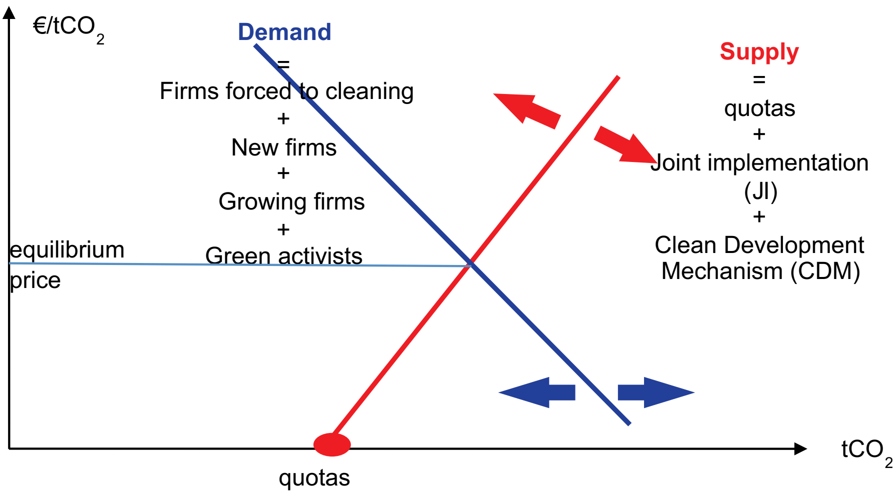
Because it is impossible to imagine what preferences and technologies will be in the long run, no solution can be perfect. As a second-best solution, however, we should require that the institutional arrangement takes the future into account. The probably less inefficient solution draws on the case of so-called orphan diseases, where one entity is specifically in charge of replacing the missing side of the market. Pharmaceutical firms invest in the development of new therapies only if they face a solvent demand, i.e., enough potential buyers with enough money to spend. A disease that does not meet these conditions is one of the 6,000 to 8,000 rare diseases listed by the World Health Organization as having little chance of being considered by the industry, except if a public or private entity enters the arena as a surrogate for the missing solvent demand. An example is the Global Fund, created in 2002, as a public-private partnership that raises and spends resources to prevent and treat HIV and AIDS, tuberculosis and malaria.

Similarly, as regards CO_2 emissions, a fully independent entity (let us call it the Intergenerational Regulation Fund, or IRF) without national political interference could be installed as the representative of both present and future generations. It would be responsible for allocating the rights to use common resources, such as the atmosphere and the oceans. Again, this would not solve the difficulty of evaluating future needs and technical possibilities. However, the fund could at least make quota and pricing decisions without being focused on short-term worries. As the seller of permits to emit pollutants, it would collect large amounts of money that could be invested in less-polluting technologies and used to compensate poor people and poor countries for the regressive effects of expected increases in energy prices. According to the Coase principle, whoever the rights holder is, the volume of the externality will be efficient on the condition that the rights are well defined. Creating an IRF with the power to regulate access to common natural resources would make it possible to meet environmental targets and to apply the polluter-pays principle as well.

This solution has all the qualities and defaults of natural monopolies, alleviated by *ex post* trade possibilities. As shown in Figure 2.1, the supply of allowances in the EU Emission Trading System is currently made up mostly of quotas, supplemented by permits from the Joint Implementation scheme[17] and the Clean Development Mechanism.[18]

The way these allowances are calculated and allocated to obligated parties can create distortions of competition that do not exist in the case of a single supplier. By contrast, there is a risk that the monopolistic institution could abuse its position by restricting the supply of quotas. That risk can be reduced if the IRF is a non-profit private-public partnership with transparency obligations.

Figure 2.1 *Equilibrium in the EU Emission Trading System*



Another problem with the EU's Emission Trading System is carbon leakage.[19] Because the abatement mechanism is limited to Europe, the potential increase in electricity prices that could result from high carbon prices could put certain EU energy-intensive sectors at an economic disadvantage compared with firms located in countries where carbon constraints do not apply. Additionally, it could result in larger emissions worldwide. Because of this risk, Article 10a(6) of

17 The Joint Implementation scheme promotes emissions reduction projects in the developed countries listed in Annex I of the Kyoto Protocol, financed by another developed country of Annex I. The project developer obtains an emissions reduction unit (ERU) credit for each ton of carbon dioxide equivalent. Russia and Ukraine have hosted the majority of Joint Implementation projects to date.

18 Annex I countries finance emission reduction projects in developing countries and earn certified emission reduction (CER) credits that are priced on the EU ETS. The projects are mainly aimed at developing renewable energies (36% of expected credits) and improving energy efficiency (11% of expected credits). More than three quarters (81%) are in Asia, 13% in South America, and 4% in Africa.

19 "Carbon leakage is the term used to refer to the observation that emission reductions in one country or region may be offset by increasing emissions in other countries or regions." OECD (2011: 10).

Directive 2009/29/EC provides that member states may adopt financial measures in favour of 164 energy-intensive sectors determined by the Commission.[20] This means that we are back to state aid and its potentially distortionary effects on competition within the European market. Again, administrative rules are required to limit the distortions,[21] and again, we glide farther and farther from pure market mechanisms, closer and closer to industrial policy at the level of each member state. A global mechanism applied by a single institution would be preferable.

Overall, we see that the core of the EU policy against global warming is an administrative planning process biased by a set of subsidiarity issues. It requires bureaucracy, monitoring, and registers for *ex ante* evaluation and *ex post* control. It creates a lot of red tape and transaction costs still to be estimated, as well as some opportunities for fraud.

Given the complexity of the installed mechanism, one could have expected better results. If the EU Emission Trading System had been correctly set up, it would have produced a much higher price for carbon emissions, thus a much higher cost for electricity production burning fossil fuel, and thus the following:

- an incentive to invest in R&D to develop technologies to reduce the level of polluting emissions in the atmosphere (e.g., carbon capture and storage);
- an incentive to invest in R&D to develop technologies with low emissions (RES, hydro, nuclear); and
- an incentive to reduce the consumption of energy.

So, the need for custom-made policies to sustain renewables and energy saving can be viewed at best as an acknowledgment of the failure of the current mechanism, and at worst as the inability of the authorities to understand that curbing polluting emissions is the paramount objective, next to which the two other policy tools should be subordinated. The EU Emission Trading System is a tool to correct an externality. There is no such externality for renewables and energy efficiency.

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20 Commission decision of 24 December 2009 determining, pursuant to Directive 2003/87/EC of the European Parliament and of the Council, a list of sectors and subsectors which are deemed to be exposed to a significant risk of carbon leakage.

21 "Those measures shall be based on ex-ante benchmarks of the indirect emissions of CO_2 per unit of production. The ex-ante benchmarks shall be calculated for a given sector or subsector as the product of the electricity consumption per unit of production corresponding to the most efficient available technologies and of the CO_2 emissions of the relevant European electricity production mix." (Article 10a(6) of Directive 2009/29/EC.)

The Green 20

To achieve the binding target of a 20% share of renewable energies in overall EU energy consumption by 2020, member states have implemented various policies in favour of the production of energy from wind, solar, aerothermal, geothermal, hydrothermal and ocean energy, hydropower, biomass, landfill gas, sewage treatment plant gas, and biogases.[22] Some member states use direct investment subsidies; others prefer quota obligations, sometimes combined with tradable green certificates.[23] However the most widely used financial tool around the world is a non-market system: fixed feed-in tariffs (FITs) paid to green producers to compensate high investment costs and low reliability.[24]

In the next section, we sketch the analysis of the effects of FITs on the structure of the market for green technologies used in the production of electricity, such as windmills and photovoltaic panels. We show that FITs set above the consumption tariff automatically increase the demand for RES equipment, transforming all consumers into would-be electricity producers with dramatic effects on the financial equilibrium of the aid system. On the supply side of the equipment industry, as R&D and investment are sustained by subsidised demand, an asymmetrical learning-by-doing effect drives the less efficient European manufacturers out of the market.

The following section is devoted to the problem of intermittency. We observe that the promotion of electricity from renewable sources is not accompanied by a comparable increase in flexibility on the demand side. This means that the European authorities are encouraging the development of random and cyclical sources of production, whereas the demand by final consumers cannot be made contingent on the state of nature that prevails at the production nodes. For that reason, plants operating on RES should not be viewed as substitutes to fossil-fuelled plants. The latter are necessary complements to satisfy demand by nonresponsive consumers, i.e., consumers not equipped with smart meters and appliances to respond to scarcity signals. This underestimated effect creates structural and financial constraints for the future of the energy industry.

22 The list is fixed by Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources.

23 "By early 2009, policy targets existed in at least 73 countries, and at least 64 countries had policies to promote renewable power generation, including 45 countries and 18 states/provinces/territories with feed-in tariffs (many of these recently updated). The number of countries/states/provinces with renewable portfolio standards increased to 49. Policy targets for renewable energy were added, supplemented, revised, or clarified in a large number of countries in 2008." REN21 (2009). See also European Wind Energy Association (2005: 29-31).

24 This has been encouraged by the EC: "[W]ell-adapted feed-in tariff regimes are generally the most efficient and effective support schemes for promoting renewable electricity," European Commission (2008). See also Energy Economics Group (2010). For a comparison of alternative support tools, see Butler and Neuhoff (2008).

The structural effects of FITs

Most EU member states – in particular France, Germany, Italy, and Spain – have hugely subsidised the solar and wind energies by guaranteeing generous selling prices (FITs) to electricity producers operating windmills and photovoltaic panels. These programmes have been so successful that they have endangered the financial equilibrium of the funding system in the four countries listed above, forcing their governments to decrease tariff levels and redefine the conditions of eligibility for these promotion programmes.

The point is that the programmes for subsidising the generation of electricity from RES through demand were launched without any analysis of the strategic behaviour that could be expected from the agents affected by such a public bonanza, in particular:

- the consumers/producers who benefit from the feed-in tariff; and
- the firms that manufacture the production assets, in particular PV panels.

Other important players are the firms that install and maintain the physical assets that produce green electricity and the operators of the distribution and transmission networks. The integration of RES into the grid requires huge investment in transformers, lines, and two-way meters (European Wind Energy Association 2005).

Public authorities often emphasise several side benefits from the promotion of RES. For example, clause 4 of Directive 2009/28/EC states:

> When favouring the development of the market for renewable energy sources, it is necessary to take into account the positive impact on regional and local development opportunities, export prospects, social cohesion and employment opportunities, in particular as concerns SMEs and independent energy producers.

Clause 6 of the same document states:

> The move towards decentralized energy production has many benefits, including the utilization of local energy sources, increased local security of energy supply, shorter transport distances and reduced energy transmission losses. Such decentralization also fosters community development and cohesion by providing income sources and creating jobs locally.

Similarly, according to the European Commission (2011):

> Renewable energy is crucial to any move toward a low-carbon economy. It is also a key component of the EU energy strategy. The European industry leads global renewable energy technology development employs 1.5 million

> people and by 2020 could employ a further 3 million. The promotion of renewable energy also develops a diverse range of mostly indigenous energy resources.

Clearly, all these appealing outcomes cannot surge without public intervention:

> The State Aid Action Plan also stressed that environmental protection can provide opportunities for innovation, create new markets and increase competitiveness through resource efficiency and new investment opportunities. Under some conditions, State aid can be conducive to these objectives, thus contributing to the core Lisbon strategy objectives of more sustainable growth and jobs.[25]

On top of all these positive expectations, electricity production from RES also has an exciting feature for green supporters. RES-electricity plants can be installed on a small scale in a decentralised way. Therefore, RES electricity would make consumers more responsible in energy use, as they would balance the relative advantages of selling rather than consuming electricity produced locally.

This is true in a framework where the FIT is below the retail tariff or price, as argued below.[26]

Under circumstances where local energy is abundant (say, a large surface of PV panels and bright sun), keeping the entire local production for consumption is not efficient since the consumer's marginal valuation is smaller than the market valuation represented by the FIT. The consumer equipped with PV panels is better off selling any extra production to the grid. The production, consumption, and sale decisions are all governed by the FIT. The retail price plays no role, because the local production is so abundant that it is not necessary to buy extra energy from the grid.

In contrast, when electricity from RES is scarce (small PV panels or cloudy skies), it would be inefficient to limit consumption to the local production because the consumers' valuation is above the price at which they can obtain extra energy – that is, the retail price. Consumers are better off buying a part of their consumption from the grid. The production, consumption, and purchase decisions are all governed by the retail price. The FIT plays no role because the local production is so scarce that there is no energy left to be sold after consumption.

In this framework, the agent does not simultaneously buy from and sell to the grid.[27] He is a 'green citizen' in the sense that he must make a set of related decisions concerning consumption and local production backed by the grid where he can sell or buy extra power. This is not the case in the EU member states that have set the FIT so high that all consumers and producers of electricity from

25 Introductory clause 5 of "Community guidelines on State aid for environmental protection" (2008/C 82/01).

26 For a formal proof of the following statements, see Crampes and Lefouili (2011).

27 At some exceptional times, he can even live in autarky.

RES actually behave strategically by totally separating their two roles: on the one hand, consumption and purchase decisions depend solely on preferences and the purchase price; on the other, production and sale decisions depend solely on the local generation cost and the FIT. The system has transformed all consumers with local possibilities of production into producers, driven only by the promise of profit. This is good for the development of green technologies, but it has three serious drawbacks:

- It is financially unsustainable because subsidised green investment has gone too far and too fast; all member states using FITs have been obliged to decrease them drastically.[28]

- It increases the randomness of production.

- It has created a violent shock of demand in the market that produces green equipment, and that shock has forced out European manufacturers.

Let us comment briefly on this third negative outcome. The mechanism behind the expected development of RES through demand subsidies is based on decreases in production cost from learning-by-doing.[29] Contrary to the logic of R&D subsidies, where an increase in demand is due to lower prices resulting from lower costs, in the FIT system demand is the driver of the cost decrease. Therefore, with FITs, an increase in demand comes sooner than under the regime of R&D subsidies. Nevertheless, this system can have adverse effects for competition. According to Dasgupta and Stiglitz (1988):

> Learning-by-doing involves a form of sunk cost. Production leading to a gain in experience, is the cost which is sunk. Learning therefore manifests itself as an irreversibility in production possibilities.

28 This start-and-stop policy obviously creates uncertainty for the investors. Italy, after the other big EU countries, decided in March 2011 to decrease the advantages given to green investors. As a result, the EU energy commissioner said in a letter to Italy's industry minister that he was concerned about the consequences of such changes for investment in the RES sector after receiving complaints from sector operators: "It is fundamental that the Italian government creates as soon as possible a clear, stable and predictable internal framework for incentives to guarantee the development of renewable energy. The changes which alter financial returns on existing projects risk violating general principles of national and EU rights and, moreover, compromising the stability of the investments in the sector." The European Commission's energy spokesperson said the Commission could open an infringement procedure against countries that cannot provide certainty about the incentives to renewable energy investors. (Euractive, www.euractiv.com/en/climate-environment)

29 "Productivity increases are realised not only as a result of the explicit allocation of resources to capital accumulation and research and development, but also often as a by-product of the process of production; that is, learning-by-doing. Learning gives rise to a special kind of intertemporal externality in production. It was used as an argument for the protection of infant industries, the idea being that in the absence of public intervention a domestic infant industry capable of learning would be stifled by foreign competition." Dasgupta and Stiglitz (1988). See also Arrow (1962), Cabral and Riordan (1994), Fudenberg and Tirole (1983).

This implies that under FIT schemes, there is a potential for creating a natural monopoly instead of promoting competition. One benefit expected from green policies was the promotion of a European high-tech industry innovating in new technologies with an accompanying increase in local employment. However, the European authorities have apparently not considered the consequences of learning in a worldwide competition framework. Actually, the FIT-based EU policy has excluded European champions from the equipment market instead of giving them a boost. Thus, the industrial policy slice of the promotion plan is a total failure.

To conclude this section, note that FITs are not the only tool used to promote renewable energy sources. Some countries rely instead on premiums or on tradable green certificates. In both cases, the green producer sells its energy to market and, on top of the spot price, receives a fixed premium or a green certificate for each kWh of electricity produced. Certificates are then sold to obligated parties (suppliers in Belgium and the UK, producers in Italy, grid companies in Germany). The premium system is a light form of FIT. The tradable green certificate system looks like the EU Emission Trading System, except that it is organised on a national basis.[30] Therefore it has the same qualities and defects as the ETS, in particular the administrative cost of registration and monitoring.

Backup technologies for green electricity

The substitution of renewable sources of energy for fossil fuel in electricity production is one of the key technological solutions to mitigate global warming. It is currently being pushed by many scientists and policymakers within the context of the debate on reducing emissions of greenhouse gases. We have seen that environmental policies support less carbon-intensive renewable sources of energy by means of subsidies, FITs, and mandatory minimal installed capacity. In all developed countries, the generation of electricity from geothermal, wind, solar, and other renewable sources is increasing by more than 20% a year.

An essential feature of most renewable sources of energy is intermittency. Electricity can be produced from wind turbines only on windy days, from photovoltaic cells on sunny days and certainly not at night, and from waves and swell when the sea is rough. All these intermittent sources of energy rely on an input (wind, sun, waves, tide) the supply of which is under no-one's control. Some of these conditions are perfectly predictable, for example, the seasonal duration of daylight or the tide level. Others, such as the strength of the wind and the intensity of the sunshine, can be forecast only a few days in advance, and even then with some degree of uncertainty.

30 Comparing with Figure 2.1, demand for certificates is vertical because the obligated firms have no way to decrease their obligation, whereas supply is an increasing curve because a higher price of certificates is an incentive to produce more green energy. However, note that the exact location of the supply curve depends on the energy spot price, since green plants produce two outputs: energy and certificates.

Yet a contractual characteristic of the electricity industry is the commitment of retailers to supply electricity to consumers at a given price at any time and at any level of demand. This business model reflects the consumers' taste for a reliable source of energy, which is viewed as essential for lighting, cooling, or heating, for example. In developed countries where power outages and blackouts are very costly both economically and politically, electricity production and supply are designed to match the demand of consumers any time and at any location on the grid. Thus, the variability and unpredictability of intermittent sources of energy clearly conflict with a reliable supply of electricity.

One way to reconcile intermittent supply with permanent demand consists in storing the input, the output, or both. In that respect, hydropower production is an attractive source of energy. Although it relies on uncertain rain and snow, water can be stored in dams to supply electricity during periods of peak load. In northern countries, water is stored during the autumn and spring to be used in winter for heating and lighting.

In contrast, input storage is not possible for two growing renewable sources of energy: wind and solar power. Output storage is also very limited. The current storage technologies using batteries are still very costly and inefficient at large scale. An intermediary solution in combination with hydropower is pumped storage.[31]

The introduction of a large share of intermittent and non-storable sources of energy is a new challenge for the operators and regulators of the electricity industry. In addition to difficulties in transportation and distribution (NERC, 2009), intermittent sources raise problems at the generation stage, in particular:

- the efficient mixing of intermittent sources (wind, solar) with reliable sources such as fossil fuel (coal, oil, natural gas) or nuclear power;
- the compatibility of intermittent sources of energy with market mechanisms (can competitive markets decentralise an efficient mix of capacity?); and
- the design of an environmental policy aimed at promoting low-carbon technologies by relying on intermittent sources of energy and simultaneously guaranteeing security of supply.

These issues can be analysed in a formal model of energy investment and production using two sources of energy: a low-cost intermittent source (wind), and a costly non-intermittent source (fossil fuel) (Ambec and Crampes, 2012). The two sources differ in cost and availability. Both require installed capacities at a cost. Electricity generation in plants using non-intermittent energy costs the price of the fossil fuel plus a possible emission tax or carbon price. In contrast,

31 Cheap electricity is consumed in periods of low demand to restore water resources that can be used to generate electricity in periods of peak demand. See Crampes and Moreaux (2010).

producing electricity from wind is (almost) free once capacity is installed. Nevertheless, it is possible only when and where the input (wind) is available. One can characterise the efficient energy mix in terms of installed capacity and production for all possible values of their costs. Wind power is used either as a substitute for or a complement to fuel power on windy days.

Decentralising the efficient energy mix requires that prices be based on the availability of the intermittent source of energy, that is, on weather conditions at the production node. Unfortunately, this requirement is not implementable because of the lack of price responsiveness on the consumer side; consumers are not informed about the availability of the RES or they receive a signal but cannot adapt because the electrical appliances are not flexible enough. So prices have to be the same in all states of nature, independent of whether wind turbines are spinning or not.

This results in a second-best solution characterised by underinvestment in wind power and overinvestment in plants burning fossil fuel compared with a first-best solution. The reason is that a uniform price cannot reflect energy scarcity in each state of nature. The price is too high on windy days when energy is abundant, and too low on windless days when energy is scarce, with the consequence that production (or consumption) is too small (large) when the wind is (not) blowing. The result is that wind power production is more profitable than fossil power. A regulated electricity monopoly that operates the two technologies under a zero-profit condition experiences a deficit on fossil power that is compensated by the profit from its wind power division. If, however, electricity is supplied by competing firms each owning only one of the two technologies, and if there is free entry, the zero-profit condition of the fossil power producers implies strictly positive profits for wind power producers.

Let us consider some consequences of this result in terms of energy policy. In the near future, intermittent technologies will be able to compete against fossil fuel technologies after a technological breakthrough or some drastic learning effect, or because of more stringent climate change mitigation policies (higher carbon taxes or fewer emission permits) that lead to a higher marginal cost for fossil combustion.[32] Meanwhile, intermittent technologies will be sustained by public aid or purchase requirements that are a financial burden for society. These costs are well known. In contrast, the other costs identified in Ambec and Crampes (2012) have received less emphasis and still have important policy implications for the future of the energy industry, in particular:

- the cost of altering the electrical appliances used by consumers and adapting the network to enable responsive consumers to participate in achieving the optimal energy mix;

32 According to a report of the French Senate (summer 2012), the cost of 1 MWh is €54 from nuclear plants (including the post-Fukushima costs), €82 from on-shore windmills, €220 from off-shore windmills, and between €229 and €371 from photovoltaic panels.

- the structural or institutional arrangements required to decentralise the optimal energy mix with non-responsive consumers; and
- the conflict between the environmental regulation of fossil sources and the financial regulation of intermittent sources.

Smart consumers
First-best analysis suggests that intermittent technologies should be promoted in parallel with smart meters and/or smart boxes. These intelligent devices can make electricity consumption dependent on the state of nature that prevails at the location of production plants. By controlling in real time programmed electrical equipment such as boilers and heaters (disconnecting them when the intermittent source of energy is not available), smart meters and smart boxes can make electricity demand sensitive to energy scarcity across time and space (a topic dealt with in the section on 'the white 20'). Such devices (and therefore the consumers who use them) are likely to be more receptive and responsive than consumers exposed to messages such as 'the wind turbines you are connected to are currently running; therefore the price of electricity is low'. The smart meters and boxes that dispatch consumption automatically over time need to paired with information technologies (ICTs) installed all along the energy network. More generally, the growth of intermittent energy calls for further investment in the network to intensify both connections and information processing. Compared with thermal power plants, wind and solar plants are more likely to be scattered across a given territory. This has two consequences. First, connection requires large investment in small-scale lines, transformers, and two-way meters. This obviously makes coordination necessary between producers, transmitters, and system and market operators. Second, random local injections radically modify the business model of distributors, since the latter now have to balance flows on sections of the grid under their responsibility and, in some cases, must install new lines and transformers or reinforce old ones to guarantee the reliability of the local system under the constraint of accepting injections from authorised generators. In most developed countries, making the grid smart is now a priority, a goal that entails huge investments to embed information and communication technologies into the grid.

Structural arrangements
The huge cost of installing smart appliances at consumption nodes and information technologies all along the grid is still too high when compared with the welfare increase derived from introducing prices contingent on the state of nature. Consequently, consumers continue to be offered only one price, whether wind turbines are producing or not. Compared with the optimal energy mix under state-contingent prices, today's consumers demand too little energy when the intermittent source is available and too much when it is not. If the resulting equilibrium price were an average value of the marginal costs of production in the different types of generation plants, generators using fossil energy would

lose money and eventually would prefer to leave the industry. We therefore must consider structural and legal solutions to implement the optimal energy mix under the constraint of non-contingent prices. Assuming free entry and exit, in order to keep generators using fossil fuel in the market, the price should be equal to the long-run marginal cost of their MWh. This can be construed as a requirement that consumers must pay a premium for guaranteed service. The drawback of this solution is that the owners of plants using intermittent energy pocket a profit equal to the difference between the long-run marginal cost of electricity from fossil fuel and the long-run marginal cost of electricity from intermittent energy. Consumers pay for being insured against random supply, and the money they pay accrues to those who create randomness.

Two basic public policies can restore the second-best energy mix. The first consists of taxing RES and subsidising thermal plants in order to balance the budget for each type of technology, the reverse of current policy. The second consists of a mandatory technological mix in order to produce a non-random energy outflow. Each producer should either control the two technologies or buy an insurance contract that secures energy supply at all times. These legal arrangements would force both the incumbents and new entrants to guarantee energy provision whatever the state of nature at the production plant locations. Both policies have drawbacks. The first, which is the more market-oriented, comes at the cost of levying and redistributing public funds. The second, which is more in line with command-and-control regulation, restricts firms' flexibility in their choice of technology.

An intermediate solution is to reinforce the role of suppliers in providing final consumers with both energy and insurance through a menu of contracts. Yet this is for a more distant future, because providing some consumers with cheap intermittent electricity and others with expensive reliable electricity within the same distribution network will necessitate more than smart meters. Consumption appliances will have to be equipped with microprocessors and connected through the 'internet of things' to suppliers. At periods of scarce energy, suppliers will then be able to (partly) disconnect Mr. A, who did not sign a 'non-random contract', while still fully supplying Ms. B, his nearest neighbour, who did.

Environmental policy

The cost of energy production must include the environmental costs of air pollution, resources used, and waste generated for present and future generations. When consumers are non-responsive, the regulator must mitigate two market failures. The first is the pollution externality created by plants that generate electricity from fossil fuels. The mitigation of that externality requires favouring less dirty sources of energy such as wind and solar power.

When consumers do not react to pricing that is contingent on the state of nature, the demand for electricity is independent of the availability of energy. This is the second market failure. Producers must supply the same quantity of electricity at the same price in all states of nature. Under perfect competition with free entry, the regulator should set the average profit of the electricity industry to zero in the long run by taxing windmills to subsidise thermal power.

The two market failures call for opposite policies. The net tax or subsidy on each source of energy would depend on the magnitude of each market failure. If pollution damages are more important than consumers' loss of surplus (owing to their non-responsiveness), fossil fuel power should be taxed and wind power subsidised. Money should move the other way in the opposite case.

The White 20

Energy services

"Doing more with less" was the teaser of the Green Paper on energy efficiency published by the European Commission in 2005.[33] The idea was that electricity is just an input used at consumption nodes to produce energy services, such as heating and lighting, in combination with some piece of equipment. By promoting the insulation of buildings and the use of low-consumption electrical devices, the logic went, one could increase energy services while reducing the amount of electricity consumed.

In 2007, the EU set the objective of achieving 20% primary energy savings in 2020,[34] again forgetting that a high price for or tax on carbon emissions would induce decision-makers to instinctively favour energy-saving decisions. The EU was also apparently forgetting that as competition policy pushes retail prices toward marginal production costs, it is not abnormal to observe a limited decrease in demand, even possibly an increase. Despite this behavioural evidence, in 2011 the Commission estimated that taking into account the national energy efficiency targets set by member states in the context of the 2020 strategy, the EU would achieve only half of the 20% target in 2020. It then decided to prepare a new directive[35] transforming certain aspects of its energy efficiency plan into binding measures.

To comply with the 20% energy-saving objective, member states have adopted a variety of measures, some purely administrative (such as standards for the consumption of primary energy in new buildings), others in line with the cap-and-trade mechanism.

The consumption cap raises an interesting case of contradiction between public policies. In France, it has been fixed at 50 kWh/m²/year. Obeying the rule makes it impossible to equip new apartments with electricity-fuelled water boilers

33 (COM(2005) 265 final; ec.europa.eu/energy/efficiency/doc/2005_06_green_paper_book_en.pdf

34 The 20% improvement in energy efficiency by 2020 was set out in the Commission communication of 19 October 2006 entitled "Action Plan for Energy Efficiency: Realising the Potential." It was endorsed by the European Council of March 2007 and by the European Parliament in a Resolution of 31 January 2008.

35 Directive 2012/27/EU of the European Parliament and of the Council of 25 October 2012 on energy efficiency, amending Directives 2009/125/EC and 2010/30/EU and repealing Directives 2004/8/EC and 2006/32/EC.

because, with a conversion factor of 2.6 for electricity (an old administrative coefficient), the quantity of primary energy required would be above the 50 kWh cap. Therefore, in most cases, boilers burning natural gas will be installed. Because most of the electricity consumed in France comes from nuclear plants, and because nuclear generation emits much less CO_2 than gas generation, the mandatory 50kWh cap results in an increase of CO_2 emissions.

An example of a (mildly) market-based incentive is the white certificates mechanism. Energy companies are the obligated parties.[36] To acquire the certificates that they will have to surrender to the regulator, they must promote or fund energy efficiency improvements. The certificates can also be traded (though very few are), but only at a national level. Like the green certificates and unlike the Emission Trading System, the energy-saving certificates have no EU-wide value. The administrative costs of the scheme are high, as the mandatory savings to be evaluated are those above business-as-usual consumption and must be discounted for a duration that varies with the type of investment. It has been necessary to define standardised operations (such as the replacement of an old refrigerator with an A-rated refrigerator/freezer). For non-standard operations (such as wall insulation producing an energy saving that varies with the type of dwelling and the location), the public officials in charge of the implementation have some discretionary power. These measures resemble those found in any centrally planned economy.

The system can be coupled with operations to combat fuel poverty. For example, France and the UK have identified some customers (low-income and elderly people) as a priority group for investments in energy efficiency.

The countries using the white certificates system seem so happy with it that they have decided to tighten the constraint by increasing the objective that energy firms must meet.[37]

In the next section, we switch to a more promising market-based system: the development of demand responsiveness – more precisely, distributed load-shedding. The case illustrates how good economic initiatives can be compromised by erroneous legal decisions.

Load-shedding

The need to balance the electric power system in real time to account for the non-storability of electricity is the main explanation for vertical integration in the sector, either structurally or contractually. Non-storability also explains the secondary role traditionally given to demand in the physical balancing of the

36 Electricity distributors in Flanders, retailers of non-transport energy in France, electricity and gas distributors in Italy, electricity and gas retailers in the UK.

37 "There is now around €2 billion per year being spent by energy companies in the EU to deliver energy efficiency under Energy Efficiency Obligations. This figure still only represents between 1 and 5 percent of the energy bill to customers depending on the Member States. The success of this policy tool prompted two more EU Member States—Poland and Ireland—to develop similar schemes." (European Council for an Energy Efficient Economy, 2012).

power system. However, the advances in smart networks based on information and communication technologies suggest drastic changes in the near term, changes that will provide consumers with a more active role make the whole system more efficient.

Balancing the electric power system has long been a centralised matter, usually achieved through:

- outages or rolling and selective blackouts, methods still experienced daily in many developing countries; and
- the installation of operational reserves to ensure a given level of security of supply.

Nevertheless, large consumers, in particular, wish to achieve finer control of their energy bills. Since their electricity use has a significant impact on total demand, producers have progressively proposed contracts that include negotiated curtailment clauses under which the value of electricity signals the time and duration of selective curtailments. When negotiating a contract to supply low-price electricity, the electricity producer buys an option on the production of negawatt-hours (NWh) that are cheaper than the production of the additional megawatt-hours (MWh) necessary to balance the system without consumers' participation.[38] For its part, a client that can decrease its consumption pays a lower bill on the condition that it will either stop consuming energy or switch to alternative sources upon request.

The total load-shedding potential is much larger than the capacity offered by a handful of large consumers. Every consumer can be disconnected at low damage for dates, durations, and quantities varying with his equipment and preferences. The barrier is the cost of implementation. The installation of information technology allowing specialised service providers to control consumption equipment overcomes this obstacle. It is now technically possible to aggregate distributed load-shedding nodes on a large scale. Additionally, to meet environmental constraints and requirements in energy saving, the active participation of consumers is increasingly seen as politically desirable, especially voluntary load-shedding. But successful participation of consumers in system balancing requires more than technology; it also takes economic rules that make it possible to decentralise efficient dispatch.

The possibility of exercising an option to discontinue consumption can approximate the optimal peak production, provided that this option is acquired at the wholesale price and rewarded at the adjustment price. If that is the case, interruptible consumers supply NWh to compete against the suppliers of additional MWh on a level field. The efficient rule for financial balancing requires that the firms responsible for the need to re-dispatch acquire, at the

38 On negawatts, see Joskow and Marron (1992).

price of the real-time market, the electricity they had committed to sell at the wholesale price.

To be more explicit,[39] consider a competitive day-ahead market in equilibrium at price *p*. The market operator (MO) informs all bidders about their rights and duties at this price:

- consumers who have bid below *p* and producers who have bid above *p* will not be served or called;
- the others will have to withdraw or inject the amounts of power to which they have committed.

Let *u* be the use value of one MWh of electricity and *c* the production cost. Denoting by *n* the last demand bid served and by *m* the last supply bid called at equilibrium (given that the efficient ranking of bids by the MO follows the merit order) we have:

$u_n \geq p \geq c_m$ where $u_n > u_{n\text{-}1}$ and $c_m < c_{m+1}$.

Optimal adjustment

One of the *m* producers supposed to be active at equilibrium informs the MO that it will fail to deliver 1 MWh. The MO faces two elementary rebalancing solutions:

- either the MO calls the last nonplanned producer to supply the missing MWh (which will cost c_{m+1}); or
- the MO asks the planned consumer with the lowest electricity valuation to reduce its demand by 1 MWh (in which case the cost is the lost gross surplus u_n).

The least costly adjustment rule is:

- call producer m + 1 if $c_{m+1} < u_n$
- curtail consumer *n* if $c_{m+1} > u_n$

Decentralised adjustment

Assume that there is no organised market for rebalancing. The defaulting producer is obliged by law to find a solution. If it organises an auction between available producers to buy the missing quantity, competition will drive the adjustment price to $p_a = c_{m+1}$. With this solution, the defaulting producer is like a supplier without generation assets buying from an adjustment market at

39 For the details of the model, see Crampes and Léautier (2012).

price p_a and selling at the wholesale price p to which it had committed. Because the reserve assets are more costly than the assets planned to be dispatched, the producer's net loss is $p_a - p = c_{m+1} - p$.

The second possibility is to propose a compensation r to one of its customers because that customer will not be served. The producer prefers to buy the missing production if $r > c_{m+1} - p$ and to propose a deal to the consumer otherwise. This decision is in line with the optimal adjustment portrayed above only if $r = u_n - p$. Therefore, to implement the first-best solution, the power-cut deal must be concluded with customer n, the one with the lowest willingness to pay that also holds the right to consume. Moreover, n must be compensated only for its *net* surplus. Consequently, if customer n has already paid the market price p to the defaulting producer and if that customer is called to rebalance the system, the producer must pay the customer u_n so that it receives the net reward $u_n - p$ for not consuming. If the customer had not yet paid for the option to withdraw energy but receives compensation u_n, it must pay back p to the defaulting producer.

This process is increasingly common in day-ahead and real-time markets, rather than on a bilateral basis. In real-time markets, candidates for load-shedding compete against reserve producers to solve market imbalances either directly (big consumers) or indirectly (small consumers delegating decisions to aggregators). If we want this pure market adjustment process to decentralise the optimum, candidates for rebalancing must satisfy the following necessary conditions:

a. producers must have the capacity to produce on hand; and

b. consumers must own rights to the quantity of power they intend to renounce, which means they must pay the options to consume or not to consume at wholesale price p.

In such a market, competition between consumers that can reduce their energy demands and producers that can increase injections gives the equilibrium price $p_a = min\,(u_n, c_{m+1})$.

The apparently innocuous rule (b) above is denied by aggregators of decentralised load-shedding who consider that they should be allowed to keep the whole price p_a when they participate in the balancing mechanism. Actually, allowing consumers to exert an option without paying to acquire it violates the merit order that is at the core of electricity wholesale markets. In contrast, the economists' conclusion is clear: voluntary curtailed consumers should be paid $p_a - p$, not p_a. In France, the highest administrative authority (the *Conseil d'Etat*) invalidated the efficient reward scheme ('pay $p_a - p$') designed by the energy regulator (CRE), and the case was still pending as of summer 2013. In the US, the reverse is occurring - the Federal Energy Regulatory Commission has designed an inefficient rule ('pay p_a'), which is currently under appeal after the action of a large number of economists and energy companies at the Court of Appeals for the District of Columbia Circuit.[40]

Increasing the flexibility of the demand for electricity should be a priority (Hogan, 2009). The ever-rising cost of fossil fuels and the growing importance of environmental externalities prohibit the business-as-usual approach of continuing to invest in production facilities to meet a demand insensitive to price. The information and communication technologies applied to electrical networks should make possible significant changes in demand response in the near future. As consumers become more concerned with their energy bill and are increasingly able to delegate control of their consumption to service providers, we will gradually reach a state of the industry where demand plays a fully active role in the balancing process. We must therefore encourage R&D leading to the installation of electronic tools that allow consumers to control their demand efficiently.

Nevertheless, the solution is not just technical. It also requires a regulatory framework that respects the principles of an efficient allocation of resources, which means, in a market economy, a system of rights and fees that can decentralise optimal dispatch and re-dispatch (Torriti *et al.*, 2010). When consumers are allowed to freely choose either to consume or to be paid for not consuming, then the quantity of put options they acquire, the price they pay to acquire them, and the price they receive when they exercise them must be objective and verifiable in order to be included in detailed subscription contracts. The legal framework for firms that will develop the service of distributed load-shedding must also be clearly defined, since they will progressively acquire a lot of information on the behaviour of consumers and will intervene at critical periods under the supervision of the market operator.

Concluding remarks

With the European environmental and energy programme aimed at (i) reducing polluting emissions, (ii) using more renewable sources of energy, and (iii) consuming less energy, the EU authorities have swung open the door of energy markets to state aid. Because the problem to be solved is global warming, it is clear that market mechanisms cannot work efficiently without public intervention. The environmental externalities created by greenhouse gas emissions must be reduced, and this requires a specific public policy. However the solution cannot come from the superposition of uncoordinated policies, in particular because the promotion of renewable sources of energy and reductions in energy consumption should not be considered as intrinsic objectives on a par with the curbing of greenhouse gas emissions. The cap-and-trade system should be sufficient to reach the objective, provided allowances of pollutants are not given away free or auctioned in excessively large quantities.

40 See www.hks.harvard.edu/hepg/Papers/2012/Economists%20amicus%20brief_061312.pdf

Indeed, the basic problem at stake is the allocation of rights to use common resources. This should be done by an independent 'intergenerational regulation fund' created to manage common natural resources in the joint interest of present and future generations, independently of the myopic and egoistic interest of industrial and political decision-makers. Such an agency will not escape the bureaucracy curse. However, by efficiently allocating the rights to emit pollutants and using the resulting revenue to initiate green and white R&D programmes and to sustain social programmes against fuel poverty, the proposed agency would internalise the overlapping effects of separate policies. Having a single unit in charge would make it easier to implement the maximisation of intergenerational welfare.

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3

Do European Climate and Energy Policies Threaten to Postpone the Energy Transition?

Johan Albrecht

European climate and energy policies are under stress. The Emissions Trading System (ETS) of the EU suffers from a severe over-allocation of emission permits, leading to a very low CO_2 price. In almost all European countries, wholesale electricity prices are declining and are already too low to trigger investments in new generation and network assets. Such investments are essential to prepare for the coming transition towards a more sustainable global energy system.[41] Estimates of conventional generation reserve margins between now and 2020 suggest low electricity prices and a problematic investment climate for the next years. As the energy transition is a gigantic investment project, the current disincentives to invest are likely to significantly delay the pace of decarbonisation efforts in Europe.

Meanwhile, the production of coal and its use for electricity generation is increasing in Europe. In 2011, the consumption of coal in the EU increased by 3.6%, while demand fell by 1.1% in all other countries of the OECD (Rühl and Giljum, 2012). In the UK, the share of coal in electricity generation increased from 30% in 2011 to 42.8% in 2012, leading to an increase in coal consumption of 32.5% in 2012 (Department of Energy and Climate Change, 2013). Similar evolutions in Germany and Spain conflict with decarbonisation scenarios for Europe.

In the period between 2000 and 2010, greenhouse gas emissions dropped by 5.7% in the US, but by only 4.4% in the EU-27 (EC-JRC, 2012). As the very complex European climate and energy policy architecture is outperformed by a country without explicit climate policy targets – but with a higher economic growth rate – how sustainable is the perception that the EU holds the leadership in international climate policy?

41 Fossil fuels have a role to play in all transition scenarios up to 2050.

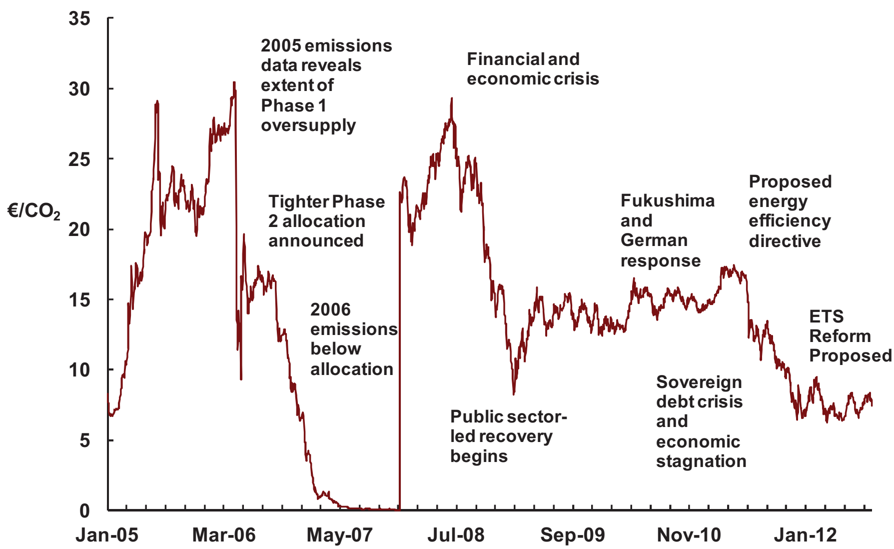
The goal of this chapter is to explain and assess some of the problematic interactions in European climate and energy policies. Is the complex European approach contributing to the problem it was designed to cure? Do we risk delaying the European component of the energy transition? How problematic might such a delay be? Based on a transition perspective, I conclude by discussing some options to improve the effectiveness of policy frameworks in the next decade.

Overallocation in the Emissions Trading System and '20/20/20'

Too soft a cornerstone

IHS CERA (2011) estimates that the overallocation of emission permits under the ETS is equivalent to 1.4 billion tonnes of CO_2 in the period between 2013 and 2020. The steep economic downturn since 2008, combined with the current double-dip outlook, is partly responsible for this overallocation. Although Phase III of the ETS (2013–20) introduced auctioning for the energy sector, CO_2 prices under the ETS fell further in the first half of 2013 (to €5). Figure 3.1 shows the evolution of the CO_2 price under the ETS between 2005 and 2012.

Figure 3.1 *The ETS CO_2 price between 2005 and 2012*



Source: Roques (2012).

The contrast with projections of the ETS price made in 2007 is large. As a consequence, the ETS sectors – responsible for close to 45% of total European CO_2 emissions (EC-JRC 2012) – currently do not have a market incentive to invest in ambitious carbon-mitigation measures. Without a significant carbon penalty, the relative fossil fuel prices of today ensure that old CO_2-intensive coal-powered electricity plants in Europe can easily compete with gas-powered plants that are much more carbon efficient but face a higher fuel cost per MWh of electricity produced. As the EU unfailingly presents the ETS as "the cornerstone of its drive to reduce emissions of man-made greenhouse gases" (EC-JRC, 2012), the current situation is far from optimal.

Interactions among climate policy goals and the ETS

Climate and energy policy options determine technological choices for the production of energy services as well as for the mitigation of greenhouse gas emissions. An economy-wide carbon tax will result in other technological choices than binding targets for renewable energy sources (RES). The European '20/20/20' approach of 2007 sets an overall emissions reduction target of 20% (the first '20' of 20/20/20) but also imposes very direct technological choices by 2020 (European Commission, 2007). Economic agents are required to invest in RES and in energy efficiency projects, irrespective of the availability of low-cost sources and technologies. By its nature, the 20% reduction target suggests that economic agents are free to decide how to meet the mitigation target. But emissions trading or carbon pricing is limited to those emissions not yet reduced by RES and efficiency policies.

Important decisions on the future allocation of CO_2 emission permits up to 2020 under Phase III of the ETS were also taken in 2007. The time horizon of the 20/20/20 package and of Phase III of the ETS is often presented as offering a long-term perspective to investors. However, the lifetime of energy system assets is typically in the range of 25 to 50 years. From this perspective, targets through 2020 mainly affect short-term investment decisions.

Twenty per cent or 30 per cent?

The EU initially wanted to commit to a 30% reduction target by 2020 upon the condition that other leading economies, such as the US, would commit to similar efforts. This easy switch of emission reduction targets reveals that the 20% target is a soft one because of the ongoing deindustrialisation of Europe. With less energy-intensive activities in Europe and more imports of manufactured goods from outside the EU, it is rather easy to lower the domestic production of CO_2 emissions (Helm, 2012). From a strategic perspective, Europe risks losing credibility by choosing domestic reduction targets as a bargaining chip.

Why supplemental policies?

The 20/20/20 package contains two additional policies to support carbon pricing as the core policy instrument to trigger a least-cost market response to the challenge of climate change. Because of multiple market barriers and failures (imperfections), carbon pricing alone will not fully unlock the existing potential for energy efficiency. Without technology-support policies, no radically new low-carbon technologies will hit the market in the coming decades. The availability of cost-effective energy-efficiency opportunities offers the potential to meet a given emission-reduction goal at a low carbon price. Without the emission reduction from energy efficiency investments, other sectors – such as industries exposed to international competition – need to take additional and more expensive mitigation measures (IEA, 2011).

Unfortunately, the use of supplementary policies adds additional uncertainty to the ETS market. The companies participating in the ETS base their strategic behaviour on price expectations. If supplementary policies such as RES and efficiency targets over- or under-deliver on their expected level of emissions reductions, the needed abatement within the ETS and, hence, the ETS price will be affected. These additional fluctuations in the CO_2 price can delay investment decisions.

Recent policy experiences show, furthermore, that the cost of supplementary policies can be higher than expected. Deployment targets for RES threaten to bring (too) expensive technologies into the market because of the historical under-investment in energy research, development, and demonstration (RD&D). Premature support for immature technologies should be avoided (Kramer and Haigh, 2009). It is not a coincidence that EU countries with very generous support schemes for photovoltaics today face a real explosion of retail electricity costs (see CEER, 2013). This could have been avoided by scaling up past public RD&D efforts in order to set more ambitious deployment targets at a lower cost to society. As the high cost of deploying RES is partly channelled to ETS companies through higher electricity network costs, this supplementary measure risks undermining the competitiveness of energy-intensive ETS companies on international markets.

Finally, measures to accelerate the potential for energy efficiency often are not justified from a market failure perspective. Many energy efficiency opportunities are neglected because of high discount rates, differences in preferences, or limited access to capital. These are not market failures – everyone would like to have more capital – and hence do not justify the use of expensive fiscal subsidies that primarily benefit those economic agents with higher and middle incomes. These fiscal subsidies do not have a direct impact on the electricity price but they do have an opportunity cost (for example, by crowding out resources available for public R&D). Policy interventions should focus on traditional market failures such as principal-agent relationships, split incentives (landlord-tenant), and adverse selection. Such market failures can partly be addressed with smart regulation at a lower cost.

Policy interactions and impact on the ETS price

Because of the economic crisis, electricity demand in many European countries was lower in 2012 than in 2007. Overcapacity in conventional generation increased during that period, and wholesale electricity prices in northwestern Europe fell from €75 in 2007 to less than €50 in 2012. More than five years after the start of the crisis, Europe is entering a new – or perhaps just another – crisis in the steel industry, with job losses and plant closures. Energy demand can be further reduced, leading to an even greater over-allocation of permits in the ETS.

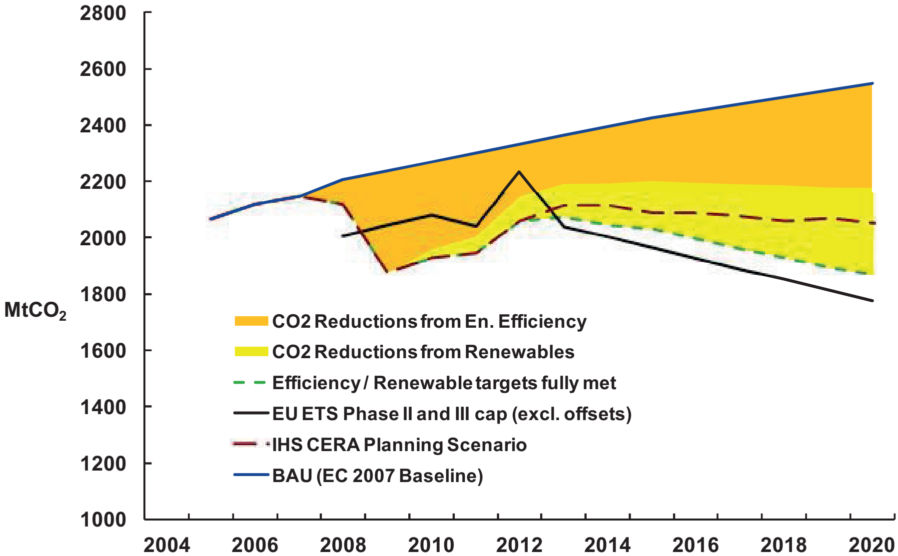
But the efficiency of the ETS is also affected by the 20% RES target and the 20% energy efficiency target.

The obligation to invest in RES serves to reduce emissions, especially from gas-powered plants in markets with stagnating demand. As a consequence, CO_2 emissions in the electricity sector – a major sector in the ETS – are in principle lower than in scenarios without high RES obligations. Because the electricity sector has to execute a technological mandate, the 20% RES mandate affects the remaining demand for emission permits. Simultaneously, all economic sectors – including the ETS sectors – are required to improve their energy efficiency performance between now and 2020. Higher energy efficiency levels lead to lower consumption of fossil energy and lower CO_2 emissions.

IHS CERA (2011) and Roques (2012) estimated the impact of both targets on CO_2 emissions – 20% RES and 20% energy efficiency – to conclude that their potential impact on emissions from ETS companies is large enough that the cap of the ETS Phase III can be met without any further mitigation effort. Figure 3.2 shows that subtracting the CO_2 reductions from both 20% targets by 2020 leads to emissions very close to the ETS Phase III cap. From this perspective, the 20/20/20 package seems to be a deliberate effort by policymakers to make the ETS redundant. After 2013, projected emissions exceed the ETS cap in Figure 3.2. However, the 2007 projection of baseline emissions for the period 2007–20 in the figure dates from the pre-crisis era. Since 2008, emissions of ETS companies followed a bumpy road. In 2009 alone, there was a reduction of 200 million tonnes of CO_2 (Roques, 2012). So while the economic crisis has had a profound impact on over-allocation in the ETS, even without the crisis the cap would be a soft one. With the crisis, the cap has no relevance whatsoever. Even with a 30% reduction target for the EU, this would likely be so – an embarrassment for the '*backbone of European climate policy*'.

The assessment by IHS CERA (2011) shows that energy efficiency measures, in particular, can lead to very strong emission reductions, even in a few years. This may be an overly optimistic presentation of the emission-reduction potential of energy efficiency measures in the short run. Nevertheless, the conclusions of this quantitative assessment are largely confirmed in other assessments. The IEA (2012) also argues that the strong growth of renewable energy, driven by policies outside the trading system, undermines the efficiency of he ETS. The IEA therefore concludes that "policy considerations aimed at enhancing coherence between renewable policies and the ETS would be justified" (IEA, 2012, p. 569).

Figure 3.2 *Interaction between ETS and the 20% RES and efficiency targets*



Source: Roques (2012) and IHS CERA (2011).

Although 20/20/20 is a soft package in terms of reduction ambitions, its design is not responsive to external factors such as the ongoing economic crisis or the rise of unconventional energy sources. The ETS faces the same rigidity – the cap cannot be adjusted to a new economic reality. The rigidity is problematic because of the use of short-term targets in 20/20/20 and in the ETS. With a longer time horizon – for example, 2030 or 2035 – unforeseen events would have a less dramatic impact on the relevance of policy goals because markets would have a better chance to adjust before the end of the longer commitment period. The alternatives of flexible reduction targets and flexible caps in the ETS by 2020 – for example, a cap inversely indexed to EU GDP – would severely complicate the ability to plan long-term energy technology investments. The alternative of a general carbon tax not connected to a specific short-term emission reduction target would avoid the current situation of economic incentives too low to trigger investments, but at the cost of creating another challenge: paying the carbon tax at times of severe economic crisis.

Electricity generation overcapacity

European electricity markets today face a significant generation overcapacity despite phase-out scenarios for old nuclear and coal capacity. In major economies, the reserve margin for conventional generation, or the available or remaining generation capacity at times of peak load, is in the range of 10% to 25%. E.ON AG (2011) projects a reserve margin of 15% between 2013 and 2020 for Germany, France, and the Benelux countries. For the Nordic region, the reserve margin is close to 25% in the same period. Spain, too, faces an overcapacity of close to 20% in the period 2013–20. Only in the UK does the reserve margin fall back to zero around 2016.

Because of additional investments in renewable energy technologies between now and 2020, the reserve margin will remain rather high in coming years. For onshore wind, generation capacity in Europe is expected to triple between 2008 and 2020 while offshore wind capacity will increase more than tenfold (E.ON AG, 2011). The prospect of sustained overcapacity puts pressure on electricity prices. In fact, electricity prices below €40 per MWh are no longer exceptional on forward markets (European Commission 2012a). The contrast with pre-crisis prices is large.

The downward price evolution is enforced because of the very low marginal generation cost of intermittent renewable technologies. As the supply of generation technologies on wholesale markets is based on marginal costs, subsidised RES technologies push conventional generation technologies with the highest marginal generation costs out of the wholesale market under optimal weather conditions. This combination of structural overcapacity and the low prices on electricity wholesale markets excludes investment possibilities in generation technologies that do not benefit from subsidy regimes.

The low prices on electricity wholesale markets are of little relevance for photovoltaic (PV) and wind projects, as they benefit from subsidy schemes (FITs) that cover their full cost. From a societal perspective, the high cost of PV and offshore wind – not to be confused with their very low marginal generation cost (Table 3.1) – increases the cost of short-term climate policy targets.

In other words, the current support schemes for energy from RES shelter a large sector from market dynamics, while the expansion of subsidised RES exerts a significant impact on wholesale prices and on investment opportunities in conventional generation. It remains unclear how long this type of market distortion can be sustained in a market that should be liberalised and fully integrated at the European level. The differences among the national RES support schemes already distort investment decisions in renewables.

Table 3.1 compares the marginal generation cost – for simplicity restricted here to fuel costs – to the total generation cost for the main generation technologies. The levelised cost of electricity (LCOE) is used to calculate the full generation cost. The LCOE values in Table 3.1 are based on a 10% discount rate but exclude a carbon or a CO_2 cost per technology. For wind and solar technologies, optimistic load factors from northwestern Europe have been selected: 25% for onshore wind, 35% for offshore wind, and 12% for PV. For conventional generation, the high load factors typical of the pre-crisis period have been selected – for example, 70% for gas-powered plants – although the current generation overcapacity and the expansion of RES do lead to much lower load factors that preclude investment.

Table 3.1 *Marginal versus total electricity generation costs for NW Europe in 2012*

	Fuel cost (€/MWh)	Total cost (LCOE, exclusive of CO_2 cost), €/MWh
PV (photovoltaics)	0	198
Wind onshore	0	107
Wind offshore	0	142
Nuclear	8	98
Coal	30	67
Gas	50	76
Biomass	75	122

Source: Albrecht *et al.* (2012).

An assessment of the LCOE is based on a stand-alone perspective for the technologies considered. This implies that the necessary costs of backup, balancing, and system flexibility are not included in the LCOE of intermittent generation technologies.

Table 3.1 confirms that in Europe, gas-powered electricity is not competitive once (wholesale) electricity prices are close to €50/MWh. As a consequence, coal-powered generation with a much lower marginal cost – €30/MWh in northwestern Europe – remains in the market and replaces gas capacity. This merit-order effect explains why electricity companies close down gas-powered plants but burn more coal. The most efficient coal-powered electricity plants can emit 740 g CO_2/kWh, whereas state-of-the-art gas-powered plants emit less than 400 g CO_2/kWh (IEA, 2012). In northwestern Europe, many old coal-powered plants are still in use today, so we can assume that emissions are close to 1,000 g CO_2/kWh. With a high CO_2 price in the ETS, efficient gas-powered plants would be much more competitive. But the electricity prices of today exclude all investment projects – including coal-powered generation – that do not benefit from production subsidies such as FIT.

The closings of gas-powered plants in northwestern Europe are not attributable solely to low wholesale electricity and CO_2 prices. In the first months of 2013, European gas prices were three times as high as gas prices in the US. This price gap is partly due to Europe's historical preference for gas contracts with oil-indexed prices. Meanwhile, the US economy benefits from low gas prices because of the ongoing shale gas revolution. Coal-powered plants are being closed in the country; new electricity plants are efficient gas-powered plants. As a consequence, CO_2 emissions in the US are decreasing, and the surplus of coal on the US market is shipped to Europe and Japan.

Investing in new gas-powered plants is consistent with decarbonisation scenarios because flexible gas plants offer the capacity needed to balance intermittent or weather-based generation. Hence, investments in flexible new gas-powered plants avoid the risk of a carbon lock in. Because the attractiveness of gas-powered electricity depends on gas prices, Europe not only needs to reconsider its climate policy goals but also the current organisation of its gas markets.

The energy transition as an investment challenge

The energy transition is a global project, and all economic regions should contribute to it. When economic agents do not face CO_2 mitigation incentives and the investment climate excludes the construction of flexible new gas-powered plants and intelligent energy networks, investments in crucial components of the transition to a low-carbon economy risk being delayed by several years. Can we afford the current levels of inactivity and uncertainty? What policy options can be considered to break the current stalemate?

A transparent assessment of the investment needs of the energy transition can be found in *Energy Technology Perspectives 2012* of the *International Energy Agency* (IEA). We focus now on the global investment needs in the electricity sector to support the energy transition (Table 3.2).

Table 3.2 *Global investment needs in the electricity sector, 2010–50 (US$ trillion)*

	2010–20	2020–30	2030–50	Total
Expansion of the electricity system without the transition investments	5.9	6.5	15.9	28.3
Expansion of the electricity system with transition investments	6.5	8.7	20.7	35.9
Additional transition investments in the electricity sector	600	2.2	4.8	7.6

Source: Based on IEA (2012).

According to IEA (2012), close to $28 trillion will have to be invested in the global electricity system by 2050 to replace old assets and expand the electricity system in response to global economic and population expansion. Most of these investments will occur in emerging markets and be triggered by market forces.

If the expansion of the electricity system also has to support the goals of the global energy transition, additional decarbonisation investments will be needed. To support the energy transition, total investment will have to amount to $36 trillion in the period 2010–50.

The additional investment cost of the energy transition is close to 30% of the projected investment needs to modernise and expand the electricity system. Of the total investment needs in the electricity sector of $36 trillion by 2050, $25.4 trillion is allocated to generation technologies, while $10.5 trillion needs to be invested in transmission and distribution. Table 3.2 shows that the bulk of the transition investments should take place in the period 2030–50. In optimisation models such as those used for IEA (2012), a carbon value is introduced to trigger the deployment of available technologies and to invest in the development of new and much more efficient technologies. To minimise the cost of the energy transition, the models assume massive investments in energy R&D in the first model periods, thereby lowering future deployment costs while also avoiding premature investments.

The expected increase in investments in the electricity system is geographically concentrated in Asia. Between 2010 and 2020, close to 30% of all investments will take place in China. With a total investment of $1.8 trillion by 2020 – including energy transition investments – China will invest more than Europe and the US together. Energy technology companies know this. Because of its economic expansion, investments in Asia will be largely market-driven, which is definitely not the case in Europe. Total investment needs in Europe – including energy transition needs – are estimated by the IEA (2012) to amount to $950 billion between 2010 and 2020. In case the transition investments in Europe cannot take place because of the problematic investment climate of today, the amount needed in the period 2020–30 will increase by a similar amount.

As long as energy R&D projects remain financed – even in times of crisis marked by budget cuts – at a level sufficient to deliver efficient low-carbon technologies over the coming decades, the energy transition as a whole will not be endangered because of a decade of bad investment climate. Unfortunately, it remains uncertain whether energy R&D efforts are indeed high enough to prepare for an ambitious energy transition. The share of energy R&D expenditures in the total R&D budgets of OECD countries has been decreasing – from 12% in 1980 to less than 4% today (IEA, 2012). In an earlier publication, the IEA (2010) compared current annual energy R&D spending levels to the estimated annual R&D investments needed to realise ambitious energy transition targets. That publication concluded that the annual estimated R&D spending gap ranged from $40 to $90 billion. To benchmark this R&D spending gap, consider that current public energy R&D spending is less than $13 billion.

As a final note, all discussions about low-carbon electricity systems should include the other components of the global energy system that also need to be transformed – among them, manufacturing processes and the electrification of transportation.

Technological choices in uncertain times

Investing in energy assets is a risky business today. Investment decisions hinge on market expectations; poor market outlooks will delay investment programmes. Investors may wonder how energy markets will respond to a decade of low economic growth. We now know that the high economic growth rates of recent decades were artificially boosted and reflected unsustainable overconsumption based on the excessive and unsustainable debt positions of governments, private companies, and households (Rajan, 2010). Unfortunately, the unavoidable deleveraging (or reduction of outstanding excess debt) will take place at a time when the increasing cost of an ageing population will make it more difficult for governments to balance budgets. The weak economic outlook will continue to have a direct impact on prices and energy demand expectations, and hence on investment decisions.

The energy transition is premised on the development of new technologies that are then selected by investors. To minimise the cost to society of the transition, no single technological trajectory should be favoured; instead, the selection of technologies should be based on competitive mechanisms. Today's climate and energy policy framework strongly influences the way technologies are selected. In Europe, the selection process is very complex because of the coexistence of technology-neutral and technology-imposing instruments. The ETS as the backbone of European climate policy is a technology-neutral policy instrument designed to ensure the selection of least-cost mitigation options by market forces. By contrast, the 20/20/20 package, with its RES and efficiency obligations, directly imposes specific technological choices. Other environmental policies, such as the Large Combustion Plant Directive (LCP Directive 2001/80/EC) to limit emissions pollutants other than CO_2 (mainly SO_2, NO_X, dust particles, and ozone precursors), also affect the use of old power plants and hence can lead to significant CO_2 emission reductions. The LCP Directive can even accelerate the phase-out of old (coal) power plants. At the national level, nuclear phase-out scenarios in Germany and Belgium directly affect technological choices.

Technology-neutral and technology-imposing measures

As many policy goals and processes can affect technological choices, Table 3.3 distinguishes between European policy processes, goals, and instruments that are technology-neutral and those that can be considered as imposing technological choices on economic agents. The simultaneous use of technology-neutral and technology-imposing processes, as found in Europe today, can be counterproductive. In Europe, a blurred combination of multiple views on how to select technologies is the heart of the problem. Eskeland *et al.* (2012) and Böhringer *et al.* (2009) provide estimates of the additional cost to society of some of Europe's multiple targets and approaches.

Table 3.3 *Technology-neutral versus technology-imposing processes, goals and instruments in European climate and energy policy*

Technology-neutral processes, goals, instruments	Liberalisation of energy markets, ETS, 20% reduction target of 20/20/20
Technology-imposing processes, goals, instruments	20% RES target of 20/20/20, 20% efficiency gains target of 20/20/20, phase-out scenarios, LCP Directive

Because the short-term technology-imposing instruments (such as the 20% RES goal) are not backed up by historical energy R&D support schemes, the mandatory investments in renewable generation are very expensive, while the opportunity of selecting less expensive mitigation options is foregone.

From a philosophical perspective, the imposition of very specific technological targets is typical of the economic planning tradition, whereas the use of technology-neutral processes or instruments expresses belief in the power of market forces. However, as there is no monolithic attitude with respect to economic planning versus market forces within the EU, it is not surprising that European climate and energy policies combine both approaches. In principle, there is nothing wrong with this combination (IEA, 2011). What matters is that public R&D spending trajectories must be planned to avoid important market failures. Short-term penetration rates for young technologies should not be planned when it is more appropriate to invest first in better technologies.

Two extreme abstract views on the selection of technologies and the evolution of the energy system can be teased out of Table 3.3. When the free-market approach dominates, energy markets must be fully liberalised and a European carbon tax or cap-and-trade system applies to all economic sectors. From an investment perspective, a carbon tax is more predictable than the fluctuating CO_2 price in the ETS. An escalating carbon tax provides the strongest incentive to invest in new mitigation technologies. As market forces will select technologies and trigger investment decisions, national policymakers are mainly observers or gatekeepers. Domestic preferences for technological mixes become irrelevant as the European landscape will adjust to the European policy targets.

Even in this free-market approach, policymakers have to invest in public R&D to ensure that more efficient energy and mitigation technologies can hit the markets in the next decades. Otherwise, the carbon incentives will bring only mature technologies into the market. Radical innovation projects such as the energy transition are impossible to realise without multiple policies working together in a synergistic package. That package includes supply-push measures – mainly public R&D expenditures followed by demonstration projects – and demand-pull measures such as the creation of niche markets, public procurement or fiscal incentives (Norberg-Bohm, 2002). Once technologies evolve into concepts ‘close to the market’ the balance will shift toward demand-pull measures. An effective and efficient package of policies measures should be based on a consistent view of how to select and diffuse technologies.

National phase-out scenarios and short-term obligations to invest in renewable energy and energy efficiency technologies are not consistent with this market-oriented view on the organisation of energy markets. But because the energy landscape of today reflects historical choices and preferences, the pure free-market approach alone is not a realistic option for the selection of energy technologies.

The other extreme is a completely planned energy system. This option, too, requires the allocation of sufficient resources to energy R&D projects, in this case by planning departments. Under this scenario, planners define short-term and long-term policy targets and regulate the optimal mix of energy and mitigation technologies. Economic agents lobby for adequate support mechanisms, and investments are made in a low-risk environment. As energy decisions are still made at the national level, liberalisation can only disturb the implementation of planning decisions.

The ideal scheme of policy measures should be based on the dynamic interactions between supply-push and demand-pull measures. As it often takes decades to develop radically new but efficient technologies, the obsession with short-term targets in international climate negotiations and in the 20/20/20 approach of the EU is problematic. For policymakers, however, the selection of short-term targets is tempting because many new and promising technologies are already available. Why not push massive deployment of the new technologies to realise a quick switch to low-carbon energy?

Kramer and Haigh (2009) challenge this view on the grounds that the mere availability of a new technology should be distinguished from the economic significance (in their terms, the "materiality") of this new technology. When reaching 1% of the global energy mix is taken as a benchmark, history teaches that it can take 30 years before a new technology achieves some market importance. PVs supply just 0.01% of world energy today and enjoy exponential growth rates. As it takes a few hundred billion dollars to bring new technologies to materiality and many years to build the human and industrial capacity to realise this, the relevance of short-term national targets on the evolution of new technologies is limited. Furthermore, exponential growth rates for new technologies will always be replaced by linear growth rates. Because energy technologies have a long lifetime – between 25 and 50 years – replacement rates have to be low to avoid large capital losses. Technological targets become especially expensive when technologies that are too young or too inefficient are selected too early, or when it becomes necessary to replace existing capital too early.

Liberalisation or 'small is beautiful'?

Climate and energy policy goals through 2020 were established around 2007, when the liberalisation of European energy markets was in full swing. In principle, the liberalisation process should be complete by 2014. However, several member states are already experiencing a significant delay in implementing the liberalisation directives. Abolishing price regulation, particularly, appears to be very difficult in some countries.

Liberalisation can have a strong impact on energy market decisions in the period during which energy and mitigation technology choices should align with the climate policy goals. From an investment perspective, it is challenging to predict the possible interactions between liberalisation as an ongoing process and progress with the climate policy goals.

The liberalisation of energy markets purports to replace historical national energy monopolies with a larger, more efficient, transparent, and interconnected system in which economic agents compete and invest at the European level.

To ensure high levels of competition and economic efficiency, domestic market barriers need to be abolished. And to trigger investments and production decisions in the open European energy market, market forces need to be empowered. Ultimately, market forces will select technologies based on their market merits at the European scale.

The final configuration of liberalised energy markets has never been explicitly specified, but capital-intensive industries are typically evolving into oligopolies dominated by a few transnational companies. Indeed, a likely consequence of the EU's wish to foster energy companies with the capacity to pursue strategic goals at the European level may be that European energy markets will be dominated by a small number of large companies by 2030, or even earlier. The European Commission (2012b) has identified as a recent achievement that by 2012 "at least 14 European electricity and/or gas companies are now active in more than one Member State." We can assume that these 14 international companies are not small. This potentially oligopolistic market outcome may conflict with popular visions of decentralised generation in local energy clusters of small companies. In several member states, governments have taken certain measures to limit the power and market share of the incumbent utilities. In Germany, there is a gathering trend away from the mega-integrated utilities, back to the *Stadtwerke*. The German government even wants to fund 15% of new-plant capital expenditures of small utilities with a market share of less than 5% (HSBC, 2011). Schumacher's 'small is beautiful' principle (1974) is again a very popular concept for national energy policy makers, while Europe is preparing the energy landscape for the rise of a limited number of powerful transnational corporations.

The opportunity of emerging markets for energy companies

Once energy companies operate with a European perspective, it is a small step to approach energy markets from a global perspective. Because the growth prospects for the European economy are meagre when compared with the emerging economies, the major European energy companies may well shift their focus. In the emerging markets, close to 1.8 billion people will enter the global consuming class over the next 15 years. Because of this expansion, McKinsey (2012) projects that global consumption will nearly double to $64 trillion before 2030. Developing countries will continue to drive global growth in demand for manufactured goods as well in demand for energy system investments. The needed expansion of the Chinese electricity system alone over the next decade offers a market opportunity of $1.8 trillion (IEA, 2012). Why invest in a stationary European market with uncertain returns when emerging markets offer a guaranteed profit?

What's next?

The current climate and energy policy framework is not optimal. Several options can be considered to improve its overall effectiveness. We can distinguish between short-term and long-term options. Their relevance depends on a more consistent view of how to change the energy system. In the short run, it is unlikely that Europe's policy framework will change radically – for example, by phasing out the ETS after 2020 or suddenly eliminating the 20% RES or the 20% efficiency target from the 20/20/20 package. Radical changes in policy development are possible only in the long run.

Between now and 2020

The European Commission has launched a debate over so-called backloading options to increase the ETS price in the next years. Backloading refers to temporarily removing from the market a huge volume of permits – for example, a billion ETS permits in the period between 2013 and 2015 – and re-injecting them into the market later on. With backloading, there is no destruction or buyback of permits. As such, it can alter the average CO_2 price in a given year but will not lead to a structural change in the CO_2 price. Hence, backloading will hardly affect decisions on mitigation investments by ETS companies in ETS Phase III. Moreover, ETS companies object to backloading strategies because they further complicate investment decisions without offering a real solution.

The ETS price could easily be regulated by installing a price floor that would vary over time. It could be limited to auctioned permits or set for all transactions in the ETS. Given the low CO_2 prices of today, the floor would set the market price. The ETS would then be transformed into a carbon taxation scheme. This is not a desirable transformation of the cornerstone of European climate policy and the ETS was thus the wrong choice. Although public authorities count on ETS revenues to finance energy R&D projects and a price floor could secure sufficient resources to finance the needed research efforts, ETS companies would object to a shifting floor as an unpredictable and discriminatory market intervention. (Discriminatory because the floor would be especially beneficial for companies with excess permits that they could now sell at higher prices.) It would be difficult to introduce a price floor without discriminatory consequences. Because the low CO_2 price in the ETS reflects some structural economic trends – partly embedded in the design of European policies – why tamper with a market mechanism intended to reveal information? If a price floor were to be installed, a European floor should be preferred over different floors in different member states.

A much more attractive option relates to the cap for ETS Phase IV. Around 2015, Europe should present a clear post-2020 climate policy perspective to all ETS and non-ETS economic agents. The cap for ETS Phase IV should be consistent with the overall CO_2 reduction target by 2030 or by 2035. When the energy transition is taken as the reference perspective, it would make sense to set a long-term reduction target with ETS caps up to 2035, or even later. In that case, the next ETS phase would run from 2021 until 2035. But if saving the ETS as the cornerstone of climate policy is the main priority, a 2028 or 2030 cap for the next phase will have more impact on the ETS market in the period 2015–20. Because of banking (i.e., transferring non-used permits from one Phase to another) between Phase III and Phase IV, a very challenging ETS cap by 2028 or 2030 would increase demand for permits before 2020 and push prices up. To avoid the risk that complementary targets (articulated in a possible 30/30/30 follow-up to the 20/20/20 package) would again reduce the demand for ETS permits and hence the relevance of the ETS as a cost-minimising policy instrument, it is essential that no RES target and no energy efficiency target should be set after 2020. Europe should support the future deployment of energy from renewable sources and efficiency technologies by allocating a significant share of ETS revenues to R&D projects dedicated to future generations of renewable and efficiency technologies. In the absence of binding targets for RES after 2020, member states would be able to phase out subsidy regimes, thus lowering the cost of the energy transition. The removal of an important sheltered sector with an impact on the investment climate for conventional generation technologies would facilitate the completion of the internal market.

Some ETS companies argue that the low CO_2 price in the ETS should not be seen as a problem because European industry still faces a recession. A higher CO_2 price would increase the operational costs of energy-intensive companies that are already struggling with the crisis. Some ETS companies state that those not pleased by the current functioning of the ETS are free to buy CO_2 permits to increase the price; given the estimated overallocation of 1.4 billion permits, buying permits to eliminate the overallocation would cost close to $7 billion. This clearly is not a realistic option. But if some governments decide to buy 300 million CO_2 permits in 2014 as an exceptional intervention to restore market fundamentals and announce their intention to buy additional volumes in Phase III when deemed appropriate, market expectations could adjust to a lower level of overallocation, leading to higher prices. Although ETS companies with excess permits would support this type of intervention, European institutions and national authorities should not participate directly in the market because they designed the ETS and will later decide on its future caps. Regulators, too, should stick to their role and not act like the market participants they regulate. Another aspect relates to insider trading. When public authorities today buy permits at a low price and later introduce a very ambitious cap for 2030, they can sell their permits at much higher prices. Such an abuse of market power to create profits would not be acceptable to private market parties.

Long-term options

The ETS can be saved. At the same time, phasing out technology-imposing measures would increase the consistency of European climate and energy policy. A phase-out of RES targets would also be consistent with the goal of integrating energy markets. The continuation of the ETS in its next phases – possibly through 2050 – does not eliminate the risk that external factors, such as a new recession between 2020 and 2025, might again depress CO_2 permit prices, bring on a temporary excess in generation capacity, and cloud the investment climate.

The situation today does not immediately threaten the prospects for the energy transition by 2050, because most transition investments will have to take place after 2030 to avoid expensive lock-ins of young technologies. But that could change if we face several recessions between now and 2050. Since 1975, financial crises that have a sizable impact on the real economy have become more frequent (Reinhart and Rogoff, 2009). With today's excessive debt positions, the frequency of future financial crises accompanying economic downturns may even increase. The prospect of several such periods in which investment incentives dry up because of economic slowdowns may fundamentally endanger the energy transition.

We saw from Table 3.2 that the transition of the electricity system will require a total investment of \$4.8 trillion between 2030 and 2050. That is a small part of the total energy transition investment needs of \$36 trillion between now and 2050, which come on top of a total investment of \$120 trillion to modernise and expand the global energy system irrespective of transition targets (IEA, 2012). Financing \$120 trillion will be an enormous challenge. A severe economic crisis between 2030 and 2035 could easily slow investment in expansion and transition. After such a recession, investment would resume, but is unlikely that all of the investments needed for the period 2030–40 could be executed in the second half of that period. Without very strong economic incentives – comparable to the attractiveness of investing in growing markets – energy transition investment would likely be crowded out by investment in deferred conventional expansion. As capital markets and technology companies face limitations in their ability to manage and execute projects, it is quite likely that a severe economic crisis between 2030 and 2035 would lead to a very low level of transition investments between 2030 and 2040. As long as future economic downturns do not endanger energy R&D spending levels, the constant technological improvements can provide a permanent incentive to re-launch transition efforts after the next crisis. But if a crisis leads to cuts in public and private spending on energy R&D, the energy transition may become a utopian project. For a long-term investment project such as the energy transition, stable and strong economic incentives, as well as a guaranteed investment in energy R&D, are essential.

Whatever policy design is selected, a severe economic crisis will always affect investment behaviour and can delay the pace of the energy transition. Some policy instruments will respond more strongly to economic downturns than others. Because of its design, the ETS, for example, with its rigid caps will always respond strongly to economic downturns. A carbon tax offers a stable price incentive to invest in mitigation technologies. With carbon taxation, fiscal revenues are rather easy to predict as long as the economy avoids cyclical extremes. Although a severe recession would certainly cut carbon taxation revenue, once the economy recovered that revenue would bounce back. (The

ETS price, by contrast, could remain at too low a level for much too long.) However, carbon taxes will not be popular during recessions, and rigid taxes could even deepen or extend the recession. This could be avoided by relating the carbon tax rate to GDP growth rates. During recessions and early recoveries, carbon tax rates could be cut by some specified amount. During good economic times, revenue from carbon taxes should be reserved to finance future energy R&D expenditures, thereby reducing the risk of R&D investment being cut during downturns.

The crowding out of energy transition investments by energy expansion investments may be the main long-term challenge for the energy transition. To protect transition investments, the economic attractiveness of energy transition technologies should be enhanced through a decisive increase in energy R&D efforts.

Conclusion

The energy transition is a gigantic global investment project. However, because of the current economic crisis and the design of European climate and energy policies, Europe today faces a very unfavourable investment climate for low-carbon initiatives. The EU ETS suffers from a severe overallocation of emission permits, which has depressed the CO_2 price. ETS companies have no market incentive to invest in mitigation technologies. Because of overcapacity in conventional generation, wholesale electricity prices are falling and are already too low to trigger investments in new generation and network assets. The resulting dispropensity to invest could significantly delay the pace of decarbonisation efforts in Europe.

Europe's current policy design combines technology-neutral instruments, such as the ETS, with technology-imposing targets, such as the 20% RES target for 2020. Conflicts between policy goals, meanwhile, reduce the effectiveness of the ETS. To make matters worse, European policy goals have a short time horizon and are not responsive to external factors such as an economic recession. The most likely solution (i.e., the most feasible from a pragmatic policy perspective) for the current inefficiencies is the introduction of an ambitious Phase IV cap for the ETS by 2028 or 2030. Because of banking between Phase III and Phase IV, the future cap would influence market behaviour and the CO_2 price between 2015 and 2020. After 2020, no further mandatory targets for energy from RES or for efficiency investments should be set. Targets for subsidised RES have created a large, sheltered sector that is not consistent with energy market integration and liberalisation.

Today's poor investment climate need not endanger the energy transition as a long-term project because the bulk of the needed transition investments will take place after 2030. Unfortunately, the world is sure to experience global recessions between now and 2050, and today's excessive debt will aggravate economic vulnerability in the next decades. To avoid a crowding out of investment in the energy transition by deferred investments in energy system expansion at the end of each recession, policy frameworks will have to ensure the continuous funding of energy R&D at very high levels. The more attractive energy transition technologies become, the lower the risk that investments in those technologies will be crowded out. Allocating carbon taxation revenues to energy R&D budgets offers the advantage of a relatively predictable flow of revenue. Future recessions will always have the effect of depressing the CO_2 price in the ETS, thereby putting mitigation investments on hold and lowering the revenue derived from CO_2 auctions. A carbon tax, by contrast, offers a permanent economic incentive. Because the energy transition will be delayed by stop-and-go investment dynamics, policy designs should try to maximise predictability and stability. A radical reform of the European policy framework is therefore essential. Reconsidering the 1992 proposal for a European carbon tax could offer inspiration.

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4

Reducing Energy Use Without Affecting Economic Objectives: A Sectoral Analysis

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Energy use has become an important issue when assessing the productivity of nations. In particular, it can give rise to greenhouse gas emissions, which are generally seen as an undesirable side-effect of economic growth. In this chapter, we conduct a macro-efficiency analysis of European countries that explicitly accounts for these undesirable side-effects of energy use. We present an efficiency-assessment method that is specially tailored for addressing this issue. A distinguishing feature of our efficiency analysis is that it concentrates on the sector level (agriculture, transport, and other industry) rather than the aggregate country level, which allows us to formulate more refined policy advice than would otherwise be possible.[42]

Undesirable outputs and input efficiency

Our analysis models the production behaviour of a particular economic sector as using two inputs (capital and energy) to pursue two main economic objectives – economic growth (measured as added value) and job creation (measured by the employment rate) – under the restriction that greenhouse gas emissions should be kept as low as possible. We explicitly model greenhouse gases as undesirable by-products of the production process. Formally, this means that European sectors use two inputs (capital and energy) to produce two good outputs (added value and employment) and one bad output (equivalent CO_2 emissions).[43]

The specific focus of our efficiency analysis is on the input side of the production process. Our method of measuring efficiency quantifies the maximum input reduction for a given level of output. This can provide useful policy data in

42 Other industry stands for construction, manufacturing, electricity, gas and water.

43 Equivalent CO2 emissions is an aggregate measure of greenhouse gas emissions; see the section on data for more details.

at least two ways. First, our efficiency results provide information on profitable input allocations: they tell countries to what extent a given sector can reduce its inputs, information that can then be used (more) productively in a different sector. Second, (fossil) energy use and, to a somewhat lesser extent, capital use is often directly linked with the emission of CO_2. As such, identifying an inefficient (over)use of energy or capital can directly suggest possibilities for reducing pollution (CO_2) while preserving the given level of the other good outputs.

A tailored efficiency model

A very popular method for analysing the productive behaviour of decision-making units (DMUs) such as countries, sectors, and firms is data envelopment analysis (DEA), which was originally introduced by Charnes et al. (1978). Essentially, this method benchmarks DMUs by measuring their input-output performance relative to other (observed) DMUs that operate in a similar production environment.[44] We see two main reasons for the widespread popularity of DEA. First, it is easily implemented. The computation of DEA efficiency measures merely requires solving simple linear programming problems. Second, DEA is intrinsically non-parametric. It does not require any prior (and typically non-verifiable) parametric assumptions about the functional relationship between inputs and outputs (that is, about the production technology). As such, it provides the greatest possible assurance that functional misspecification will not contaminate the efficiency analysis.

As indicated above, we compute the maximum input reduction for a given level of output. In this respect, we make use of a tailored DEA model that is designed for dealing with bad inputs. In particular, we build on original work of Cherchye *et al*. (2012) and Cherchye *et al*. (2013) to design an efficiency-measurement methodology that models the production of each (bad and good) output in terms of a *separate* output-specific production technology, while at the same time allowing for interdependencies between production processes through inputs that contribute *simultaneously* to multiple outputs. In other words, we explicitly account for the simultaneous production of different (good and bad) outputs through *joint* inputs while avoiding the requirement for specific (often non-verifiable) technology assumptions to model the production of bad outputs. As extensively discussed in Cherchye *et al*. (2012) and Cherchye *et al*. (2013), this approach significantly increases the discriminatory power of the efficiency analysis without making extra (non-verifiable) assumptions and, importantly, it also accounts naturally for the fact that it is usually impossible to produce good outputs without generating some bad output.

44 See, for example, Färe et al. (1994a), Cooper *et al.* (2007), Fried *et al.* (2008), and Cook and Seiford (2009) for extensive reviews of DEA.

Related literature

We can distinguish two different approaches to incorporating bad outputs in 'traditional' DEA.[45] The first approach consists of using standard efficiency models and translating the undesirable (bad) outputs into desirable (good) outputs through an appropriate transformation. Scheel (2001) points out three ways to do this: (i) take the additive inverse of bad outputs (multiply by −1, following Koopmans (1951)); (ii) take the multiplicative inverse of the bad outputs (following Golany and Roll (1989)); (iii) or incorporate bad outputs as inputs. The second approach consists of using the concept of a so-called 'environmental' DEA technology, which requires making the (usually non-verifiable) technological assumptions of weak disposability (reducing bad output requires a proportional reduction of the good output) and null-jointness (zero bad output requires zero good output). Färe and Grosskopf (2004) provide a detailed discussion of this last approach. As we explain in the section on methodology, we adopt the first approach in exposition and so avoid extra technological assumptions. In particular, we explicitly consider CO_2 emission as an output of the production process, and we use joint inputs to model the interdependency between this output and the other outputs.

At this point, it is also worth mentioning that the literature on efficiency measurement has already devoted considerable attention to the question of whether and to what extent countries act efficiently in producing GDP and creating jobs while minimising undesirable greenhouse gases (see, for example, Ramanathan (2006), Zhou *et al.* (2008), and Lozano and Gutierrez (2008) for surveys). Most of this existing work used one of the two approaches described above and focused on the country level. A main conclusion of these earlier studies is that ignoring CO_2 emissions (as negative externalities of the production process) may lead to severely biased efficiency results. All this provides a direct motivation for our own empirical analysis, which focuses on a sectoral efficiency analysis while taking CO_2 emissions into account.

Our main contributions

Summarising, our study contributes to the existing literature in two ways. First, we apply a tailored method to deal with bad (environmental) outputs in DEA evaluations of productive efficiency. We believe that modeling bad and good outputs as being associated with different (interdependent) technologies yields a more realistic modeling of the production environment.

Second, we do not consider the aggregate country efficiency, but rather measure efficiency at the sectoral level (Agriculture, Transport and Industry). In our opinion, a sector-level analysis leads to more balanced (i.e., sector-specific) policy recommendations. In particular, our empirical application considers the sectoral performance of 18 European countries from 2000 to 2007. We use the added value per capita and employment rate as 'good' outputs, and the equivalent

45 See Zhou *et al.* (2008) for a survey.

CO_2 emissions per capita as a 'bad' output.[46] Our inputs are capital and energy consumption per capita.[47]

Outline

The remainder of this chapter is organised as follows. The first section presents our methodology for efficiency measurement, the second introduces our data, the third presents our empirical application, and the last section draws conclusions.

Methodology

As indicated above, we consider a DEA method that assesses input minimisation for a given level of output. In this section, we build on original work of Cherchye et al. (2012) and Cherchye *et al*. (2013) to present a method that is specially tailored for dealing with both good and bad outputs. The section is structured as follows. The first subsection introduces our notation and terminology. The second defines our measure of technical efficiency. The third shows how our framework can be used for dynamic efficiency analysis that focuses on intertemporal efficiency trends.

Preliminaries

We start by introducing our notations and the concept of input requirement sets. Using a different input requirement set for every individual output (good or bad) explicitly recognises that each output is characterised by its own production technology.

Inputs and outputs

We assume a production technology that uses N inputs, captured by the vector $\boldsymbol{X}$, for producing M outputs, captured by the vector $\boldsymbol{Y}$. As we will explain below, the output vector $\boldsymbol{Y}$ can contain both good outputs (those related to GDP and job creation) and bad outputs (related to CO_2 emissions).

The inputs (capital and energy) can be characterised as *joint* since they are used to produce all outputs simultaneously.[48] These joint inputs obtain interdependence between the different outputs that are produced. Actually, this interdependence is directly relevant for our own application to good and bad outputs: it indeed seems to be impossible to produce good outputs without producing the bad output.

Formally, we represent good outputs by the vector $\boldsymbol{Y}^G \in \mathbb{R}_+^{M_{good}}$, which thus contains the desirable outcomes of the production process, and bad outputs

46 The added value is often used as a proxy for GDP when the DMUs are sectors or states; see, for example, Färe *et al*. (2001).

47 We use per capita figures for inputs and outputs to correct for scale differences across countries.

48 At this point, we indicate that our methodology can actually be extended to deal with inputs that are not joint but specific to individual outputs. We will abstract from such an extension in what follows. See Cherchye *et al*. (2012) for dealing with output-specific inputs in a setting similar to ours.

by the vector $\boldsymbol{Y}^B \in \mathbb{R}_+^{M_{bad}}$, which captures the undesirable by-products of the production process. By construction, we obtain that $M_{good} + M_{bad} = M$. As indicated in the introduction, the application that follows will use added value and the employment rate as the good outputs and equivalent CO_2 emissions as the bad output, which yields $M_{good} = 2$ and $M_{bad} = 1$.

To operationalise our approach, we must integrate the undesirable feature of bad outputs in our construction of the output vector $\boldsymbol{Y}$. This requires converting bad outputs into good outputs. Referring to our discussion in the introduction, such a conversion may be achieved, for example, by multiplying the bad output by –1 or by taking the reciprocal of the bad output values. In general, we can represent the transformation of the bad outputs by the function $g(\boldsymbol{Y}^B)$. Our two examples then comply with $g(\boldsymbol{Y}^B) = -\boldsymbol{Y}^B$ or $g(\boldsymbol{Y}^B) = 1/\boldsymbol{Y}^B$. For a given specification of the function $g(\boldsymbol{Y}^B)$, we obtain the output vector $\boldsymbol{Y}$ as:

$$\boldsymbol{Y} = \left(y^1,\ldots,y^M\right)' = \begin{bmatrix} \boldsymbol{Y}^G \\ g\left(\boldsymbol{Y}^B\right) \end{bmatrix}$$

At this point, it is important to note that the value of our efficiency measure (introduced in the next section) will be the same for the two specifications of $g(\boldsymbol{Y}^B)$ that we presented above (namely, multiplication or taking reciprocals), which we see as an attractive feature of our method. See Cherchye *et al*. (2013) for a more detailed discussion.

Input requirement sets

It follows from our discussion above that we assume all outputs $\boldsymbol{Y}$ to be produced simultaneously by the inputs $\boldsymbol{X}$. When using y^m to represent the mth ($m = 1, ..., M$) output, we then associate a production technology with each individual y^m, which describes the relation between the joint inputs $\boldsymbol{X}$ and the output y^m. In terms of our application, this defines separate production technologies for the outputs of added value, employment rate, and CO_2 emissions. Importantly, these technologies are interdependent because of the joint inputs.

Formally, the technology of each output m is represented by input requirement sets $I^m(y^m)$, which contain all the combinations of the joint inputs $\boldsymbol{X}$ that can produce the output quantity y^m:

$$I^m(y^m) = \{\boldsymbol{X} \in \mathbb{R}_+^N | (\boldsymbol{X}, y^m) \in T^m\}$$

where $T^m = \{(\boldsymbol{X}, y^m) \in \mathbb{R}_+^{N+M} | \boldsymbol{X} \textit{ can produce } y^m\}$ is the production technology set containing the feasible combinations of input quantities $\boldsymbol{X}$ and output quantities y^m. By explicitly describing this production technology in terms of output-specific input requirement sets, we obtain a more precise modeling of the interaction between inputs and outputs. As formally discussed in Cherchye *et al*. (2012), this approach significantly enhances the discriminatory power of the efficiency analysis without making extra (non-verifiable) assumptions.

Technical efficiency measurement

In what follows, we will first define our technical efficiency measure for some given input requirement sets $I^m(y_t^m)$. In practice, however, because we typically do not observe the 'theoretical' sets $I^m(y_t^m)$ we need to use empirical approximations $\hat{I}^m(y_t^m)$. To obtain these empirical sets, we follow the usual DEA practice and construct $\hat{I}^m(y_t^m)$ on the basis of some maintained technology axioms. Using the resulting empirical input sets then allows us to compute our technical input efficiency measure in practical applications.

Defining technical input efficiency

In practice, technical efficiency measurement starts from an observed set of input and output data associated with a sample of DMUs. For each DMU $t = 1, \ldots T$ (in our case production sectors of European countries), we observe the inputs $\boldsymbol{X}_t$ and the (good and bad) outputs $\boldsymbol{Y}_t$ (with y_t^m the quantity of output m). Taken together, this gives the dataset S:

$$S = \{(\boldsymbol{X}_t, \boldsymbol{Y}_t) | t = 1, \ldots, T\}$$

Following our previous discussion, for some given set S we can define the input sets $I^m(y_t^m)$ which contain all the input combinations that can produce the output quantities y_t^m. These input sets are bounded from below by the input isoquants $IsoqI^m(y_t^m)$ which are defined as:

$$IsoqI^m(y_t^m) = \{\boldsymbol{X} \in I^m(y_t^m) | for\ \beta < 1, \beta\boldsymbol{X} \notin I^m(y_t^m)\}$$

Intuitively, $(\boldsymbol{X}, y_t^m) \in IsoqI^m(y_t^m)$ means that the inputs $\boldsymbol{X}$ can be thought of as 'minimal' input quantities to produce the output quantity y_t^m; it is impossible to further reduce these inputs (equiproportionately) for the given output. We say that $IsoqI^m(y_t^m)$ represents the 'technically efficient frontier' of the set $I^m(y_t^m)$.

Given that the set $IsoqI^m(y_t^m)$ contains all technically efficient input quantities, it is natural to quantify technical efficiency of some evaluated input combination in terms of the distance to this isoquant. A popular distance measure is the radial input distance function $D_t(\boldsymbol{Y}_t, \boldsymbol{X}_t)$ that was originally proposed by Shephard (1970). This distance function measures the maximum equiproportionate reduction of all inputs $\boldsymbol{X}_t$ for a given output production $\boldsymbol{Y}_t$. Formally, $D_t(\boldsymbol{Y}_t, \boldsymbol{X}_t)$ is defined as:

$$D_t(\boldsymbol{Y}_t, \boldsymbol{X}_t) = max\left\{\phi \middle| \forall m: \left(\frac{\boldsymbol{X}_t}{\phi}\right) \in I^m\left(y_t^m\right)\right\}$$

We can verify that $D_t(\boldsymbol{Y}_t, \boldsymbol{X}_t) \geq 1$ if, for all m, $\boldsymbol{X}_t \in I^m(y_t^m)$. Next, $D_t(\boldsymbol{Y}_t, \boldsymbol{X}_t) = 1$ indicates that, for some m, $\boldsymbol{X}_t \in IsoqI^m(y_t^m)$ and thus, given our above discussion, technically efficient production.

In what follows, we will take the reciprocal of the function $D_t(\boldsymbol{Y}_t, \boldsymbol{X}_t)$ as our measure of technical efficiency:

$$TE_t(\boldsymbol{Y}_t,\boldsymbol{X}_t)=\frac{1}{D_t(\boldsymbol{Y}_t,\boldsymbol{X}_t)}=min\{\theta \mid \forall m:(\theta \boldsymbol{X}_t)\in I^m(y_t^m)\}$$

This measure is known as the Debreu-Farrell measure of technical efficiency. It has a natural interpretation as indicating the degree of efficiency; it is situated between 0 and 1, with higher values indicating better performance (i.e., less technical inefficiency). More specifically, $TE_t(\boldsymbol{Y}_t, \boldsymbol{X}_t)$ defines the maximal equiproportionate input reduction (captured by $\theta \boldsymbol{X}_t$) that still allows the DMU to produce the output $\boldsymbol{Y}_t$. This Debreu-Farrell input-efficiency measure is the most commonly used efficiency measure in the DEA literature. We have tailored it to our specific multi-output setting by defining it in terms of output-specific input sets $I^m(y_t^m)$.

Technology axioms

The input efficiency measure $TE_t(\boldsymbol{Y}_t, \boldsymbol{X}_t)$ that we defined above is not directly useful in practice. It is defined in terms of the 'theoretical' sets $I^m(y_t^m)$, which are typically not observed. In what follows, we will build an empirical approximation $\hat{I}^m(y_t^m)$ of any input set $I^m(y_t^m)$.

As is standard in DEA, we proceed axiomatically. In particular, we start from four axioms regarding the production technology. We assume that the input requirement sets are nested (Axiom 1), monotone (Axiom 2), and convex (Axiom 3). We also assume that what we observe is feasible (Axiom 4).[49] Then, any empirical set $\hat{I}^m(y_t^m)$ satisfies the 'minimum extrapolation principle', which means that it is the smallest approximation of $I^m(y_t^m)$ that effectively satisfies the four stated axioms. This minimum extrapolation principle guarantees that $\hat{I}^m(y_t^m) \subseteq I^m(y_t^m)$ – that is, the empirical set $\hat{I}^m(y_t^m)$ provides an inner bound approximation of the true (but unobserved) set $I^m(y_t^m)$.

Axiom 1 (nested input sets): $y^m \geq y^{m'} \Rightarrow I^m(y^m) \subseteq I^m(y^{m'})$.

In words, Axiom 1 says that, if some input $\boldsymbol{X}$ can produce the output y^m, then it can also produce less output (i.e., $y^{m'}$). Essentially, this means that outputs are freely disposable.

Axiom 2 (monotone input sets): $\boldsymbol{X} \in I^m(y^m)$ and $\boldsymbol{X}' \geq \boldsymbol{X} \Rightarrow \boldsymbol{X}' \in I^m(y^m)$.

Axiom 2 complements Axiom 1 and states that inputs are freely disposable – that is, more input never leads to less output. Again, this is often a very reasonable assumption to make.

49 See, for example, Varian (1984), Tulkens (1993), Petersen (1990), Bogetoft (1996), and Cherchye *et al.* (2012) for discussions of these technology assumptions in a (DEA) production context similar to ours.

Axiom 3 (convex in put sets): $\boldsymbol{X} \in I^m(y^m)$ and $\boldsymbol{X}' \in I^m(y^m) \Rightarrow \forall\lambda \in [0,1]: \lambda\boldsymbol{X} + (1-\lambda)\boldsymbol{X}' \in I^m(y^m)$.

Axiom 3 says that, if two input combinations $\boldsymbol{X}$ and $\boldsymbol{X}'$ can produce the output y^m, then any convex combination of these inputs can also produce the same output. Intuitively, it imposes that marginal rates of input substitution are nowhere decreasing when moving along the isoquant of the set $I^m(y^m)$.

Axiom 4 (observability means feasibility): $(\boldsymbol{X}_t, \boldsymbol{Y}_t) \in S \Rightarrow \forall$m: $\boldsymbol{X}_t \in I^m(y_t^m)$.

Axiom 4 states that what we observe is certainly feasible. Or, if we observe $\boldsymbol{X}_t$ in combination with $\boldsymbol{Y}_t$, then we conclude that $\boldsymbol{X}_t$ can effectively produce $\boldsymbol{Y}_t$. Basically, this axiom guarantees that our empirical input requirement sets $\hat{I}^m(y_t^m)$ will effectively be based on the observed input-output combinations contained in the dataset S.[50]

Using the minimum extrapolation principle, we define the empirical input sets $\hat{I}^m(y_t^m)$ as the smallest input sets that are consistent with the Axioms 1–4. We can verify that, for any output y_t^m, these sets are defined as:[51]

$$\hat{I}^m(y_t^m) = \left(\boldsymbol{X} \;\middle|\; \begin{array}{c} \forall\text{m}: \sum_s \lambda_s^m \boldsymbol{X}_s \leq \boldsymbol{X} \text{ with } \sum_s \lambda_s^m = 1\ , \\ \lambda_s^m \geq 0 \text{ and for all s: } \mathrm{y}_s^m \geq y_t^m \end{array} \right)$$

Measuring technical input efficiency

Using our approximations $\hat{I}^m(y_t^m)$ of the sets $I^m(y_t^m)$, we can now define an empirical counterpart of the input efficiency measure $TE_t(\boldsymbol{Y}_t, \boldsymbol{X}_t)$. Specifically, our following application will use the empirical measure:

$$\widehat{TE}_t(\boldsymbol{Y}_t, \boldsymbol{X}_t) = min\{\theta | \forall\text{m}: (\theta\boldsymbol{X}_t) \in \hat{I}^m(y_t^m)\}$$

As before, we have that $\widehat{TE}_t(\boldsymbol{Y}_t, \boldsymbol{X}_t)$ is situated between 0 and 1, with lower values indicating greater technical inefficiency. Because $\hat{I}^m(y_t^m) \subseteq I^m(y_t^m)$, we also have that $\widehat{TE}_t(\boldsymbol{Y}_t, \boldsymbol{X}_t) \geq TE_t(\boldsymbol{Y}_t, \boldsymbol{X}_t)$. In words, $\widehat{TE}_t(\boldsymbol{Y}_t, \boldsymbol{X}_t)$ provides a 'favourable' estimate of the theoretical measure $TE_t(\boldsymbol{Y}_t, \boldsymbol{X}_t)$. Intuitively, by taking the best possible efficiency score, this favourable estimate gives the benefit of the doubt to the DMUs under evaluation in the absence of complete technology information.

Interestingly, using our above definition of $\hat{I}^m(y_t^m)$, we can compute $\widehat{TE}_t(\boldsymbol{Y}_t, \boldsymbol{X}_t)$ through simple linear programming. In particular, it suffices to solve the programme:

50 We note that Axiom 4 actually assumes that all input and output data are measured accurately. We will return to the possibility of extending our methodology to deal with measurement error in the beginning of the section on efficiency analysis.

51 See Cherchye *et al*. (2012) for a formal proof.

$$\widehat{TE}_t(\mathbf{Y}_t,\mathbf{X}_t) = \min_{\lambda_s^m (m\in\{1,\dots,M\}, s\in\{1,\dots,T\})} \theta$$

s.t.

(1) $\forall$m: $\sum_s \lambda_s^m \boldsymbol{X}_s \leq \theta \boldsymbol{X}_t$ for all s: $y_s^m \geq y_t^m$

(2) $\forall$m: $\sum_s \lambda_s^m = 1$ for all s: $y_s^m \geq y_t^m$

(3) $\forall$m: $\forall$s: $y_s^m \geq 0$

(4) $\theta \geq 0$

As a final remark, we indicate that the technical efficiency measure $\widehat{TE}_t(\boldsymbol{Y}_t, \boldsymbol{X}_t)$ also has an interesting interpretation as a measure of multioutput cost efficiency. In particular, Cherchye *et al.* (2012) demonstrate that the dual version of the above linear programming problem represents our technical efficiency measure as the ratio of minimal over actual cost defined at shadow prices. These authors argue that this allows for multi-output cost-efficiency analysis that naturally extends the single-output cost-efficiency analysis originally considered by Afriat (1972), Hanoch and Rothschild (1972), Diewert and Parkan (1983), and Varian (1984). See Cherchye *et al*. (2008) for more details on this cost-efficiency perspective.

Dynamic efficiency measurement

In our application, we will use the methodology introduced above for assessing the technical efficiency of DMUs (in our case production sectors of countries) at a given point of time (a particular year), which effectively boils down to static efficiency measurement. In our application, we use a panel dataset, which means that we observe the same DMUs in multiple consecutive time periods. Interestingly, this panel data structure allows us to conduct a dynamic efficiency evaluation.

Specifically, in our case we will evaluate dynamic efficiency in terms of technical efficiency changes over time. To introduce our dynamic efficiency measure, we need to introduce some additional notation, which relates to the panel structure of our dataset. Specifically, let us consider a setting with observations on T DMUs for K periods. We now have a dataset S^k for each period k:

$$S^k = \{(\boldsymbol{X}_t^k, \boldsymbol{Y}_t^k) \mid t = 1, \dots, T\}$$

On the basis of each such dataset, we can use our above methodology to define a technical efficiency measure $\widehat{TE}_t^k(\boldsymbol{X}_t^k, \boldsymbol{Y}_t^k)$ for each DMU t and period k. Essentially, this measure evaluates the static efficiency of DMU t by comparing its input-output performance to those of all other DMUs observed in the same period. Using this, we can define, for each DMU t, the following measure of efficiency change between periods k and $k+1$:

$$\textit{Efficiency Change} = \widehat{CE}_t^{k+1} = \frac{\widehat{TE}_t^{k+1}\left(\boldsymbol{X}_t^{k+1}, \boldsymbol{Y}_t^{k+1}\right)}{\widehat{TE}_t^{k}\left(\boldsymbol{X}_t^{k}, \boldsymbol{Y}_t^{k}\right)}$$

The interpretation is immediate: if $\widehat{CE}_t^{k+1} > 1$ then the technical efficiency of DMU t has improved between periods k and $k+1$, while the opposite conclusion holds if $\widehat{CE}_t^{k+1} < 1$. In our case, improved (or deteriorated) technical efficiency signals a better (or worse) allocation of inputs in period $k+1$ than in period k (accounting for the possibly different output quantities produced in the two periods). Clearly, this reveals interesting information from the perspective of policy evaluation, which is particularly relevant for our following application

As a concluding remark, it is interesting to relate our efficiency change measure to the literature on dynamic DEA. See, for example, Färe and Grosskopf (1992), Kumar and Russell (2002), and Henderson and Russell (2005). Based on the original work of Caves *et al.* (1978), these authors set out a DEA-based framework for disentangling changes in total productivity (i.e., changes in the ratio of aggregate output over aggregate input) according to alternative sources of productivity change. In this framework, our efficiency measure $\widehat{CE}_t^{k+1}$ is a so-called catch-up indicator, which quantifies the degree to which a particular DMU catches up with (or, conversely, falls behind) the best-practice DMUs in period $k+1$ (as compared with period k).

From this perspective, it may actually be fruitful to extend our methodology to include the other components of productivity change included in the above mentioned framework. A particularly useful extension here pertains to the possibility of quantifying technology change (as a component of productivity change), which in the setting of our application can also be interpreted as 'change in the (policy) environment'. Specifically, this indicator of environmental change captures the extent to which, between any two periods k and $k+1$, the environment of the DMU under evaluation has become more or less favourable for achieving particular economic objectives (i.e., for creating added value and employment while reducing the emissions of greenhouse gases).[52] Clearly, such a measure may reveal interesting policy information, especially for the type of questions (related to European countries) that we address in this chapter. For the sake of compactness, however, we will not explore this further in what follows. But we do see this as a potentially interesting avenue for follow-up research.

52 Technically, the more or less favorable nature of the environment is then quantified by comparing the performances of the (reference) best practice DMUs in periods k and $k+1$. See Cherchye *et al.* (2007) for a detailed discussion of the interpretation of 'technology change' indicators in terms of changes in the policy environment in a European context comparable to ours.

Data

As indicated in the introduction to this chapter, we focus on three sectors (agriculture, transport, and other industry) of 18 European countries (EU-18), which we evaluate over the period 2000–07. The countries are Austria, Belgium, the Czech Republic, Denmark, France, Finland, Germany, Greece, Hungary, Ireland, Italy, Luxembourg, the Netherlands, Norway, Slovakia, Slovenia, Spain, and Sweden. Aggregated over all countries, the three sectors represent 28% of total production (GDP), 35% of total employment, and 40% of total CO_2 emissions for the period under consideration (Table 4.1).

Table 4.1 *Size of the sectors, 2000–07 (%)*

	Agriculture	Transport	Industries	Total
GDP	2	6	20	28
Employment	4	6	25	35
CO_2 emissions	10	18	12	40

For each sector and every country, we consider three outputs and two inputs. Our good outputs are added value per capita and the employment rate, the bad output is CO_2 emissions per capita. Our inputs are capital per capita and energy per capita. We use per capita normalisations to account for scale differences across countries. Our data on CO_2 emissions and energy consumption come from the Eurostat database, while our data on capital, employment and added value are taken from the OECD database.

In what follows, we will highlight some sector characteristics through a descriptive analysis. In particular, we present trendlines depicting the evolution of each input and output dimension at the sample (EU-18) level. The Appendix reports additional details on our data.

Outputs

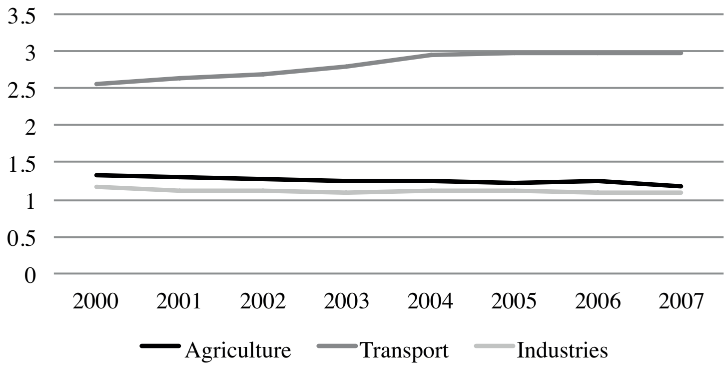
In this section, we present our three outputs. First, we consider the bad output, CO_2 emissions. We then turn to the good outputs of added value and employment.

The bad output: CO_2 emissions

The measure for CO_2 emissions is expressed in equivalent tonnes per capita and is an aggregate measure of greenhouse gas emissions such as CO_2, SO_x, and NO_x. The respective greenhouse gases are weighted by their global-warming potential. Figure 4.1 presents the trendlines for our three sectors, taking averages over the countries.

Figure 4.1 *CO_2 emissions in the EU-18*

Equivalent tonnes per capita



The trendlines for agriculture and industry are more or less the same and decrease only slowly during our sample period. On average, the agriculture sector produced 1.34 equivalent tonnes per capita in 2000 and 1.18 in 2007, while the industry sector generated 1.16 equivalent tonnes per capita in 2000 and 1.09 in 2007. For the transport sector, we observe a clearly different pattern. CO_2 emissions are much higher when compared to the other two sectors and, in addition, the trendline is increasing. On average, the greenhouse gas emissions for transport amount to no less than 2.56 tonnes per capita in 2000 and 2.97 in 2007.

Importantly, from Tables 4A.5 and 4A.6 in the Appendix we conclude that one should not focus solely on these average emissions. For our sample of observations, we find a great deal of heterogeneity in CO_2 emissions both across sectors and across countries. For instance, some countries exhibit increasing CO_2 emissions in the three sectors (e.g., Luxembourg and Ireland), while others have decreasing CO_2 emissions in two of the three sectors (e.g., Germany and Czech Republic). Not one country shows decreasing CO_2 emissions in all three sectors.

The good outputs: added value and employment

Our measure for the employment rate is given in full-time-equivalent workers as a percentage of the active population. Our proxy for GDP is gross added value (GAV) expressed in euros per capita. GAV is a measure of the value of goods and services produced in a particular sector of the economy. It is defined as the difference between outputs and intermediate inputs. Figures 4.2 and 4.3 depict the associated trendlines for the three sectors under study, where we again take averages over our 18 countries.

Figure 4.2 *Employment in the EU-18*

Workers per active population

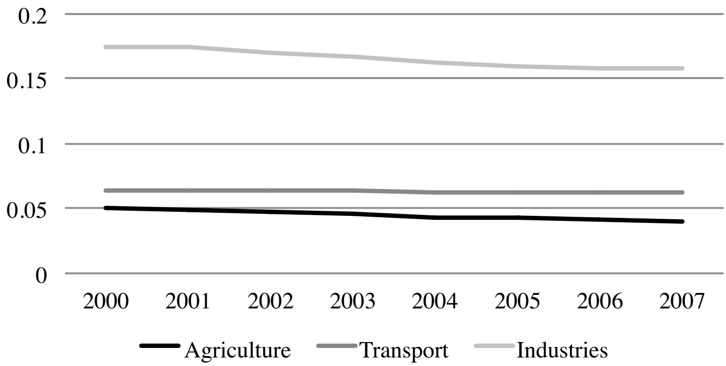
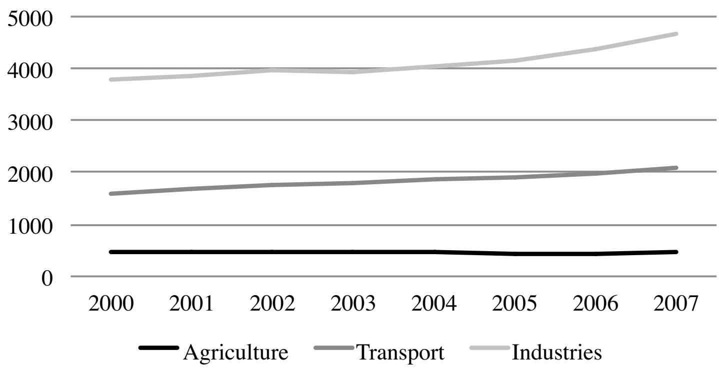


Figure 4.3 *Added value in the EU-18*

Euros per capita



Just as for CO_2 emissions, we again conclude that it is important to conduct a sector-level analysis. Industry is clearly dominating the other two sectors in the good outputs, while transport is slightly ahead of agriculture. Actually, these findings should not come as a big surprise given the numbers we reported in Table 4.1. However, the trendlines suggest that the pattern of evolution over time is quite different for the three sectors. In terms of the employment rate, industry and agriculture show a decreasing pattern, whereas transport remains more or less constant. With respect to added value, we find that the trendline is more or less stable for agriculture, while sharply increasing for the other two sectors.

Finally, Tables 4A.7–4A.10 in the Appendix confirm our earlier point on cross-observational heterogeneity. Specifically, even though most countries exhibit patterns that are fairly similar to the average patterns described above, we do observe a lot of variation over countries, sectors, and time.

Inputs

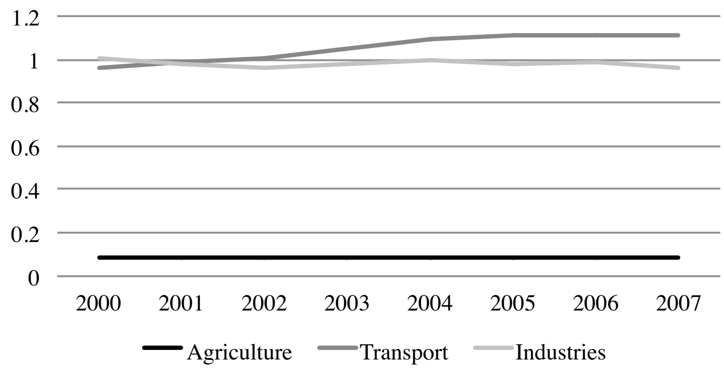
In this section we present our two inputs. We will first consider energy and then focus on capital.

Energy

We use final energy consumption in tonnes of oil equivalent (toe) per capita.[53] Final energy consumption in industry includes consumption in all industrial sectors with the exception of the energy sector. Final energy consumption in transport covers consumption in all types of transportation (rail, road, air transport, and inland navigation). Figure 4.4 presents the corresponding trendlines for our sample.

Figure 4.4 *Energy in the EU-18*

Tonnes of oil equivalent per capita



As one may have expected, the transport sector is the biggest energy consumer (1.05 toe on average), and its energy consumption is increasing over time (0.99 toe on average in 2000 and 1.14 in 2007). In fact, the average energy consumption of the industry sector (0.98 toe) is quite similar to that of the transport sector, but the trendline is clearly different. Specifically, the energy consumption in industry is slowly decreasing from (on average) 1.00 toe in 2000 to 0.96 in 2007. Finally, the pattern of energy consumption of the agriculture sector is totally different. Compared with the other two sectors, this sector appears not very energy intensive (0.09 toe on average). In addition, its consumption of energy is more or less stable over time.

From Tables 4A.11 and 4A.12 in the Appendix we again conclude that these average figures hide a lot of heterogeneity in sectors and countries. For instance, we find quite different values for the standard deviations associated with the three sectors. In our opinion, this suggests that patterns of energy consumption

53 One toe = 1.07 x 10 cal (thermochemical) = 44.769 GJ = 42.46 MBtu (thermochemical).

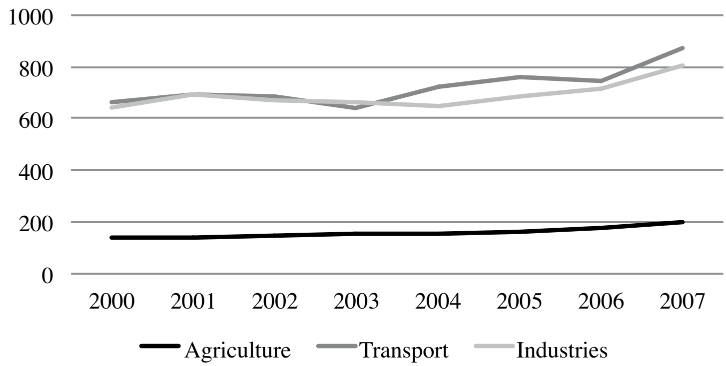
are not only sector-specific, but also country-specific. As argued before, our efficiency analysis will account for this feature.

Capital

We use gross fixed capital formation (expressed in euros per capita) as an indicator for the capital input. At this point, it is worth indicating that other studies have focused on more specific capital indicators (such as tractors, lands, human capital, and so on). For our study, however, we opt for gross fixed capital formation to enhance comparability over the three sectors. Figure 4.5 presents trendlines for our capital input.

Figure 4.5 *Capital in the EU-18*

Euros per capita



Just as for the energy input, we conclude that industry and transport are very comparable in terms of average values. In this case, too, the trendlines depict the same (increasing) pattern. As before, the agriculture sector uses much less of the capital input than the other two sectors and, although its capital use is increasing over time, the increase is also much more modest. Finally, and consistent with our earlier findings, Tables 4A.13 and 4A.14 in the Appendix plead once more for a country-specific and sector-specific analysis.

What do we learn from all this?

The patterns described above strongly indicate that the production of outputs and the use of inputs is country-specific and sector-specific. Similarly, the evolution of output and input over time also varies significantly by sector and country. These are important observations for the policymaker who wants to set objectives in terms of CO_2 production or energy use. For instance, our findings suggest that one should better specify sector-specific and country-specific objectives to reach the Europe 2020 objectives (stated in the EU's growth strategy for the coming decade).

This being said, the numbers that we have discussed above are only one side of the story. For instance, although transport is much more energy intensive than agriculture, it could well be that agriculture is not as efficient as transport in its use of energy. That is, the agriculture sector may well have more potential to reduce its energy consumption.

This is what we will investigate in the following (non-parametric) efficiency analysis. In particular, we will compare the performance of a given sector in one European country to the performance of that same sector in other countries. For the country under evaluation, this will identify whether and to what extent sector-specific efficiency gains are possible (meaning that less input can be used for the given output level). As explained before, a specific feature of our empirical analysis is that it simultaneously accounts for CO_2 emissions as an undesirable output.

Efficiency analysis

Using the data presented in the previous section, we next evaluate the productive efficiency of the three sectors under study for our sample of countries. In particular, for every sector and country we compute the input efficiency measure $\widehat{TE}_t(\boldsymbol{Y}_t, \boldsymbol{X}_t)$ for each year of the time period 2000–07. This gives us information on the extent to which inputs have been allocated efficiently to achieve the three economic objectives that we focus on: reducing greenhouse gas emissions, creating jobs, and generating productivity growth. Attractively, the panel structure of our dataset also allows us to evaluate efficiency trends over time.

Before beginning our analysis, it is important to observe that sampling issues (e.g., measurement error and small-sample bias) may be a concern in the application at hand.[54] In turn, these problems may affect the reliability of the efficiency results that we report. In this respect, it is worth noting that the DEA literature has proposed alternative procedures to resolve sampling issues (see Daraio and Simar (2007) for a survey). For example, bootstrap (or subsampling) procedures can correct small-sample bias, and robust frontier procedures (such as order-*m* and order-α procedures) can improve the robustness of the efficiency scores with respect to outliers in the data. For compactness and to facilitate our discussion, we will not report results for these extended procedures here. However, we did apply alternative methods to check the extent to which our results were robust with respect to sampling issues. Our main qualitative conclusions proved quite robust.[55]

The remainder of this section unfolds as follows. The first subsection reports on the efficiency levels of the different sectors and countries under study. The second focuses on feasible input reductions that are revealed through our efficiency assessment. The third takes a dynamic viewpoint and looks at

54 The difference between the ‘true’ and estimated efficiency scores is called the bias. This bias can be greater with the smaller samples.

55 Detailed results of our robustness checks are available from the authors upon request.

efficiency trends over time. In particular, it considers whether we can discern specific catch-up patterns in the three sectors under evaluation.

Efficiency results

The results of our efficiency analysis are presented in Table 4.2. This table contains the average efficiency score (over the eight years in our sample) for each country and sector.

When considering the average scores per sector, we conclude that transport is clearly the most efficient sector. Again, this means that transport is the sector that uses its inputs most effectively to produce the given outputs. In particular, we find that the transport sector can reduce its inputs by no more than 4% (on average) for a fixed output. The possible input reductions for the agriculture and industry sectors are substantially more pronounced (14% and 12%, respectively). This confirms what we suggested before: although transport uses large amounts of input, there appears to be more potential for input reduction in the other two sectors.

Table 4.2 *Efficiency scores*

Country (DMU) *t*	Agriculture	Transport	Industries
Belgium	0.83	0.95	0.84
Czech Republic	0.95	0.97	0.83
Denmark	0.50	1	1
Germany	0.96	1	0.93
Ireland	1	0.76	1
Greece	1	1	1
Spain	1	0.85	0.92
France	0.99	1	1
Italy	0.96	1	0.77
Luxembourg	0.80	1	0.60
Hungary	0.89	1	1
Netherlands	0.62	0.99	1
Austria	0.80	0.90	0.88
Slovenia	0.93	0.90	0.83
Slovak Republic	1	1	0.82
Finland	0.89	1	0.90
Sweden	0.76	0.99	0.68
Norway	0.55	1	0.90
Average	*0.86*	*0.96*	*0.88*

Generally, we observe a great deal of heterogeneity in the efficiency scores across sectors and countries. This being so, it makes little sense, when focusing on a specific sector, to formulate objectives that do not take the identity of the country into account. Efficiency-enhancing strategies ought to be country-specific. For example, our results tell us that the Czech Republic should focus on industry to improve its overall efficiency level, while Ireland should concentrate on transport.

Possible energy reduction

To further illustrate our results in Table 4.2, we next quantify the possible energy reductions for every sector and country. This shows the extent to which countries can reduce their energy use in a given sector, without decreasing its output production. In fact, because (fossil) energy is directly linked with the production of CO_2 emissions, our results here also shed light on the degree to which CO_2 emissions can be decreased by behaving more efficiently.

As explained in the first section of the chapter, our input-oriented measure of technical efficiency $\widehat{TE}_t(\boldsymbol{Y}_t, \boldsymbol{X}_t)$ is defined as:

$$\widehat{TE}_t(\boldsymbol{Y}_t, \boldsymbol{X}_t) = min\{\theta | \forall m: (\theta \boldsymbol{X}_t) \in \hat{I}^m(y_t^m)\}$$

and gives the maximal equiproportionate input reduction (captured by $\theta \boldsymbol{X}_t$) that still makes it possible to produce the given output ($\boldsymbol{Y}_t$). Based on this definition, for each DMU t we can define the relative and absolute input reductions as:

$$\widehat{IR}_t^R = Input\ Reduction\ (Relative) = (1 - \theta)$$

$$\widehat{IR}_t^A = Input\ Reduction\ (Absolute) = \boldsymbol{X}_t \times (1 - \theta)$$

Table 4.3 reports the feasible absolute energy reductions for our sample of countries. Between brackets we present the associated relative input reductions, which correspond to the efficiency scores given in Table 4.2. The results in Table 4.3 clearly demonstrate the value added of computing absolute input reductions corresponding to efficiency improvements and so further illustrate the usefulness of an efficiency analysis such as ours in arriving at effective policy recommendations. In our opinion, the absolute numbers in Table 4.3 are quite impressive. This is all the more true because, by construction, the input reductions given by our model define only the upper bounds on possible input savings of evaluated DMUs (i.e., the 'benefit of the doubt' interpretation of DEA measures that we indicated before).

Table 4.3 *Energy reduction (toe/persons)*

Country (DMU) *t*	Agriculture	Transport	Industries
Belgium	0.012 (17%)	0.045 (5%)	0.221 (16%)
Czech Republic	0.0026 (5%)	0.012 (3%)	0.162 (17%)
Denmark	0.082 (50%)	0	0
Germany	0.013 (4%)	0	0.052 (7%)
Ireland	0	0.278 (24%)	0
Greece	0	0	0
Spain	0	0.133 (15%)	0.0564 (8%)
France	0.002 (1%)	0	0
Italy	0.0024 (4%)	0	0.157 (23%)
Luxembourg	0.0107 (20%)	0	0.833 (40 %)
Hungary	0.0067 (11 %)	0	0
Netherlands	0.0963 (38%)	0.0015 (1%)	0
Austria	0.0141 (20%)	0.110 (10%)	0.119 (12%)
Slovenia	0.0023 (7%)	0.070 (10%)	0.136 (17%)
Slovak Republic	0	0	0.146 (18%)
Finland	0.0166 (11%)	0	0.245 (10%)
Sweden	0.0211 (24%)	0.012 (1%)	0.460 (32%)
Norway	0.0750 (45%)	0	0.139 (10%)
Average	*0.0191*	*0.0367*	*0.152*

Efficiency trends

While our results in Tables 4.2 and 4.3 already reveal interesting conclusions, they do not shed any light on efficiency trends. Specifically, they do not tell us whether or to what extent sectors and countries are behaving more efficiently over time. We conclude our empirical application by exploring these issues of dynamic efficiency.

To do so, we use the measure of efficiency change (or catch-up) that we defined previously, which we calculate as the ratio of efficiency scores corresponding to two consecutive periods of time. A value for this catch-up measure above (or below) unity then indicates an efficiency improvement (of deterioration) of the DMU under study between the two periods. Essentially, this means that the DMU allocates its inputs more (less) optimally in the second period than in the first period.

Table 4.4 presents our results on efficiency change for the three sectors under study. We find that, on average, the catch-up measure is about one in the transport sector, which suggests that, for this sector, the average efficiency score remained more or less constant over the period 2000–07. For agriculture, the measure of efficiency change is slightly more than one, suggesting that the average country is catching up in terms of its efficiency performance. The opposite is true of the industry sector.

All in all, these (average) numbers are fairly similar over sectors and seem to indicate that there is not much improvement in terms of efficient input use for the given outputs. However, we also observe from Table 4.4 that there is (often substantial) variation in sector-specific efficiency change over years. In this respect, it is also important to recall that catching-up effects represent only one part of dynamic efficiency. As we indicated in the section on measuring dynamic efficiency, it may be interesting to complement the efficiency-change measure that we consider here by a measure of technology-change effects on the observed sector productivity. We see the development of such a technology-change measure for our type of multi-output DEA analysis as a valuable avenue for follow-up research.

Table 4.4 *Catch-up effects*

	2001	2002	2003	2004	2005	2006	2007	Mean
Agriculture	1.01	0.96	0.98	1.09	0.99	0.97	1.05	1.01
Transport	0.98	1	1	1.01	0.99	0.99	1	1
Industry	0.93	1.05	0.88	1.10	1.04	0.99	0.93	0.99

Conclusion

Focusing on three sectors (agriculture, transport, and other industry) in 18 European countries, we have evaluated the efficient use of two inputs – energy and capital – to achieve two main economic goals: economic growth and job creation. A distinguishing feature of our analysis is that we explicitly account for the negative side-effects of energy use by including the reduction of greenhouse gas emissions as a third main economic objective. We represented the first two objectives as 'good' (desirable) outputs and the last as a 'bad' (undesirable) output.

Building on Cherchye et al. (2012) and Cherchye *et al.* (2013), we presented a specific DEA methodology that describes the production of each output (good or bad) as resulting from a separate technology, while at the same time accounting for interdependencies in the production processes through joint inputs. This effectively accounts for the fact that it is usually impossible to produce good outputs without generating the bad output. Moreover, our approach does not require specific (often non-verifiable) technology assumptions to model the production of bad outputs (such as weak disposability or null-jointness).

Our empirical application demonstrated the value-added of both our sector-level orientation and our efficiency-measurement methodology. In particular, our analysis allowed us to identify sector-specific efficiency levels, efficiency trends, and feasible energy reductions (removing not only input inefficiencies, but also greenhouse gas emissions). A most notable finding was that countries often exhibit quite different performance patterns depending on the sector that is evaluated. In our opinion, this directly suggests the usefulness of evaluating productive efficiency at the sector level (and not only at the aggregate country level). In this respect, our results can lead to sector-specific policy recommendations for every country.

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APPENDIX: DESCRIPTIVE STATISTICS

Table 4A.1 *CO_2 emissions for each year (tonnes per person)*

	2000	2001	2002	2003	2004	2005	2006	2007
Agriculture								
Mean	1.34	1,31	1.28	1.25	1.24	1.21	1.24	1.18
Max	5.20	4.99	4.86	4.80	4.68	4.54	4.88	4.11
Min	0.65	0.66	0.66	0.63	0.60	0.60	0.59	0.60
Std	1.03	0.98	0.95	0.94	0.91	0.89	0.96	0.79
Transport								
Mean	2.56	2.63	2.70	2.81	2.94	2.99	2.96	2.97
Max	10.96	11.51	12.16	13.30	15.00	15.25	14.63	13.85
Min	0.78	0.89	0.92	0.94	0.99	1.17	1.08	1.22
Std	2.18	2.29	2.43	2.68	3.06	3.11	2.97	2.78
Industries								
Mean	1.16	1.12	1.11	1.09	1.13	1.11	1.10	1.09
Max	2.58	2.45	2.28	2.13	2.27	2.18	2.15	2.12
Min	0.51	0.54	0.54	0.56	0.56	0.45	0.47	0.47
Std	0.53	0.50	0.49	0.47	0.51	0.49	0.49	0.49

Table 4A.2 *CO_2 emissions for each country (tonnes per person)*

Country (DMU) t	Agriculture	Transport	Industries
Belgium	0.97	2.48	1.42
Czech Republic	0.81	1.56	1.37
Denmark	1.87	2.41	0.55
Germany	0.80	2.05	1.23
Ireland	4.70	3.06	0.88
Greece	0.88	1.96	1.14
Spain	1.01	2.32	0.78
France	1.59	2.25	0.70
Italy	0.66	2.19	0.66
Luxembourg	1.49	13.33	1.66
Hungary	0.90	1.06	0.61
Netherlands	1.17	2.14	1.02
Austria	0.94	2.81	1.31
Slovenia	1.04	2.13	0.59
Slovak Republic	0.62	0.99	2.01
Finland	1.11	2.58	1.14
Sweden	0.98	2.31	0.76
Norway	0.95	3.11	2.23

Table 4A.3 *Employment by year (workers per active people)*

	2000	2001	2002	2003	2004	2005	2006	2007
Agriculture								
Mean	0.0537	0.0516	0.0493	0.0477	0.0456	0.0444	0.0429	0.0414
Max	0.145	0.137	0.131	0.127	0.109	0.108	0.104	0.100
Min	0.0221	0.0217	0.0211	0.0206	0.0202	0.0196	0.0196	0.0195
Std	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02
Transport								
Mean	0.0657	0.0670	0.0647	0.0639	0.0626	0.0616	0.0613	0.0612
Max	0.105	0.112	0.109	0.121	0.126	0.124	0.127	0.119
Min	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Std	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05
Industries								
Mean	0.172	0.174	0.116	0.172	0.158	0.164	0.159	0.158
Max	0.261	0.269	0.262	0.261	0.263	0.259	0.263	0.261
Min	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10
Std	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05

Table 4A.4 *Employment by country (workers per active people)*

Country (DMU) *t*	Agriculture	Transport	Industries
Belgium	0.018	0.063	0.135
Czech Republic	0.039	0.067	0.261
Denmark	0.029	0.063	0.144
Germany	0.021	0.050	0.181
Ireland	0.060	0.059	0.145
Greece	0.120	0.053	0.102
Spain	0.046	0.051	0.151
France	0.032	0.057	0.126
Italy	0.038	0.047	0.195
Luxembourg	0.023	0.115	0.171
Hungary	0.051	0.072	0.218
Netherlands	0.031	0.056	0.113
Austria	0.070	0.062	0.156
Slovenia	0.094	0.053	0.242
Slovak Republic	0.037	0.056	0.196
Finland	0.048	0.067	0.171
Sweden	0.023	0.062	0.163
Norway	0.028	0.081	0.114

Table 4A.5 *Gross added value by year (€ per person)*

	2000	2001	2002	2003	2004	2005	2006	2007
Agriculture								
Mean	468.1	481.8	469.9	460.1	469.9	423.9	415.6	457.3
Max	764.8	752.9	753.1	729.5	733.2	710.6	643.7	876.3
Min	209.2	239.1	234.6	223.8	254.1	208.6	214.2	239.4
Std	191.3	189.1	168.2	178.1	163.4	160.3	137.1	166.8
Transport								
Mean	1590.4	1673.5	1753.5	1796.7	1868.0	1921.8	1982.8	2087.7
Max	4734.6	4880.4	5041.3	5005.8	5251.5	5444.6	5710.3	6181.8
Min	359.2	410.3	479.2	490.6	549.0	582.28	593.9	704.4
Std	1052.4	1081.2	1099.0	1061.4	1097.2	1154.8	1199.7	1253.2
Industries								
Mean	3787.9	3865.1	3975.7	3949.8	4050.3	4154.0	4383.2	4665.6
Max	8110.1	8650.1	9673.4	8904.4	8426.0	8162.5	8348.3	8555.7
Min	988.1	1130.4	1295.8	1342.1	1494.2	1636.0	1707.4	1862.0
Std	1930.1	1939.6	2063.3	1911.6	1807.3	1745.3	1817.5	1906.0

Table 4A.6 *Gross added value by country (€ per person)*

Country (DMU) *t*	Agriculture	Transport	Industries
Belgium	259.1	2023.1	4336.1
Czech Republic	244.4	846.2	2079.2
Denmark	540.5	2545.9	4650.6
Germany	253.1	1376.8	5531.1
Ireland	667.4	1709.9	8603.8
Greece	671.7	1282.6	1476.1
Spain	585.4	1253.8	2903.9
France	562.9	1503.2	3309.6
Italy	486.1	1597.5	4096.1
Luxembourg	295.3	5281.3	5421.0
Hungary	292.3	521.1	1460.9
Netherlands	600.4	1943.3	3867.6
Austria	476.1	1768.8	5144.0
Slovenia	313.3	837.6	2815.3
Slovak Republic	301.0	666.6	1772.4
Finland	742.8	2280.4	6245.4
Sweden	499.1	2154.2	5724.9
Norway	413.7	3424.9	4433.0

Table 4A.7 *Energy by year (toe per person)*

Country (DMU) *t*	Agriculture	Transport	Industries
Belgium	0.069	0.940	1.39
Czech Republic	0.057	0.540	0.95
Denmark	0.168	0.940	0.54
Germany	0.029	0.772	0.71
Ireland	0.077	1.146	0.61
Greece	0.104	0.715	0.39
Spain	0.067	0.887	0.67
France	0.060	0.824	0.60
Italy	0.058	0.766	0.70
Luxembourg	0.039	5.20	2.08
Hungary	0.058	0.388	0.34
Netherlands	0.252	0.919	0.90
Austria	0.071	1.01	0.96
Slovenia	0.030	0.72	0.75
Slovak Republic	0.030	0.314	0.79
Finland	0.015	0.910	2.38
Sweden	0.087	0.927	1.46
Norway	0.167	1.04	1.42

Table 4A.8 *Energy by country (toe per person)*

Country (DMU) *t*	Agriculture	Transport	Industries
Belgium	0.069	0.940	1.39
Czech Republic	0.057	0.540	0.95
Denmark	0.168	0.940	0.54
Germany	0.029	0.772	0.71
Ireland	0.077	1.146	0.61
Greece	0.104	0.715	0.39
Spain	0.067	0.887	0.67
France	0.060	0.824	0.60
Italy	0.058	0.766	0.70
Luxembourg	0.039	5.20	2.08
Hungary	0.058	0.388	0.34
Netherlands	0.252	0.919	0.90
Austria	0.071	1.01	0.96
Slovenia	0.030	0.72	0.75
Slovak Republic	0.030	0.314	0.79
Finland	0.015	0.910	2.38
Sweden	0.087	0.927	1.46
Norway	0.167	1.04	1.42

Table 4A.9 *Capital by year (€ per person)*

	2000	2001	2002	2003	2004	2005	2006	2007
Agriculture								
Mean	138	141	148	152	153	163	178	201
Max	260	293	281	329	303	319	422	456
Min	47	59	67	46	58	63	55	73
Std	72	72	73	82	78	82	101	114
Transport								
Mean	664	693	683	640	726	760	748	872
Max	1841	2300	2217	1528	2076	2201	1868	2622
Min	163	147	160	154	185	233	227	249
Std	412	482	469	331	436	465	400	572
Industries								
Mean	643	692	674	660	648	685	717	803
Max	1055	1047	1250	1220	1042	1177	1440	1801
Min	242	240	177	176	221	271	206	266
Std	245	243	259	219	206	221	270	325

Table 4A.10 *Capital by country (€ per person)*

Country (DMU) *t*	Agriculture	Transport	Industries
Belgium	76	729	790
Czech Republic	62	412	2501
Denmark	302	1106	1402
Germany	78	410	739
Ireland	192	1293	708
Greece	145	605	225
Spain	86	654	553
France	164	361	500
Italy	188	606	1035
Luxembourg	307	2082	1211
Hungary	71	190	180
Netherlands	209	542	513
Austria	220	796	782
Slovenia	103	506	673
Slovak Republic	66	351	630
Finland	278	643	772
Sweden	161	783	1910
Norway	161	957	1010

5

Can Smart Grids Reduce the Costs of the Transition to a Low-Carbon Economy?

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The UK is committed to reducing its greenhouse gas emissions (GHG) by at least 80% by 2050, relative to 1990 levels. Smart grid investments may reduce the costs of the transition to a low-carbon carbon economy by increasing the efficiency of existing infrastructure and thereby postponing the need for investment in new network capacity. But any investment in smart grid technologies will require an assessment of the costs and benefits of smart technologies in comparison to those of conventional alternatives. That is the goal of this chapter, which develops a framework for evaluating smart grids using a two-stage decision tree to account for option value.

The chapter builds on research commissioned by Ofgem (the regulator of gas and electricity markets in Great Britain). The research was undertaken in collaboration with EA Technology, to feed into the work programme of the Smart Grids Forum (SGF).[56] Established in early 2011, the SGF brings together key opinion-formers, experts, and stakeholders to help shape Ofgem's and the UK Department of Energy and Climate Change's (DECC) leadership in smart grid policy and deployment and to establish a common focus in addressing future network challenges.

We first describe the smart grid characteristics that must be considered in an evaluation, we then present our approach to evaluating smart grids, we next present the results of our analysis, and finally we present our conclusions.

56 The terms of reference are available here: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=7&refer=Networks/SGF

The characteristics of smart grids

There is no single definition of a smart grid. We use the *Smart Grid Routemap* developed by the Energy Networks Strategy Group (ENSG) as our starting point (ENSG 2010), which states that:

> [A] smart grid is part of an electricity power system which can intelligently integrate the actions of all users connected to it – generators, consumers and those that do both – in order to efficiently deliver sustainable, economic and secure electricity supplies.

Expanding on this definition, DECC identified several common characteristics of a smart grid (DECC, 2009).

- **Observable**: The ability to view a wide range of operational indicators in real time, including where losses are occurring,[57] the condition of equipment, and other technical information.

- **Controllable**: The ability to manage and optimise the power system to a far greater extent than currently possible, which may include adjusting some electricity demand according to available supply, as well as enabling the large-scale use of intermittent renewable generation in a controlled manner.

- **Automated**: The ability of the network to make certain automatic demand response decisions (it will also respond to power fluctuations or outages, for example, by reconfiguring itself).

- **Fully integrated**: Integrated and compatible with existing systems and with other new devices such as smart consumer appliances.

At the transmission level, the network is already relatively 'smart', given its requirement to manage frequency, voltage, and current in an active manner. Our framework therefore focuses on 'smart' investments at the distribution level, where networks are currently more passive. Distribution network operators (DNOs), both in the UK and internationally, have conventionally operated networks with relatively straightforward flows of electricity. Although DNOs have occasionally made trade-offs between investment and active management options, they have generally limited active management. Many of the near-term activities required to transition to a low-carbon energy sector will require more flexibility in the current electricity distribution network. Smart grids are therefore likely to be focused on the distribution networks.

A smart grid evaluation framework must account for a range of characteristics.

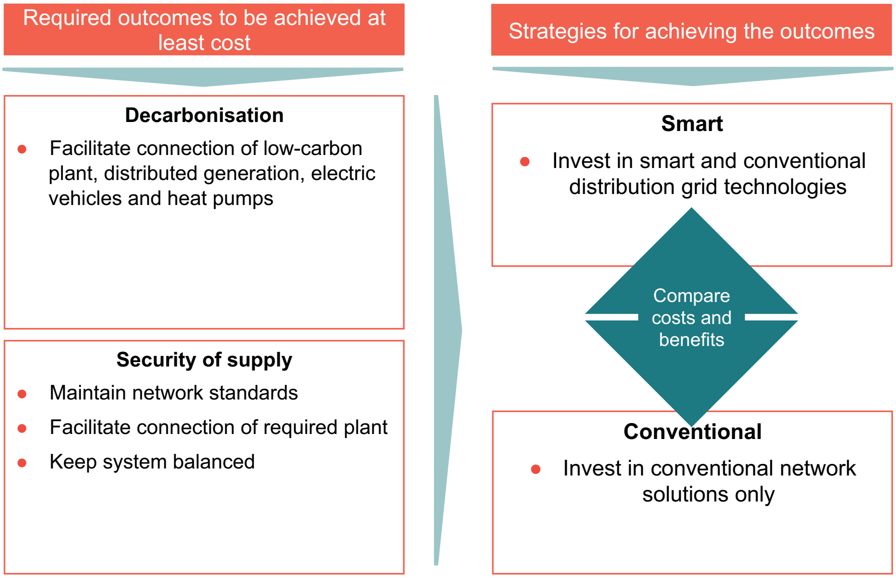
57 We note that the prominence given to loss management in this definition has been questioned.

Smart grids as enabling technologies

A smart grid is an enabling technology, rather than an end in itself. While it may help meet the goals of high-level decarbonisation and security of supply, these can also generally be achieved through traditional reinforcement of networks.

Our evaluation therefore focuses on smart grids as a means to these ends. Holding objectives such as overall emissions and supply reliability constant, our framework compares the costs and benefits associated with different ways of achieving these outcomes (Figure 5.1).

Figure 5.1 *Overview of our approach*



Source: Frontier Economics.

Multiple solutions

A smart grid is not one technology. There are multiple solutions available in different combinations and for different circumstances. While solving for the 'optimal' mix of smart grid technologies was beyond the scope of this work, our evaluation framework had to pay close attention to the potential interactions between technologies.

We therefore assess the costs and benefits of representative smart grid investment packages or strategies, rather than considering individual technologies in isolation.

Scale and profile of investment required

The relationship between the costs and benefits of smart grids and the scale and profile of investment may be complex. Solutions may differ in the following ways:

- the extent to which they must be applied in a coordinated fashion to be effective;
- the extent of up-front capital investment required and the subsequent lifespan of these assets; and
- the speed with which they can be deployed.

To take account of these differences, we assess two smart grid investment strategies: one based on a top-down or holistic implementation, the other based on a more incremental, reactive rollout.

Uncertainty and option value

There is a high degree of uncertainty over future demand and supply conditions in the electricity sector to 2050. So our evaluation must not only consider which technology performs best under a given future scenario, but also convey which technology is best suited to the range of possible scenarios. In practice, this means our evaluation framework must:

- consider more than one possible scenario; and
- take account of the 'option value' that arises from networks' ability to modify their investment strategies in future years in response to new information.

To capture these uncertainties, we consider three scenarios that represent potential developments in the electricity sector to 2050, and employ a real options-based approach in our evaluation framework.

Our approach

First, we set out our assessment of the factors likely to drive the value of smart grids. Varying the level of these factors then forms the basis of our scenario development.

Second, we identify the 'conventional' and 'smart grid' technologies that could be deployed in response to these challenges, and we set out an approach to defining the deployment strategies that we will evaluate in our model.

Third, we describe the model we have developed, including our approach to assessing the impact of uncertainty in this context.

Value drivers and scenarios

We have focused on the factors most likely to affect the net benefits of smart grids. Where there is significant uncertainty over these factors, they must be varied across scenarios.

Our value driver analysis suggests that the following developments are the most important.

The electrification of heat and transport. The change in the level and profile of demand associated with the electrification of heat and transport will pose a range of challenges for networks. This electrification may also increase the amount of demand available for customer demand-side response (DSR). By DSR, we mean changes customers can make to the time of their electricity consumption. For example, to undertake DSR, customers may shift electricity demand from the early evening peak to the off-peak overnight period, or from weekdays to weekends. Our framework will therefore assess the impacts of electric vehicles, plug-in hybrids, vehicle-to-grid technology, heat pumps, and heat pumps with storage.

The increase in distributed generation. The increase in generation connected to the distribution network will raise network challenges. We will therefore assess the impacts of solar PV, small-scale wind, and large-scale wind and biomass generation connected to the distribution network.

The increase in intermittent and inflexible generation. Changes in the large-scale generation mix are likely to increase the role for DSR. Where this DSR aims to follow the pattern of large-scale intermittent generation, it may increase peaks on distribution networks. Our framework therefore includes an assessment of changes in the generation mix.

The importance of DSR. Some smart grid technologies will help facilitate DSR. Assessing the value of this service will likely be integral to assessing the value of smart grids. However, there is uncertainty over how responsive customers will be to various kinds of signals, and there are a number of competing uses of DSR (notably, demand-shifting by suppliers to reduce wholesale energy costs), which will have different values under different conditions. Given the uncertainty over customers' propensity to undertake DSR, we vary this across scenarios.

We have developed three scenarios, which vary the level of these value drivers (Table 5.1).

- **Scenario 1** includes projections of heat and transport electrification consistent with meeting the fourth carbon budget.

- **Scenario 2** contains the same rollout of low-carbon technologies as Scenario 1, but customers exhibit less flexibility with regard to the demand associated with each of these low-carbon technologies.

- **Scenario 3** is consistent with a situation where the UK chooses to meet its carbon targets through action outside the domestic electricity sector (for example, through purchasing international credits). In this scenario, the rollout of demand-side low-carbon technologies is slower than expected, and the generation mix contains less inflexible and intermittent low-carbon plant.

Table 5.1 *Summary of scenarios*

	Electrification of heat and transport	Increase in distributed generation	Increase in intermittent and inflexible generation	Extent to which customers engage with demand response
Scenario 1	Medium transport, high heat (consistent with Scenario 1 of the Government's Carbon Plan)	Medium	Medium	Medium
Scenario 2	Medium transport, high heat (consistent with Scenario 1 of the Government's Carbon Plan)	Medium	Medium	Low
Scenario 3	Low	Low	Low	Medium

Source: Frontier Economics.

Definition of investment strategies

Our model includes three investment strategies. Each strategy maintains current levels of security of supply and facilitates the same quantity of connections of low-carbon plant and demand-side technologies. The strategies will differ solely in terms of how they deliver these outcomes.

- **A top-down smart grid investment strategy.** This entails an initial investment in control and communication infrastructure and lower associated costs of ongoing investment in smart technologies, with conventional technologies deployed where cost-effective. Under this strategy, investments in smart or conventional technologies required to maintain security of supply to today's levels are undertaken on each feeder.[58]

- **An incremental smart grid investment strategy.** Once again, smart and conventional technologies are delivered as required on each feeder type, with the lowest-cost solutions chosen first. The incremental strategy differs from the top-down strategy in that it does not include

58 A feeder is a circuit on the distribution network. Feeders include low-voltage circuits connected to homes, extra-high voltage circuits that link to the transmission network, and everything in between.

an upfront investment in the control and communications infrastructure. Because this infrastructure is not in place, all ongoing investments in smart technologies cost more than in the top-down investment strategy.

- **A conventional strategy.** This strategy differs from the top-down and incremental strategies in that it only includes conventional technologies.

We have chosen to focus on a set of representative technologies, including:

- battery electrical energy storage (e.g., flow-cell, Li-Ion, sodium sulphur);
- dynamic thermal ratings;
- overhead lines;
- underground cables;
- transformers;
- enhanced automatic voltage control;
- active network management (e.g., dynamically reconfiguring the network in response to load); and
- technologies to facilitate DNO-led DSR.[59]

Our model includes the main types of smart grid technologies and strategies required for an evaluation, but they do not form a comprehensive set. It should also be stressed that there is significant uncertainty over the cost and performance estimates of these technologies. Evidence to support and refine these estimates will become increasingly available as projects, including the LCN Fund projects,[60] yield results.

These alternative strategies are described in Table 5.2.

59 EA Technology chose, analysed, and characterised these technologies. By DNO-led DSR, we mean the shaping of demand specifically to avoid peaks on the local distribution network, as opposed to load-shifting carried out to reduce nationwide generation and transmission costs.

60 Ofgem established the Low Carbon Networks Fund (LCN Fund) as part of the price control that runs until March 2013. The LCN Fund allows up to £500 million to support DNO's to trial new technology and operating and commercial arrangements.

Table 5.2 *Investment strategies*

	Characteristics
Top-down smart grid investment strategy	Upfront rollout of control and communications infrastructure Rollout of smart and conventional technologies when required
Incremental smart grid investment strategy	Rollout of smart and conventional technologies, and associated control and communications infrastructure when required
Conventional strategy	Rollout of conventional technologies only, when required

Source: Frontier Economics/EA Technology

Modelling

The purpose of the model is to increase our understanding of what drives the value of smart grids. Therefore, we have aimed to maintain flexibility (by ensuring users can vary key assumptions to run sensitivities) and transparency (by ensuring that all assumptions are clear) throughout.

The model, developed with EA Technology, calculates the costs and benefits of alternative distribution network investment strategies. This calculation is carried out for each of the investment strategies (conventional, top-down, and incremental) and across each of the three scenarios.

Smart grid technologies may benefit society in a variety of ways. Our model takes the following costs and benefits into account:

- **Distribution network reinforcement:** The value of investments made to ensure that distribution networks can handle the load imposed upon them. This includes conventional reinforcement options, as well as any smart solutions.

- **Distribution network interruption costs:** The cost to customers of interruptions caused by distribution network faults.

- **Distribution network losses:** The cost associated with any change in losses caused by smart grid solutions.

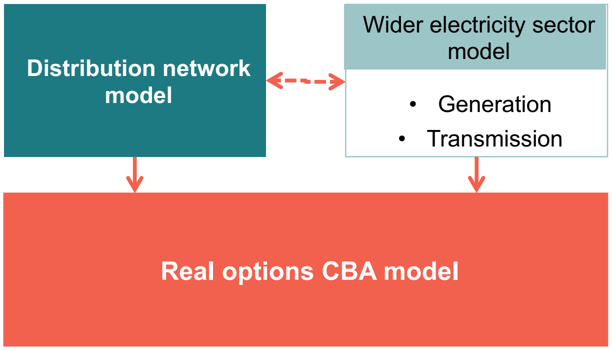
- **Generation costs:** The resource costs (both opex and capex, and including carbon costs) of generating sufficient electricity to meet demand at all times.

- **DSR 'inconvenience' costs:** An assumed monetary value associated with the inconvenience of using DSR to shift load.

- **Transmission network reinforcement:** An order-of-magnitude estimate of the cost of reinforcing the transmission network to handle UK-wide peak loads.

Figure 5.2 illustrates the overall structure of the model.

Figure 5.2 *Model overview*



Source: Frontier Economics.

The model has three parts.

The '**distribution network model**' assesses those costs and benefits that accrue on the distribution networks. This includes the cost of distribution network reinforcement, in addition to interruption and cost of losses. EA Technology have developed a parametric, rather than a nodal, approach to this distribution network modelling.

The '**wider electricity sector model**' considers the costs and benefits that depend on nationwide electricity demand and supply at a high level. These include generation costs, transmission network reinforcement costs, and any costs associated with smart appliances. Smart technologies can impact on the wider electricity sector through DSR and embedded storage. For example, if measures to encourage DSR result in a shift in consumption to the overnight period, more generation will be required overnight. Similarly, if DNOs use storage to help manage local peaks, generation that would have been required at the time of local peaks will now be required at other times.

Finally, the **'real options-based cost-benefit analysis model'** combines the outputs of these models to calculate net present values and related indicators for each of the investment strategies.

Model scope

To maintain flexibility and transparency, some simplifying assumptions have been included:

- We do not value the use of DSR or electrical energy storage for system balancing.
- Demand and wind patterns have been represented by using typical and peak days.

- We consider the potential to shift demand within days, but not between days.
- Full optimisation between different uses of DSR has not been carried out.

This work has focused on developing a robust and flexible appraisal methodology and formalising this in a model, rather than on carrying out detailed research on each of the parameters included in the model. We do not consider this to be the definitive dataset for use in this area and we envision that the data in this model will be updated as new information becomes available.

The model's simplifications and the likelihood of new data becoming available mean that the results of this modelling should be seen as a first step in understanding the drivers of the costs and benefits of smart grids, rather than a definitive assessment of their value.

Addressing uncertainty

The uncertainty surrounding smart grid investment decisions makes conventional cost-benefit analysis techniques difficult to apply, particularly when assessing options over time under uncertain conditions, which may yield misleading results. For example, under a standard cost-benefit analysis, which implicitly assumes perfect foresight, a capital-intensive option might have a higher net present value than an option that has high ongoing costs, but no upfront costs. Once uncertainty over the future outturn scenario is taken into account, the latter approach might look more sensible because of the flexibility associated with it; you can choose not to run it if it turns out not to be needed.

Given that smart and conventional options have different levels of capital intensity, a more innovative method of evaluation should be applied. This method must be able to factor in the option value associated with early investment in flexible solutions (i.e., potentially ahead of need) or delaying investment until more information is available.

We have based our cost-benefit analysis on the principles of 'real options' analysis. This recognises the possibility that, under some circumstances, networks might be able to adapt their investment strategies in future years as new information about the utility of smart grids becomes available. This allows the evaluation framework to account for the option value associated with any smart grid investments that avoid lock-in to a particular investment path. Examples of investments with option value may include:

- investments that can be incrementally augmented in future periods;
- investments that promote learning, which may therefore make future investments less costly or more feasible;[61] or
- investments that entail high upfront costs but reduce ongoing investment costs.

Real options-based analysis allows the best strategy to be chosen in the face of uncertainty by factoring in:

- the impact of new information at a decision point in the future (will new information lead to a change in the optimal strategy?); and
- the extent to which the investment strategy today facilitates or limits the ability of networks to adjust their investment strategies when this new information becomes available (have decisions taken in the early period reduced the choices available in the later period?)

We capture the differing option values associated with the different strategies by looking at the costs and benefits across two time periods. As a default assumption in the model, the first time period is between 2012 and 2023, and the second is between 2023 and 2050. We use the year 2023 for the decision point in our decision tree analysis as this is likely to coincide with the beginning of the first price control period after the completion of the smart meter rollout, and is hence a logical point for the industry to adjust its smart grids strategy if necessary.[62] However, users can change the date of the decision point in the model.

The model assesses the costs and benefits of each strategy for each scenario in the first period.

The model then considers the second time period. For each strategy that has been chosen at the first decision point (2012), a set of strategies is still possible at the second decision point (2023). However, not all will be possible. For example, if a top-down strategy has been chosen in 2012, it is not possible to change to an incremental strategy or a conventional strategy in the mid-2020s without stranding a number of assets.

For each scenario, therefore, we identify the best available strategy at the second decision point (2023), given:

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61 While we do take account of the fact that the cost of smart technologies is likely to fall over time, learning is not modelled endogenously in our framework (on the basis that it is likely to be driven at least partly by global, rather than UK, deployment).

62 Many, but not all, consultation respondents agreed with the choice of date for the decision point. We note that the industry would begin to discuss any changes to its smart grid strategy for ED2 several years before 2023, however, the actual changes would be more likely to occur from the beginning of ED2 in 2023.

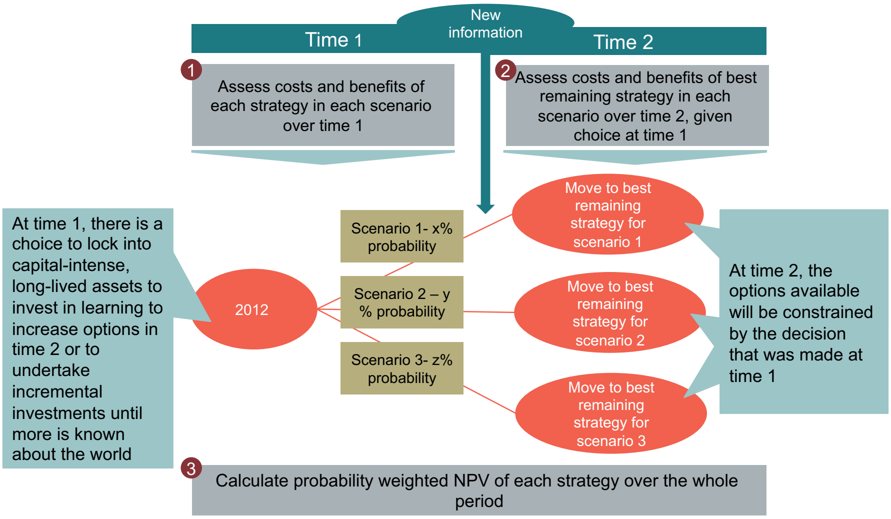
- the assumed scenario; and

- the optimal investment strategy associated with this scenario, subject to the constraints imposed upon the set of available strategies by the investment strategy chosen at the first decision point (2012).

The final step is to combine the results of the conventional cost-benefit analysis for the first period with the results of the analysis for the second period to identify a total net present value (NPV) benefit measure for each scenario and strategy. By weighting the NPV benefit estimates by assumed probability of each scenario occurring, we can identify a single probability-weighted NPV benefit estimate for each investment strategy.

Figure 5.3 provides a diagrammatic illustration of the 'real options' approach described above.

Figure 5.3 *Real options–based approach*



Source: Frontier Economics.

We believe that this kind of decision tree analysis provides the right balance between accounting for uncertainty and avoiding the questionable accuracy of a more data-intensive modelling approach.

- A decision tree analysis takes the principles of real options analysis and ensures that path dependency has been taken into account. This assigns a higher value to investments that keep options open than to those that lock in to a certain path.

- At the same time, this analysis maintains simplicity and transparency. Rather than requiring the inevitably subjective development of detailed probability distributions around key variables in the model and their interdependencies, decision tree analysis allows assumptions about the probability of each scenario to remain explicit and changeable for the use in sensitivities analysis. By limiting the decision tree to two periods, we will be able to take account of the different option values associated with different smart grid investment strategies without allowing the evaluation framework to become too complex.

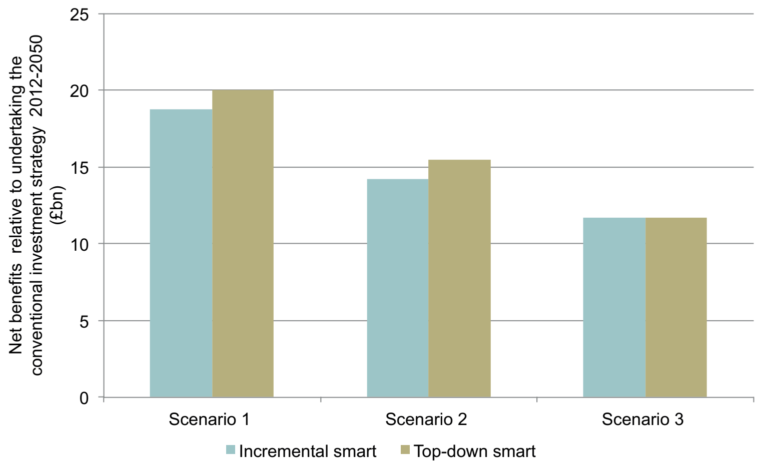
Results

Given the scope and level of granularity of this modelling, it is important that results are seen as a first step to better understand the drivers of the costs and benefits of smart grids, rather than as a definitive assessment of their value.

Core results

We first undertake a straightforward cost-benefit analysis out to 2050. Given the set of assumptions used in the modelling, this analysis suggests that smart grid technologies can deliver significant savings over the period (relative to using only conventional alternatives). This is because including smart solutions in a strategy expands the options for DNOs, allowing them to choose less costly solutions and defer conventional investment where appropriate. These results are shown in Figure 5.4.

Figure 5.4 *Net benefits of smart strategies relative to conventional strategies, under default assumptions*

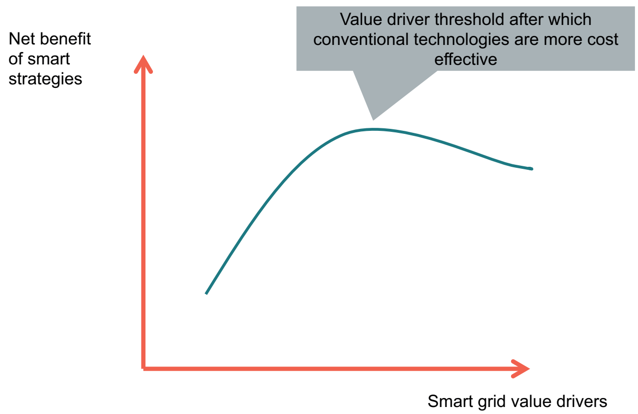


Source: Frontier Economics.

Figure 5.4 shows that these savings are demonstrated across all scenarios analysed, but are highest where low-carbon technologies have the greatest penetration and customer engagement with DSR is highest.

Despite higher levels of peak demand, the net benefits of Scenario 2 are lower than in Scenario 1. This is because of threshold effects in network investment. When peak demand on the distribution network reaches a certain level, major conventional investment programmes can provide the most cost-effective solutions. This means that the net benefits for smart grids first rise as peak demand on the distribution network increases (for example, due to the rollout of low-carbon technologies), but then decline once the level of value-driving technologies reaches the point where major work is required. This effect is illustrated in Figure 5.5.

Figure 5.5 *Illustration of threshold effects in estimating net benefits of smart strategies*



Source: Frontier Economics.

Note: There may be more than one threshold.

Decision tree analysis

The counterfactual underlying the results presented in Figure 5.4 was based on pursuing the conventional strategy to 2050, with no option to switch strategy.

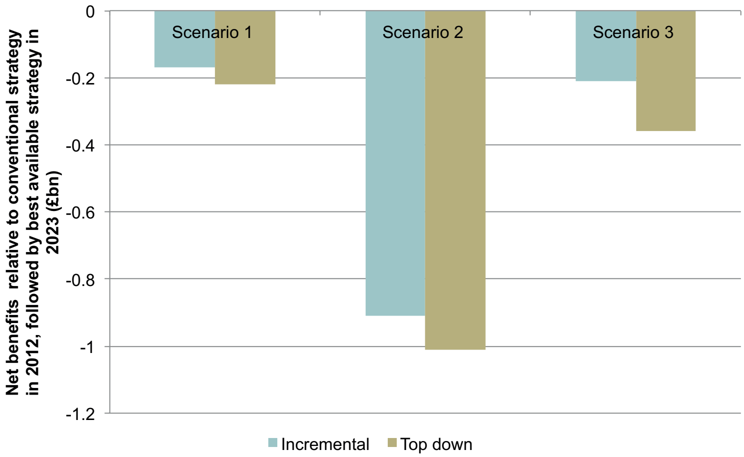
To take account of option value, we now apply a two-stage decision tree and assume the network investment strategy decision made in 2012 can be changed in 2023[63] in both the conventional counterfactual and the smart investment cases.

This means that the counterfactual against which we assess our choice of smart strategies may itself become smart at the decision point in 2023, if this turns out to be a better option than continuing to only employ conventional technologies.

63 We use the year 2023 for the decision point in our decision tree analysis, as this may coincide with the beginning of the first price control period in the 2020s. However, users can change the date of the decision point in the model.

Figure 5.6 sets out the results once a two-stage decision tree has been applied to this analysis. The results in the figure suggest that there is not a clear case for *immediate* widespread rollout of smart grid technologies, based on the assumptions we use. Under all scenarios, the conventional strategy is marginally preferred in 2012, though the net cost of pursuing smart strategies is very small and is well within the range of uncertainty associated with the modelling assumptions.

Figure 5.6 *Net benefits of choosing smart strategies in 2012 assuming the decision can be changed in 2023*



Source: Frontier Economics.

The large net benefits shown in Figure 5.4 are no longer present because we are now focusing on the impact that choosing a smart strategy can have in the period to 2023. The reduction in net benefits makes sense, given that the rollout of the value-driving technologies such as heat pumps, electric vehicles, and distributed generation is unlikely to have a large impact across the system until the 2020s (although clustering will cause issues in particular areas).

The overall conclusion is that smart grid solutions are expected to deliver benefits in the coming decades, but more analysis is required to decide at what point their significant deployment should begin.

Our engineering analysis suggests that choice of strategy in 2012 only constrains the future choice of strategy in one case: if a top-down strategy is chosen in the initial period, it must be pursued until 2050. This reflects the fact that the assets enabling the top-down strategy have a long lifetime and will remain on the system beyond the decision point. If either the incremental or conventional strategy is chosen in 2012, any strategy can then be chosen in 2023.

Under our default assumptions, the model finds that – under all scenarios, no matter which strategy was pursued in the first period – a smart strategy is optimal after 2023 (with the top-down strategy being marginally preferred to the incremental strategy). This makes sense, as after 2023 penetration of low-carbon technologies has reached significant levels in these scenarios.

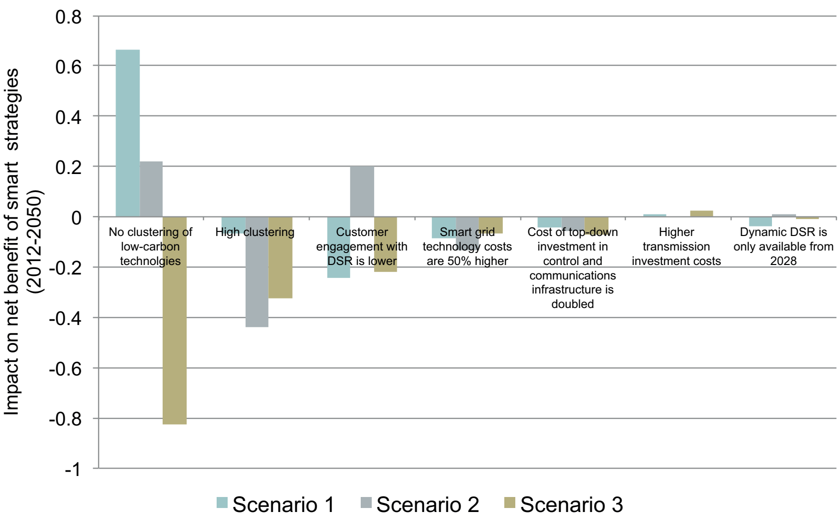
These results suggest that continuing with a conventional strategy in the near term does not lead to lock-in to a costly strategy over the long run and that there is not a clear case for the *immediate* widespread rollout of the smart grid strategies, based on the assumptions we use. The results also suggest that the option value associated with smart grids is low since widespread rollout of smart strategies today does not increase the set of options available in 2023.

We note, however, that if there are long lead times associated with some aspects of the smart strategies, immediate action may be required in some areas. For example, experience with implementing the smart technologies (for example, as part of LCN Fund projects) may be very helpful in driving down their costs.

Sensitivity analysis

We also looked at a range of sensitivities around the core results (presented in Figure 5.4). The results of the sensitivities are presented in Figure 5.7. While the results are sensitive to these changes, the positive net benefit of smart strategies relative to conventional strategies is maintained in each case.

Figure 5.7 *Key results of the sensitivity analysis*



Source: Frontier Economics.

Figure 5.7 shows that the results are particularly sensitive to the assumptions made about the clustering of low-carbon technologies and that the effect of changing this assumption differs depending on the scenario. This is because reducing the clustering of low-carbon technologies has two impacts:

- It reduces the pressure on the parts of the distribution network where low-carbon technologies were clustered. This will tend to reduce the net benefits of smart strategies.

- It increases the pressure on the parts of the distribution network that had fewer low-carbon technologies when clustering was in effect. This will tend to increase the net benefit of smart strategies.

In Scenario 3, the penetration of low-carbon technologies is low. In this case, the first impact dominates. A reduction in clustering reduces pressure on the feeders on which low-carbon technologies were clustered, but there are not sufficient low-carbon technologies to require widespread investment once these are spread evenly across the network.

In Scenarios 1 and 2, the penetration of low-carbon technologies is higher. In these cases, the second effect dominates, and reducing clustering increases the benefit of smart grid strategies because the number of feeders that require smart or conventional investment increases.

Figure 5.7 also shows that increasing the technology costs of smart grids by 50% does not have a significant impact on the net benefits of smart technologies. This suggests that the results are relatively robust to the high degree of uncertainty around these costs. This is because most smart grid technologies included in the model turn out to be more cost-effective than the conventional alternatives under our base case assumptions about costs and network conditions, and because the smart strategies contain significant levels of conventional investment.

Conclusions

It is important that the results of this modelling are seen as a first step in understanding the drivers of the costs and benefits of smart grids, rather than as a definitive assessment of their value.[64]

Under the set of assumptions used in the modelling, this analysis suggests several conclusions.

Smart grid technologies can allow significant savings in distribution network investment costs over the period to 2050. Including smart solutions in a strategy widens the set of options available to DNOs, allowing them to choose less costly measures and defer conventional investment.

64 The Smart Grid Forum has recently carried out additional work to extend the model described in this chapter, the latest output of which is available in Smart Grid Forum (2013). A number of assumptions were altered for this piece of work (for example, there are lower costs to conventional reinforcement), which lead to lower network investment costs under all scenarios and strategies. The overall results reported in this chapter are robust to these changes: Smart Grid investment is still associated with a positive NPV over the long run, however the vast bulk of such investment is required after 2023.

The benefits of smart grid strategies are highest under the scenarios with the most low-carbon technologies. When penetration of low-carbon technologies is low, both conventional and smart distribution network investment levels are much lower. However, our analysis suggests that smart grid investments have a positive net benefit, even when the penetration of low-carbon technologies is relatively low.

Although the benefits of smart grid strategies at first rise with an increase in peak demand on distribution networks, when a certain threshold in peak demand is reached, major conventional investments become more cost effective. This is due to the 'lumpy' nature of many conventional reinforcement options (which, while costly, can often free up large amounts of headroom on networks). For this reason, among others, it is often difficult to predict the way in which a change in a value driver may affect the incremental value of the smart strategy.

Some smart grid technologies aim to facilitate DSR. In addition, smart meters on their own may facilitate some forms of DSR (which will itself lead to a change in the load imposed on distribution networks). There is a great deal of uncertainty over the extent to which customers will engage with DSR. Under our assumptions, a reduction in the level of customer engagement with DSR has two impacts:

- It increases peak demand on networks in the counterfactual, since the impact of smart meters on peak demand is reduced. Whether this has a positive or negative impact on the net benefit of smart grids will depend on threshold effects.

- It reduces the effectiveness of smart grid technologies that facilitate DSR. This will have a negative impact on the net benefit of smart grids.

Overall, under our assumptions, a reduction in the level of customer engagement with DSR reduces the net benefit of smart grids in Scenarios 1 and 3, and increases the net benefit of smart grids in Scenario 2.

Because the penetration of low-carbon technologies is relatively low until the 2020s under the scenarios presented by WS1, there is not a clear case for the immediate widespread rollout of smart grid technologies. However, where they are clustered there may be opportunities to reduce distribution network costs through the use of smart investments in the near term. Further, if there are long lead times associated with some aspects of the smart strategies, action in the near term may be required.

Our real options-based analysis suggests that the option value associated with the widespread rollout of smart grids is low. Undertaking conventional investments now does not lead to lock-in to expensive strategies. However, there is likely to be significant option value associated with piloting new smart grid technologies, where this provides learning.

These results are robust to changes in assumptions around clustering, the functionality of smart meters, the cost of technologies, the extent to which customers engage with DSR, transmission investment costs, and the variability of wind.

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The Impact of Changes in Regulatory Regime on Productivity of Spanish Electricity Distribution Firms

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Since the beginning of the 1990s, many countries have experienced a wave of regulatory reforms in their electricity sector. A common pattern can be observed in all cases: unbundling the electricity business by introducing competition in production and sales; creating wholesale markets and granting access to networks; designing or redesigning incentive-based regulatory schemes in transmission and distribution, which are still considered natural monopolies; creating independent regulators; and privatising public utilities (Newbery, 2000). Spain is no exception to this trend. It began its liberalisation process in 1998, though the sector had been regulated by means of incentive-based schemes since 1988. In this sense, Spain could be considered a pioneer in the application of these regulatory mechanisms. Preceding its liberalisation, the Spanish electricity sector went through an intense process of privatisation that led to mergers between companies, substantially increasing concentration in the sector.

With reference to distribution, from 1988 to 1997, preceding the liberalisation process, a price-cap scheme with some characteristics common to yardstick competition was in place. Since 1998, however, a revenue-cap scheme has been in force, benchmarked on the performance of a reference utility. Currently, Spain is one of the few countries that still use a reference model based on engineering standards. Other countries that apply a revenue-cap model, such as Norway, Germany and Austria, use parametric and non-parametric methods to set their benchmarks (see Farsi *et al.* (2007) for a description). Of course, one of the main objectives of any regulatory system is to encourage the growth of the regulated companies' productivity; that is, to make more efficient use of inputs to produce outputs, to incorporate technological innovations and technical progress in a timely way, and to exploit economies of scale. The ultimate goal is to share these productivity gains with consumers in the form of lower electricity prices.

In the case of Spain, attaining this ultimate objective is crucial, since it is more than probable that electricity prices will increase steadily in coming years, a trend that started in 2008. This escalating tendency is the consequence of both an incoherent electricity pricing policy and an imperfectly designed wholesale production market.[65] This combination has kept revenues and costs of regulated activities from converging, leading the government to accumulate a debt of €25 billion with electric companies, almost 3% of the country's GDP. This bulky debt must be paid off via tariffs charged to current and future consumers. The additive nature of electricity tariffs compels the electricity sector to increase its productivity in order to slow the rise in prices. In this sense, it is essential to have information on companies' performance and to identify the determinants of that performance.

Fuentes *et al*. (2001) proposed a parametric estimation and decomposition of the Malmquist productivity index into two main components: technical change and technical efficiency change. Later studies have expanded this approach to include the scale efficiency component in the index decomposition. This chapter introduces the definition of scale efficiency suggested by Ray and Desli (1997) as one of the components of the parametric Malmquist index. We show that Ray and Desli's definition of scale efficiency fits naturally with the other two components. Their product produces a parametric Malmquist index that correctly measures total factor productivity (Grifell-Tatjé and Lovell, 1995). We then apply this methodology to study the impact of different regulatory regimes on the performance of Spanish electricity distribution companies from 1988 to 2010. To do this, we calculate and combine several input-oriented distance functions specified in a translog form in a context of stochastic frontier analysis.

Although many studies analysing the efficiency of the electricity distribution sector have been published for numerous countries, the empirical evidence for the Spanish electricity distribution is scarce. Blázquez and Grifell-Tatjé (2008, 2011) have studied this industry, but using non-parametric techniques. This study intends to fill this gap. Additionally, although the methods proposed in this study or alternative decompositions of the Malmquist index have been used to analyse other utilities (e.g., Saal and Parker (2006) for the water industry; Pantzios *et al*. (2011) for the aquaculture sector) our approach is still relatively innovative in analyses of the electricity distribution industry (e.g., Tovar *et al*., 2011).

The remainder of the chapter is organised as follows. The next section presents a brief description of the regulatory schemes applied to distribution companies in the last two decades. The following section explains the methodology applied in the study. The third section discusses the data and econometric specification. The fourth outlines the main results of the analysis. The last section offers some concluding remarks.

65 See Arocena *et al*. (2011) for an analysis of the effects of Spain's electricity sector law on stakeholders.

The regulation of electricity distribution in Spain

The period under consideration (1988–2010) may be subdivided into three main regulatory periods: (i) 1988–97; (ii) 1998–2008; and (iii) 2009–10.

The 'Stable Legal Framework'

During the first regulatory period (1988–97), Spanish electricity companies were subject to the Stable Legal Framework (*Marco Legal Estable*, or MLE), which was applied to all electricity-related activities. The most important concept within this framework was 'standard costs'. That is, the government determined a set of 'objective' system-wide costs with the idea of eliminating unnecessary expenditures. Companies' reimbursements and electricity rates were based on those costs. Thus, the MLE was an incentive-based regulatory framework that combined aspects of price-cap regulation with features of the yardstick competition model, a model that was eventually applied in many countries.

The MLE regulatory framework had two different systems of remuneration for distribution according to the level of voltage: low-to-medium voltage (below 36 kV) and high voltage (36 kV or greater). High-voltage distribution was rewarded in terms of physical units (kilometres of line, number of cells, and transformer capacity), regardless of their effective use. By contrast, distribution in low-to-medium voltage was paid in terms of the amount of energy circulated.[66]

Electricity sector law (LSE) I: 1998–2008

The electricity sector law (*Ley del Sector Eléctrico*, or LSE), which emerged from negotiations between the Ministry of Energy and the electricity companies, came into force in 1998. The LSE introduced competition into generation and retailing and stipulated consumers' right to choose a supplier, a right that was implemented gradually. Transmission and distribution remained regulated, although they, too, were liberalised by widening third-party access to the electricity networks. Under the LSE, the average electricity rate was still based on the total expected objective costs, which included distribution costs, as well as expected final demand as determined by the government. However, a revenue-cap system was introduced to remunerate distribution companies, with the development of an optimal network (based on engineering standards) as a benchmark.

Reimbursements paid to electricity distributors were based on the following factors: (i) capital investment costs (taking into account the distribution facilities needed to meet demand, based on a reference network model for nationwide

66 For a more extensive analysis of the MLE regulatory framework, see Crampes and Laffont (1995). Additionally, Blázquez and Grifell-Tatjé (2008) include an empirical analysis of its consequences on the revenue of electricity distribution companies.

distribution),[67] as well as actual investments; (ii) operating and maintenance costs, based on the reference network and the actual facilities; (iii) electricity supplied at various voltage levels, which were used to determine operating and maintenance costs; (iv) commercial management costs; (v) incentives to boost the quality of supply and reduce electricity losses;[68] and (vi) costs incurred to reduce electricity consumption.

The overall reimbursements to new distributors (R), which were implemented after the LSE came into force, were determined on the basis of the aforementioned factors and updated annually using the expected consumer price index (CPI) minus a fixed productivity improvement factor (X) of 1%. In addition, the increase rate in demand over the entire system was taken into account (ΔD), affected by a correction parameter known as the 'efficiency factor' (Fe), which, in principle, could not exceed a value of 0.4. The efficiency factor was fixed at 0.3 until 2008, when it was changed to 0.65:

$$R_t = R_{t-1} \cdot (1 + CPI - X) \cdot (1 + \Delta D \cdot Fe)$$

For those distributors operating before 1998, the reimbursement was calculated on the basis of the previous remuneration in 1997. We should note that remuneration is calculated for the entire distribution system. In 1999, for the first time, reimbursement for the distribution of electricity was established in conformity with the new LSE, along with the methodology for sharing it among the different distributors in succeeding years. Theoretically, the sharing criteria were based on the reference network. However, the methodology was curtailed in practically every period, and one may reasonably suspect that the percentage shares were merely agreed upon by the companies and the ministry in the absence of solid knowledge about the criteria upon which they were based. In any case, the methodology had some clear problems:

- It did not provide any incentive to the distributor since it does not fulfill basic regulatory principles, such as (i) individual treatment of companies; (ii) the link between remuneration and quality; and (iii) the link between real and necessary investment and compensation.

  The reimbursement scheme did have one incentive – a rise in demand did not imply a proportional rise in income. The efficiency component

67 This is the network needed to link the transmission network with all high, medium-and low-voltage customers. It is calculated on the basis of planning criteria, minimising the investment-losses binomial while certain supply-quality standards are fulfilled. The latter are represented by the drop in voltage and the number of power cuts per customer. Grifell-Tatjé and Lovell (2003) analyse the application of this reference network under the LSE. In Spain, the reference network follows a model proposed by one of the electricity companies, Hidrocantábrico, known as BULNES. Other countries that at some point adopted reference-network models are Sweden (Larsson, 2003) and Chile (Rudnick and Rainieri, 1997).

68 In 2004, this incentive could not be higher than €50 million. In 2005, that amount increased to €80 million. Between 2006 and 2008, it was €90 million.

of the revenue mechanism relies on the possibility for the regulator to arbitrarily fix the weight of the demand increase (Fe) as long as it was less than 40% (Crampes and Fabra, 2005). Therefore, the estimates of the increase in demand did not take into account the territorial differences in demand growth. But by setting this limit the regulator assumed the presence of very large scale economies in the sector, an assumption that runs against empirical evidence in the literature, which indicates that scale economies are rapidly becoming exhausted in distribution (see, for example, Salvanes and Tjotta, 1994). Moreover, the reward mechanism did not explicitly encourage investment, so that distributors were adapting to higher demand without developing their facilities. This factor signalled a very significant change in the MLE, with investments coming to be compensated as soon as they were acknowledged by the regulator. The new situation could make distributors more efficient in the short term, when facilities are oversized, but could be harmful in the long term if it leads to structural congestion. Additionally, if the growth rate in demand is not the same for every distributor, some will be overcompensated and others undercompensated.

- The productivity growth factor, calculated as the ratio between the variation in investments and variation in demand, is not a proper productivity estimator associated with the CPI.

- The quality incentive could distort companies' investment plans and serve as an incentive to invest less in areas where quality was lower.

- The regulation did not specify the period over which the compensation base was to be revised or the formula for updating this compensation base, nor did it mention the parameter for correcting the CPI. Neither the criteria that justified the determination of this value nor the efficiency factor for each year explicitly identified.

Based on this schematic analysis, under the MLE and LSE the regulation of electricity distribution in Spain faced a fundamental problem – uncertainty. The MLE introduced numerous changes, a trend that continued or even increased under the LSE. Moreover, the process used to determine the regulated prices was far from transparent. Electricity rates were not based on the cost-allocation methodology; instead, they were determined on an *ad hoc* basis within government-prescribed limits to meet macroeconomic targets.

Electricity sector law (LSE) II: 2009–10.

From 2001, the electricity companies pressured the regulator to modify the remuneration methodology used for distribution. Royal Decree 222/2008 represented an attempt to solve some of the existing problems by establishing a new methodology that was a huge step forward compared with its predecessor, in the sense that it reimburses distributors individually rather than calculating a total sector payment to be divided among companies after the fact.

Under the methodology adopted in 2008, each company's remuneration is renewed on the basis of its own demand instead of on average system-wide demand. In other words, the efficiency factor is calculated individually for each company. The regulation is reviewed every four years.

A reference model is applied, which should be based on these two models: (i) A 'zero base reference network' that connects customers with transmission (or distribution) networks. This network is mainly used for calculating the reference remuneration at the beginning of a regulatory period. (ii) An 'incremental reference network' for new customers that takes into account either horizontal or vertical expansion of demand, given the existing network.

The reference remuneration level for distribution company, *i*, in the baseline year is proposed by the regulator (CNE, the national energy commission) and approved by the ministry for each regulatory period. It is calculated as follows:

$$R^{i}_{base} = CI^{i}_{base} + COM^{i}_{base} + OCD^{i}_{base}$$

where (i) CI^{i}_{base} is the remuneration for investment, calculated as the sum of the straight line linear depreciation term for fixed assets and a remuneration term for net assets for each distributor (return on assets) calculated with a weighted average cost of capital (WACC) that is representative of distribution activities;[69] (ii) COM^{i}_{base} is the remuneration for operating and maintenance costs of the network facilities according to their typology and use, with a yardstick factor being applied to these costs;[70] and (iii) OCD^{i}_{base} is the remuneration for other distribution costs such as commercial management costs or metering, access, and connection to the network, as well as network planning and energy management, a yardstick factor being also applied to these costs. To determine the increase in investment and operating and maintenance costs, the incremental reference model is applied.[71]

The annual remuneration for distribution activities for each distributor, i, during the four years of the regulatory period is determined using the following formula:

69 Royal Decree 222/2008 does not specify the methodology to be used to calculate the capital base. Most likely, the reference network will play a relevant role in determining it.

70 So far, it is not clear how the unitary operating and maintenance costs are going to be calculated and what the yardstick factor will be.

71 The reference remuneration level used to calculate the remuneration of distribution activity "*i*" for regulatory period 2009–12, is adjusted according to the following formula: $R^{i}_{0\text{-}2008} = R^{i}_{2007} \cdot 1,028 \cdot (1 + \Delta D^{i}_{2007} \cdot Fe^{i})$.

$$R^i_0 = R^i_{base} \cdot (1 - IA_0)$$

$$R^i_t = (R^i_{t-1} - Q_{t-2} - L_{t-2}) \cdot (1 - IA_t) + Y^i_{t-1} + Q^i_{t-1} - LR^i_{t-1}$$

where IA_t is the weighted index price corrected for efficiency.[72] Additionally, $Y^i_{t\text{-}1}$ represents the increases in revenue derived from the increase in the number of customers or connections.[73] Finally, $Q^i_{t\text{-}1}$ can have a positive or negative value reflecting either a reward or a penalty to each distributor based on the degree to which they achieved the established quality objectives in the previous year.[74] Similarly, $LR^i_{t\text{-}1}$ is a reward or penalty term applicable for reducing network losses.[75] Therefore, the system for resetting remuneration is based on investigating the efficiency of each company using the last recorded actual costs and setting efficiency targets for the next regulatory period.

Methodology

Caves *et al*. (1982) introduced a productivity index based on the work of Malmquist (1953). Their productivity index required that the observations under evaluation be either revenue maximisers or cost minimisers. Farë *et al*. (1994, 1992) generalised the method by allowing for inefficiency. When inefficiency is permitted, the Malmquist index can be expressed as the ratio of two distance functions. An input distance function as defined in Shephard (1970) is the potential radial contraction of a firm's input vector up to the input set isoquant (boundary), given an input vector $x^t = (x^1_t, \dots, x^t_K) \in \mathbb{R}^{K+}$ and an output vector $y^t = (y^1_t, \dots, y^t_M) \in \mathbb{R}^{M+}$ at time t=1,…, T. Formally, an input distance function is defined as follows:

$$D^t_I = max\{\Phi : (x^{i,t} / \Phi) \in L^t(y^{i,t}, x^{i,t})\}, \quad t = 1, \dots, T \tag{1}$$

where $L^t(y^{i,t}, x^{i,t})$ is the feasible production technology, defined as:

$$L^t(y^{i,t}, x^{i,t}) = \{x^{i,t} \text{ can at least produce } y^{i,t}\}, \quad t = 1, \dots, T \tag{2}$$

by definition, the input distance function is homogenous of degree +1 in inputs, non-decreasing in inputs, and non-increasing in outputs (Khumbakar and Lovell, 2000). It is assumed that $D^t_I(y^t, x^t) \geq 1$, with $D^t_I(y^t, x^t) = 1$ if x^t is located in

72 In particular, $IA_t = 0{,}2^*(CPI_{t-1} - 1 - \chi) + 0{,}8(IPRI_{t-1} - 1 - \psi)$, where *CPI* and *IPRI* are, respectively, the annual change in consumer and producer price index for equipment goods, and x and y efficiency factors which are χ=80 percentage points and ψ=40 percentage points for the period 2009–12.

73 This variation covers the increase in investment costs, operation and maintenance costs, and other costs caused by an increase in demand; it is calculated using the 'incremental reference network' model.

74 It could fluctuate between ±3 percent of R_{base}. See Annex 1 of Royal Decree 222/2008.

75 See Annex 2 of Royal Decree 222/2008.

the efficient boundary of the input requirement set, and hence it is technically efficient in the manner of Farrell (1957).

Following Coelli and Perelman (1999, 2000) and Coelli et al. (2003), the input distance function is estimated using a translog specification of L^t for a panel of $i=1,\ldots I$ producers observed over $t=1,\ldots T$ periods, in which technical progress is defined in the usual form as a trend variable (t) and z represents exogenous variables outside the control of firms but which could influence their input requirements. Thus,

$$
\begin{aligned}
lnD_I^t(x^{i,t},y^{i,t}) = {} & \alpha_0 \\
& + \sum_{k=1}^{K} \alpha_k ln\, x_k^{i,t} + \frac{1}{2}\sum_{k=1}^{K}\sum_{l=1}^{K} \alpha_{kl} ln\, x_k^{i,t} ln\, x_l^{i,t} \\
& + \sum_{k=1}^{K}\sum_{m=1}^{M} \delta_{km} ln\, x_k^{i,t} ln\, y_m^{i,t} + \sum_{m=1}^{M} \beta_m ln\, y_m^{i,t} + \frac{1}{2}\sum_{m=1}^{M}\sum_{n=1}^{M} \beta_{mn} ln\, y_m^{i,t}\, ln\, y_n^{i,t} \\
& + \gamma_1 t + \frac{1}{2}\gamma_2 t^2 \\
& + \sum_{k=1}^{K} \eta_k ln\, x_k^{i,t} t \\
& + \sum_{m=1}^{M} \mu_m ln\, y_m^{i,t} t + \sum_{s=1}^{S} \xi_s ln z_s^{i,t} \qquad i=1,\ldots,I \qquad (3)
\end{aligned}
$$

where the parameters of the function satisfy a set of restrictions as symmetry $\alpha_{kl} = \alpha_{l,k}$ with (k, l = 1, ..., K) and $\beta_{mn} = \beta_{mn}$ with (m, n, = 1, ..., M) and with homogeneity of degree +1 in inputs:

$$
\sum_{k=1}^{K} \alpha_k = 1; \qquad \sum_{l=1}^{K} \alpha_{kl} = 0, \quad k=1,\ldots,K; \quad \sum_{k=1}^{K} \delta_{km} = 0, \quad m=1,\ldots,M;
$$

and $\sum_{k=1}^{K} \eta_k = 0.$ (4)

Fuentes et al. (2001) proposed a parametric Malmquist index following the approach of Farë et al. (1994). As in Fuentes *et al.* (2001), we define the Malmquist index in period t as the ratio between two parametric distance functions corresponding to input and output vectors of the i-th firm in periods t and $t+1$. However, in line with Pantzios *et al.* (2011), our approach differs from that of Fuentes *et al.* (2001) in two respects. First, we use an input-oriented distance function instead of an output-oriented one to calculate the Malmquist productivity index. Second, we apply to the case of Spanish electricity distribution the definition of scale efficiency proposed by Ray and Desli (1997) as one of the components of the parametric Malmquist index. Thus, together with change in technical efficiency and technical change, we include a scale efficiency effect as an additional driver of growth in productivity. The product of these three components produces a parametric Malmquist index that accurately measures total factor productivity (Grifell-Tatjé and Lovell, 1995). This decomposition is shown in Table 6.1, in which the symbol (~) indicates an input distance function associated with constant return to scale (CRS).

Therefore, initially, by using the framework provided by Färe *et al*. (1997), the Malmquist index can be expressed as the product of two components: technical efficiency change (*TE*), which measures the producer's capacity to improve technical efficiency from period t to period $t+1$; and technical change (ΔTC), which measures the radial shift in the input set (measured with period $t+1$ data). We can further break technical change down into two components: (i) technical change with period t data, which measures the technical change for unchanged inputs and outputs; and (ii) a bias index to collect potential input bias, which compares shifts in the input set in period t and $t+1$ corresponding to changes in the bundle of inputs, as well as potential output bias, which compares shifts in the input set in period t and t+1 corresponding to changes in the combination of outputs between the two periods. Additionally, we can complete the decomposition of the Malmquist index by using Ray and Desli's (1997) input-oriented scale effect (*SE*), which measures the change in scale efficiency relative to period t technology using data (x^t,y^t) and (x^{t+1},y^{t+1}). We can further break down this scale effect into two components: the scale efficiency change (SEC) and the scale efficiency/input mix effect (IME), both defined in terms of an input-oriented scale efficiency measure that evaluates the productivity of an observed input-output bundle (x^t,y^t) relative to that of the technically optimal scale, for which production exhibits CRS and average ray productivity reaches its maximum. SEC, proposed by Grifell-Tatjé and Lovell (1999) and used by Balk (2001) and Pantzios *et al*. (2011), is greater (less) than one when the output bundle in period t+1 lies closer to (farther away from) the point of technical optimal scale than the output bundle of period t, given the input mix of period t – and thus scale efficiency increases (decreases). Meanwhile, according to Balk (2001), IME measures how the distance of a frontier point to the frontier of cone technology (CRS) changes when the input mix changes, conditional on the same output mix, that from period t. Thus, it measures the contribution of the change in the input mix to the change in scale efficiency. It is easy to show that when $x^t = \lambda x^{t+1}$ (with λ being a scalar equal or greater than 0), *IME* takes a value equal to one. Logically, as Balk (2001) points out, "if the technology exhibits global CRS, then *IME* is identically equal to one" (p. 169). However, insofar as the value of *IME* depends on the distance between the technologies with constant and variable returns to scale, there could be many situations other than global CRS in which *IME* = 1.

Table 6.1 *Malmquist index decomposition*

$M_I^t(y^{i,t}, x^{i,t}, y^{i,t+1}, x^{i,t+1}) = \frac{\breve{D}_I^t(y^{i,t}, x^{i,t})}{\breve{D}_I^t(y^{i,t+1}, x^{i,t+1})} = \Delta TE \cdot \Delta T \cdot SE$ $i = 1, \ldots, I$ $t = 1, \ldots, T-1$	
$\Delta TE(y^{i,t}, x^{i,t}, y^{i,t+1}, x^{i,t+1}) = \frac{D_I^t(y^{i,t}, x^{i,t})}{D_I^{t+1}(y^{i,t+1}, x^{i,t+1})}$	$\Delta TE(y^{i,t}, x^{i,t}, y^{i,t+1}, x^{i,t+1}) = exp\left[TL\left(y^{i,t}, x^{i,t}, t, z^{i,t}; \hat{\theta}\right) - TL\left(y^{i,t+1}, x^{i,t+1}, t+1, z^{i,t+1}; \hat{\theta}\right)\right]$ $\hat{\theta} = \left[\hat{\alpha}, \hat{\beta}, \hat{\delta}, \hat{\gamma}, \hat{\eta}, \hat{\mu}, \hat{\xi}\right]$
$\Delta T(y^{i,t+1}, x^{i,t+1}) = \frac{D_I^{t+1}(y^{i,t+1}, x^{i,t+1})}{D_I^t(y^{i,t+1}, x^{i,t+1})}$ $\Delta T(y^{i,t+1}, x^{i,t+1}) = \Delta T(y^{i,t}, x^{i,t}) \cdot B(y^{i,t}, x^{i,t}, y^{i,t+1}, x^{i,t+1})$	$\Delta T(y^{i,t+1}, x^{i,t+1}) = exp[lnD_I^{t+1}(y^{i,t+1}, x^{i,t+1}) - lnD_I^t(y^{i,t+1}, x^{i,t+1})]$ $= exp\left[TL\left(y^{i,t+1}, x^{i,t+1}, t+1, z^{i,t+1}; \hat{\theta}\right) - TL\left(y^{i,t+1}, x^{i,t+1}, t, z^{i,t+1}; \hat{\theta}\right)\right]$ $= exp\{[\hat{\gamma}_1 + \hat{\gamma}_{11}(t+1/2) + \sum_{k=1}^K \hat{\eta}_k lnx_k^{i,t+1} + \sum_{m=1}^M \hat{\mu}\ lny_m^{i,t+1}]\}$
$\Delta T(y^{i,t}, x^{i,t}) = \frac{D_I^{t+1}(y^{i,t}, x^{i,t})}{D_I^t(y^{i,t}, x^{i,t})}$	$\Delta T(y^{i,t}, x^{i,t}) = exp[lnD_I^{t+1}(y^{i,t}, x^{i,t}) - lnD_I^t(y^{i,t}, x^{i,t})]$ $= \exp\left[\mathrm{TL}\left(y^{i,t}, x^{i,t}, t+1, z^{i,t}; \hat{\theta}\right)\text{-}\mathrm{TL}\left(y^{i,t}, x^{i,t}, t, z^{i,t}; \hat{\theta}\right)\right]$ $= exp\{[\hat{\gamma}_1 + \hat{\gamma}_{11}(t+1/2) + \sum_{k=1}^K \hat{\eta}_k lnx_k^{i,t} + \sum_{m=1}^M \hat{\mu}\ lny_m^{i,t}]\}$
$IB(x^{i,t}, y^{i,t+1}, x^{i,t+1}) = \frac{D_I^{t+1}(y^{i,t+1}, x^{i,t+1})}{D_I^t(y^{i,t+1}, x^{i,t+1})} \cdot \frac{D_I^t(y^{i,t+1}, x^{i,t})}{D_I^{t+1}(y^{i,t+1}, x^{i,t})}$	$IB(x^{i,t}, y^{i,t+1}, x^{i,t+1}) = exp\left[\sum_{k=1}^K \hat{\eta}_k\left(\ln x_k^{i,t+1} - \ln x_k^{i,t}\right)\right]$
$\frac{SE_I^t(y^{i,t+1}, x^{i,t+1})}{SE_I^t(y^{i,t}, x^{i,t})} = \frac{D_I^t(y^{i,t+1}, x^{i,t+1})}{\breve{D}_I^t(y^{i,t+1}, x^{i,t+1})} \cdot \frac{\breve{D}_I^t(y^{i,t}, x^{i,t})}{D_I^t(y^{i,t}, x^{i,t})}$	$\frac{SE_I^t(y^{i,t+1}, x^{i,t+1})}{SE_I^t(y^{i,t}, x^{i,t})} = SEC_I^t(y^{i,t}, x^{i,t}, y^{i,t+1}, x^{i,t+1}) \cdot IME_I^t(y^{i,t+1}, x^{i,t}, x^{i,t+1})$
$SEC_I^t(y^{i,t}, x^{i,t}, y^{i,t+1}, x^{i,t+1}) = \frac{\breve{D}_I^t(y^{i,t}, x^{i,t})}{\breve{D}_I^t(y^{i,t+1}, x^{i,t})} \cdot \frac{D_I^t(y^{i,t+1}, x^{i,t})}{D_I^t(y^{i,t}, x^{i,t})}$	$SEC(y^{i,t}, x^{i,t}, y^{i,t+1}, x^{i,t+1}) = exp\left\{\frac{1}{2\beta}\left[\left(\frac{1}{\varepsilon^t(x^{t+1}, y^{t+1})} - 1\right)^2 - \left(\frac{1}{\varepsilon^t(x^t, y^t)} - 1\right)^2\right]\right\}$ $\varepsilon^t(x, y) = \sum_m^M \left[\hat{\beta}_m + \sum_{k=1}^K \hat{\delta}_{km} lnx_k^{i,} + \sum_n^M \hat{\beta}_{mn}\ lny_n + \hat{\mu}_m t\right]^{-1}$
$IME_I^t(y^{i,t+1}, x^{i,t}, x^{i,t+1}) = \frac{\breve{D}_I^t(y^{i,t+1}, x^{i,t})}{\breve{D}_I^t(y^{i,t+1}, x^{i,t+1})} \cdot \frac{D_I^t(y^{i,t+1}, x^{i,t+1})}{D_I^t(y^{i,t+1}, x^{i,t})}$	$IME(y^{i,t+1}, x^{i,t},, x^{i,t+1}) = exp\left\{\frac{1}{2\beta}\left[\left(\frac{1}{\varepsilon^t(x^{t+1}, y^{t+1})} - 1\right)^2 - \left(\frac{1}{\varepsilon^t(x^t, y^{t+1})} - 1\right)^2\right]\right\}$

Note that these decompositions require the computation of several distance functions different from $D_I^t\,(x^{i,t},y^{i,t})$ As in Perelman *et al.* (2001), we used the estimated parameters of the translog distance function in order to compute technical change and the input bias index. The definitions of these effects in terms of the estimated parameters are shown in Table 6.1.[76]

Data and econometric specification

We gathered information on the major electric distribution utilities that operate in the Spanish electricity sector throughout the period 1988–2010: Unión Fenosa (UNF), Gas Natural-Fenosa (GN-UNF), Hidroeléctrica del Cantábrico (HC), Iberduero (IBE), Hidroeléctrica Española (HDE), Iberdrola (IB), Hidroeléctrica Ribagorzana (ENHER), Eléctricas Reunidas de Zaragoza (ERZ), Eléctrica del Viesgo (EV),[77] Fuerzas Eléctricas de Cataluña (FECSA), Hidroeléctrica de Cataluña (HECSA), and Sevillana de Electricidad (CSE). The result is an unbalanced data panel made up of 149 observations. The unbalanced nature of the panel reflects the intense concentration process that took place in the Spanish electricity sector during the period analysed. In 1991, the merger of Iberduero and Hidroeléctrica Española, the largest companies in 1990, gave rise to Iberdrola. Between 1996 and 1999, ENHER, ERZ, EV, FECSA, HECSA, and CSE all merged into ENDESA, until then the largest Spanish electricity generation company and, after the integration process, the largest complete cycle company.[78] Finally, in 2009, Unión Fenosa merged with the largest Spanish gas company, forming Gas Natural-Fenosa.

The most important factors affecting electricity distribution are, on the output side, the amount of energy distributed, the total number of customers served, the dispersion of consumers in the service area and the size of the distribution area; and, on the input side, the building and maintenance of tangible assets, in particular distribution lines, mains, and transformers. Because of the high correlation between these variables and the small number of observations, it is not possible to introduce all these variables into the model specification. Additionally, some of them could be considered exogenous in the sense that they are beyond the control of companies, while still affecting companies' technology and relative efficiency. In order to solve the multi-collinearity problem and take into account the exogenous nature of some of the variables, we decided to use for the model the number of customers per kilometre of distribution network as an

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76 One important difference from the framework used by Perelman *et al.* (2001) is the fact that we incorporate a control variable in the estimation procedure.

77 In 2002, Electra Viesgo was acquired by the Italian company Enel in 2008, it was acquired by E.ON. Unfortunately, neither Enel nor E.ON offer separate information for their subsidiary Viesgo in Spain.

78 Two important additional changes took place in the sector during the period analysed. The asset exchanges between companies in 1994 and the operation exchanges between the companies and REE, the public high-voltage transport corporation. In Spain, since 1985, transmission has been carried out by REE, which today owns all the transmission assets, but during the period under analysis some of the high-voltage lines were owned by the other companies and considered part of their distribution business for the purposes of revenue allocation.

exogenous determinant of technology.[79] The introduction of this variable into the model, in combination with the energy distributed, is necessary because input and output mixes vary notably depending on customer density. In particular, capital density varies substantially across customer density quintiles (Coelli *et al*., 2012).

Therefore, our model includes one output – electricity distributed to end customers, measured in GWh (y) – and two inputs – capital (x_1) and labour (x_2). We estimated the company's amount of capital by means of an indirect approach similar to the method of depreciated replacement value.[80,81] Labour input is proxied by the personnel cost attributed to the distribution activity, measured in constant 2010 euros. As mentioned above, we included the number of customers per kilometre of distribution network as a control variable (z).[82] Annual reports from the electricity companies furnished the information on these variables.[83]

Table 6.2 offers the descriptive statistics on these variables and clearly shows the intense concentration of the sector over the period, especially during the years preceding the liberalisation process. This concentration and privatisation of public companies is a particular feature of the Spanish liberalisation process. Also noteworthy is the coexistence of large and small companies operating within the sector, especially after the consolidation of the sector. Another interesting fact is the slowdown in the pace of capital growth during the early years of liberalisation after an expansive period while the MLE was in force. We can also observe the effect of the financial crisis, which is reflected both in the capital strategy of companies that disinvested in 2009–10 and in the decrease in the amount of energy distributed. Finally, a moderate increase in labour costs can be noticed throughout the period under consideration.

79 The problem of this small dataset has to be borne in mind when interpreting the results.

80 Coelli et al. (2003) show that the depreciated replacement value gives a more accurate measure of capital than the depreciated nominal capital stock, which is more common in applied studies because it introduces lower disparity between the companies owing to their different investment profiles.

81 Thus, we take as a starting value the net tangible assets of 1988, published by the utilities. To construct the capital stock for period t (x_l^t), we first discount the annual asset depreciation from the capital stock existing at the end of the previous period (x_l^{t-1}). To do this, we use the average depreciation rate of the electricity sector for the distribution activity (δ) computed from the annual reports of the industry association UNESA (the Spanish Electricity Industry Association, comprising the major electricity companies in the country). Second, this value is updated by the annual capital inflation rate by means of the deflator of gross fixed capital formation reported in the national accounts of Spain (f). Third, we add the investment made by the company in year t (I_t). Finally, capital stock is valued at constant 1988 prices by applying the deflator f cumulatively from 1988 to year t (f_{1988}). Thus, the amount of capital employed by a distribution company in year t valued at 1988 prices ($x2t$) is calculated as: $x_1^t = [(x_l^{t-1})\cdot(1-\delta_t)\cdot(1+f_t)+I_t]/(1+f_{1988}) \quad t = 1989, \ldots, 2010.$

82 When measuring outputs it should be borne in mind that after the liberalisation process distribution companies could distribute energy to other companies' customers and vice versa. Therefore, the amount of energy distributed is not exactly equivalent to the amount of energy sold

83 Because of the vertical integration of companies, before 1997 we do not have separate information on labour costs for distribution activities. Therefore, the data for 1988–96 have been estimated based on the information on tangible assets and employees included in the companies' annual reports. This shortcoming must be taken into account when interpreting the results.

Table 6.2 *Statistics*

Regulatory period	Year	Number of companies	Energy distributed (Kwh)			Deflated capital (millions)			Labour cost distribution (millions 2010 euros)			Customers/Kms		
			Min	Ave.	Max	Min	Ave.	Max	Min	Ave.	Max	Min	Ave.	Max
MLE	1988	10	2.333	11.033	22.951	173	634	1.265	32	90	147	21.21	39.21	55.85
	1989	10	2.440	11.698	24.173	187	703	1.512	31	102	175	19.89	39.01	55.70
	1990	10	2.985	12.027	24.173	209	722	1.548	33	106	162	19.13	38.03	55.38
	1991	9	3.032	14.529	53.593	212	679	1.376	38	146	565	18.76	37.08	55.40
	1992	9	2.969	14.719	54.303	220	739	1.628	40	155	616	18.69	36.76	55.68
	1993	9	3.031	14.656	53.659	226	781	1.827	43	157	605	18.21	36.50	55.84
	1994	9	3.140	15.136	51.896	279	833	1.518	33	158	559	18.03	38.20	53.28
	1995	9	3.345	15.828	54.163	276	875	1.677	35	160	554	18.24	37.46	55.92
	1996	9	3.424	16.217	54.746	377	1.043	2.146	37	174	582	20.22	37.44	60.23
	1997	8	3.682	18.479	57.431	334	1.319	2.666	38	157	504	20.00	35.69	60.26
	Ave.	9	3.038	14.432	45.109	249	833	1.716	36	141	447	19.24	37.54	56.36
LSE (I)	1998	9	3.898	25.647	74.043	336	1.941	6.247	40	212	689	19.94	35.12	59.75
	1999	4	7.208	44.898	78.837	391	2.869	6.418	39	311	615	28.63	34.40	40.34
	2000	4	7.545	47.985	83.783	393	2.916	6.619	38	265	537	29.03	32.95	40.86
	2001	4	7.919	50.064	85.779	397	2.892	6.429	34	248	486	29.01	34.08	41.34
	2002	4	8.375	50.684	85.080	422	2.824	6.340	35	231	421	29.47	34.45	41.98
	2003	4	8.659	54.642	91.970	425	2.714	6.022	37	224	420	29.46	35.24	44.15
	2004	4	9.002	57.210	96.088	410	3.361	8.538	28	227	442	29.55	35.59	44.66
	2005	4	9.247	59.953	101.268	407	3.641	9.488	28	263	582	29.52	35.58	44.27
	2006	4	9.535	61.852	104.383	411	3.892	10.252	28	249	527	29.80	35.96	44.48
	2007	4	9.650	63.664	107.359	420	4.181	10.972	26	245	528	29.34	36.19	45.57
	2008	4	9.665	64.989	109.096	457	4.552	11.882	25	246	514	29.41	35.68	43.56
	Ave.	4	8.246	52.871	92.517	406	3.253	8.110	32	247	524	28.47	35.02	44.63
LSE (II)	2009	4	9.130	64.336	115.467	502	4.222	9.955	22	292	756	29.44	35.48	43.00
	2010	4	9.363	65.524	117.670	504	4.166	9.525	23	275	616	28.86	36.18	45.55
	Ave.	4	9.247	64.868	116.569	503	4.194	9.740	23	283	686	29.15	35.83	44.28

An approach such as the one offered by parametric distance functions and Malmquist indexes is clearly appropriate for electricity distribution firms. Additionally, the translog function is a suitable form insofar as it offers desirable properties such as flexibility, ease of derivation, and the possibility of imposing homogeneity. Bearing in mind that electricity distribution companies have a statutory obligation to meet demand for electricity, it is appropriate to assume that outputs are exogenous and inputs are endogenous (Jasmab and Pollit, 2000). Taking advantage of the homogeneity property for the econometric estimation of the input distance function, we follow Lovell *et al.* (1994) and arbitrarily select one input, (labour, x_2), as the dependent variable and as the variable of normalization of the other input, capital (x_1). Therefore, we have modelled the distance function *i,t* in the following way:

$$D_I^t(y^{i,t}, x^{i,t}) = x_2^{i,t} \cdot lnD_I^t(y^{i,t}, x_1^{i,t} / x_2^{i,t}), \tag{5}$$

or, taking logarithms:

$$lnD_I^t(y^{i,t}, x^{i,t}) = lnx_2^{i,t} + lnD_I^t(y^{i,t}, x_1^{i,t} / x_2^{i,t}) \tag{6}$$

Then, equation (3) can be written as:

$$lnD_I^t(y^{i,t}, x^{i,t}) = lnx_2^{i,t} + TL(y^{i,t}, \tilde{x}_1^{i,t}, t; z, \theta) \tag{7}$$

with *TL* indicating the translog distance function (3), or equivalently:

$$-lnx_2^{i,t} = TL(y^{i,t}, \tilde{x}_1^{i,t}, t; z, \theta) - lnD_I^t(x^{i,t}, y^{i,t}) \tag{8}$$

where, in our case, $\tilde{x}_1^{i,t} = x_1^{i,t} / x_2^{i,t}$, $i = 1, \ldots, I$ and $t = 1, \ldots, T$. Since $lnD_I^{i,t}(y^{i,t}, x^{i,t})$ is unobservable, we can write $-lnD_I^{i,t}(y^{i,t}, x^{i,t}) = u_{i,t}$ (Coelli and Perelman, 1999; 2000), where $u_{i,t}$ is a one-sided, non-negative error term representing the stochastic shortfall of *i* company's output from its production frontier owing to technical inefficiency. Then, we can rewrite the input distance function model as:

$$-lnx_2^{i,t} = TL(y^{i,t}, \tilde{x}_1^{i,t}, t; z, \theta) + u_{i,t} + v_{i,t}, \tag{9}$$

where $v_{i,t} \sim \mathrm{N}(0, \sigma_v^2)$ is a symmetrically distributed error term that represents data noise, while $u^{i,t}$ corresponds to the one-sided error term that captures inefficiency. In this application, $u^{i,t}$ is assumed to follow a half-normal distribution. It is also assumed that v_{it} and u_{it} are distributed independently of each other. Thus, the econometric specification of the parametric input distance function would be as follows:

$$-lnx_2^{i,t}=\alpha_0+\alpha_1 ln\ \tilde{x}_1^{i,t}+\frac{1}{2}\alpha_{11} ln\ \tilde{x}_1^{i,t} ln\ \tilde{x}_1^{i,t}+\delta_{11} ln\ \tilde{x}_1^{i,t} ln\ y_1^{i,t}+\beta_1 ln\ y_1^{i,t}$$
$$+\frac{1}{2}\beta_{11} ln\ y_1^{i,t}\ ln\ y_1^{i,t}+\gamma_1 t+\frac{1}{2}\gamma_2 t^2+\eta_1 ln\ \tilde{x}_1^{i,t} t+\mu_1 ln\ y_1^{i,t} t+\xi_1 z_1^{i,t}+v^{i,t}$$
$$+u^{i,t} \tag{10}$$

The technical efficiency score is then computed as $E[\exp(-u_{i,t}|v_{i,t}+u_{i,t})$. From here, the input distance function is the inverse of the technical efficiency computed.

The additive and non-interactive specification of the *z* variable implies the assumption that it simply shifts the input distance function and therefore provides *net* efficiency estimates (Coelli et al., 1999; Saal and Parker, 2005).

Table 6.3 *Parametric input distance function estimation*[a]

	Variables		Maximum likelihood parameters		
			Coefficient	Std. Dev.	t-ratio
	Intercept	$\hat{\alpha}_0$	0.333	0.047	7.145**
Inputs	ln x_1	$\hat{\alpha}_1$	0.381	0.095	3.999 **
	(ln x_1)^2	$\hat{\alpha}_{11}$	- 0.013	0.317	-0.040
Outputs	ln y_1	$\hat{\beta}_1$	-0.963	0.024	-39.275**
	(ln y_1)^2	$\hat{\beta}_{11}$	0.058	0.058	0.997
Inputs-outputs	(ln x_1)(ln y_1)	$\hat{\delta}_{11}$	-0.295	0.051	-5.760**
Technical change	T	$\hat{\gamma}_1$	0.062	0.009	6.821**
	t^2	$\hat{\gamma}_{11}$	0.005	0.001	5.049**
	(ln x_1)t	$\hat{\eta}_1$	-0.033	0.025	-1.324
	(ln y_1)t	$\hat{\mu}_1$	0.004	0.006	0.672
Control variable	z_1	$\hat{\xi}$	-0.006	0.076	-0.084
Other ML parameters		$\hat{\sigma}^2$	0.127	0.013	9.788**
		$\hat{\gamma}$	0.982	0.033	29.555**

Notes: **indicates that estimates or test statistics are significant at the 1 percent level. Number of observations: 149. Coefficients for the input used for normalization (x_2): ln x_2 = 0.619; (ln x_2)^2 = 0.013; (ln x_1)(ln x_2) = 0.013; (ln x_2)(ln y_1) = 0.296; (ln x_2)t = 0.033. LRχ^2 test on one-side error = 6.4.

Empirical results

Input distance function estimation

Table 6.3 shows the results of the input-oriented distance function estimation. From a methodological standpoint, the results seem to indicate that the maximum likelihood coefficients are accurately estimated. Technical inefficiency is correctly identified within the error term composed: (i) the LR test on the one-side error is highly significant; ii) the share of technical inefficiency in total variance is high $\hat{\gamma} = 0.982$; and (iii) the expected mean efficiency, $E[\exp(-u) \setminus \varepsilon]$, is equal to 0.757.

The magnitude and highly significant first-order coefficient on energy distributed ($\hat{\beta}_1 = 0.963$) reveal that this output has, as we could expect, an extraordinary impact on the increase in input requirements: inputs increase almost proportionally to output. However, the second-order coefficient ($\hat{\beta}_{11}$) is not statistically significant. The coefficient and significance of $\hat{\alpha}_1$ (0.381) would suggest that, as expected, as the relative level of fixed capital increases (or decreases) so does the magnitude of labour requirements, albeit by a smaller proportion. The statistically significant estimate of $\hat{\gamma}_1$ and $\hat{\gamma}_{11}$ would indicate a rate of technical change of 6.2% per year with an estimated rate of technical change growing by 0.5% per year. However, technical change seems not to significantly affect either the input or the output elasticities. Finally, we can observe that, as expected, the impact of customer density on the estimated model is negative, although it is not significant. Therefore, the input requirements are not significantly affected by variations in customer density. An initial overcapacity in the distribution system could explain this result.

Malmquist index decomposition

Table 6.4 sums up the main results of the Malmquist index decomposition, which are presented in average values per year. In Table 6.4, the second column shows that the average technical efficiency scores have been around 0.767 over the period analysed. Average efficiency declined substantially under the MLE. During the first few years of the liberalisation period, technical efficiency rose rapidly until 2004 and then worsened steadily. The sector was 26.4% less efficient in 2010 than in 1988. Additionally, we can observe that the variation in the technical efficiency rating is moderate, with the average standard deviation being around 10%. Our results show an inverse relationship between concentration and efficiency levels.

The third column of Table 6.4 shows estimates of Malmquist productivity indexes with constant returns to scale technology. The indexes are on average over unity and, therefore, it seems that over the period reviewed the average productivity in the Spanish electricity distribution sector increased by 3.3% annually, on average. In the first regulatory period, when the MLE was in force, we can see a widespread, though moderate, improvement. However, during the liberalisation stage, we can observe two clear periods. In the first period (1997–2008), the sector increased its productivity sharply, while in the second it underwent a significant decline, losing 20.3 percentage points of productivity in only two years.

The fourth, fifth, and sixth columns of Table 6.4 show the contribution of technical efficiency change and technical change to the growth in productivity, the latter being broken down into its two drivers according to the approach presented in Table 6.1: technical change, with period *t* data; and the bias index, which collects and input and output bias.[84] We can see a continuous rise in technical change that has managed to offset the general worsening of technical efficiency change. While the former grew at an average annual rate of 5.6%, the latter declined at an average rate of 2.0% per year. This balance was especially prominent during the second part of the MLE (1991–96) and the last part of the LSE (2005–10). Considering the components of technical change, we could not say that the positive technical change has been associated with the bias effect – that is, specific combinations of inputs (capital and labour). Indeed, this result is in accordance with the lack of significance of the corresponding estimated parameter.

Therefore, the technical change component has been the main source of improvements in the sector. That is, distribution companies have managed to satisfy electricity demand with relatively fewer resources. In this sense, we should bear in mind that during the first stage of the LSE, there was no a link between companies' investment effort and remuneration. This fact, together with an overcapacity in the distribution system inherited from the previous regulatory framework, the MLE, allowed the companies to slow down their capital investments and to adjust their labour force and still manage to satisfy demand without major compromises in quality. In this context, we can see that from 1998 to 2004 there is an improvement in efficiency as well as positive technical change. It seems paradoxical, however, that, after that point, efficiency levels declined while technical change increased, in particular in the later years of our study. During those years, input requirements were adjusted as companies tried to weather the economic crisis and subsequent decreases in demand. However, in an industry like electricity distribution, the speed with which inputs, particularly capital, are adjusted to demand is fairly limited, insofar as companies must not only maintain their installations but also expand their investment to serve new customers and increases in local demand. As a result, the inefficiency of the industry increases.

It is worth noting that during the years in which demand underwent important contractions, the recent reforms in the regulation were already in force. As explained earlier, since 2009, companies' investments have been reimbursed according to the reference model instead of the variation in activity of the system as a whole. Under the previous regulatory system, as we also saw, the drop in demand would have meant a decrease in companies' reimbursement, which in our view not only would discourage necessary investments but could also, as a consequence, negatively affect the quality of service, which was not specifically considered under the previous system. Furthermore, we should recall that the Gas-Natural–Union Fenosa merger took place in 2009 and had a major impact on the relative performance of an industry that was already highly concentrated.

84 Farë *et al*. (1997) show that the condition of one output is not enough to make the output bias equal to one. Constant returns to scale technology is required. Our results show that the output bias is on average equal to one (1.0002) but not exactly one. The main component of the bias is the input bias, although it is also very close to one on average (0.9983).

Table 6.4 *Technical efficiency and Malmquist index decomposition (arithmetic means)*

Year	Technical efficiency	Malmquist Productivity Index	Efficiency change	Technical change (t)	Bias index	Scale effect (SE)	Scale efficiency change (SEC)	Input mix effect (IME)
1988	0.785							
1989-88	0.782	1.016	1.004	1.011	1.001	1.025	1.002	1.023
1990-89	0.814	1.072	1.053	1.017	1.000	0.990	1.002	0.987
1991-90	0.812	1.040	1.016	1.024	0.999	0.987	1.003	0.984
1992-91	0.785	0.994	0.964	1.033	0.999	0.978	1.002	0.977
1993-92	0.765	1.011	0.975	1.037	1.000	0.974	1.000	0.975
1994-93	0.717	0.975	0.939	1.042	0.996	1.035	1.006	1.029
1995-94	0.696	1.031	0.989	1.043	1.000	0.957	1.002	0.955
1996-95	0.615	0.923	0.884	1.048	0.996	0.993	1.001	0.992
1997-96	0.687	1.158	1.113	1.049	0.992	0.938	1.002	0.937
Average MLE	0.746	1.024	0.993	1.034	0.998	0.986	1.002	0.984
1998-97	0.668	1.049	1.004	1.046	0.998	1.022	1.000	1.023
1999-98	0.780	1.133	1.074	1.056	0.998	0.965	1.007	0.959
2000-99	0.869	1.200	1.137	1.059	0.996	0.969	1.004	0.966
2001-00	0.902	1.102	1.042	1.060	0.998	1.008	1.000	1.008
2002-01	0.895	1.056	0.994	1.063	1.000	1.003	1.000	1.003
2003-02	0.901	1.094	1.024	1.068	1.001	0.962	0.999	0.963
2004-03	0.921	1.105	1.034	1.074	0.995	1.058	1.000	1.058
2005-04	0.810	0.942	0.876	1.074	1.002	0.971	0.999	0.972
2006-05	0.791	1.057	0.980	1.081	0.998	1.009	1.000	1.009
2007-06	0.767	1.044	0.966	1.084	0.997	1.014	1.000	1.015
2008-07	0.699	0.989	0.914	1.086	0.997	1.046	1.000	1.046
Average LSE (I)	0.819	1.070	1.004	1.068	0.998	1.003	1.001	1.002
2009-08	0.653	0.790	0.726	1.087	1.003	1.067	1.000	1.066
2010-09	0.521	0.944	0.863	1.089	1.003	0.891	0.996	0.894
Average LSE (II)	0.587	0.867	0.795	1.088	1.003	0.979	0.998	0.980
Mean	*0.767*	*1.033*	*0.980*	*1.056*	*0.999*	*0.994*	*1.001*	*0.993*
Stand. Deviat.	*0.100*	*0.089*	*0.091*	*0.023*	*0.003*	*0.041*	*0.002*	*0.041*

Finally, the scale effect (SE) is presented in column seven of Table 6.4, and its two drivers – scale efficiency change (SEC) and input-mix effect (IME) – are shown in columns eight and nine, respectively. The input-mix effect had a moderately negative contribution to scale efficiency over the entire period under consideration. Its average value indicates that scale efficiency associated with the change in the input mix decreases at an annual rate of 0.7%. This effect can be seen as residual, which may explain its inconsistent behaviour over time. By contrast, the average value of SEC – 1.001 – indicates that the radial scale efficiency associated with the output combinations (conditional upon the same input mix) was almost neutral with respect to productivity growth. That means that, given the input mix, the output bundle was close to the optimal scale over practically the entire period. This result is consistent with the first-order coefficient on energy distributed (0.963) in Table 6.3, the value – close to one – shows a technology with few returns to scale. Moreover, this component exhibited stable behaviour over time, with significant deterioration only in the last period of the LSE. We should note that the regulation in force from 1998 to 2008 reimbursed the companies as if they were operating with significant returns to scale. Our results are not in line with this assumption.

The combination of the two components, SEC and IME, results in a scale effect that slightly decreased productivity growth by 0.6% annually. Hence, the IME was damaging enough to outweigh the almost non-existent positive effect of the SEC on productivity. But the singular contribution of the IME to scale efficiency advises us to take these results with caution. One might say that the Spanish distribution network has been at least big enough and dense enough to meet increases in demand without substantial increases in inputs. Additionally, it seems that further consolidation of the sector is not justified by the quest for improvements in productivity.

Therefore, we can say that technical change has been the main source of productivity improvement of the distribution sector over the period analysed, outweighing the significant negative effect of the technical efficiency change and the detrimental (though more moderate) scale effect. However, it is noteworthy that during the first stage of the liberalisation process, productivity grew steadily and the contribution of each driver was positive. Recent consolidation processes and the economic crisis, by contrast, have negatively affected technical efficiency and the scale effect, causing significant deterioration of the sector's productivity.

The company analysis presented in Table 6.5 also shows interesting results. First of all, two of the four companies operating at present have managed to improve their productivity – HC and ENDESA. The recently consolidated company GN-UNF seems not to have been as promising as expected in terms of productivity gains. Curiously enough, some of the companies that were acquired had achieved larger productivity improvements than those obtained by the larger companies that emerged from consolidation, such as UNF and IBERDUERO (which merged with HDE into IBERDROLA). However, the formation of ENDESA could be considered successful from the standpoint of productivity improvements, although its success has not stemmed from its larger scale. In fact, we can see that for the majority of companies, technical change again has been the main source of productivity growth, while changes in technical efficiency have had, overall, a negative impact on productivity growth. The most significant improvements in technical change are seen in the largest companies, and these large companies also show an SEC effect, with values close to one. These results are consistent with the previous literature pointing to the rapid exhaustion of scale economies in electricity distribution.

Table 6.5 *Malmquist index decomposition by company (arithmetic means)*

Company	Technical efficiency	Malmquist Productivity Index	Efficiency change	Technical change	Bias index	Scale effect (SE)	Scale efficiency change (SEC)	Input mix effect (IME)
ENDESA	0.671	1.057	0.989	1.072	0.999	0.997	0.999	0.998
ENHER	0.700	1.032	0.999	1.038	0.996	1.031	1.006	1.025
ERZ	0.814	1.022	0.985	1.040	0.998	0.979	1.004	0.975
EV	0.550	1.025	0.997	1.030	0.998	1.012	1.000	1.012
FECSA	0.664	1.052	1.022	1.030	0.999	0.999	1.001	0.998
GAS NATURAL	0.804	0.697	0.645	1.068	1.012	0.640	0.988	0.648
HC	0.901	1.033	0.989	1.046	0.999	1.031	0.998	1.033
HDE	0.792	0.958	0.952	1.008	0.998	1.004	1.000	1.004
HECSA	0.680	0.991	0.968	1.024	0.999	1.003	0.999	1.004
IBERDROLA	0.807	1.061	0.982	1.084	0.997	0.918	1.007	0.912
IBERDUERO	0.963	1.060	1.045	1.014	1.000	1.005	1.001	1.004
CSE	0.784	0.992	0.955	1.041	0.998	0.989	1.005	0.984
UNF	0.746	1.042	0.998	1.045	0.999	1.004	0.998	1.005

Concluding remarks

In this chapter, we analysed the performance of Spain's electricity distribution companies over the period 1988–2010. During this period, two major regulatory regimes were in force. From 1988 to 1997, a price-cap system with some characteristics of yardstick competition was applied. In 1998, a revenue-cap system was implemented. This system was broadly modified in 2008 to amend serious deficiencies in the previous framework. The transition between the two major systems brought with it the liberalisation of the sector and a significant increase in its concentration, characterised by numerous mergers and acquisitions.

We performed our analysis by extending the parametric approach framework proposed by Fuentes et al. (2001) and estimating a translog specification for the input-oriented distance function underlying production technology.

We observed that the sector increased its productivity over the period under consideration. We detected a significant improvement after the liberalisation process; however, we cannot say that those improvements are the consequence of an adequate system of regulation – on the contrary. Distribution companies reacted to an opaque and uncertain compensation system that did not encourage capital investments and quality improvements and wrongly assumed the existence of significant scale economies. The oversized system fostered under the price-cap regime allowed companies to satisfy demand without making adequate capital investments, but also without compromising quality standards, although in recent years several episodes of blackouts have happened in some regions. This situation has made technical change the main driver of the productivity improvements in the sector.

In recent years, in spite of reforms, the sector's productivity has been severely damaged. The rigidity and, in some cases, the indivisibility of some inputs, together with the economic crisis, which has slashed demand for electricity, may explain these results. During this later period, the constant significant progress on technical change managed to offset the worsening technical efficiency change that has moved firms away from the production frontier.

It is too early to evaluate the impact of the recently introduced reforms on companies' performance, and it is possible that some of their virtues are being obscured by the consequences of the economic crisis on the electricity demand. However, from our standpoint, bearing in mind the uniqueness of the application of this system around the world, the reforms have entailed significant improvements over the previous regulatory system. However, it is crucial that authorities allow the regulatory system to function correctly and avoid the possibility of using the remuneration of regulated activities to adjust electricity prices, as the government has done in recent years. In a context in which it is necessary to push down electricity tariffs as much as possible to offset the effect of the bulky deficit of demand in the sector, improvement in the sector's performance is fundamental. It is also essential that consumers share part of these gains. Additionally, regulations should sufficiently encourage the investments that are necessary to guarantee the quality of service and to face the crucial future role that network activities will play in the development of more sustainable mixes of electrical generation and the implementation of demand response systems that respond quickly to demand.

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7

What Support Mechanism is Needed for Flexible Capacity in Belgium?

Estelle Cantillon

In the spring of 2012, Belgians were pondering the timing of the phase-out of their country's nuclear reactors.[85] A 2003 law had set 2015 as the date by which the first reactor would shut down. Much political uncertainty had remained surrounding this decision, however. Several leading politicians had repeatedly mentioned the possibility of delaying or even suspending the phase-out. The law itself contained a clause that stipulated that the exit decision could be reconsidered if the security of Belgium's energy supply was at risk.

It is in this context that the Ministry of Economic Affairs was asked in early 2012 to assess Belgium's security of supply. The ministry's report (Wathelet Report, 2012) used data on installed capacity and planned capacity additions and exits over the 2012–17 horizon to assess the country's ability to meet electricity demand.[86] It highlighted a risk of capacity shortage that, in some scenarios, would occur even before the decommissioning of the first nuclear reactors in 2015. The surprise was elsewhere, however. The report also documented increasing signs of *excess* capacity during base load – installed capacity in inflexible and 'must-run' technologies increasingly exceeded the system's minimum load.

This report, and its political use by various stakeholders, dramatically changed the nature of the policy debate around electricity in Belgium. From the 'simple' question about the ideal timing of the nuclear phase-out, the central debate became how to adapt Belgium's electricity system to a world characterised by more energy from renewable sources.

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85 This chapter builds and expands on a policy brief that the author wrote in June 2012 in the context of the debate surrounding the timing of the nuclear phase-out in Belgium. The author is grateful for the suggestions, comments and expertise that Jan Bouckaert, Claude Crampes, Eric De Keuleneer, Natalia Fabra, and Thomas-Olivier Léautier shared.

86 The report is available at: http://economie.fgov.be/fr/binaries/Rapport_moyens_production_electricite_2012-2017_20120702_FR_tcm326-186312.pdf.

In this chapter, I revisit the economic fundamentals behind the policy discussions in Belgium about the ability of liberalised electricity markets to provide adequate capacity in the presence of renewables. This discussion echoes similar debates that have been taking place in many other European countries (see, for example, European Commission, 2012). We argue that part of the *specific* problem with which Belgium is confronted is the consequence of uncoordinated policies for the support of renewables, on the one hand, and for the management of reserves and market operations, on the other.

There are many ways to guarantee a country's security of supply. However, they are not equivalent when it comes to their overall costs.[87] In order to guarantee the country's security of supply at the lowest cost, and more generally to help the transition of the country's electricity system toward a world with more renewables, I define four principles that should guide the design of a solution: neutrality between electricity demand and supply, technological neutrality, accountability, and price transparency. I then propose a specific support mechanism for *flexible* capacity that Belgium could put in place to restore incentives for flexible capacity provision, and thereby ensure the country's security of supply in the presence of renewables. The solution I propose comes down to an expanded role for the transmission system operator's (TSO) tertiary reserves, a new mechanism for allocating and activating those reserves, and new cost-sharing rules.[88]

This new mechanism has two distinctive features that ensure that security of supply is met at the lowest cost today and tomorrow. First, the mechanism optimises contributions to flexibility from both the demand side and the supply side. Contributions could come from the standard providers of flexible capacity, such as turbojets and pump storage, but it could also take other forms, such as interruptible contracts, distributed load-shedding, or another technology. Second, the mechanism uses a cost-sharing rule that provides incentives to market participants to take action and make investments that reduce the size of the required reserve.

This proposal remains preliminary in several aspects. First, several key parameters of the mechanism and some technical aspects of its operationalisation require fine-tuning. Second, an important part of the fine-tuning has to do with political arbitrages – for example, between accountability and overall costs, and between taxpayers and consumers. I highlight those political arbitrages and discuss the trade-offs that they imply.

Despite its preliminary nature, the proposal serves to illustrate:

- the implementation of the principles of neutrality, accountability, and transparency;
- the many different elements that make up the proposed flexible-capacity support mechanism and the considerations that should drive their design;

87 Independently of the equally important question of who should bear these costs.

88 Tertiary reserves refer to reserves that can be activated manually within 15 minutes.

- the different arbitrages that need to be made, and their implications; and
- the necessary coordination with other existing support and market mechanisms for electricity.

Can liberalised markets provide the necessary incentives for adequate capacity investment?

The liberalisation of electricity markets that has spread across industrialised countries since the 1990s rests on the idea that electricity production scales are small enough to ensure competition in generation and that wholesale markets can be designed in a way to foster competition while preserving system reliability (Joskow and Schmalensee, 1983; Al-Sunaidi and Green, 2006).

A central question is whether markets can both ensure efficient short-term allocation of *existing* capacity and, at the same time, deliver the appropriate incentives for capacity *investment*. In this section, I review three limitations of liberalised electricity markets in providing appropriate incentives for capacity investment: the so-called missing-money problem that has been at the core of much of the discussion in the EU around capacity-support mechanisms, market power, and the public-good nature of reserves.[89] I argue that the development of renewables exacerbates the missing-money problem and increases the role of reserves.

Three sources of market failure for electricity capacity investment

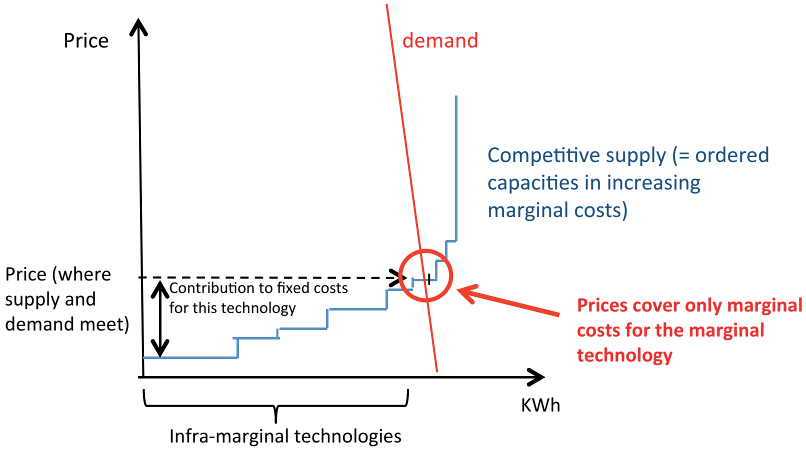
High fixed costs and the missing-money problem

Electricity generation entails high fixed costs owing to the sizable investments required before producing the first kilowatt hour. To make these investments profitable, wholesale prices must be sufficient to cover not only the marginal costs of producing electricity, but also the fixed costs. This condition may not be satisfied for all technologies in markets that rely mostly on spot (i.e., day-ahead and intraday) markets. Indeed, in a competitive wholesale spot market, competition pushes prices to the marginal cost of the most expensive technology (in terms of marginal costs) used. Thus, while infra-marginal technologies benefit from prices that are higher than their marginal costs and that contribute to covering fixed costs, this is not the case for the marginal technology (Figure

89 Under some conditions, markets and the individual pursuit of self-interest by market participants guarantee efficient outcomes. When these conditions are not met, there is a case for public intervention (which can take many forms – among them regulation, standards, taxes, and subsidies) to restore efficiency. These cases are referred to as 'market failures' because markets, left unregulated, have proved unable to deliver efficient outcomes. Given the objective of this chapter, I focus on the ability of markets to generate proper investment incentives in electricity generation capacity and leave aside other reasons for public intervention in electricity markets. For simplicity, I also take electricity demand as given and ignore the inefficiency introduced by nonresponsive retail prices (on this specific problem, see Borenstein and Holland, 2005).

7.1).[90] In practice, uncertainty about the actual number of hours a plant can hope to operate adds risks and further reduces investment incentives for the likely marginal plant.

Figure 7.1 *The failure of prices to cover the fixed costs of the marginal technology in a competitive market*



Market power and lack of competition in the generation market
Two peculiarities of electricity make its wholesale markets especially prone to the exercise of market power:

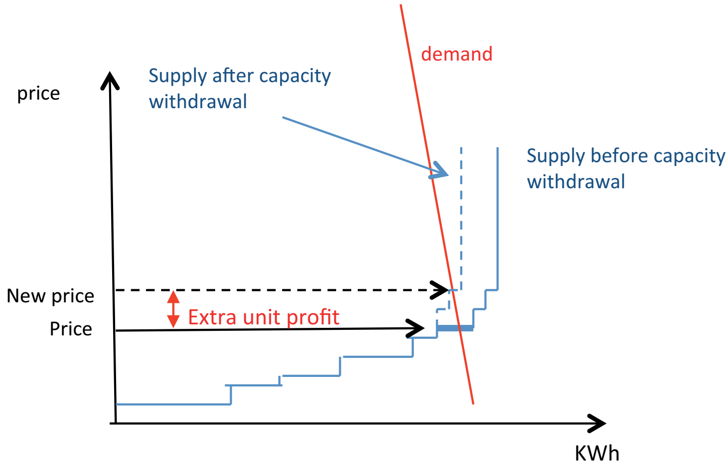
- the fact that electricity is difficult to store; and
- the inelasticity of demand in the wholesale market.

These features can make short-term withdrawals of capacity profitable; by withdrawing some capacity, a firm can significantly push wholesale prices up. The resulting extra profits that these higher prices generate for the infra-marginal capacities (that is, those units that continue to produce) more than compensate for the profits lost from the withdrawn capacities. This is illustrated in Figure 7.2, where the withdrawn capacity corresponds to the thick horizontal line. These manoeuvres are made all the more profitable by the fact that a high fraction of the wholesale market goes through the spot market, and hedging activity is small.

90 Note that this argument is independent from the often-heard argument according to which the source of the missing money problem is a price cap or political constraints on the level of spot prices (Joskow and Tirole, 2007; Léautier, 2012). The missing-money problem here arises from the different time horizon for investment and electricity production; capacity investment is sunk by the time the electricity (spot) markets operate. It would occur even in the absence of a price cap.

The perverse effects of market power are not limited to short-term capacity withdrawals, however. When a dominant firm analyses the opportunity to invest, it takes the likely effect of its investment on future electricity prices into account, and in particular on the prices at which it sells the electricity generated from its *existing* generation plants. This effect reduces incentives to invest.[91]

Figure 7.2 *Incentives for short-run capacity withdrawals*



Security of supply as a public good

A public good is a good that benefits all, in a non-rival way, without the possibility of excluding anyone from its consumption. Security of electricity supply[92] has exactly these characteristics: when the system is balanced, all benefit from its quality; when this condition is not met, all are affected by a blackout, which effectively disconnects all existing capacities (Abbott, 2001; Joskow and Tirole, 2007).

Markets do not offer proper incentives for the provision of public goods. Individual market participants (such as generation firms and retail distributors) lack sufficient incentives to contribute, on their own, to the security of supply by, for example, maintaining sufficient backup capacity in case of failure in one of their generation plants. Indeed, such backup capacities are costly, and individual market participants will not integrate the benefit they provide to the other market participants when deciding on the level of backup they want to keep.

91 Léautier (2012) argues, on the basis of a model calibrated to the French market, that market power is more important as a source of underinvestment than price caps.

92 Security of supply entails two components: the ability of the system to meet demand (adequacy) and the ability of the system to withstand sudden disturbances such as electric short circuits or unanticipated electrical plant defaults (reliability).

The public-good nature of security of supply explains why all liberalised electricity markets have a system operator that manages or ensures the availability of backup capacity.[93]

Relevance for Belgium

To what extent do these three sources of market failures (high fixed costs, market power, and security of supply as a public good) apply to Belgium? Here I argue that the current electricity market organisation and regulatory structure in Belgium provide sufficient incentives for capacity investments, *except for flexible capacity*. I further argue that the changing mix of electricity generation in Belgium calls for a broadening of the role of reserves.

Structural factors of the Belgian market that constrain the exercise of market power

The Belgian electricity generation market is dominated by one firm; the historical operator, Electrabel, has close to a 70% market share. Nevertheless, two structural factors alleviate (but do not eliminate) the problem of underinvestment in capacity that this dominance can cause.

- *Low reliance on short-term markets.* Only approximately 18% of electricity is traded through spot markets in Belgium. Most wholesale electricity is traded through long-term contracts. This reduces the effectiveness and profitability of the short-term *capacity withdrawal* manoeuvres described in the discussion of the sources of market failure.[94] Whether this argument also applies to *capacity investments* depends on the length of the 'long-term contracts' – that is, on the ability of new investments to significantly affect contract prices for current installed capacity (since this spillover is the source of the underinvestment), for which we have no information.

- *Interconnections.* Imports can provide competition for domestic producers, thereby further reducing their ability to exert market power. In Belgium, interconnection capacities stand at 3,500 MW (approximately 25% of peak load demand), and more is planned for the near future. Several signs suggest that these interconnections do play their role of increasing competition. First, wholesale prices in France, the Netherlands, and Belgium have converged over time as a result of the market coupling of power exchanges in the three countries. This is

93 Typically, part of this balancing responsibility is transferred directly to the market via balancing responsible parties (BRPs) who aggregate demand and supply in a given zone and are given financial incentives to balance their positions. The residual imbalance is covered by reserves.

94 Note that there is an open case at the Competition Commission against Electrabel for abuse of market power through capacity withdrawal between January 2007 and June 2008 (SPF Économie press release, February 7, 2013).

exactly what would be expected if imports were playing their competitive role.[95] Second, imports respond to economic forces, not to capacity problems. Belgium is a net importer of electricity, while maintaining excess capacity during peak load. This suggests that imports are cheaper than domestic production at those times and that interconnections allow market participants to engage in arbitrage and secure lower prices.

The development of intermittent renewables exacerbates the missing-money problem for flexible units

The EU has, since 2001, made electricity production from renewable sources a priority. In 2008, that priority was expressed in the so-called 20-20-20 targets: a 20% reduction in carbon, 20% of energy consumption coming from renewable sources, and a 20% improvement in energy efficiency by 2020. Belgium has committed to having 13% of its energy consumption coming from renewable sources by 2020.

To achieve the national target, the country has put in place a system of tradable green certificates that reward electricity production from renewable sources, coupled with an obligation imposed on retailers that a fraction of their sales be covered by green certificates.[96] The number of green certificates issued per MWh produced is technology-specific. It is essentially designed to compensate investors for cost differences across technologies and to ensure a sufficient financial return. Minimum price floors on the price of green certificates further reduce the risk that investors bear.

The resulting growth of renewables in the electricity production mix (14.8% of installed capacity in 2012) has changed the residual load profile that conventional electricity generation plants have to serve. Figure 7.3 shows the evolution of the residual load profile in Belgium between 2010 and 2012.[97] Residual load has systematically decreased over the past three years, reflecting the increase in electricity production from intermittent sources. The maximum load has not decreased to the same extent. In fact, the load that must be served just 1% of the time (less than 88 hours per year) increased slightly from 1,172 MW in 2010 to 1,279 MW in 2012.

95 CREG's (2012) study on the level and evolution of prices shows a convergence of average monthly day-ahead wholesale prices across the Netherlands, Belgium, Germany, and France (see, in particular, Figure 26). Küpper et al. (2009) provide evidence of convergence at higher frequency. Higher frequencies are relevant because monthly prices may converge without peak prices converging – for example, because capacities are insufficient to ensure arbitrage). In their study of hourly wholesale price differences between France, the Netherlands, and Belgium in 2007, they find prices to be the same 60% of the time and Belgian wholesale prices to be higher less than 2% of the time.

96 For the electricity producer, the price of the green certificate comes on top of whatever price it can command for its electricity in the market.

97 For the purpose of Figure 7.3, residual load was computed as the difference between the load on the high-voltage grid and the electricity produced by windmills connected to the high-voltage grid, at a 15-minute frequency (there are no other intermittent renewables connected to the high voltage grid). Decentralised electricity production from renewable sources (for example, solar panels on individual houses) is implicitly included in the net load observed on the high-voltage grid. The data come from Elia, the national TSO.

Figure 7.3 *Residual load in Belgium (in MW), as a function of the number of hours in the year it is called, 2010–12*

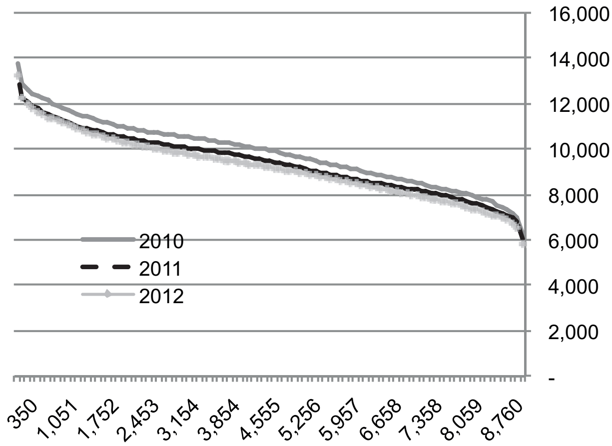
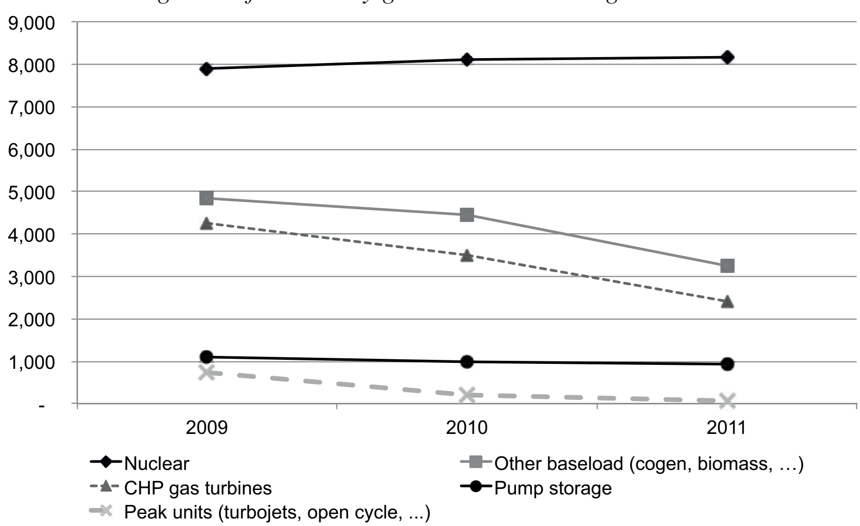


Figure 7.4 shows the consequence of this changing load profile and of the priority that renewables have in the merit order. While the average number of hours of operation of nuclear reactors in Belgium has been fairly stable in recent years (and close to the maximum of 8,760 hours), the number of hours during which combined heat power (CHP) gas turbines have been operating has decreased by more than 40% in three years. Operation times for the more expensive peak units have decreased by almost 100%.

Figure 7.4 *Evolution of the average number of hours of operation for different categories of electricity generation technologies*



Source: Belgian Energy Observatory, 2012, taken from Wathelet Report (2012).

This is where the current paradox lies: on the one hand, intermittent sources of electricity increase the need for flexible backup capacity in the system; on the other hand, their effect on prices and on operation times for flexible units actually reduces the profitability of these units. As of 2012, four gas turbines were slated to close within the next two years, three of them for economic reasons (SPF Économie, 2012, pp. 28).

Broadening the scope of application of the 'public good' argument
As argued above, security of supply – in its two dimensions of reliability and adequacy – is a public good that liberalised markets will not provide adequately.

The traditional view of reserves largely focuses on the reliability dimension of security of supply (see, for example, Hirst and Kirby, 1997). Reserves are designed to cope with unexpected events such as outages and forecast errors. The development of intermittent sources of electricity adds additional forecast errors into the system and therefore increases the levels of required reserves to ensure the reliability of the system. Elia (2013) provides an illustration of this phenomenon in the Belgian context.

There is, however, an argument for extending the role of reserves to cover the *adequacy* dimension of security of supply as well as the reliability dimension. Indeed, the structural change in the production mix that is taking place, and in particular the increasing need for flexible units and the concomitant reduction in the number of hours during which they operate (Figures 7.3 and 7.4), no longer guarantees that the *known* few hours per year during which flexible capacity will be called upon will be sufficient to cover their fixed costs. At the same time, the public good argument applies equally to the provision of capacity for these few hours: ensuring adequate supply during those few hours benefits all market participants in a largely non excludable way.[98] The role of reserves should therefore go beyond the ability to meet *unexpected* demand and supply shocks, to also secure adequacy of supply during these *few known hours* of peak load demand.

Belgium's security of supply in the broader energy policy context

In the previous section, we argued that in the Belgian context, there is an argument for expanding the role of reserves to explicitly account for the adequacy dimension of security of supply. In this section, we cast this particular issue within the broader context of electricity sector policy in Belgium and define four principles that should drive the search for a solution.

Belgium's electricity system was designed in the 1960s in the context of a vertically integrated structure. The vision then was that of a production mix relying on nuclear technology to serve the base load and on more flexible technologies to serve the rest of the load profile.

98 Priorities for disconnection can be set to avoid a full blackout.

The European energy agenda, and Belgium's commitments under that agenda, are challenging this vision. The development of renewables is decreasing the required base load and increasing the need for flexibility. This has operational and financial implications at all levels in the system.

Multiple objectives for electricity sector policy

One very simple way to summarise the problem that Belgium faces when it comes to its electricity sector policy is to say that the country is juggling four different objectives:[99]

- The *development of renewables*, as part of its commitments under the European energy agenda
- The assurance of the country's *security of supply*
- *Cost-effectiveness* – that is, the ability to achieve these two first objectives at the lowest cost for society[100]
- *Dynamic efficiency* – that is, the ability of policies to generate the proper signals to secure cost-effectiveness in the long run.

One reading of the situation highlighted in the 2012 report of the Ministry of Economic Affairs is that the country has had one set of instruments to reach the first objective (the system of green certificates and the various capacity subsidies and tax breaks) and one set of instruments to reach the second objective (the wholesale market and the TSO's system of reserves), but the two sets of instruments were not coordinated.

- On the one hand, the support mechanisms in place for renewables have ignored their impact on investment incentives for other technologies and on balancing needs. They have increased the need for flexible capacity while worsening the economic conditions for private provision of that capacity. They have also increased balancing needs.
- On the other hand, the TSO's system of reserves was not designed to deal with the impact of renewables on the system's reliability and adequacy

99 In reality, the problem is much more complex than the pursuit of these four objectives because of additional constraints and concerns. For example, the solution must be politically and institutionally feasible, it must be sufficiently simple to implement (administrative feasibility), it must be equitable (who will pay?), and it must be able to secure a smooth transition between short- and long-term objectives. We will return to some of these additional constraints and objectives when we describe our proposal.

100 Cost-effectiveness is an input to other related objectives such as industrial competitiveness (through low electricity prices) and redistribution (through low electricity prices to consumers).

requirements. More generally, market and reserve operations are largely based on the idea that supply reacts to demand, rather than the reverse.

The failure to coordinate these two instruments has introduced a number of distortions that endanger security of supply while reducing short-term cost-effectiveness and dynamic efficiency.

Four principles to guide the search for a solution

How should we solve this problem? Since we are not starting from scratch, a realistic option is to build on the existing instruments, seeking to make them more compatible with one another and better adapted to the current and future electricity production mix.

We now describe and discuss four principles that should guide the search for a solution in order to ensure that the objectives of development of renewables and security of supply are met at the lowest cost (cost-effectiveness) both today and tomorrow (dynamic efficiency).

Neutrality between electricity demand and electricity supply

Demand and supply neutrality is a principle that is relevant mainly for the security-of-supply objective. It says that the solution should not only allow both supply-side (backup capacity, storage) and demand-side (interruptible contracts, load-shifting schemes) contributions to the adequacy of supply and demand, but also that it should integrate these in a neutral way. That is, the rules for demand-side and supply-side contributions should be the same and depend only on the characteristics of the contributions (size, reliability, duration, ramp-up time, etc.), not on where they come from. (Ultimately, what we care about is adequate balance between demand and supply, *not* where the contribution comes from.)

Applying exactly the same rules to all contributions will decrease the costs of maintaining the security of supply for at least two reasons:

- Having the same rules of participation for both demand and supply contributions will foster competition (since demand-side contributions will compete with supply-side contributions).

- Rewarding equal contributions from each side equally will ensure that we select the most economical way of ensuring adequacy.

The way tertiary reserves (manual activation, maximum 15-minute ramp-up time) are currently procured in Belgium provides an illustration of the failure of demand and supply neutrality. Although tertiary reserves are made up of both supply contributions and demand contributions (the latter in the form of interruptible contracts), the call for tenders is separate for each side, and the total size of the reserve is split in advance between the supply side (approximately two-thirds of the size of the reserve) and the demand side. Moreover, while the supply-side contributions are selected on a competitive basis, the price at which demand-side contributions are rewarded is not set competitively but instead is linked to prices observed on the supply side.[101] Therefore, demand-side contributions and supply-side contributions do not compete with one another to secure the lowest cost for the reserves.

Technological neutrality

Technological neutrality means that the solution should treat technologies as a function of their contribution to the objective, not according to their names (gas, wind, nuclear, or cogeneration). The motivation for this principle is very much like the motivation for demand and supply neutrality: ensuring the largest pool of contributors and minimising costs.

Technologically neutral rules also promote innovation and therefore contribute to dynamic efficiency because *any* new ways of contributing to the objectives can automatically be accepted without requiring new rules or regulations.

One potential concern with technological neutrality is that, sometimes, new technologies may need additional support to compensate for significant adoption costs or for the learning and economies-of-scale benefits that early adopters generate for later adopters. This is fine. What the principle of technological neutrality says is that, *given an objective* (such as security of supply), all technologies that can contribute to the objective should be put on the same footing. It does not prevent having, in addition, a support scheme for new technologies to meet *another objective* (such as internalising the benefits of learning economies). In fact, the transparency principle below will advocate making these two schemes as transparent as possible with regard to the objective pursued and how the specific support meets that objective.

Belgium's system of green certificates provides an example of a support mechanism that is not technologically neutral: the number of certificates received per MWh produced is largely driven by financial cost differences across technologies rather than by their respective contributions to decreasing the carbon intensity of electricity or compensating early adopters for the benefits that they generate for later adopters.

Accountability

The principle of accountability says that market participants should be held accountable as much as possible for the effect of their actions on the objectives, *especially* when these participants have control over those actions (that is, when they can adapt or change them).[102] Actions that contribute to meeting the objectives should be rewarded. Actions that make the objectives harder to reach should be penalised.

101 See http://www.elia.be/en/products-and-services/ancillary-services/purchase-of-ancillary-services (accessed July 2013).

102 Otherwise, accountability merely induces a redistribution of the costs.

Accountability is important because it can trigger changes in actions and behaviour that help reduce costs. The following examples help illustrate the effect of accountability, or lack thereof, on costs in the context of reserves. In both examples, the action of one market participant increases the need for flexibility. This has a cost. By holding that market participant accountable for the impact of his or her action on the size of reserves, one can direct action toward less costly outcomes for society.

- *Example 1:* Consider two renewable sources of energy; one is intermittent, the other is not. Both sources contribute equally to the objective of a low-carbon economy, but the first increases the need for flexible capacity. Accountability implies that this intermittent technology should bear a greater fraction of the costs of reserves than the other. This will affect the relative profitability of both technologies in favour of technologies that do not increase the need for flexible capacity, and it will provide incentives for innovations that reduce intermittency.

- *Example 2:* Consider two large electricity consumers (industrial customers), one with a very stable load profile at peak time and one with a very variable load profile at peak time. The second consumer increases the amount of flexible capacity needed in the system, which has a cost. Accountability requires that this consumer should bear a greater fraction of the costs of the adequacy reserves, which can trigger efforts on the part of the consumer to smooth its consumption or install some cogeneration capacity for peak times.

As in most other countries, responsibility for balancing supply and demand on the Belgian grid is partly delegated to market participants. This is done through ‘balancing responsible parties’ (BRPs), which are supply-and-demand aggregators with responsibility for balancing in their predefined areas. This responsibility is coupled with penalties in the event of imbalances. The penalties help internalise the costs of their demand and supply profile on reserves and provide some elements of accountability. It is useful to note, however, that this internalisation is partial, because the penalties are based on *actual* imbalances, whereas reserve requirements are based on *potential* imbalances. Moreover, offshore wind benefitted until recently from a preferential treatment in terms of penalties (De Vos *et al*., 2011).

Price and signal transparency

As in any other market, transparent prices and signals help guide market participants’ behaviour and investments by aligning their economic incentives to actions that are desirable at the system level.

A SUPPORT MECHANISM FOR FLEXIBILITY IN BELGIUM

The transition of the Belgian electricity system toward a system that is more compatible with a high penetration rate of renewables is a long-term endeavour that will require changes at many levels – among them, the way renewables are subsidised and integrated into the market and the way demand contributes to system flexibility. In this section, we propose a solution for the flexible capacity problem that Belgium faces as a result of the development of renewables.[103] This solution takes the form of an expansion of the role of the TSO's reserves (which we will refer to as adequacy reserves) and a new mechanism for allocating and activating those reserves. The new mechanism builds explicitly on the four principles laid out in the previous section.

Overview

The idea is to secure enough flexible capacity, very broadly defined, not only to deal with accidents and forecast errors (the traditional role of reserves) but also to serve the few hours per year of very high demand when intermittent sources are not available. In other words, in our proposal, the TSO not only rewards market participants for making capacity available in case of accidents and forecast errors, as it is the case today, but also rewards some participants for making flexible capacity available to cover the known few hours per year when demand is very high or production from renewables is very low. The rationale is that explained previously: these market participants provide a public good to the rest of the system by avoiding blackouts during these few hours, but the market as it is presently configured and regulated does not compensate them for this.

How to procure this flexible capacity is critical to ensure that this capacity comes at the lowest possible cost for market participants and that proper signals are generated for future capacity investments. The mechanism we propose has two ingredients that help lower costs.

Demand- and supply-neutral and technology-neutral rules for determining who can contribute capacity and how 'capacity contributors' are selected

The idea here is to encourage participation from every possible source as long as it satisfies a few key technical conditions, such as controllability, a maximum activation lag, and minimum time availability. In other words, this capacity is likely to come from gas turbines, pump storage, interruptible contracts, decentralised load-shedding, and technologies yet to be developed. Applying the same rules to all these sources fosters competition, innovation, and the selection of the least-cost solution to the flexible capacity problem.

103 Alternatives include horizontal integration of producers of intermittent and flexible energy, contracts, and public subsidies, to cite just a few (see, for example, Ambec and Crampes, 2012). The common element in all these solutions is the idea that intermittent sources must cross-subsidise flexible sources. In our view, one merit of the proposal offered here is its ability to integrate the demand side and its scalability according to needs.

Cost-sharing rules that foster accountability
As discussed earlier, the behaviour of some market participants increases the need for adequacy reserves. The idea is to make those market participants bear a greater share of the costs of the system. This ensures that they have incentives to adapt their behaviour in ways that benefit the system as a whole.

Beyond new rules for participation, selection, and cost-sharing, the proposed mechanism also involves new rules for activation. Indeed, a part of the reserves is designed to cover *predicted* peaks in demand. This part is therefore an alternative to the spot market for the demand side (energy suppliers/distributors and large customers). In the proposed mechanism, reserves can be activated either by the TSO or from the demand side (via the TSO). Activations from the demand side are charged at full cost to the requesting party to avoid opportunistic behaviour by market participants that might be tempted to activate the reserve instead of using the spot market.

This mechanism is compatible with the other support mechanisms in place, especially green certificates. To the extent that intermittent sources of energy are, as proposed, held accountable for their impact on the required adequacy reserves, there is no longer a tension between the objectives of promotion of renewables and security of supply. Non-intermittent sources of renewables will continue to benefit from the support of green certificates; the support for intermittent sources of renewables will be corrected for their impact on the reserve requirements. This correction creates incentives for new production systems that combine intermittent sources with storage capabilities or make them less intermittent and therefore foster dynamic efficiency.

Details

In this section, we discuss in detail the various components of our proposed flexibility support mechanism: (i) the determination of the optimal size of the adequacy reserve; (ii) the definition of what should be procured; (iii) bidding rules, activation merit order, and award criteria; (iv) activation rules and settlement prices; and (v) cost-sharing. For each decision, we highlight the trade-offs at play, as well as remaining grey areas.

Size of the adequacy reserve
How large should the adequacy reserve be? Clearly, the larger it is, the lower the risk of blackout but the higher the costs. It is therefore important to assess the optimal size of the reserve.

One way to do this is to evaluate the capacity that is called less often than the minimum amount of hours per year needed to make that capacity financially viable using a given flexible capacity generation technology.

The value of this ‘unprofitable flexible capacity’ (which needs to be computed) depends on several factors, including the importance of installed intermittent capacity in the system (the more important, the larger it will be); the degree of base-load overcapacity (the higher, the larger the unprofitable capacity); the system load profile, in particular the difference between the peak demand and the base demand (the flatter and smoother, the lower the unprofitable capacity); and developments in interconnected markets. It can be scaled up or down according to changes in these drivers. In particular, any developments in the integration of demand-side management into the spot market will reduce the size of the adequacy reserve. Note also that because the adequacy reserve is also intended to cover expected peaks, its optimal size may vary across time and be larger during peak times.

What should be procured?

In the proposal, market participants are asked to offer flexible capacity over some period of time. In line with the principles of demand-supply neutrality and technological neutrality, the origin of that capacity or consumption load-shedding should not matter as long as:

- it is dispatchable within 15 minutes (the current standard for Belgium's tertiary reserve);
- its reliability has been certified by the TSO (as are all contributions to Belgium's tertiary reserve); and
- it is available for a minimum amount of time (to be determined on the basis of operational considerations).

One open question concerns the frequency of capacity tender calls and the time frame covered by these calls. There is a trade-off here. One the one hand, calls that cover a relatively long period (say, one year) and are held sufficiently in advance of the time they are used allow for greater planning by market participants. This is favourable to new investments in capacity.[104] On the other hand, commitments of such long term can be difficult to make for demand-side participants whose activity is harder to forecast. It would be worthwhile to study this trade-off closely using market data and interviews of potential participants. It may be optimal to auction part of the capacity well ahead of time and for long periods, and the other part through more frequent auctions.

Bidding rules, activation merit order, and award criteria

In the simplest form of the mechanism, participants should bid on the following items: flexible capacity available (MW), a price for making that flexible capacity available for a given period of time (€/MW per hour), a price for the actual energy used (€/MWh), and a maximum amount of time for which the capacity will be available.

The mechanism should then select the best offers to cover the adequacy reserve needs. These best offers are those that cover the adequacy reserve needs

104 To be clear, in my proposal, the rules apply equally to new and existing sources of capacities.

and minimise *expected* costs, taking into account the probability of activating each reserve. This is a fairly straightforward optimisation problem. It also yields the optimal activation rule (activation merit order) for the capacity in question.

There are two additional concerns to address. First, to ensure full technological neutrality, participants should also be able to bid on activation costs, because ramp-up is costly for some technologies. Conceptually this is simple; it makes the optimisation problem more complex only because one will now need to account for the time profile of activations and the likelihood of these activations.

The second concern relates to incentives. How can we be sure, given these award criteria, that market participants do not manipulate their bids? Ensuring enough competition is a first answer to this, which is why ensuring neutrality for demand, supply, and technology is essential. A second answer lies in carefully crafting the settlement rules (that is, the payments to be made to winning bidders), a question to which we turn next.

Activation rules and settlement prices

Because the adequacy reserve substitutes for the spot market in case of extremely high demand peaks, demand-side participants should be able to request its activation when needed.

This raises the question of how activations and energy used from the reserve should be charged to those participants to avoid abusive activations of the reserve (even when supply is available on the spot market or through imports) or opportunistic behaviour whereby demand-side participants become less prudent than today in their use of long-term contracts and the day-ahead market, thereby increasing the size of the adequacy reserve needed (and thus its costs). My suggestion is that participants requesting the activation of the reserve be charged at full cost (that is, the price of the capacity used, plus the price of the MWh drawn, plus the activation fee).

Cost-sharing and accountability

The costs of the adequacy reserve, as described here, amount to the price paid for the unused capacity (since any used capacity is charged at its full cost to the market participants that activated it). Because this adequacy reserve is a public good that benefits all market participants, it is logical that those who benefit from it should pay for it.

The principle of accountability implies that the cost-sharing rule should oblige participants whose actions increase reserve requirements to assume a larger share of these costs. Such a cost-sharing rule will foster lower costs and generate more accurate investment signals than a simple pro rata rule under which all consumers are charged according to their consumption.

In the current context, this means taking the model suggested earlier to determine the size of the optimal adequacy reserves, and applying that model to the task of assessing the required adequacy reserve induced by specific consumption patterns or production technologies. The idea is then to charge the cost of the added adequacy reserve to these specific market participants (or the relevant BRP).[105] What will remain is an incompressible adequacy reserve, the cost of which can be charged to all consumers according to their consumption or some other metric.[106]

Accountability is a politically sensitive issue. Three remarks are in order here. First, accountability is not new to electricity markets, and in particular to the Belgian electricity market, in which BRPs are incentivised to maintain balance in their respective areas. Second, accountability is useful only when market participants can adapt their behaviour as a result, for example, by smoothing their consumption or bundling their windmill-to-storage capability. It has little value otherwise (because it is only about the sharing of total costs, rather than minimising them). This can be an argument for deciding to protect some market participants from accountability. Third, it must be clear that there is a trade-off between accountability and total costs. Reducing accountability increases costs, which are eventually borne by firms, consumers, or taxpayers. If the goal is to keep electricity prices affordable, accountability should be encouraged.

Relationship with other schemes and markets

Relationship with Elia's current system of reserves

The proposed mechanism would be managed by the TSO as part of its public service obligation. Because the flexibility requirements for the adequacy reserve are essentially the same as those for the existing tertiary reserve, there is an argument for merging the adequacy reserve with the tertiary reserve (with the result that the resulting reserve would be the sum of the adequacy reserve and the tertiary reserve). Indeed, it can be difficult in practice to determine which events are supposed to be covered by the traditional role of the tertiary reserve as opposed to the adequacy reserve. Furthermore, any non-fungibility between the two reserves can only raise costs. The proposed procurement scheme (Who can offer capacity? How are offers selected?), the proposed activation rules, and the proposed cost-sharing rules differ very much from those currently in play for the tertiary reserve. They are, however, entirely compatible with the role of the tertiary reserve.

Role for interconnections

Interconnections increase the size of the 'effective market' over which demand and supply interact. This has great economic benefits: more competition and therefore lower electricity prices. At the technical level, interconnections bring

105 Note that this is a harder problem than it seems because marginal impacts may not be well-defined. The marginal impact of a windmill will be different depending on whether there is another windmill in the system whose production is not perfectly correlated with that of the first. In the latter case, the volatility in production is lower, requiring lower reserves.

106 There are many alternative possibilities, depending on redistribution concerns (making retail consumers bear less) and competitiveness concerns (making industrial customers bear less). The rule adopted does not influence the cost of the mechanism.

both costs (exposure to supply or demand shocks abroad) and benefits (lower variability of intermittent sources).

One open question concerns the potential role of interconnections and imports in the proposed flexible capacity mechanism. A priori, allowing bidding by providers of flexible capacity abroad can only decrease the costs of the support mechanism, which is a good thing. On the other hand, periods of peak demand are fairly correlated within the interconnected grid, and risks of blackouts abroad could affect the availability of imported flexible capacity. There is therefore a trade-off here between total costs and risks, which needs to be assessed, taking the capacity situation in neighbouring countries into account before deciding whether foreign providers can bid to provide flexible capacity. One possibility is to place a limit on the share of foreign flexible capacity.

Relationship with the spot market

One key consequence of the expansion of the role of reserves to account for *known* demand peaks is that the adequacy reserve becomes a substitute for the spot market. As a consequence, the reserve will necessarily put a cap on the spot price. It may also decrease volumes in the spot market, which can hurt liquidity. In our view, the proposed pricing of the reserve when activated by demand-side participants (full-costing) minimises these potential adverse effects, but the interactions between the two must be assessed and monitored carefully.

It may be useful to organise the market for reserve takeoffs via Belpex, the Belgian electricity exchange, to ease comparisons between the spot price and the reserve takeoff price and to foster transparency.

Support for renewables

The proposed mechanism is entirely compatible with the existence of another capacity support mechanism for renewables. In fact, it is designed to adapt to developments in the installed capacity of intermittent sources of electricity.

The fact that intermittent sources of energy will be charged according to their impact on reserve requirements contributes to transparency by distinguishing their contributions to the two different objectives of promoting renewables and assuring security of supply.

Absent changes to the existing system of green certificates, the proposed cost-sharing rule will tilt the balance toward non-intermittent sources of electricity within renewables or foster solutions that will transform intermittent sources into non-intermittent sources (for example, through storage). In that sense, the proposed solution will move Belgium away from the current hands-off policy regarding the optimal mix of renewable production and toward the most cost-effective mix.

Link with demand-side management

The irregularity of the load profile (the difference between base load and peak load, but also the fact that peak loads occur only a few hours per day) drives not only the need for flexible capacity but also its economic profitability (that is, how many hours it operates). Smoother load profiles contribute to lowering costs by decreasing the time during which capacities are idle. Demand-side management measures such as retail peak/off-peak tariffs have exactly this role. Any further development in the integration of demand-side contributions to the wholesale market will reduce the required size of the adequacy reserve and therefore reduce its costs.

The demand- and supply-neutral design, as well as the cost-sharing rule of the proposed flexible capacity mechanism, fosters the integration of demand-side management into the mechanism:

- The design is made to optimise contributions to flexible capacity from the demand side.

- The cost-sharing rule provides incentives to large consumers and local energy suppliers to smooth their load profiles. More generally, this cost-sharing rule fosters the integration of demand-side contributions to the operations of wholesale markets.

Epilogue

The report of the Ministry of Economic Affairs and the resulting plan that the state secretary for energy proposed to the government in June 2012 (Wathelet Report, 2012) were game-changers. Whereas, before, the debate had been cast mainly in terms of Belgium's opportunity to continue to rely on nuclear power, the talk in town became how to adapt Belgium's electricity system to a world characterised by more electricity from renewable sources. Discussions shifted from electricity production to the electricity *system*, including transmission, interconnections, production, *and* demand. This was quite revolutionary in the Belgian context.

Much has happened since then. First, Elia, the TSO, has moved from a traditional N-1 method of computing reserve requirements to a method that accounts for both supply shocks (outages) *and* demand shocks (forecast errors).[107] This is important because intermittent sources of renewable electricity increase the likelihood and size of forecast errors. Second, industrial clients, which already had been contributing to the tertiary reserve, started to participate in the operations of the primary reserve in 2013, and there are calls by the regulator and the TSO for further participation of the demand side in the operation of reserves (CREG, 2012; Elia, 2013). Third, rules for load-shedding to avoid a blackout in the event of predicted insufficient capacity were clarified. Fourth, support for solar panels and offshore wind has been adapted to correct for the windfall profits that investment in these technologies offered in a context of falling costs.

107 N-1 methods refer to deterministic methods that evaluate the size of reserve requirements in terms of the size of the largest production unit.

Other measures are being discussed, including operational standards to maximize the flexibility of new production units. There are also discussions about the possible curtailment of renewables and cogeneration units in case of overcapacity (Elia, 2013). These measures all go in the right direction, by removing obstacles to demand participation in the management of reserves and to the operations of markets, and by removing earlier distortions.

Measures under discussion to ensure electricity *adequacy* remain a sore spot, however. In the original Wathelet report, two measures were proposed to ensure adequacy:[108] the creation of a 'strategic reserve' made up of flexible units that existing operators wished to close down, and a call for tenders for the construction of new combined heat power gas turbines. Neither of these proposed measures satisfied any of the four principles that we have outlined in this chapter.[109] By focusing on generation, they did not treat supply and demand in a neutral way. By focusing on gas, they were not technology neutral. Cost audits (which are notoriously subject to manipulation), instead of competition, would determine the financial remuneration of these units. The proposed cost-sharing schemes did not encourage accountability, as the cost would be charged to consumers on the basis of their consumption, in the case of the strategic reserve, and would be financed by a charge on nuclear production, in the case of the call for tenders. These measures were heavily criticised, even by partners in the coalition.

In July 2013, the government approved a modification of the 'strategic reserve', whereby demand-side contributions by industrial clients and demand aggregators could compete with closing production units to offer capacity. This is an improvement that moves in the direction of the adequacy reserve proposed in this chapter (although details of the tender mechanism were not known at the time of writing this chapter). The government also confirmed, on the same occasion, its intention to tender 800 MW of new gas capacity. In our view, this additional mechanism would not be needed if the new 'strategic reserve/ adequacy reserve' were properly designed and sized.

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108 Beyond the fact that the plan advocated a postponement of the closure of one of the three nuclear reactors that were due to close in 2015.

109 In addition, it is difficult to ignore the political economy aspects of the announcement of these measures. Before the report, six investment projects in CHP gas turbines, for a total capacity of 4,600 MW, were at an advanced stage (Wathelet Report 2012:. 28). Once the report was released, investors stood still, waiting to be paid to play.

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