Lecture Notes in Energy 30

George Giannakidis
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Informing Energy and Climate Policies Using Energy Systems Models

Insights from Scenario Analysis Increasing the Evidence Base

Springer

Lecture Notes in Energy

Volume 30

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ISSN 2195-1284 ISSN 2195-1292 (electronic)
Lecture Notes in Energy
ISBN 978-3-319-16539-4 ISBN 978-3-319-16540-0 (eBook)
DOI 10.1007/978-3-319-16540-0

Library of Congress Control Number: 2015933834

Springer Cham Heidelberg New York Dordrecht London

Printed on acid-free paper

Springer International Publishing AG Switzerland is part of Springer Science+Business Media
(www.springer.com)

Foreword

Climate change mitigation and transformation to a global low-carbon economy is a pressing issue in policy discussions and international negotiations. The political debate is supported by the scientific community through a wide range of projections, pathway simulations, and scenario analyses of the global energy system and its development over the next decades. Achieving balance between economic competitiveness and the need to respond to climate change threats and to ensure energy security constitutes a significant challenge policy makers face today.

Efforts to develop energy models began back in the 1960s but it was the first oil crisis in 1973 that highlighted the need for analytical tools to inform strategies and sparkled the development of energy models as instruments aiming to contribute to informed decision-making in energy policy planning. ETSAP[1] was one of the multilateral technology initiatives (formally called Implementing Agreements, or 'IAs') initiated in 1976 under the aegis of the International Energy Agency, IEA, with the aim of carrying out a joint program of energy technology systems analysis. The IEA through its broad range of Implementing Agreements and the Energy Technology Network enables member and nonmember countries, businesses, industries, international organizations, and nongovernmental organizations to share research on technology-related activity that supports energy security, economic growth, environmental protection, and engagement worldwide.

ETSAP evolved from the analysis of existing tools to evaluate R&D strategies in its first year of operation to the combination of the energy flow optimization approach with macroeconomic top-down modeling, technology learning, and stochastic modeling. Today, ETSAP is a unique network of energy modeling teams from approximately 70 countries involving 177 institutions over the world, well beyond the number of its contracting parties, which are the governments of 18 countries and the European Commission.

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[1] Energy Technology Systems Analysis Program.

ETSAP's objective was (and still is) to build, maintain, and expand modeling capability in order to assist and support government officials and decision makers in creating the robustness of the evidence base underpinning energy and environmental policy issues by applying these tools for energy technology assessment and analysis. ETSAP developed through cooperation the MARKAL (MARKet ALlocation) and subsequently the TIMES (The Integrated Markal-Efom System) energy systems model generators.

These bottom-up technoeconomic models have been used in Global models like the IEA Energy Technology Perspective model, the global TIMES Integrated Assessment Model and the Global TIMES model of the European Fusion Development Agreement. At national and regional levels, MARKAL-TIMES models for countries in all continents as well as the Pan-European TIMES model were also developed. The latter was used for the evaluation of the RES Directives implementation in EU27 for 2020, an analysis of the future European gas supply, the interplay between the global goal of mitigating climate change and the European goal of reducing dependence and vulnerability of the energy system, the transmission infrastructure development to support sustainable electricity supply, the effect of a White Certificate Trading Scheme in the EU-27 and the analysis of potentials and costs of CO_2 storage in the North Sea. A large number of ETSAP applications also produced Sub-National Models, for example for Western China, Reunion Island (France), Lombardy and Pavia (Italy), Southwest region (Sweden), and Kathmandu (Nepal). Local models for rural areas and cities have been developed, e.g., Madrid (Spain), Beijing, Guangdong and Shanghai (China), and New York City (United States).

The main selling point of the ETSAP modeling frameworks is that they combine a detailed technology rich database with an economically optimizing solver, providing useful guidance into how to achieve policy decisions (e.g., emissions targets) using a least-cost approach.

This book collates together for the first time, in one volume, a range of methodological approaches and case studies of good modeling practice at national and international scale from the IEA-ETSAP energy technology initiative and demonstrates the high degree of flexibility of the ETSAP tools to represent extremely different energy systems from national to global scales. The book captures in a coherent structure the strength and breadth of energy systems modelling undertaken by ETSAP teams. Most chapters provide insights into key methodological features backed up with concrete applications. It demonstrates how energy systems models have been and are being used to answer complex policy questions relating, amongst others, to energy security, climate change mitigation, and the optimal allocation of energy resources.

I trust the readers will find within the book analysis and insights that demonstrate both the complexity and usefulness of energy systems modeling in increasing the robustness of energy and climate policy decisions.

The publication of this book in 2015 coincides with the 40th anniversary of the IEA Implementing Agreement mechanism, in existence for longer than many other international energy technology initiatives, increasingly being recognized as a time-proven, flexible, and effective means of international collaboration on energy technology and science, within and beyond IEA member countries.

January 2015

Alicia Mignone
Chair of the IEA Committee on Energy Research and Technology
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Preface

This book collates a range of methodological approaches and case study applications of good modeling practice at national and international scales from the IEA Energy Technology Systems Analysis Program (IEA-ETSAP), a collaborative network of energy modeling teams from around 70 countries that has operated for over 40 years. A key objective of IEA-ETSAP is to assist decision makers in robustly developing, implementing, and assessing the impact of energy and climate mitigation policies with the bottom-up technoeconomic models of the MARKAL/TIMES family.

The methodologies and cases studies presented in the book provide a critical understanding of the richness and width of application of energy systems models, demonstrating the underlying methods as well as the policy questions they can address. Energy engineers and technology specialists will find in the book the rationale for innovation in the field of energy technologies and insights into their evolving costs and benefits. Energy economists will gain deep insights into the key future role of energy technologies. Energy and climate policy makers as well as environmental scientists will learn about how energy systems modeling can provide unique perspectives and insights into national energy and environment challenges like climate change. Students and researchers in energy system analysis, sustainable energy, and climate change mitigation will reinforce their knowledge of energy system modeling and may find new ideas of research and applications.

The editors are grateful to the chapter authors and peer reviewers who willingly shared their expertise and contributed their valuable time, without which this book would not have been possible. In addition, the editors acknowledge the English language revision support provided by Seán Collins, Paul Deane, James Glynn, Eamonn Mulholland, Maitiú Ó Ciarain, Fionn Rogan, Clare Watson, and Evelyn Wright.

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Introduction: Energy Systems Modelling for Decision-Making

Alessandro Chiodi, George Giannakidis, Maryse Labriet, Brian Ó Gallachóir and GianCarlo Tosato

Abstract The role that energy modelling plays in improving the evidence base underpinning policy decisions is being increasingly recognized and valued. The Energy Technology Systems Analysis Program is a unique network of energy modelling teams from all around the world, cooperating to establish, maintain and expand a consistent energy/economy/environment/engineering analytical capability mainly based on the MARKAL/TIMES family of models, under the aegis of the International Energy Agency. Energy systems models like MARKAL/TIMES models provide technology rich, least cost future energy systems pathways and have been used extensively to explore least cost options for transitioning to an energy secure system and a low carbon future. This chapter presents an overview of ETSAP's history and objectives, introduces the main principles of energy system modelling and summarizes the different chapters of the book.

Policy makers face significant challenges in balancing on the one hand the drive for economic competitiveness, with the need to respond to the threats posed by climate change and ensuring energy security. Achieving this balance requires a comprehensive and cohesive set of robustly informed long term policies, targets and

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_1

strategies, combined with appropriate short and medium term action plans and measures. Increasingly, the important role that energy modelling plays in improving the evidence base underpinning policy decisions is being recognized and valued. There is a wide range (Gargiulo and Ó Gallachóir 2013) of energy modelling tools and typologies available (including simulation, optimisation, partial equilibrium, general equilibrium, sectoral demand, single technology, power system, energy system, etc.). It is important for policy analysts to understand the strengths and weaknesses of the different approaches, in order to determine which type of modelling tool is best suited to the policy question being assessed.

This book focuses on one important branch of energy models, namely energy systems models. Energy systems models provide technology rich, least cost future energy systems pathways and have been used extensively to explore least cost options for transitioning to (initially in the 1970s and 1980s) an energy secure and (more recently, in particular since 2000) a low carbon future.

This chapter introduces energy system analysis and modelling, and summarizes the different applications presented in the book: part I of the book focuses on policy insights obtained from MARKAL/TIMES models at country, regional or global levels; parts II present how to model and assess the sector specificities of the energy system, such as power, oil and end-use sectors; part III proposes model coupling to reinforce the insights obtained with energy models.

1 The IEA Energy Technology Systems Analysis Program

The first energy models developed from the 1960s were focussing on the demand and supply of a single commodity; they were soon succeeded by energy system models. Economic competitiveness and growing environmental awareness added the necessity for improved understanding of the interaction of energy systems with the environment and the economy. Since the beginning of 1970s a plethora of energy models have been developed and used to generate many energy/environment scenarios, and to undertake scientific and technical policy impact evaluations at the global, multi-regional, national and local level. These energy models are formulated using different approaches that vary in terms of model starting point and the type of questions they are designed to answer (Gargiulo and Ó Gallachóir 2013); and they are generally able to provide insights on the energy systems, which, in the absence of a modelling framework, would revert to educated guesswork. Energy models adopt theoretical and analytical methods from several disciplines including engineering, economics, operations research and management science, and apply different techniques, including mathematical programming (especially linear programming), econometrics and related methods of statistical analysis and network analysis (Hoffman and Wood 1976).

The development of energy models is not an end in its self but it is a tools aiming to provide an important contribution to the solution of the energy and environmental issues. Energy policy and planning is getting more and more complex and uncertain as questions related to the availability of primary energy sources are coupled with environmental protection issues, security of supply and related risk. The vision of a low carbon (or even a carbon-free) energy system that has emerged over the last decade needs detailed studies of roadmaps. The technical constraints of the new technologies, their efficiencies, costs and the timing of the commercial introduction contain high uncertainties. Therefore the main policy questions asked today are related to what an energy policy should look like in order to be robust and flexible enough to deal with the uncertainties of the future. Energy models are necessary in order to help in decision making and in the context described above it does not make sense to be used for forecasting (since forecasts are by definition uncertain and wrong). The models should demonstrate the robust steps that have to be taken in the immediate future and at the same time make sure that the chosen path will not be regretted later in time. Of course no single model can give answers to all the possible questions due to the complexity of energy policy issues. Therefore it is always a suit of models that are used in order to support energy planning effectively.

The use of energy models in order to analyze alternative scenarios on a global scale, is an important component of the work of the International Energy Agency (IEA). The IEA started publishing medium to long term energy projections in 1993, using the World Energy Model (WEM) which is a large scale simulation model, trying to replicate the operation of energy markets. The scenarios analyzed in the World Energy Outlook publication are based on the results of the WEM.

The IEA also publishes the Energy Technology Perspectives since 2006, which presents a core analysis of energy technologies and policies. It focuses on the long-term analysis of trends in the energy sector and the technologies that are necessary to reach a secure, low-carbon energy system. The ETP model used in this analysis is made out of four soft linked models: the energy conversion model, the industrial model, the transport model and the buildings model. The energy conversion model, covering energy supply from primary energy to transformation and final energy, is based on the TIMES model generator and is called the ETP-TIMES model.

The ETSAP[1] Implementing Agreement, a multilateral technology initiative, was initiated in 1976, under the aegis of the International Energy Agency (IEA), with the aim of carrying out a joint program of energy technology systems analysis.

In the first year of its operation, ETSAP focussed on the analysis of existing tools for evaluating R&D strategies. Then for the period 1978–1980 the MARKAL model generator development was its only activity. In 1981 the first Annex of the Implementing Agreement was initiated, with a duration of three years and this was the first time that the Energy Technology Systems Analysis Project was used as a title. After this the ETSAP community continued to coordinate for common projects and tools improvement. Environmental issues were always taken into consideration. During the 1980s, SO_2 and NO_x emissions were the main concern. The focus changed towards greenhouse gases since about 1990. The tools development moved towards

[1] Energy Technology Systems Analysis Programme.

the combination of the energy flow optimisation approach with macroeconomic top-down modelling, technology learning, and stochastic modelling.

Today ETSAP is a unique network of energy modelling teams from approximately seventy countries over the world. The contracting parties of ETSAP are the governments of eighteen countries and the European Commission. The key focus of ETSAP was (and still is) to cooperate to establish, maintain and expand a consistent multi-country energy/economy/environment/engineering analytical capability mainly based on the MARKAL/TIMES family of models. The objective was to build modelling capability in order to assist and support government officials and decision-makers in increasing the robustness of the evidence base underpinning energy and environmental policy issues by applying these tools for energy technology assessment and analysis (IEA-ETSAP 2008a). ETSAP developed through co-operation the MARKAL (MARKet ALlocation) and—subsequently—the TIMES (The Integrated Markal-Efom System) energy systems model generators, both based on a multi-regional, multi-period, bottom-up, linear programming, optimization paradigm (Loulou et al. 2004, 2005). These bottom-up techno-economic models have been used to build long term energy scenarios and to provide in-depth national, multi-country, and global energy and environmental analyses.

ETSAP's energy systems models have underpinned a significant body of research studies, as evidenced by the most recent achievements summarised in the ETSAP Annex X and XI reports (IEA-ETSAP 2008b, 2011). This research and analysis contributes to building a rich knowledge base in energy systems, impacts of policy decisions, climate change mitigation and energy security. Experiences have been mixed with respect to effectiveness in directly influencing the policy-making process.

The work of ETSAP members using the MARKAL/TIMES tools includes a wide range of models, from global to city models, used to support decision-making in the energy, environment and economy fields. This book presents applications of several of these models.

2 Energy Systems Modelling

Energy systems models approach energy as a system rather than as a set of elements. This has the advantage of providing insights into the most important substitution options that are linked to the system as a whole and that cannot be understood when analysing a single technology, or commodity, or sector. A focus on the electricity sector, for example, risks excluding possible unforeseen step changes in electricity demand, due to say, the electrification of transport or of heating. Current energy systems are the result of complex country dependent, multi-sector developments. By considering energy supply and demand across all sectors simultaneously, systems analysis applies systems principles to aid decision-makers in problems of identifying, quantifying, and controlling a system.

Building an energy systems model requires a number of key components, namely a model generator, a solver, interfaces for handling data and results and a detailed database. Energy systems models also require key exogenous inputs, comprising the demand component (energy service demands), the supply component (resource potential and costs) and the policy component (scenarios).

Two model generators have been developed and made available via the ETSAP collaboration, namely MARKAL (MARKet ALlocation) in the 1980s and subsequently during the early 2000's TIMES (The Integrated Markal-Efom System). Both MARKAL and TIMES are written in GAMS (General Algebraic Modelling Software) code and CPLEX and XPRESS are typically the solvers used. A key characteristic of these model generators is that the code is transparent and well documented (Loulou et al. 2004, 2005; IEA-ETSAP), distributed free of charge, and maintained, improved and updated through a collaborative research initiative co-ordinated by ETSAP.

ETSAP has also been instrumental in generating two interfaces for data and results, namely ANSWER (developed by Noble-Soft Systems) and VEDA (VErsatile Data Analyst, developed by KanORS). The database required includes both energy supply side and demand side technologies and contains technical data (e.g. thermal efficiency, capacity), environmental data (e.g. emission coefficients) and economic data (e.g. capital costs) that vary over the entire time horizon.

MARKAL and TIMES model generators are currently in use in 177 institutions across 70 countries. They are have been and are being used to generate MARKAL and TIMES energy systems models for local, national or multi-regional energy systems, providing a technology-rich basis for estimating energy dynamics over a long-term, multi-period time horizon. They are usually applied to the analysis of the entire energy sector, but may also be applied to study individual sectors in detail. They compute a dynamic inter-temporal partial equilibrium on integrated energy markets with the objective (objective function) of producing least-cost energy systems while respecting environmental and many technical constraints. The energy system cost includes investment costs, operation and maintenance costs, plus the costs of imported fuels, minus the incomes of exported fuels, minus the residual value of technologies at the end of the horizon. The main *selling point* of the ETSAP modelling frameworks is that they combine a detailed technology rich database with an economically optimizing solver. They are able to generate robust energy policy scenarios over medium to long time horizons and are able to offer strategic insight into long-term policy formation. This is especially important for the energy sector, which has such large capital investments with long project lifetimes. The modelling perspective of these tools is that of a benevolent central planner: as if there was a single decision-maker (mono-objective) taking rational choices surrounding all energy-related issues on technologies and fuels at the lowest cost to the economy and to society. This clearly does not reflect reality, where there are many decision makers and not all decisions are rational, but it does provide very useful guidance into how to achieve policy decisions (e.g. emissions targets) using a least-cost approach. The complex dynamics (incorporating technologies, fuel prices, infrastructures and capacity constraints) of the entire energy system can be analysed through this modelling approach to better inform policy choices.

Like all energy models, MARKAL and TIMES models also have a number of limitations which should be considered when interpreting the results and scenario analyses. In some instances, these are simply limitations born of the structure of the model; they are inevitable based on the way the model is built. In other instances, they could be considered weaknesses and in these cases, research should be carried out to generate improvements. The following list presents the main limitations: (i) *Time resolution*: Long term energy systems model are generally inadequate to capture daily supply and demand curves. Even though there are no limitations on the number of time-slices in MARKAL/TIMES models; it would become computationally unwieldy if the model had to make decade long decision as well as hourly decisions. (ii) *Macro-economic assumptions*: The results of the scenarios are tied to the assumption and results of the macro-economic model, which by themselves are inherently uncertain. While scenario analysis, by its nature, tries to counteract this uncertainty by producing a range of results, this uncertainty is nevertheless present. (iii) *Limited macro-economic feedback*: MARKAL and TIMES models are generally not able to take account feedbacks between the output of the energy system analysis and the macro-economy. (iv) *Behaviour*: ETSAP models have the limited capacity to simulate behavioural aspects. This is a limitation of most energy (and indeed macro-economic) models, in that consumer behaviour is generally limited to simple price response and non-price related behaviour is generally very poorly treated. (v) *Power system operational characteristics*: Technical characteristics, such as minimum stable generation, ramps rates and minimum up and down times play an important role in actual power system operation and planning, in particular systems with high levels of variable

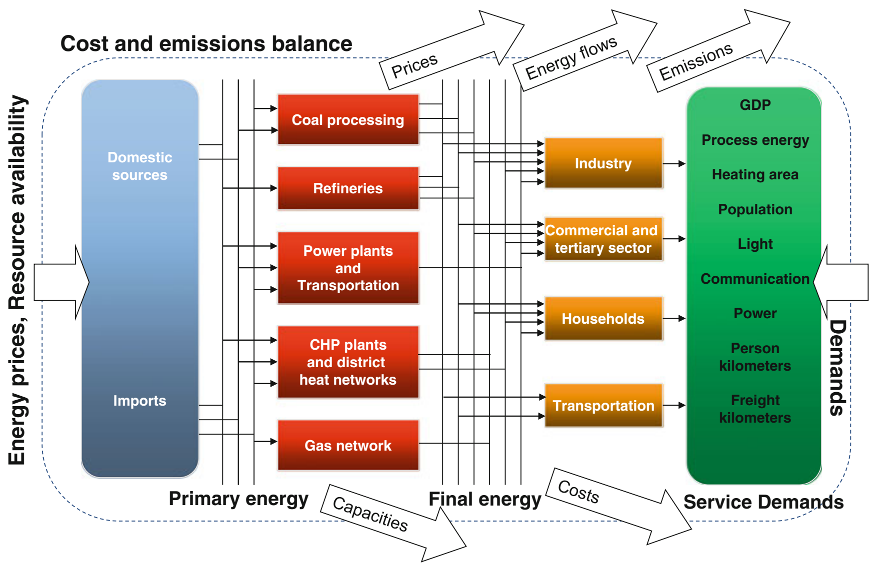

Fig. 1 TIMES model schematic (Remme et al. 2001)

renewables and these are generally not adequately incorporated into energy system models.

ETSAP energy systems models are able to generate a vast number of outputs, assessing implications for (i) the economy (including energy prices, investments in the energy system, marginal CO_2 abatement costs, etc.), for (ii) the energy mix (fuels and technologies) and energy dependence, and for (iii) the environment (in particular greenhouse gas emissions). Figure 1 shows in schematic form how a MARKAL and TIMES models operate. The exogenous model inputs are shown entering from the left hand side (energy supply) and right hand side (energy service demands) of the model. The model outputs are shown on the top and bottom.

3 Overview of the Book

This book collates together for the first time in one volume a range of methodological approaches and case studies of good modelling practice at national and international scale from the IEA-ETSAP energy technology initiative. Most chapters provide insight into key methodological features backed up with concrete applications. The book demonstrates the high degree of flexibility of the modelling tools which haves been used to represent extremely different energy systems, from national to global levels. It demonstrates how energy systems models have been and are being used to answer complex policy questions relating to energy security, climate change mitigation, the optimal allocation of energy resources, amongst others.

The book is carefully structured into three parts which focus on policy decisions that have been underpinned by energy systems models (Part I), specific aspects of supply and end-use sector modelling, including technology learning and behaviour (Part II) and how additional insights can be gained from linking different models (Part III).

3.1 Part I—From Policy Insights to Policy Decisions

Chapter by **Chiodi et al**. presents four case studies, in which there is clear evidence of a direct link between the use of MARKAL/TIMES scenario modelling activities and policy decisions. The lessons learned, along with the role of policy makers and stakeholders in the modelling process are discussed. The case studies assess how the (i) UK MARKAL model informed the development of energy and climate mitigation policy in the UK (Energy White Papers of 2003 and 2007, Climate Change Act in 2008); (ii) Irish TIMES model informed the development of climate mitigation legislation in Ireland in 2014 and Ireland's negotiating position regarding the EU 2030 Climate Energy Package in 2014; (iii) TIMES_PT model informed climate policy in Portugal in the last 10 years and has supported the design of climate mitigation policies; (iv) IEA ETP Model informed the G8 in responding to the 2005 Gleneagles Plan of Action and has supported the work of the Major Economies Forum and Clean Energy Ministerial.

Chapter by **Kumpener et al**. compares the global renewable energy roadmap to double the share of renewables in the global energy mix by 2030 compared to 2010, called REmap 2030 and published by the International Renewable Energy Agency (IRENA) in 2014, with the methods and results obtained with the IEA-ETSAP models. It discusses the advantages that ETSAP models have, by accounting for trade-offs between renewable energy and energy efficiency activities, system planning issues like grid infrastructure, competition for scarce resources in the commodity prices, or dynamic cost developments as technologies get deployed over time. Authors conclude how the REmap tool and the ETSAP models have complementary roles to play in engaging policy makers and national energy planners to advance renewables.

One key question facing policy makers is that of defining *one* course of action in a context of uncertainties, what is proposed by stochastic programming. Chapter by **Labriet et al**. explains how stochastic programming, combined with a parametric analysis of the probability of the future outlooks, and robust optimization are useful to analyze climate and energy decisions in uncertain context, and applies the methods using respectively TIAM-WORLD at the global level and MIRET in the case of France. “Super-hedging” actions can even be identified, which penetrate more in the hedging strategy than in *any* of the perfect forecast strategies (gas is a good candidate). One of the drawbacks of stochastic programming is the computational requirements. Robust optimization is an alternative since it offers parsimonious ways of dealing with problems of high dimensionality, requiring minimal information about the true probability distributions of uncertain parameters.

Pursuing the study of climate issues, chapters by **Kypreos and Lehtilä**, and by **Kober et al**. explore the allocation of greenhouse gas emission quotas to different countries under a 2 °C long-term climate policy framework using respectively the Integrated TIMES and MERGE Model (ITMM), which integrates hybrid top-down and bottom-up models, and the TIAM-ECN model, which assesses a per-capita-based scheme, and an economic capability-based scheme. Appropriate certificate trading mechanisms of course need to be in place, and depending on the certificate allocation scheme the future trade of carbon certificates might become as important as energy trade.

The next four chapters present applications of energy modelling at regional and national levels. **Fais and Blesl** evaluate how bottom-up energy system models may be utilised to evaluate the long-term effects of energy and climate policy instruments; more particularly, emissions trading systems and different support systems for renewable electricity are outlined and applied to the German energy system. **Kerimray et al**. explore the energy efficiency potential of Kazakhstan in a TIMES-based model. The model suggests significant and economically viable energy efficiency improvements. **Cabal et al**. estimate socioeconomic and environmental impacts associated to energy technologies in the current and future Spanish Energy System using the national energy optimization model TIMES-Spain. **Koljonen and Lehtilä** analyze the implications of low carbon policies with a special focus on the

Finnish energy system. They use the global ETSAP-TIAM model as well as an applied general equilibrium model and a forest sector partial equilibrium model for estimating the impacts on the overall economy as well as land-use change and forestry.

3.2 Part II—Focussing on Specific Aspects of Supply and End-Use

The power sector is a key element of the energy system, in terms of energy services, infrastructure and environmental impacts. Chapter by **Kannan et al**. provides a broad overview of temporal features in the MARKAL/TIMES energy modelling framework directly related to the modelling of electricity dispatch. This includes the trade-offs between model time horizon and intra-annual time resolution, the solver algorithm capabilities, data availability and methodological limitations. The trade-offs and benefits of an integrated system approach are discussed with a set of scenarios from the Swiss TIMES electricity and energy system models.

Nijs et al. describe a methodology to integrate DC power flow modelling and N-1 security into the JRC-EU-TIMES model, a multiregional TIMES energy system model developed by the European Joint Research Centre—Institute for Energy and Transport. The methodology improves the accuracy of modelling cross-border transmission expansion especially for energy systems with higher penetration of renewable energy sources. One of the grid representations proposed in the chapter uses the newly developed Integrated TIMES–NEPLAN Software that couples JRC-EU-TIMES energy system modelling with NEPLAN-based electricity grid modelling.

Wright and Kanudia extend the modelling of power sector of the USA to the representation of unit-level emissions of all existing coal-fired plants within the FACETS TIMES model of USA, reflecting the soon-to-be-implemented Mercury and Air Toxics (MATS) regulation. Covered emissions and retrofit costs depend in a detailed way on unit configuration and coal quality, forcing development of new techniques to handle the enormous expansion in model size and detail.

The oil industry currently plays a major role in the Canadian economy. In the future, further developments of the oil sector will be affected by the ability to transport crude oil (mainly from Western Canada) to consuming regions in Canada and abroad. Based on the use of a multi-regional TIMES energy model for Canada, chapter by **Vaillancourt et al**. analyzes different crude oil exportation scenarios based on existing pipeline expansions and the development of new pipelines.

The costs of technologies often fall over time due to a range of processes including learning-by-doing. This is a well-characterized concept in the economics of innovation, in which learning about a particular technology, and hence cost reduction, is related to cumulative investments in that technology. **Anandarajah and McDowall** explore the modelling challenges of applying technology learning endogenously in a TIMES model in a case study based on a multi-cluster learning approach in the transportation sector, where key technologies (fuel cells, automotive batteries, and electric drive trains) are shared across a set of transport modes and technologies. The multi-region TIAM-UCL Global energy system model has been used to model the multi-cluster approach. The analysis is used to explore the competitive and/or complementary relationship between hydrogen and electricity as low-carbon transport fuels.

Chapter by **Daly et al**. also focuses on the transportation sector, and more particularly the representation of travel behavioural change in MARKALT/TIMES models in addition to increased vehicle efficiency and low-carbon fuels as climate mitigation options. Modal choice within passenger transport, which to date has been exogenously modelled (with no competition allowed between alternative modes) is integrated here into a TIMES model, allowing competition between modes, while also imposing a constraint in the system on overall travel time.

The appropriate representation of energy service demands is a crucial factor of MARKAL/TIMES models, which are driven by energy service demands. In China, the growth trend in energy service demand will be a critical factor in the level of energy consumption and carbon emissions in future. Within this context, **Chen et al**. propose various approaches, including stock-based method, saturation model, discrete choices model, to project energy service demands in different sectors of the Chinese economy. The projection of energy service demand are then used as inputs in the China TIMES-ED model to generate a reference scenario.

3.3 Part III—Gaining Additional Insights Through Model Coupling

Linking MARKAL/TIMES models with carefully selected complementary models can provide useful additional insights into the results from standalone models when the multi-model approach succeeds in taking advantage of the individual strengths of different modelling approaches. Chapter by **Deane et al**. collates methodologies and results from a number of soft-linking exercises with TIMES. Two specific examples are given. Firstly the soft-linking of TIMES to a power system model to investigate the TIMES results and provide additional insights into power system flexibility, reliability and market issues. Secondly, the soft-linking of a TIMES model to a power system and a housing stock model to explore the impacts of increased electrification of residential heating on the power system and associated emissions from the residential sector. These examples show how a multi-model approach and soft-linking can provide a strong complementary analysis to TIMES modelling exercises and generate insights into results that otherwise would be difficult to achieve with a single model approach.

Key questions for policy makers surround the economic implications of future changes in the energy system, for example what will be the implications for economic growth of moving to a low carbon energy system? which sectors of the economy will thrive and which sectors will suffer? what are the implications for jobs?, etc. In a climate constrained future, hybrid energy-economy model coupling can provide rich additional insight into interregional competition, trade, industrial delocalisation and overall macroeconomic consequences of decarbonising the energy system. The two chapters by **Glynn et al.** summarize modelling methodologies developed in the ETSAP community to assess economic impacts of decarbonising energy systems at national and global levels. For example: combining MARKAL and TIMES models with the MACRO model, a simplified single-sector general equilibrium model, which maximizes an inter-temporal utility; coupling MARKAL/TIMES models with computational general equilibrium models, in which energy results (costs) from the energy systems models are fed into the CGE model which in turn generates revised energy service demands as inputs into the energy systems models; linking energy systems models with other types of economic models (e.g. econometric models) to understand the interactions between energy systems and the economy.

Chapter by **Labriet et al**. explores another field of model linkages: the coupling of the World TIMES Integrated Assessment Model (TIAM-WORLD) with an emulated version of the climate model PLASIM-ENTS to assess the impacts of future temperature and precipitation changes on the heating and cooling subsector and available hydropower. Such a coupling is important to assess regional temperature increases and therefore the possible impacts of climate change on the energy system at a regional level. The climate module of TIAM-WORLD does not compute the regional or seasonal temperature changes required for a relevant representation of the possible heating and cooling adjustments due to climate change. The coupling of TIAM-WORLD with an emulator of the climate model PLASIM-ENTS provides this additional information.

Coupling may also occur between different MARKAL/TIMES models. **Gerboni et al**. present an application of the coupling of the global TIMES Integrated Assessment Model and the Pan European TIMES model through a series of trade links characterised into a corridor model. The application focuses on the analysis of security of supply to Europe via energy corridors. A new methodology for the assessment of energy security, addressing the risk associated to each supply, is presented together with a scenario analysis related to the European Union (EU) as a whole and to some of the most populated EU's Member States.

4 Conclusion

This book captures in a coherent structure the strength and breadth of energy systems modelling undertaken by ETSAP teams. It focuses on recent analysis that builds on a unique, collaborative, international research effort over the past 40 years. It demonstrates both the complexity and usefulness of energy systems modelling and acts as a bridge between the many energy systems modelling teams and the wider analytical, research and policy community interested in increasing the robustness of energy and climate policy decisions.

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Part I
From Policy Insights to Policy Decisions

Energy Policies Influenced by Energy Systems Modelling—Case Studies in UK, Ireland, Portugal and G8

Alessandro Chiodi, Peter G. Taylor, Júlia Seixas, Sofia Simões, Patrícia Fortes, João P. Gouveia, Luís Dias and Brian Ó Gallachóir

Abstract A key objective of IEA-ETSAP is to assist decision makers in robustly developing, implementing and assessing the impact of energy and climate mitigation policies. This chapter focuses on four case studies, in which there is clear evidence of a direct link between the use of MARKAL and TIMES scenario modelling activities and the resulting policy decisions. The case studies selected assess how the (i) UK MARKAL model informed the development of energy and climate mitigation policy in the UK, focusing on the Energy White Paper in 2003, the Energy White Paper in 2007 and the Climate Change Act in 2008; (ii) Irish TIMES model informed the development of climate mitigation legislation in Ireland

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_2

in 2014 and Ireland's negotiating position regarding the EU 2030 Climate Energy Package in 2014; (iii) TIMES_PT model informed climate policy in Portugal in the last 10 years and has supported the design of climate mitigation policies; (iv) IEA ETP Model informed the G8 in responding to the 2005 Gleneagles Plan of Action and has supported the work of the Major Economies Forum and Clean Energy Ministerial. This chapter collates methodologies and results from these different case studies and summarizes some key findings regarding (i) policy frameworks and goals; (ii) how policy makers have been intertwined with the modelling tool during the modelling process; (iii) the role of the economic stakeholders dialogue; (iv) main insights from the modelling exercises; (v) lessons learnt: from effective contributions to real limitations and (vi) recommendations.

1 Introduction

This chapter presents a collection of four case studies where this direct linkage between ETSAP modelling tools and the policy-making process took place at national (United Kingdom, Ireland and Portugal) and supra-national level (G8 countries). The purpose is to show how ETSAP energy systems models have informed the environmental and energy policy choices, but also discussing the main lessons learnt, the current limitations, and recommendations both for modellers and policy makers.

The chapter structure is as follows. Section 2 presents the experience of UK MARKAL which informed energy and environmental policy in Great Britain. Section 3 focuses on Irish TIMES model which informed the Irish Government. Section 4 discusses details of TIMES_PT being used to inform climate policy in Portugal in the last decade. Section 5 presents the case of IEA ETP Model, which informed the G8 in responding to the 2005 Gleneagles Plan of Action and supported the work of the Major Economies Forum and Clean Energy Ministerial. Section 6 concludes with some discussions regarding common issues, lessons learned and some recommendations for model developers.

2 The Experience of UK MARKAL

The MARKAL energy systems model has a long history of use in the UK dating back to early versions of the model developed in the late 1970s (Finnis 1980). Yet, for most of the next two decades its impact on the energy policy process was minimal (Taylor et al. 2014). However, around the year 2000 climate change emerged as a key political issue in the UK and, since then, results from MARKAL have been used extensively to inform energy policy as the question of how to reduce greenhouse gas (GHG) emissions has become the defining challenge.

2.1 The 2003 Energy White Paper

In 2000, the Royal Commission on Environmental Pollution (RCEP)[1] recommended that by 2050 the UK should plan to reduce its energy-related carbon dioxide emissions by 60 % (Royal Commission on Environmental Pollution 2000). This conclusion had a significant impact on the Government who set up a review of energy policy in 2001, eventually leading to the publication of an Energy White Paper (EWP) in 2003 (DTI 2003a). As part of this review, the Department of Trade and Industry (DTI) commissioned AEA Technology plc to develop a new UK MARKAL model and to use it to explore future trends in carbon dioxide emissions from the UK energy sector up to 2050 and identify the technical possibilities and costs for the abatement of these emissions. The work considered three levels of abatement by 2050: 45, 60 and 70 % reductions relative to emissions in 2000, combined with three scenarios (Baseline, World Markets and Global Sustainability) for the possible future development of the UK economy and the associated demands for energy related services (DTI 2003b).

The new model database contained a wide variety of low carbon technologies including many types of renewable energy, fossil fuels with carbon capture and storage, nuclear power, efficient demand-side technologies and fuel cells and hydrogen. Two workshops with industry and academic experts were held to review the cost and performance data for low carbon power generation and infrastructure for transmission and distribution of hydrogen.

By running each of the three scenarios without any CO_2 emissions constraints and then with the three level of abatement levels described above, 12 "core" runs of the model were generated. However, these were then supplemented by 70 other "sensitivity" runs to test how the results changed with alternate assumptions on a range of issues including the availability of technologies and fuels, fuel prices and taxes, discount rates and alternative emission paths. While the model results contained a huge amount of information about future technology and fuel mixes, including at the sectoral level, the key use of the modelling in the 2003 EWP was to calculate the costs to the economy of the different abatement levels (DTI n.d.).[2] The results led the 2003 EWP to conclude that "*the cost impact of effectively tackling climate change would be very small—equivalent in 2050 to just a small fraction (0.5–2 %) of the nation's wealth, as measured by GDP*".

The results on costs proved quite controversial, with some experts arguing that they were too low (Great Britain House of Lords 2005). Despite these

[1] The Royal Commission on Environmental Pollution was an independent standing body established in 1970 to advise the Queen, the Government, Parliament and the public on environmental issues.

[2] Ironically, this calculation had to be done off model using output from MARKAL because the choice at the start had been to use the standard MARKAL model (and not MARKAL-MACRO).

controversies, a report by the Institute for European Environmental Policy, an independent institute, concluded that the results from MARKAL "*overcame a key barrier to acceptance of the 60 % target, and appears greatly to have helped develop a positive attitude to carbon reductions in government*" (IEEP 2005).

2.2 The 2007 Energy White Paper

While the 2003 EWP established the principle that emissions reduction was the key policy challenge, it left much of the detail unresolved. In addition, rapid rises in gas and oil prices from mid-2004 led to the issue of energy security joining carbon mitigation as a priority for energy policy (Pearson and Watson 2012). Therefore within a couple of years the government was planning another EWP and once again turned to MARKAL to help inform its decisions.

The UK Energy Research Centre (UKERC), a grouping of UK universities, and AEA Technology worked together on a project commissioned by the DTI using both the standard version of MARKAL and the newly developed MARKAL-MACRO (M-M). The final report focused on a set of 11 M-M model scenarios (Strachan et al. 2007) that were used as the main inputs to the 2007 EWP. The scenarios may be classified as:

1. Base-case, CO_2 emissions in 2050 constrained to 60 % of 2000 levels and alternate CO_2 emission trajectory implemented linearly from 2010;
2. Resource import (high and low) price scenarios, from DTI projections;
3. Technology scenarios: restricted innovation (limited to either 2010 or 2020 levels of improvement), no-nuclear, no-CCS or no-nuclear/CCS scenarios.

Key outputs included primary and final energy mixes, sectoral contributions to CO_2 reductions, detailed technology selection in the electricity and transport sectors, the role of demand side reductions, CO_2 prices, energy system costs and GDP impacts. In total, over 50 scenarios sets were run (including standard model runs) with results from additional scenarios being used to explore key trade-offs between mitigation pathways.

In contrast to the rather narrow use of MARKAL in the 2003 EWP, the 2007 EWP explains its use of M-M in the following terms: "*for the period to 2050, we have used a model of the entire UK energy system (UK MARKAL-Macro model) to explore the changes to the amount and use of energy required if we are to deliver our goal of reducing carbon emissions by 60 % by 2050 at least cost*" (DTI 2007a). This central role given to MARKAL by the 2007 EWP is reflected in over fourteen direct references to various insights from the modelling work, complemented by numerous graphical figures (Fig. 1) in the supplementary material supporting the White Paper (DTI 2007b).

Of particular note, is the fact that the MARKAL results were used to support a significant change in the view of nuclear power compared to the 2003 EWP, with the 2007 EWP noting "*Our modelling indicates that excluding nuclear is a more*

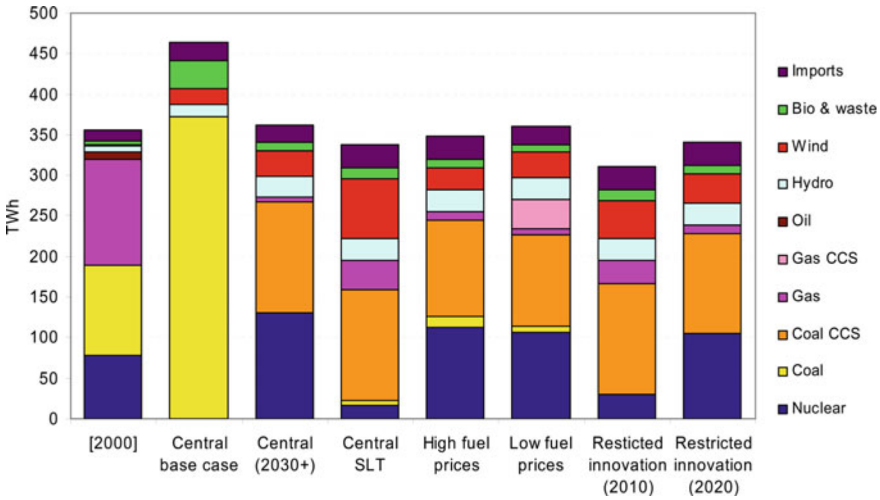


Fig. 1 Example of M-M results for the 2007 EWP: Generation mix in 2050, central and sensitivity scenarios (DTI 2007b)

expensive route to achieving our carbon goal even though in our modelling, the costs of alternative technologies are assumed to fall over time as they mature" (DTI 2007a).[3]

2.3 The 2008 Climate Change Act

Following the 2007 EWP, the Government published a draft Climate Change Bill, which became an Act of Parliament in 2008 (Great Britain 2008). This put in place a new legislative framework of five-year carbon budgets and established an independent Committee on Climate Change (CCC) to advise government on the level of these budgets. A long-term emissions target was written into the Act, but strengthened from the original 60 % recommended by the RCEP to become an 80 % emissions reduction target by 2050.

The impact assessment for the Bill (compulsory for most UK policy proposals) draws on MARKAL-MACRO analysis by AEA Technology looking at the additional impacts (economic and technological) of moving to an increasingly carbon constrained energy system, with reductions in CO_2 of 70 and 80 % by 2050 and the implications of including international aviation within the targets (DECC 2009). In a parallel exercise MARKAL-ED (a variant of MARKAL in which the level of

[3] Interestingly the modelling work for the 2003 EWP had also shown a similar result, but this appears to have been ignored as at the time the Government focus was on delivering carbon reductions through energy efficiency and renewables.

demand for energy services varies according to the costs of meeting them) was used by the CCC to examine the economic and technological implications for reducing carbon emissions by 80 or 90 % by 2050 to inform its advice to government (CCC 2008; AEA 2008a, b).

The MARKAL family of models continues to play an important role informing implementation of the Climate Change Act, including being used to support the 2009 Low Carbon Transition Plan (Her Majesty's Government 2009) and, following a change of government, the 2011 Carbon Plan (Her Majesty's Government 2011) and the setting of 4th carbon budget (CCC 2010; Usher and Strachan 2010; AEA 2011).

2.4 Discussion

Since 2000, the MARKAL family of models have become embedded as key tools used to inform UK climate and energy policy. Three attributes of MARKAL would appear to have been particularly important in facilitating its role to support ambitious climate targets. First, MARKAL is not bound by historical relationships of the kind that underpin econometric and macro-economic modelling and is therefore able to postulate radically different energy system configurations that will be needed for deep reductions in GHG emissions. Second, MARKAL is able to make the necessary changes tangible through its detailed technological representation, which has suited a prevailing techno-centric view of the mitigation challenge. Third, MARKAL's objective function is cost and this accord with the dominance of cost-benefit analysis as a tool for policy appraisal and selection in the UK. Finally, while MARKAL is far from readily comprehensible to all and sometimes criticised for being a "black-box", substantial efforts have been made by the modelling community to increase the transparency and completeness of the model structure and assumptions, including through a range of stakeholder events, expert peer review and publication of the model documentation.

3 The Experience of Irish TIMES

Irish TIMES is a mono-regional model of the entire Irish energy system that was originally extracted from the Pan European TIMES (PET) model (Ó Gallachóir et al. 2012). It has been updated and expanded since 2009 by the Energy Policy and Modelling Group in University College Cork and has been used to build a range of energy and emissions policy scenarios to explore the dynamics behind the transition to low carbon energy systems (Chiodi et al. 2013a, b), to analyse energy security (Glynn et al. 2014), to assess impacts of limited bioenergy resources (Chiodi et al. 2015a) and to explore new modelling approaches (Deane et al. 2012; Chiodi et al. 2015b). However its impact on the policy making process has been limited till 2013, when, over the period June 2013–September 2014, the Irish TIMES model has been extensively used to inform two key policy developments, namely the development of (i) national legislation on climate change and (ii) Ireland's negotiation position regarding the proposed EU 2030 Carbon and Energy Policy Framework.

3.1 Low Carbon Energy Roadmap to 2050

The Irish Government is planning to legislate for Climate Action and Low Carbon Development and published a Heads of Bill (*General Scheme of a Climate Action and Low Carbon Development Bill (CA&LCD Bill))* in 2013 (DECLG 2013). This raises key questions regarding the evolution of Ireland's future energy system to enable the transition to a low carbon future. According to Head 4 of the CA&LCD Heads of Bill, "*the Government shall arrange for the adoption and implementation of plans [...] to enable the State to pursue and achieve transition to a low carbon, climate resilient and environmentally sustainable economy in the period up to and including the year 2050. Article 5 stipulates that a key objective of a National Low Carbon Roadmap is to articulate a national vision for the transition to a low carbon, climate resilient and environmentally sustainable economy over the period to 2050*".

In the period June–December 2013, the Department of the Environment, Community and Local Government commissioned UCC to produce a *Low Carbon Energy Roadmap for Ireland to 2050* using the Irish TIMES model (Deane et al. 2013). The focus of this analysis was on technological changes in the energy system and the associated implications. A key policy question underpinning the analysis focused on the dynamics of the energy system moving towards a low carbon economy for two key time horizons, i.e. to 2050 and to 2030. The process involved modelling analysis and regular meetings and discussions with a number of Government Departments providing technical advice and guidance on the development of a long term strategy for Ireland.

The purpose of the roadmap is to explore possible routes towards decarbonisation of the energy system, with a focus on achieving this at least cost to the economy and to society. The key issue is making well informed policy choices. Hence this roadmap does not stipulate which policies are necessary to achieve the transition; it rather focuses on the key drivers and its implications for the energy system of moving to a low carbon economy. The roadmap presents three distinct scenarios to explore transitions to a near zero CO_2 future.

1. A business as usual (*BaU*) scenario which does not impose emissions targets and efficiency improvements and is used as a base case (counterfactual) against which to compare the two distinct near-zero CO_2 scenarios.
2. An 80 % CO_2 reduction (*CO_2-80)* scenario in which CO_2 emissions are constrained across the entire time horizon to be no greater than 80 % below 1990 levels in 2050.

Table 1 Ireland's low carbon roadmap to 2050

Sector	2030 relative to 1990		2050 relative to 1990	
	BaU (%)	Low carbon (%)	BAU (%)	Low carbon (%)
Electricity	45	−56 to −58	31	−84 to −94
Buildings	−11	−53	−11	−75 to −99
Services	*5*	*−33*	*−6*	*−70 to −99*
Residential	*−16*	*−59*	*−13*	*−77 to −98*
Transport	226	104 to 122	285	−72 to −92
Total	50	−29 to −31	55	−80 to −95

Services and Residential are sub-groups of 'Buildings' chategory

3. A 95 % CO_2 reduction (*CO_2-95*) scenario in which CO_2 emissions are constrained across the entire time horizon to be no greater than 95 % below 1990 levels in 2050.

The roadmap provides insights into when changes in the fuel mix are likely to occur (e.g. transitioning from oil to biogas and biomass), the timing of new technologies (e.g. when and to what extent will electric vehicles penetrate the transport fleet) and the future role of electricity and gas infrastructure. It also emphasizes the scale of the challenge ahead, assessing macro-economic implications of decarbonisation,[4] and points to a number of areas of opportunity for Ireland as it transitions for a low carbon future. Moreover it provides guidance to possible sectoral targets, with the allocation of CO_2 emissions reductions (Table 1), between the key energy sectors in the *BAU* scenario and the range of results arising from the two low carbon scenarios considered (*CO_2-80* and *CO_2-95*).

The analysis also provides useful indications of the impact of different policy metrics to the whole energy systems, resulting with different allocations of fuels, sectors, efficiencies, but also energy dependency, as testified by the energy systems snapshots of alternative future energy systems provided by the Sankey diagrams shown in Fig. 2.

3.2 Assessment and Implications of EU 2030 Climate and Energy Policy Framework for Energy Policy in Ireland

In the period January–September 2014, the Irish TIMES model was used to inform Ireland's negotiating position with respect to the European Commission's proposal of a Climate and Energy Policy Framework for 2030 (EC 2014a). Here it was used

[4] The economic impacts were assessed by the Economic and Social Research Institute using outputs from the Irish TIMES model as inputs to the HERMES macro-economic model (Deane et al. 2013).

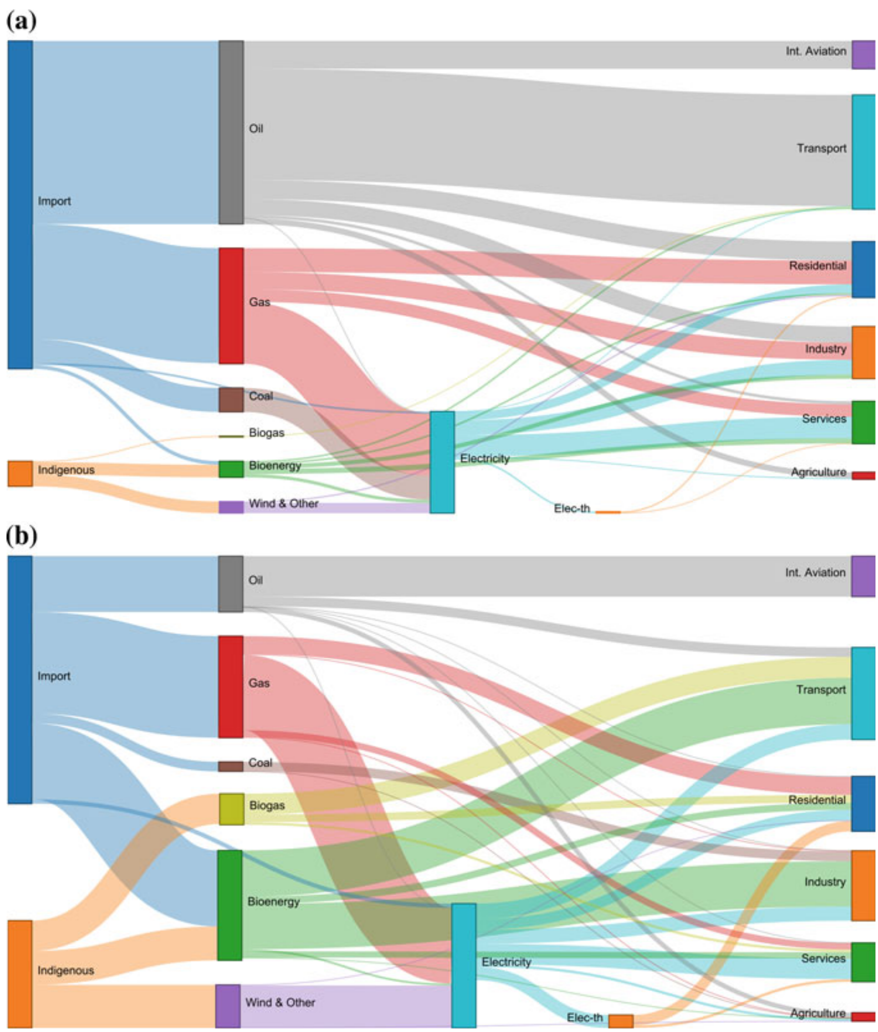


Fig. 2 2050 Sankey Diagrams for Ireland's energy system under BaU, CO_2-80 and CO_2-95 scenarios. **a** BaU scenario. **b** CO_2-80 scenario. **c** CO_2-95 scenario

to examine and provide answers to key questions arising from the proposed targets and in particular to scrutinise the findings of the modelling exercise accompanying the proposal (EC 2014b).

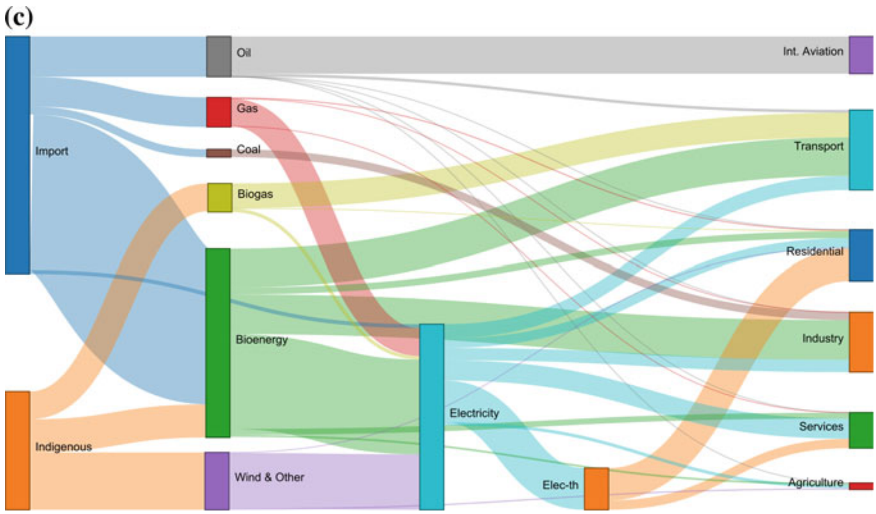


Fig. 2 (continued)

The impact assessment accompanying the proposed climate and energy package is based on the modelling analysis developed using mostly the PRIMES energy system model (NTUA 2011). It provides results for Ireland (and other Member States) arising from a scenario analysis of the EU achieving a 40 % reduction in GHG emissions by 2030 relative to 1990.[5]

The Irish TIMES energy system model has been to scrutinize the impact on the Irish energy system of the reduction in Irish GHG emissions indicated in the impact assessment (Cahill et al. 2014). It addresses a series of key questions that arise from the framework proposal: (i) what level of GHG emissions reduction can be achieved in Ireland up to 2030 at a cost of €40/tonne; (ii) what is the marginal abatement costs in Ireland in 2030 associated with achieving the 33 % emissions reduction relative to 2005 levels; (iii) what is level of effort required (measured as the increase in energy systems cost) to achieve 33 % GHG emissions reduction; (iv) what is the role of renewables in achieving the 33 % emissions reduction; (v) what is the cost optimal effort distribution between ETS and non-ETS sectors of the economy. The analysis addressed these five questions through scenario analysis

[5] The results for Ireland suggest that GHG emissions can be reduced by 33 % below 2005 levels (or 14.8 % below 1990 levels) by the year 2030 at a marginal abatement cost of €40/t CO_2 eq. The impact assessment shows that the contribution from non-ETS sectors of the economy is a 21 % reduction in 2030 relative to 2005 levels. This implies that total non-ETS emissions in 2030 would be 36.4 $MtCO_2$ and ETS emissions would account for the remaining 11.5 $MtCO_2$.

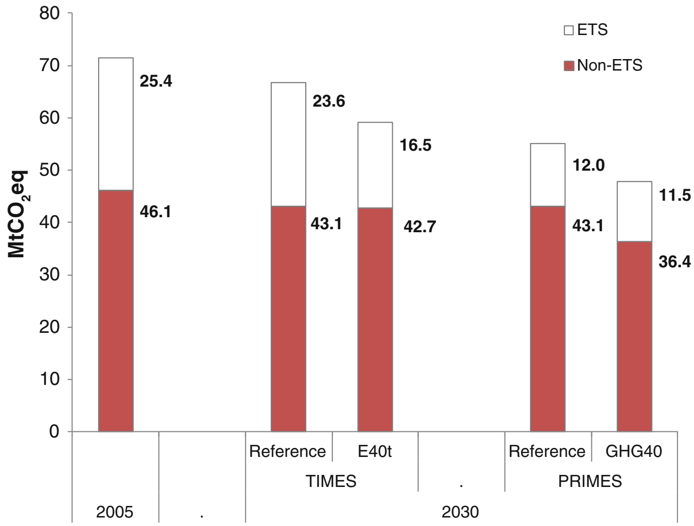


Fig. 3 GHG Emissions Scenario in Ireland in 2030—PRIMES versus Irish TIMES

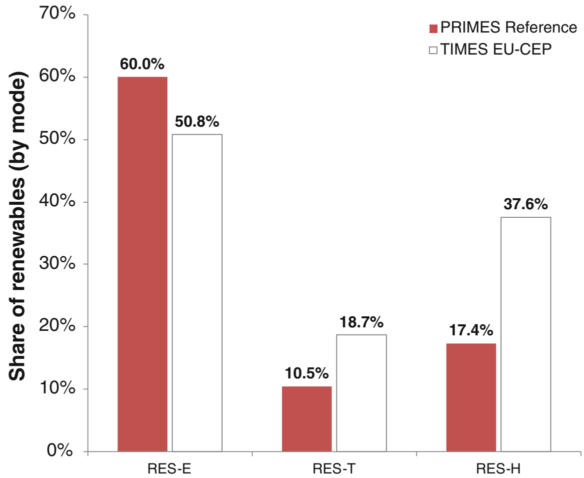
and a number of sensitivity runs to test impacts of alternative emissions pathways, renewable targets and taxation levels. Additional analysis was undertaken using the outputs of the Irish TIMES scenario analyses as inputs to a macroeconomic model (Bergin et al. 2013) to investigate the macroeconomic impacts of achieving a specific level of emissions reduction by 2030.

Key outputs from Irish TIMES suggest that a 33 % GHG emissions reduction can be achieved at marginal abatement cost of €151/t, significantly higher than the €40/t resulting from the PRIMES scenario analysis, while only 21 % GHG emissions reduction can be delivered at a marginal abatement cost of €40/t (Fig. 3).

Another key difference is also shown in the modal distribution of renewable energy (Fig. 4). Although both analyses indicate renewable energy increases from 7 % currently to 25 % in 2030 as a share of gross final energy consumption, the PRIMES results point to a higher share of electricity from renewables (60 % RES-E compared with 51 % RES-E from Irish TIMES). By contrast, the Irish TIMES scenario analysis points to share of thermal energy from renewables (38 % compared with 17 % in the PRIMES analysis).

The feedback on the analysis undertaken with Irish TIMES was very positive from the Irish delegation negotiating the Climate and Energy Policy Framework for 2030 in the weeks before the European Council meeting in October 2014. It was clear that the modelling analysis was received as being robust and very useful and that is strengthened Ireland's position.

Fig. 4 Modal shares of renewables in gross final consumption in 2030—PRIMES versus Irish TIMES



3.3 Discussion

The use of TIMES modelling tools to inform policy decision is quite recent in Ireland. Before 2009, when Irish TIMES project commenced, no similar modelling tools were in fact available in Ireland. This limited Ireland's negotiating strength in EU deliberations regarding 2020 targets for emissions reduction (Chiodi et al. 2013a). The absence of a *whole energy systems approach* has also contributed to a dominant policy renewable energy focus on wind-generated electricity (Ó Gallachóir et al. 2014). The Irish TIMES model has demonstrated the capacity of the energy system to respond directly to a number of key policy issues, facilitating the comprehension of the key challenges towards a low carbon economy and providing direct evidences on Irish negotiating position regarding new policy developments. However the major challenges have been increasing the trust on the analysis via substantial efforts made in respect of the transparency, the completeness of the model structure and assumptions, through stakeholder events, peer-reviewed publications and the online publication of model documentation and main input assumptions.[6] Moreover stakeholder input contributed directly to the development of the model, proving information and data inputs which have been used to update the model databases, i.e. the techno-economic assumptions of the electricity generation portfolio and bioenergy resource potentials and costs. Including stakeholder engagement and input into model development is challenging; however it does contribute enormous added value in terms of transparency and consistency.

[6] Available online at http://www.ucc.ie/en/energypolicy/irishtimes/.

4 The Experience of TIMES_PT

4.1 Use of TIMES_PT in Policy Support

The development of the TIMES_PT (Simões et al. 2008) model started within the EU research project NEEDS and the national research project E^{2}POL during 2004. Although its implementation was motivated by research goals, during the past decade the model has become a major tool supporting national climate mitigation policies (Gouveia et al. 2012a), and to a lesser extent, air pollution policies (Fig. 5). The Low Carbon Roadmap 2050 (Seixas et al. 2012) is a flagship policy document currently used as the Portuguese long term view on mitigation goals, while the PNAC—National Plan on Climate Change (Seixas et al. 2014) includes the visions up to 2030 from stakeholders from other policy areas, as transportation and industry. The negotiations for the revisions of the National Emission Ceilings Directive for 2020 and 2030 (Seixas et al. 2009; Ferreira et al. 2014) were supported by projections generated by TIMES_PT. More recently, TIMES_PT was linked with a national CGE model (Fortes et al. 2014), which has motivated its use in the Green Tax Reform (Seixas and Fortes 2014).

4.2 Portugal CLIMA2020

The CLIMA2020 project was the first policy support study using the TIMES_PT model as a reference tool for national climate and energy analysis. The project's main objective was the development of 2020 GHG national emission scenarios and assessment of technical and economic implications for different targets on emissions (ETS and non-ETS) and renewable energy shares. The results were provided to advise the Executive Committee of the Portuguese Climate Change Commission (CECAC)—Ministry of Environment on the EU Climate and Energy Policy Package negotiation.

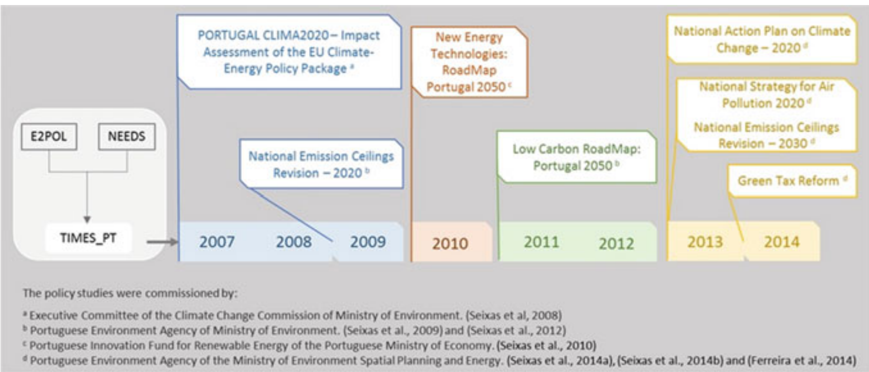


Fig. 5 Overview of the policy support studies using TIMES_PT

4.3 New Energy Technologies: Roadmap Portugal 2050 (NETRP)

The NETRP project assessed the role of new energy technologies, renewable mostly electricity generation, on the national energy system through the development of different national scenarios and focusing on endogenous resources. The work was commissioned by the Portuguese Innovation Fund of the Ministry of Economy. It emphasized the main economic and technical conditions for the competitiveness of the different renewable technologies (solar—PV, CPV and CSP—wind—onshore and offshore—geothermal) in Portugal in the long term. For this, the TIMES_PT model database was upgraded by integrating new technologies or more individual technologies like different photovoltaic and wind offshore technologies. A range of consultations with national industry and experts was held concerning the review and validation of the technical and economic parameters of the TIMES_PT technology database. The scenarios developed included different levels of CO_2 emissions constraints, and progressive reductions on the cost (investment and O&M) of mentioned renewable electricity technologies and electric vehicles.

4.4 Low Carbon Roadmap: Portugal (LCRP) 2050

The ambition to transition to a future low carbon economy in Portugal requires significant effort in achieving the necessary reduction of GHG emissions without compromising the economic and social development. The LCRP—2050 was commissioned by CECAC and established the vision for this by providing an analysis of the technical and economic feasibility of emission reduction trajectories of GHG in Portugal, focusing on modifications in the national energy system and evaluating their economic impact. The scenarios constructed with TIMES_PT covered very different economic growth trajectories and strict GHG emission targets, −60 and −70 % GHG facing 1990 values, in line with the EU low carbon roadmap. The additional co-benefits in terms of improved air quality and creation of "green jobs" were also analysed.

4.5 Portuguese National Action Plan on Climate Change (PNAPCC)—2020

The development of the Portuguese National Action Plan on Climate Change for the CECAC required the projection of GHG emission activities, assuming the implementation of national targets for climate mitigation policy and energy by 2020, and adopting exploratory goals by 2030, inspired by the 2030 framework for climate and energy policies and the positions taken by Portugal in the context of the

EU debate. The GHG national emissions trajectories evaluated by 2030 using TIMES_PT, considered two contrasting socio-economic scenarios, technological evolution scenarios, varied primary energy prices, and the national policy framework. Beyond that, it also analysed the impact of a more conservative view of the national stakeholders on the coal power plants utilization (5 more years than the expected decommissioning), and also a higher availability of the identified cost effective technologies, like solar PV technical and economic potential. Additional runs were made in order to identify potential alternatives on the significant penetration of electric vehicles, the effect of applying a CO_2 tax in sectors not covered by the EU ETS and the potential for renewable production for export, having been based on the assumption of increased interconnections with Europe for the transport of electricity.

4.6 Common Key Findings and Results

A wide number of scenarios were modelled in the policy studies above, depending of the policy requests (Table 2 provides selected examples). Typically two distinct macro-economic scenarios were considered for the long term, encompassing uncertainty. These were combined with different levels of implementation of policies and measures (P&M) according to established policy goals (e.g. National Plan for Energy Efficiency), from deployment of RES power plants to biofuels in transport. The scenarios used common assumptions on primary energy prices (imports of coal, oil and natural gas), on electricity trade with Spain and on hydrological availability, which were then varied in sensitivity analyses. Addition to the reported scenarios, the modellers typically developed more scenarios (often at the request of policy makers) to test how each assumption affects the results. Most of these "extra" scenarios are not directly used in policy support and are instead relevant for research work and model improvements.

The TIMES_PT model, by providing scenarios, has been acting as a central piece for Portuguese policy formulation. The model has been directly used in 7 major national policy development initiatives in climate mitigation, air pollution strategies and green tax reform. The model outputs have supported national communications to the European Commission, the CLRTAP[7] and the UNFCCC and led directly to a number of legislative documents.[8] The transparent approach followed by the modellers and the ongoing engagement with policy makers, has built confidence and trust in model results and contributed for the acceptance of policy proposals.

[7] United Nations Convention on Long-Range Trans boundary Air Pollution.

[8] Such as the Council Minister Resolution (RCM) 119/2004 of July 31st, RCM 104/2006 of August 23rd, or the RCM º 1/2008 of January 4th.

Table 2 Overview of selected studies using TIMES_PT for policy support

Project name (time horizon)	Project goals	Main TIMES_PT assumptions
Portugal Clima 2020 (2000–2020)	Assess impact of EU 20-20-20 policy package (Seixas et al. 2008)	Two macro-economic scenarios (2–3 % GDP growth), 84 USD_{2010}/bbl in 2020. No GHG caps
New energy technologies: roadmap Portugal 2050 (NETRP) (2005–2050)	Assess competitiveness of renewable technologies within the Portuguese energy system, identifying the critical drivers for their deployment (Seixas et al. 2010)	Two macro-economic scenarios (1–3 % GDP growth), 101 USD_{2010}/bbl in 2020. −20 % GHG cap from 1990 in 2020. Cost reduction in specific renewable technologies
Low carbon roadmap: Portugal (LCRP) 2050 (2005–2050)	Assess the feasibility of achieving a low carbon scenario for Portugal in the long term. Identification of the energy drivers/technologies for achieving a reduction of −60 % and −70 % of energy related and process GHG emissions in 2050 (Seixas et al. 2012)	Two macro-economic scenarios (0.7–3 % GDP growth), 118 USD_{2010}/bbl in 2020. +1 % GHG cap from 1990 in non-ETS in 2020
Portuguese national action plan on climate change (PNAPCC)—2020 (2005–2030)	Develop cost-effective GHG mitigation policies and measures for 2020 (Seixas et al. 2014)	Two macro-economic scenarios (0.39–3 % GDP growth), 115 USD_{2010}/bbl in 2020. +1 % GHG cap from 1990 in non-ETS in 2020. Explicit EU-ETS prices

We believe this has been fundamental to success, since during the past decade several changes have been influencing the model leading to different results for the same modelled year (Fig. 6). For example, there has been a successive downwards adjustment on the GHG projections and upwards on the RES electricity share. These differences are driven by a number of factors, e.g. differences in scenario formulation, expectations on macro-economic growth; primary energy prices, discount rates, etc. Energy systems are intrinsically dynamic and are affected by a myriad of stakeholders and factors. Therefore, any valuable energy system model has to be continually updated and improved. This is only possible if there are enough resources allocated to this time/consuming task and if there is a dedicated modelling team ensuring continuity. In our experience, such has been possible because of the continued model usage for policy making.

On a different note, common key-findings of all the policy support scenario modelling work are the cost-effectiveness of hydro and wind electricity generation technologies from 2020 onwards, and of the PV electricity plants only with the

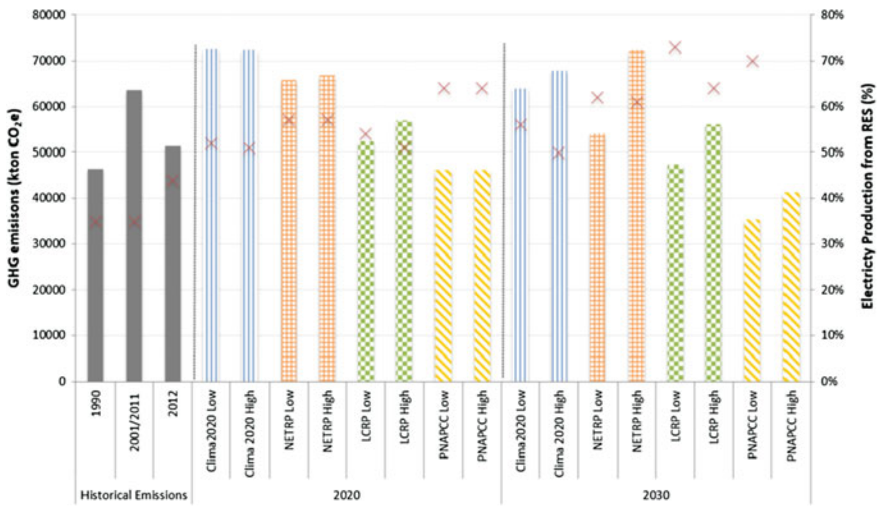


Fig. 6 Projections of GHG emissions (*left axis*) and share of electricity production from RES (*right axis*) for 2020 and 2030 from TIMES_PT within different policy support studies

more recent lower cost data. On the end-use sectors the deployment of electric vehicles is selected, subject to variations in investment costs of around 30 %. On the other hand, the deployment of heat pumps is cost-effective regardless of the several cost updates.

4.7 Discussions and Lessons Learnt

The development of policy studies relies in close cooperation between the modellers and the policy makers that commission them, complemented with frequent meetings with other policy makers and private agents. This process has proven extremely effective for strengthening the role of modelling for policy making, since it enabled the establishment of trust and a common language.

Most of the model inputs have been defined in cooperation with the policy makers that commissioned the studies, particularly the macro-economic assumptions, primary energy import prices, availability of hydrological resources and defining which P&M are in each scenario. The assumptions on energy technologies have been validated with other stakeholders, through a consolidated process (Fortes et al. 2015) including workshops, bilateral meetings and extensive information exchange with the following: Bank of Portugal, Ministry of Economy, Ministry of Transport, associations for production of pulp and paper, chemicals, ceramic, glass and cement; refining companies; electricity utilities; consumer organizations; local and national energy agencies; academia; renewable technologies manufacturers and suppliers and architects. As part of the stakeholder validation process, the files that constitute the model inputs are provided to the stakeholders for validation. Furthermore, extensive work has been done reporting the model inputs and outputs including how the data is generated when applicable (see for example Gouveia et al. (2012b) for the residential energy services demand). This process, albeit substantially time consuming, has been extremely relevant to ensure maximum transparency regarding the model. All the studies have included the opportunity, some within public events, to present results and obtain feedback.

During this process of engaging stakeholders and policy makers a number of challenges has been encountered, in particular the need to find the correct balance between a sufficiently disaggregated model structure, allowing the stakeholders to recognize it and provide useful feedback, and the need to ensure confidentiality in some industry processes coupled with very time consuming data compilation processes.

While involving policy makers, it has been difficult to ensure that TIMES_PT is used as much as possible as an optimization model when it is constrained with assumptions and parameters imposed by policy makers, usually reflecting their expectation of near-term developments, their knowledge on policies that are not fully included in the model or even concerns with eventually politically unacceptable model outcomes. Examples of such assumptions are for example renewable technologies availability factors and minimum activity for certain fossil fuel power plants (Simões et al. 2013). Additionally, policy makers are very demanding on testing new scenarios, perceived as relevant by the policy makers, and are not aware on how time-consuming this task can be. Some of these scenarios do not translate in substantial differences in model outcomes (Simões et al. 2014), particularly CO_2 emissions, which sometimes is very disappointing for policy makers. Finally, a difficulty that should be underlined refers to the need to educate policy makers on the fact that model results provide insights much more than deterministic answers to questions. Although a range of scenarios and results are generated in each policy support process, in several occasions, policy makers have stated: "*Yes, I see all these results, but I just want a number!*"

In conclusion, after ten years of supporting policy makers we have learned the following lessons: (i) opening the model to the stakeholders, public and private, involved in the policy framework is essential to ensure trust and understanding on the model outcomes; (ii) the knowledge on the continuous updates of the model data bases creates a sense of confidence on its outcomes, although they can be different from one modelling exercise to another. This is especially important if the same policy body commissions similar works along the years; (iii) the generation of disruptive scenarios totally different from possible future pathways as perceived by policy makers, usually proposed by the modellers, is very important to give the sense of true alternatives for policy goals and to assess how conservative are the "new" P&M being proposed by policy-makers; (iv) a continuous work with a policy body allows for a high-level cooperation and the recognition that a modelling tool as TIMES_PT, although with limitations, is crucial for policy design, which is directly related with policy evidence.

5 The Experience of IEA ETP Model

5.1 Model Development, Scenarios and Key Findings

In 2001, the Secretariat of the International Energy Agency in Paris launched the Energy Technology Perspectives (ETP) project, with the support of the Energy Technology Systems Analysis Programme (ETSAP) to develop a 15 region global MARKAL model that would be at the heart of the ETP modelling framework.[9] The purpose was to analyse how the deployment of new energy technologies could affect fuel markets, greenhouse gas emissions and energy security (IEA-ETSAP 2001). Over the following four years the model was progressively developed and used to help inform a number of IEA technology studies (IEA 2004, 2005). The ETP project was given significant impetus by the G8 meeting held in Gleneagles, Scotland in July 2005. This meeting launched the G8 Gleneagles Plan of Action on climate change, clean energy and sustainable development and asked the IEA to "*advise on alternative energy scenarios and strategies aimed at a clean clever and competitive energy future*" (G8 2005). As part of its response the IEA began working on a new publication: *Energy Technology Perspectives: Scenarios and Strategies to 2050* (IEA 2006a), which was published in June 2006. This used the ETP MARKAL model to create a "*series of scenarios to demonstrate the role energy technologies that are already available or under development can play in future energy markets*".

The main scenarios were:

1. *Baseline* scenario: includes the effects of technology developments and improvements in energy efficiency that can be expected on the basis of government policies already enacted.
2. *ACT Map* scenario: investigates the potential of energy technologies and best practices aimed at reducing energy demand and emissions, and diversifying energy sources. Focuses on technologies which either exist today or will become commercially available in the next two decades and assumes the successful implementation of a wide range of policies and measures aimed at overcoming barriers to their adoption. Four variants of the ACT scenario were also developed that explore more limited progress in each of four technology areas: renewables, nuclear, carbon capture and storage (CCS) and energy efficiency.
3. *TECH Plus* scenario: makes more optimistic assumptions about the progress for promising energy technologies. Specifically, the scenario assumes greater cost reductions for fuel cells, renewable electricity generation technologies, biofuels and nuclear technologies compared with the ACT Map scenario.

[9] The ETP modelling framework has evolved over time, with the ETP MARKAL (later TIMES) model being supplemented with detailed demand-side models for all major end-uses in the industry, buildings and transport sectors and MARKAL/TIMES models for individual countries and regions.

Based on the results of these scenarios, ETP 2006 concluded that the world was not on course for a sustainable energy future, but that this outlook could be changed. Specifically it proposed a way forward based on strong energy efficiency gains in the transport, industry and buildings sectors, significantly decarbonising the power-generation mix through shifts towards nuclear power, renewables, natural gas and coal with CCS and increased use of biofuels for road transport. The publication highlighted that this would require strong policy action including making energy efficiency the top priority, increasing the budgets for well-focused R&D programmes, creating stable policy environments that promote low carbon options and bridge the *valley of death* between R&D and deployment and increasing international co-operation including between developed and developing countries (Fig. 7).

The key findings from ETP2006 were reported to the St Petersburg G8 summit held in July 2006 and welcomed in a statement from world leaders on Global Energy Security (IEA 2006b). Over the following two years, work continued to develop the ETP model in preparation for a second edition of the ETP publication, including responding to a request from IEA countries for an even more ambitious scenario to address climate change. The next edition of the ETP publication released in June 2008 therefore replaced the *TECH Plus* scenario with a scenario known as *BLUE Map* (plus variants) which envisages a very rapid change in direction of the energy sector leading to a halving of global CO_2 emissions by 2050—consistent with a long term temperature rise of 2–3 degrees (IEA 2008). The ETP2008 modelling showed that halving CO_2 emissions would not be possible with the technologies currently available. Using relatively optimistic assumptions about progress in technology performance and costs, the *BLUE Map* scenario had a marginal cost in 2050 of USD

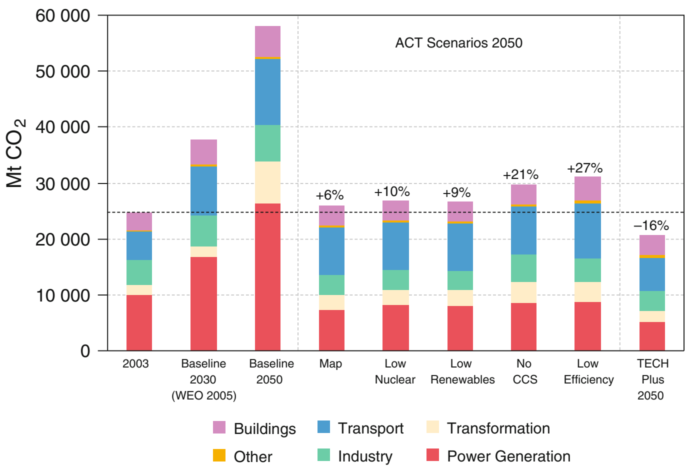


Fig. 7 Global CO_2 emissions in the Baseline Scenario, ACT scenarios and TECH Plus scenario of ETP2006. Based on IEA data from Energy Technology Perspectives © OECD/IEA 2006, IEA Publishing, Fig. 2.1 page 46, License: www.iea.org/t&c/termsandconditions

200 per tCO_2 saved and the technology mix included wide deployment of CCS in the fuel transformation and industry sectors and hydrogen fuel cell vehicles in transport.

By the time the next ETP was released in July 2010 there was a growing realisation that historically high oil prices were starting to impact the world economy. The issues of energy security and economic growth were therefore of significant interest to IEA member countries and this edition used the detailed technological and fuel cost information in the MARKAL model to demonstrate that tackling climate change and improving energy security through lower dependence on fossil fuels were not incompatible with economic priorities. The analysis showed that while realizing the *BLUE Map* scenario would require investments of USD 46 trillion more than the *Baseline* scenario over the period to 2050, over the same period, fuel savings of USD 112 trillion would result. Even if both the investments and fuel savings over the period to 2050 are discounted back to their present values using a 10 % discount rate, the net savings amounted to USD 8 trillion (IEA 2010).

ETP2010 also broke new ground by working with MARKAL analysts and experts in key countries and regions to further develop the regional representation in MARKAL and so present detailed results for OECD Europe, United States, China and India. In the *BLUE Map* scenario, all countries show considerable reductions from the *Baseline* scenario: emissions in 2050 (compared to 2007) were 81 % lower for the United States, 74 % lower for OECD Europe and 30 % lower in China, while India's emissions rose by 10 %.

The 2012 edition of ETP renamed the scenarios according to the long-term temperature rise that was likely to result from each emissions pathway. The baseline scenario therefore became the *6DS* (6° scenario), while the *BLUE Map* scenario became *2DS* and a *4DS* was introduced (somewhat analogous to the previous *Act MAP* scenario). The heart of the modelling framework covering the conversion sector (i.e. transformation of power and fuel) in ETP 2012 was transferred from MARKAL to The Integrated MARKAL-EFOM System (TIMES) model generator, which covered 28 regions and a more detailed depiction of load curves for electricity and heat. The new model was used by ETP2012 to explore the development of three important sub-systems within the energy sector: electricity, heating and cooling and hydrogen. Expanded regional coverage also allowed results to be presented for the first time for Brazil, Russia, South Africa and the ASEAN[10] region (IEA 2012).

The latest edition of ETP published in 2014 focused on the role of electricity in a decarbonized energy system, examining the actions needed to support deployment of sustainable options for generation, distribution and end-use consumption (IEA 2014). All the ETP2014 scenarios showed that electricity's role in the energy system grows faster than any other source and in ETP2014 refined chronological load curves in the TIMES model were used to explore the challenge of balancing supply and demand in greater detail than had previously been possible.

[10] Association of South East Asian Nations.

5.2 Impact of ETP on Global Energy Policy

Over five editions, Energy Technology Perspectives has established itself as the IEA's most important technology publication and a leading source of information for the global energy community. The technology scenarios have been used extensively by a wide range of stakeholders including national governments, international organisations and initiatives, the IEA itself and by academics and other researchers. This success has been due to (i) a flexible framework provided by ETSAP's MARKAL/TIMES model that combines the ability to analyse the technology characteristics of energy systems incorporating both economic and environmental performance data and (ii) access to technology expertise and up-to-date data through the IEA's technology network, consisting of more than 40 multilateral technology initiatives (Implementing Agreements) and more than 6000 specialists covering almost every conceivable energy technology.

A number of national governments have made significant use of the ETP scenarios to support policy-making. For instance, the 2010 and 2011 versions of the US Department of Energy Critical Materials Strategy used the ETP2010 scenarios to develop low and high estimates for materials consumption over the short and medium terms (USDOE 2010, 2011). The report find that many clean energy technologies in the ETP scenarios rely on raw materials with potential supply risks and identifies strategies for addressing these risks. The UK Department of Energy and Climate Change has used the results from ETP2010 to help frame its 2012 science and innovation strategy, highlighting, in particular, the likely large market for clean energy technologies based on the global investment figures from the *BLUE Map* scenario (DECC 2012).

The ETP scenarios are also a key input to many IEA publications including the technology roadmap series, which themselves have proved highly influential in informing the international debate about how best to accelerate the development and deployment of a range of clean energy technologies.[11] Over 20 roadmaps have been published for key low carbon and enabling technologies, describing the potential for transformation across various technology areas, and outlining actions and milestones for the levels of deployment seen in the *BLUE Map/2DS* scenario.

Progress with technology deployment is also monitored in a regular IEA publication *Tracking Clean Energy Progress* that has become an annual input to the Clean Energy Ministerial (CEM).[12] This report tracks each technology and sector against the progress needed to achieve in the IEA BLUE/2DS scenarios. A number of the CEM initiatives have also drawn heavily on ETP scenarios to inform their activities and work programmes including the Bioenergy Working Group, the Carbon Capture, Use and Storage (CCUS) Action Group and the Electric Vehicle Initiative.[13]

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[11] See http://www.iea.org/roadmaps/.

[12] See http://www.iea.org/etp/tracking/.

[13] See http://www.cleanenergyministerial.org/Our-Work/Initiatives.

The ETP publications have also been referred to extensively in the peer reviewed literature, with over 1500 citations in the peer reviewed literature since 2006, including internationally leading journals such as *Nature* and *Science*.

6 Conclusions

This chapter has presented a selection of case studies which recognize the value of ETSAP modelling tools in providing guidance to decision makers on developing energy and climate mitigation policies. The four case studies showed not only the value of providing quantitative assessments of the key challenges and decisions facing governments in the energy and climate policy space. They also provide insights which helped on overcoming the key barriers to acceptance of the transition to a low carbon future.

6.1 Key Lessons for Modellers

The development of powerful, detailed and robust energy systems model expands the capability for developing and analysing technology roadmaps and assessing the impacts of key climate and energy policies. However this is generally not sufficient in itself to establish trust with policy makers and to underpin policy decisions. Energy systems models are by nature complex, very detailed and not easily accessible, and ensuring transparency and understanding of the model outcomes is not simple. However, the experiences presented in this chapter recognize engagement and dialogue to achieve confidence as a key element for a successful outcome. An open and ongoing engagement between modellers, policy makers and stakeholders; frequent meetings and extensive information exchange via peer-reviewed and online publications have proven to be extremely effective for strengthening the role of modelling for policy making, even though this is very time and resource consuming. Sensitivity analysis and runs are also time consuming, but as was demonstrated they generally contribute to increase the robustness perception of the modelling analysis.

Recent analysis also points to need for expanding the range of outputs from energy systems analysis, from a technology-oriented analysis to a more comprehensive approach, assessing the macro-economic impacts (e.g. impacts on GDP, employment, etc.), impacts on land-use patterns, on non-CO_2 emissions, and the impacts of specific sets of technologies (e.g. storage, wind energy, …), etc. of low carbon economies. Additional insights are needed beyond the direct results that are generated by ETSAP models. Further work is required to investigate new methods for gaining additional insights about these new areas.

6.2 Indications for Policy

This chapter demonstrates how IEA-ETSAP energy systems models can provide unique insight to policy makers. They provide a mean of testing the impacts of single (or groups) of policy targets and assessing the implications of alternative future energy system pathways. They also expand the capability of understanding dynamics behind the interactions between the economy (technology choices, prices, output, etc.), the energy mix and the environment. Energy systems models can contribute to move from a *silos-based* approach (focused on single sets of technologies or specific sectors), to a *whole system* approach, where wide sets of technologies, sectors, and regions are analysed together in a robust and integrated manner. The case studies showed how energy systems model can support policy, how they can point to the feasibility of undertaking challenging climate and energy targets and can also help to change the perception of these challenges to governments, stakeholder and public opinion.

However the development of these modelling tools is extremely complex and time consuming; in which the production of scenarios and the analysis represents only a minimal part of the process. To allow models to continue to expand and increase in capability and robustness, sustained resources need to be allocated to establish and maintain a dedicated modelling team, ensuring continuity. The costs associated with energy systems modelling are dwarfed by the economic benefits of robust, well informed policy decisions.

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A Global Renewable Energy Roadmap: Comparing Energy Systems Models with IRENA's REmap 2030 Project

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Abstract In 2014, the International Renewable Energy Agency (IRENA) published a global renewable energy roadmap—called REmap 2030—to double the share of renewables in the global energy mix by 2030 compared to 2010 (IRENA, A Renewable Energy Roadmap, 2014a). A REmap tool was developed to facilitate a transparent and open framework to aggregate the national renewable energy plans and/or scenarios of 26 countries. Unlike the energy systems models by IEA-ETSAP teams, however, the REmap tool does not account for trade-offs between renewable

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_3

energy and energy efficiency activities, system planning issues like path dependency and investments in the grid infrastructure, competition for scarce resources—e.g. biomass—in the commodity prices, or dynamic cost developments as technologies get deployed over time. This chapter compares the REmap tool with the IEA-ETSAP models at two levels: the results and the insights. Based on the results comparison, it can be concluded that the REmap tool can be used as a way to explicitly engage national experts, to scope renewable energy options, and to compare results across countries. However, the ETSAP models provide detailed insights into the infrastructure requirements, competition between technologies and resources, and the role of energy efficiency needed for planning purposes. These insights are particularly relevant for countries with infrastructure constraints and/or ambitious renewable energy targets. As more and more countries are turning to renewables to secure their energy future, the REmap tool and the ETSAP models have complementary roles to play in engaging policy makers and national energy planners to advance renewables.

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1 Introduction

In 2012, the UN Secretary General initiated the Sustainable Energy for All (SE4ALL) initiative with a political call to double of the share of renewable energy in the global energy mix by 2030 compared to 2010. The International Renewable Energy Agency (IRENA) joined the SE4ALL initiative as the hub for renewable energy in the same year. With the United Nations General Assembly declaring 2014–2024 the decade of Sustainable Energy for All, the SE4ALL initiative is now formalized and supported by a global facilitation team.

As an intergovernmental organisation, IRENA was asked by its Members to explore potential pathways to achieve this aspirational target of doubling the share of renewable energy in the global energy mix. This request resulted in the development of a global renewable energy roadmap—REmap 2030—launched in January 2014 (IRENA 2014a).

The main challenge in developing a global roadmap is that the starting point and the potentials to accelerate the deployment of renewables are different per country and per region. For example, the USA and Tonga are two of the REmap countries, but their energy systems are very different from each other. Furthermore, the level of expertise and studies available to explore renewable energy options differs substantially among the IRENA Member countries. Third, the methods used to define renewable energy, renewable energy targets and renewable energy plans differ across countries.

To ensure an accurate representation of country-specific challenges, IRENA developed an analytical framework based on a bottom-up analysis of renewable energy potential in individual country members. In each country, existing renewable energy plans and additional renewable energy options in the 2010–2030 timeframe are identified, and then aggregated at a global level. The 26 countries selected account for around 75 % of global energy consumption, and are representative of different continents.

The tool developed to support this exercise is a relative simple accounting framework. The tool allows national experts to identify additional renewable energy options on top of existing renewable energy expansion plans up to 2030. The advantage of this tool is that it can be applied to all countries and that it provides a transparent way to communicate results with the national experts. However, it does not take into consideration any system constraints, path dependencies or competition for resources that affect both the potential and costs of additional renewable energy (RE) deployment.

There are, however, other tools available to provide a far more detailed analysis of the evolution of energy systems. Among the most widely applied tools are those developed by the Energy Technology Systems Analysis Programme (ETSAP), an implementing agency of the International Energy Agency (IEA). Established in 1976, the programme functions as a consortium of member country teams, mainly using MARKAL and TIMES models to compile long-term energy scenarios. These ETSAP models are bottom-up system engineering tools using least-cost optimisation to satisfy certain system constraints and/or policy objectives. The models can investigate scenarios for the evolution of the energy system, and can also be used to explore which pathway of renewable energy technologies achieves a national renewable energy target with the lowest overall system costs. 20 out of the 26 countries analysed under REmap actually have institutions within their country that are using ETSAP tools.

The ETSAP models are technically far more sophisticated than the REmap tool, but there are a number of specific commonalities and differences between the REmap tool and the ETSAP models that make this comparison of interest. First, both methods are based on technology-specific data, but the REmap tool is limited to energy-supply technologies and electricity-consuming heat and transportation options in the end-use sectors. In contrast, the MARKAL and TIMES models also include the whole range of energy-consuming technologies as well as energy system technologies, like transmission and distribution lines, storage options, etc. Furthermore, in TIMES models, technology deployment in one sector (and region in the case of mult-regional models) will have impacts on deployment levels in the other sectors, while in the REmap tool deployment options are chosen independently. Second, the REmap tool only examines three time instances: 2010, 2020 and 2030. The ETSAP models create time series and the TIMES models even allow for user-defined and flexible length time periods. Third, the TIMES models allow the user to model the construction phase and dismantling of facilities that have reached their end of life internally. The REmap tool assumes that considerations of life time and construction lead times are conducted prior to the selection of additional renewable energy options. Fourth, the ETSAP models allow for multiple regions to be coupled to construct geographically integrated instances, whilst the REmap tool can only be applied to individual countries. Fifth, in the REmap tool energy demand and commodity prices are set exogenously, whilst ETSAP models may include elastic energy demand in the end-use sectors as well as endogenous price setting of commodity prices and energy costs.

The aim of this study is twofold. The first aim is to understand whether the simplified REmap tool creates comparable results with the more sophisticated ETSAP models. The second aim is to understand the appropriateness and complementarity of the usage of both the REmap tool and ETSAP models.

2 Methodology

This methodology section discusses the REmap tool as well as the methodology used to compare the results of ETSAP models with the REmap results.

2.1 REmap Methodology

REmap is based on a bottom-up analysis of existing renewable energy plans and additional renewable energy options between 2010 and 2030 in 26 countries located

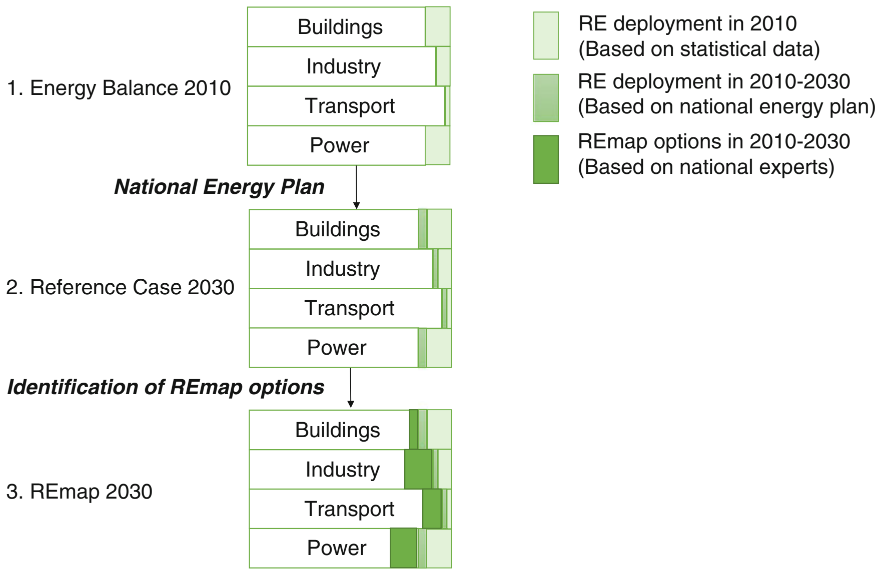

Fig. 1 The analytical steps to develop the REmap analysis

on five different continents (Saygin et al. 2015). For each country analysis, IRENA works together with a REmap expert nominated by the country. Figure 1 shows the three steps in the REmap process. First, data on the national energy balance in 2010 is collected by IRENA and verified by the country expert. Second, the REmap expert provides information on existing renewable energy plans between 2010 and 2030. Based on this information, a national energy balance for 2030 is derived. This is called the **Reference Case**. If no national energy plans are available, IRENA works with national REmap experts to make a business-as-usual projection based on data collected from literature and other sources. Third, together with the national REmap experts and based on existing reports and studies, additional renewable energy options are identified. These are called the **REmap Options**. The technical feasibility of each additional REmap Option is assessed based on resource availability, constraints in the local supply chain, and policies in place promoting or inhibiting further growth of renewables.

At each step, the renewable energy share for both the national energy system and the different subsectors of buildings, industry, power and transport is calculated. The renewable energy share is measured as a percentage of total final energy consumption (TFEC) within a given country or region or sector.[1] Within TFEC—in particular in

[1] The approach is in line with the Global Tracking Framework (GTF) of the SE4ALL initiative, but differs from the EU Directive on Renewable Energy (Article 5, 2009/28/EC) which calculates the RE share based on **gross** final consumption, which includes any RE based electricity and/or heat transmission and distribution losses, including in-house load in power plants.

the IEA statistics used as the basis for the national energy balances—heat and electricity are reported directly in the form ready for consumption although other primary energy sources (for example, fossil fuels and bioenergy used for heating in the residential sector) are still reported in terms of their fuel content. Furthermore:

- Electricity consumption for aerothermal, geothermal and hydrothermal heat pumps is included in TFEC, but the approach excludes the heat energy captured by these pumps.
- RE that is exported is not included within the RE share.
- TFEC excludes non-energy uses of energy sources such as their use as raw material for the production of plastics and chemicals.
- TFEC is computed according to the aggregation used by the IEA statistics.

The identification of additional renewable energy options is the most important step of the process. For each additional renewable energy option, the REmap expert has to determine what conventional energy technology option will be replaced. For example, additional wind power generation capacity will result in less coal, gas, or nuclear power generation capacity (or a combination) built in the period between 2010 and 2030. For each replacement, the tool calculates the so-called 'substitution costs', which is based on the difference in costs of the conventional energy technology—assumed to be in place in 2030—and the renewable energy option that has replaced the conventional energy technology.

Based on this approach, each country analysis results in the creation of a cost supply curve (Fig. 2). The x-axis represents the share of RE in final energy consumption in 2030. The y-axis represents the cost difference per unit of energy consumed [in real 2010 US Dollars per gigajoule (USD_{2010}/GJ)] between renewable and conventional energy technologies. This so-called "annualized incremental cost of substitution"[2] is calculated for each RE technology based on the costs to substitute one unit of final energy generated by non-RE technologies with the costs of one unit of final energy generated by the RE technology. The costs are based on national projections for the capital and operational and maintenance (O&M) costs, and the technical performance of conventional and RE technologies.

To allow for comparison and aggregation of results across multiple countries, standardized energy commodity prices for oil, gas and coal (without any subsidies, taxes, or levies),[3] a standardized cost calculation for electricity prices (based on the maximum RE penetration in 2030), and a fixed 10 % discount rate based on IRENA's costing studies (IRENA 2013) are used to calculate the annualized costs of both RE and conventional technologies. The fixed discount rate (for all countries and technologies) is chosen to allow for comparable results, whereby 10 % is

[2] Referred as "substitution cost" throughout this report.

[3] For coal, natural gas, biomass and electricity, exceptions were made as it is not possible to assign global values that are representative for all countries. Coal and natural gas prices are distinguished between exporting and importing countries. Biomass prices are determined at a regional level with a breakdown by energy crops, residues and waste. Electricity prices are determined for each country.

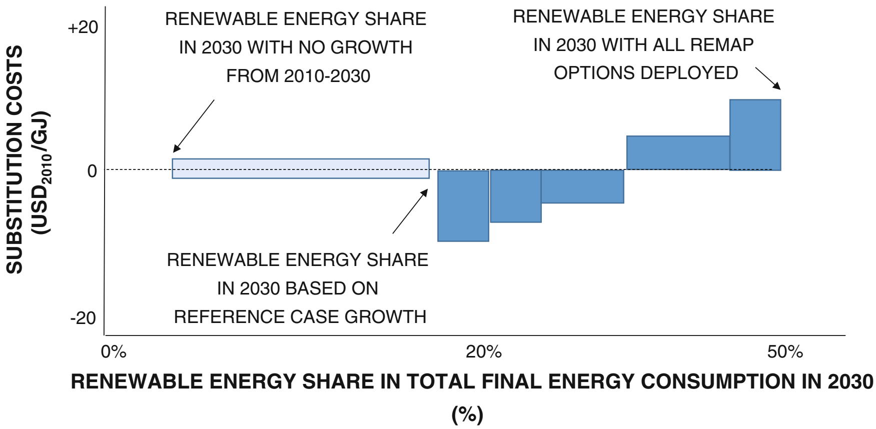

Fig. 2 The REmap cost supply curve

chosen as a middle ground between the costs of capital for energy projects in developing countries (indicative range of 15–20 %) and OECD countries (indicative range of 6–12 %). The costs are expressed in USD_{2010}/GJ.

In the electricity and heat sector, one unit of final energy generated by an RE technology substitutes the same amount of energy produced by a non-RE technology. In other words, one MWh of coal-based electricity production would be replaced by one megawatt-hour (MWh) of solar-based electricity production. For the end-use sectors, one unit of final energy used by an RE technology substitutes the units of final energy which would have been otherwise used by a non-RE technology to deliver the same amount of useful energy. Electricity consumption of heat pumps to generate heat (e.g. for space heating) from various sources including air, geothermal, hydrothermal, is included in the TFEC of the respective end-use sectors (e.g. residential sector). However, heat consumed by the end-use sectors is not reported separately in the TFEC. Substitution costs of heat pumps are expressed in USD per GJ of heat produced. To estimate heat production, the co-efficient of performance (COP) is used. The costs are calculated as follows:

Substitution cost of an RE technology for the energy transformation sector is estimated as "*(annualized costs of RE technology to generate 1 petajoule (PJ) of electricity or heat—annualized costs of non-RE technology to generate 1 PJ of electricity or heat)/total RE electricity or heat generated*".

Substitution cost of an RE technology for the end-use sectors is estimated as "*(annualized costs of RE technology to generate 1 PJ of useful energy—annualized costs of non-RE technology to generate 1 PJ of useful energy) /total RE final energy used to generate 1 PJ of useful energy*".

The cost supply curve contains two separate sets of data (Fig. 2). The first part of the curve represents the increase in the renewable energy share between 2010 and 2030 based on the Reference Case. Since the existing national energy plans are assumed to be the baseline, no costs are associated with the renewable energy expansion in the Reference Case. The second part of the curve shows the REmap Options. The width of each REmap Option is determined by the absolute amount of renewable energy consumption entering the system, and is represented on the x-axis as an increase in the renewable energy share in 2030. For each REmap options, the substitution costs are determined by the conventional energy option being replaced.

2.2 Comparing REmap and ETSAP Modelling Results

For the comparison of the results, IRENA provided the ETSAP modellers with the following data:

- Data sources for Reference Case and REmap Options;
- Total energy consumption and RE deployment in the Reference Case per sector, expressed in PJ or GWh;
- The assumed commodity prices and discount factors for 2030. These assumptions impact the cost calculations;
- List of REmap Options, expressed in PJ and with associated substitution costs;
- RE shares in the end-use sectors in 2030 in the Reference Case as well as after the REmap Options.

Based on this information, the ETSAP modellers performed clusters of multiple model runs for the year 2030 for the specific purpose of this chapter. The first model run targets the RE share in 2030 as suggested by the Reference Case. Each subsequent model run increases the RE share by a certain percentage up to the RE share achieved by the REmap Options. The RE share are only applied at a national level, and not to individual subsectors.

The approach is illustrated with the Irish TIMES model (Ó Gallachóir et al. 2012). The x-axis shows the total share of RE in TFEC by 2030, while the y-axis shows the system cost difference of each REmap scenario from the *Reference Case*. For each target scenario pathway, a scenario file has been created (e.g. in the case of Ireland, as shown in Fig. 3 we have the *Reference Case* with 16 % by 2020, and 16 % by 2030; the *REmap-18* case with 16 % by 2020, 18 % by 2030, etc.). The supply curve was built comparing differences in total system costs between scenario runs. The costs of additional RE options are only positive (incremental), because, unlike in the REmap analysis, the negative costs (savings) are already embedded in the *Reference Case* (objective minimization of total system cost).

Given the nature of MARKAL-TIMES models (vertical and horizontal competition), multiple substitution technologies and/or efficiency measures are selected as the model optimizes for an increasing share of renewables in the system. The contributions of individual renewable energy technologies (and the conventional technologies that have been substituted) are identified afterwards from results analysis, as shown in Fig. 3.

Furthermore, each scenario is run individually, which means that the system changes (i.e. electrification of the transport sector) under a 16 % scenario target

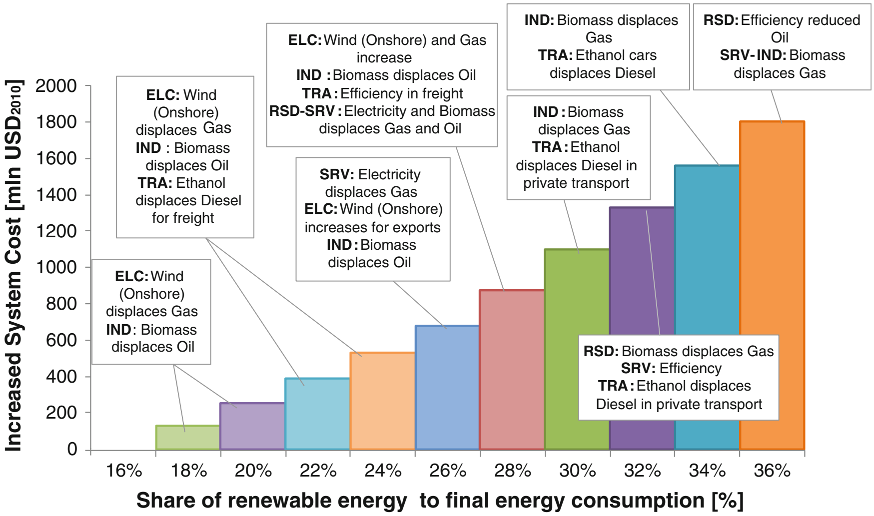

Fig. 3 Illustrative cost supply curve for Ireland. Information on the x-axis and y-axis show the share of RE in TFFC and the increased system costs, respectively

might not apply to the 18 % scenario target. Furthermore, some system changes might be reversed at a later stage. Any discontinuities are highlighted in the results analysis.

Implementation of REmap scenarios in the Irish TIMES model

The implementation in single MARKAL-TIMES models strongly depends on the model structure. In Irish TIMES the cost supply curve has been built performing a cluster of 11 model runs with the Reference Case as a starting point, in which Ireland's energy system must deliver at least 16 % renewable energy penetration by 2020 (the EU RE Directive target for Ireland for the year 2020), and is then assumed to maintain this share in the period 2020–2030. Each individual *REmap* scenario run then increases the RE share by 2 percentage points resulting in a final scenario of 36 % RE share by 2030 (Fig. 3).

Furthermore, the amount of RE consumed (measured as a share of total final energy consumption, or TFEC) was simply evaluated as the sum of green certificates produced by renewable technologies in the electricity generation sector and the end use sectors. In Irish TIMES green certificates are automatically generated by the model when renewable fuels are consumed in electricity, heat and transport sectors. The EU Directive sectoral specific target of 10 % renewables in the transport sector (with different weightings for different biofuels) was excluded in the Irish TIMES *REmap scenarios*.

Table 1 Overview of ETSAP models and the assessed range of RE share in TFEC in 2030

Model	Country/Region	RE share in Reference Case (%)	RE share with REmap Options (%)
TIAM-ECN	Global	18	36
TIAM-WORLD	Global	18	37
TIMES-FR	France	27	42
Irish TIMES	Ireland	16	36
TIMES-Italy	Italy	9.5	19
JMRT[a]	Japan	20	44
TIMES-PT	Portugal	33	62
FACETS	USA	8.3	16.7

[a] *Japan Multi-regional Transmission Model* RE shares are for electricity sector only

Table1 provides an overview of the models for which the results were compared with the REmap analysis. The starting point for each model has been the RE share in the Reference Case. For the case of Ireland and Portugal, the Reference Case was based on the EU RE Directive target for 2020 and extended towards 2030. For the case of Italy, the government's new energy strategy (*Strategia Energetica Nazionale*, SEN) was used as the *Reference Case* and the ETSAP model was used to identify and quantify the REmap Options.

In the following two subsections, the results of these comparative analyses are used to explore the aims and main questions outlined at the outset of this chapter:

1. How do the REmap Options identified by national experts compare to the renewable energy deployment identified in ETSAP models (Sect. 3)?
2. How can the different insights derived from the ETSAP models and the REmap tools be used to support policy makers (Sect. 4)?

3 Comparing Results

This section answers the question of whether the results of the simplified REmap tool are in line with the results of the more sophisticated ETSAP models. The results of the REmap tool and the ETSAP models are compared on three levels:

- Deployment of renewable energy technologies (in PJ or GWh) in 2030 (Sect. 3.1);
- The sequence with which renewable energy technologies are deployed to increase the share of RE (Sect. 3.2);
- The additional overall system costs compared to the Reference Case (Sect. 3.3).

3.1 Comparing Results: Deployment Levels in 2030

Table 2 presents some comparative deployment numbers in the ETSAP models and REmap results for France, Japan and the world (Ireland and Portugal were not part of the initial set of 26 REmap countries).

These results show that considering the differences in the overall RE share in 2030 (ranging between 0 and 5 %) in each country, the deployment levels of individual renewable energy technologies between the ETSAP models and the REmap results are comparable. In the case of France and Japan, the national REmap experts have assumed higher deployment levels of hydropower but lower levels of solar photovoltaics than the ETSAP models. This might be due to the fact that in the ETSAP models the deployment levels are a function of their techno-economic characteristics in 2030, whilst the deployment levels in the REmap tool is a deliberate choice of the national experts. For technologies like solar photovoltaics that are currently at a relative low deployment level, it might be difficult for these national experts to envision their rapid growth of deployment. Similarly, the biggest difference can be found in solar photovoltaics deployment at a global level, but this might also be explained by the fact that the TIAM-WORLD model targets 37 % RE share, whilst the REmap analysis only achieves 28 %.

3.2 Comparing Results: Substitution Choices

The comparison of absolute deployment levels in Sect. 3.1 provides a static picture of the deployment levels in 2030. The REmap model, through its cost supply curve, and the ETSAP models also allow for a comparison of the relative costs of different RE options. In the case of the REmap cost supply curve, individual RE options

Table 2 Comparison of deployment levels of renewable power generation in ETSAP models and the REmap tools in 2030

	TFEC (EJ)	RE share (%)	Hydro (TWh)	Wind (TWh)	Solar PV (TWh)
TIMES-FR	5.1	42	67	89	33
REmap France	5	40	83	89	30
TIMES-IT[a]	115.8	40	48	29.3	28.7
REmap Italy[a]	115	40	50	29.4	29
JMRT[b]	4	43.7	93	188	146
REmap Japan[b]	4	40	127	113	121
FACETS	68	16.7	251	650	361
REmap USA	66	27	430	994	235
TIAM-WORLD	491	37	5673	4043	3150
REmap World	448	28	5907	5279	1807

[a] TIMES-IT was used to populate the REmap tool for Italy

[b] Power sector only

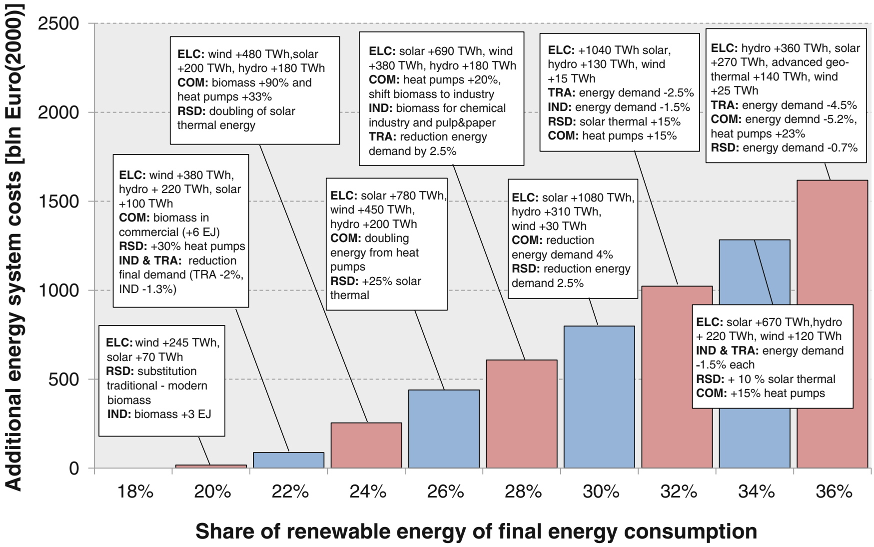

Fig. 4 Global marginal cost curve for the renewable energy share of gross final energy consumption in 2030 based on TIAM-ECN. *N.B.* (1) additional system costs refer to the Reference Case with a renewable energy share in 2030 at today's level of 18 %. (2) Descriptions in the boxes refer to effects of the incremental increase. (3) Abbreviations for sectors *ELC* elcectricity, *IND* industry, *COM* commercial and agriculture, *RSD* residential, *TRA* transport

contributing to the RE share in 2030 are displayed in order of increasing costs. The ETSAP models, by virtue of their economic cost optimization, choose the most economic options contributing to an increasing RE share. This means that the REmap Options on the left side of the curve (the cheaper options) would also be the first options that would be chosen by the ETSAP models to increase the RE share. A key difference between the REmap tool and the ETSAP models is that the latter also may choose energy efficiency options or structural changes to the energy system to increase the RE share.

Figures 4 and 5 show the sequences of RE options identified by the TIAM-World and TIAM-ECN models as the RE share increases from 18 to 36 %. These results can be compared to the global REmap cost supply curve.

The TIAM-ECN [for model description see Rösler et al. (2011), Keppo and van der Zwaan (2012), Kober (2014)] model shows that early opportunities to increase the RE share arise from the shift of biomass from traditional use to modern biomass use in the residential sector, but also an increased biomass use in the commercial sector and in industry.[4] Additional least cost opportunities to accelerate RE growth in the residential and commercial sectors include heat pumps and solar thermal appliances for room

[4] Traditional uses of biomass is not included in the renewable energy share, hence a shift to modern uses of biomass increases the share of RE.

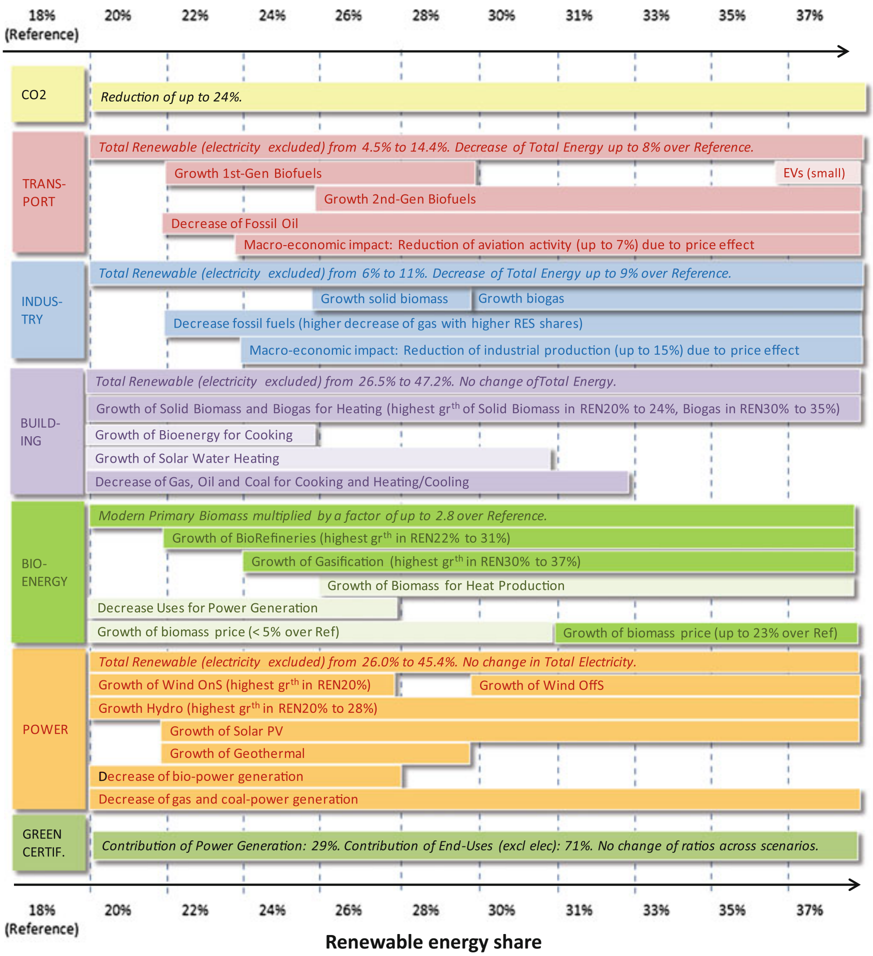

Fig. 5 Technology options with increasing RE share in the TIAM-WORLD model

heat and warm water production. For electricity generation from RE, wind offshore technology represents the least cost option, and contributes with additional 1000 TWh to increase the RE share of gross final energy consumption from 18 to 26 %.

The more costly options for increasing the RE share, which are deployed at shares higher than 26 %, include measures and technologies to diminish the total final energy demand, such as more efficient engines for road transport, and also more expensive options for the production of RE-based electricity. For RE-targets above 28 %, electricity generation from wind (onshore and offshore) is almost fully deployed (in total about 1300 GW), and additional capacity from RE technology is commissioned based on solar (mainly CSP and PV at sites with lower full load hours), small hydro power plants and advanced geothermal power plants.

At high levels of RE shares, strong reductions in energy demand use (−4.5 % in the transport sector, −5 % in the commercial and agricultural sectors) are the most cost-effective options to increase the RE share. In the TIAM-ECN model, most of the reductions in energy demand in the transport sector are realised through improvements of energy efficiency, such as more efficient engines, low resistant tires and improved aerodynamics for cars. In the commercial sector, energy savings are achieved through energy efficiency. The introduction of renewable energy targets failed to provide sufficient incentive for more substantial technology switches, such as electric cars, hydrogen vehicles or fuel cell technology in the commercial sector.

In the TIAM-WORLD model [see recent applications in Kanudia et al. (2014); Labriet et al. (2012)], bioenergy also plays a crucial role in increasing the RE share, especially in the end-use sectors. More specifically, biomass-based power generation decreases up to 26 % whilst modern biomass and biofuels increase. At higher RE shares (>30 %), biogas use in industry and for heating purposes in the building sector increase strongly (Fig. 5).

In the power sector, hydropower and onshore wind exhibit the highest growth levels at low RE shares. At higher RE shares, offshore wind and solar photovoltaics are used to increase the RE share. Similar to the TIAM-ECN model, solar water heating is one of the early technologies that is used to increase the RE share. Battery electric vehicle are only deployed at RE shares above 35 %.

In comparison, Fig. 6 shows the technology options of the REmap global cost supply curve. The brackets above each option indicate the number of countries in which the RE options is deployed. Similar to the ETSAP models, biomass options

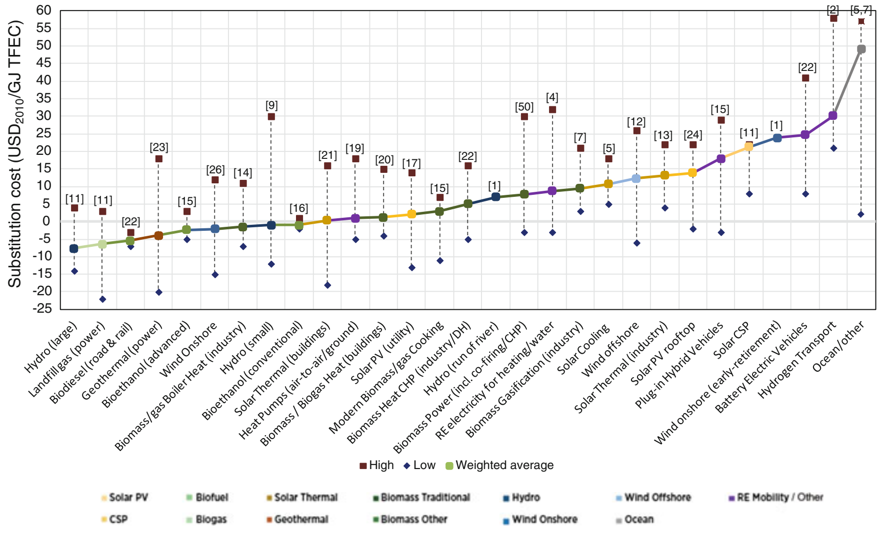

Fig. 6 Ranges of substitution costs of REmap Options in the 26 REmap countries based on the perspective of governments in 2030

are among the least-cost options to increase the RE share of modern energy use, except for biomass gasification. Solar thermal and heat pumps are cost-effective options in the buildings sector. In the power sector, hydro, wind and geothermal are the least cost options followed by solar photovoltaics. The more expensive options are solar photovoltaics on rooftops, solar concentrated solar power, and the upgrading/repowering of existing wind parks [indicated as "wind onshore (early retirement)"]. Similar to the TIAM-WORLD model, battery electric vehicles are one of the most expensive options to increase the RE share.

A similar analysis is possible at a country level. Figure 7 shows the REmap cost supply curve of the USA (IRENA 2014b). Figure 8 shows the RE options contributing to an increasing RE share in the FACETS model (for model description see Wright and Kanudia (2014) and http://facets-model.com).

The results from the FACETS model and the REmap tool show that the main contributors (wind, solar PV, biomass heat and electricity production, and biofuels) to an increasing renewable energy share are the same, but they differ in terms of the sequence with which they are deployed. These differences are partly due to the different RE targets for 2030. Wind power (nr. 4 in Fig. 7) is one of the cheaper options in the REmap tool, but is only chosen at a later stage in the FACETS model. Similarly, biofuels seem to be a technology option that is relatively cheap in the REmap tool (nr. 7 in Fig. 7), deployed at later stages in the FACETS model.

One explanation for the differences is the explicit choice for substitution technologies that is offered by the REmap tool. In the USA analysis, national REmap analysts determine that the additional renewable power generation would mainly

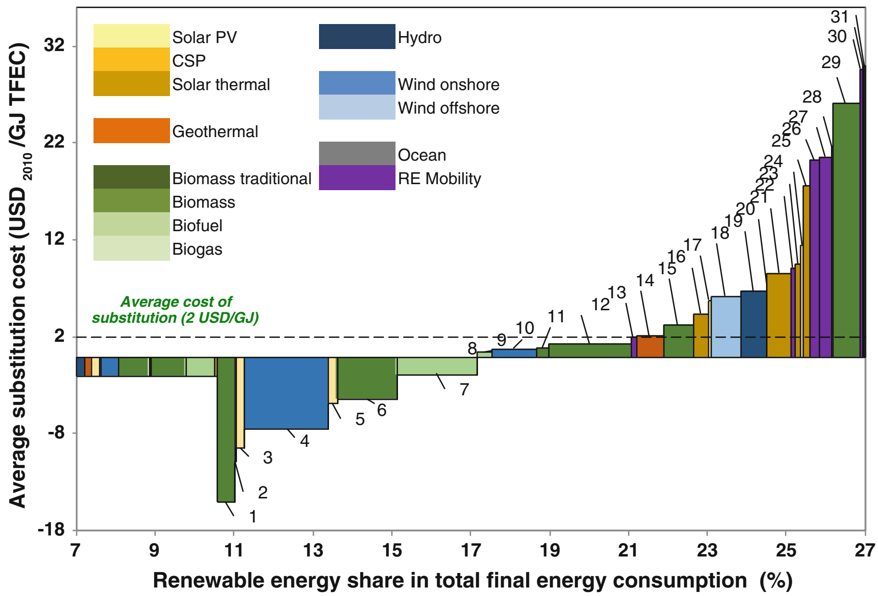

Fig. 7 REmap Options cost supply curve, government perspective, by resource

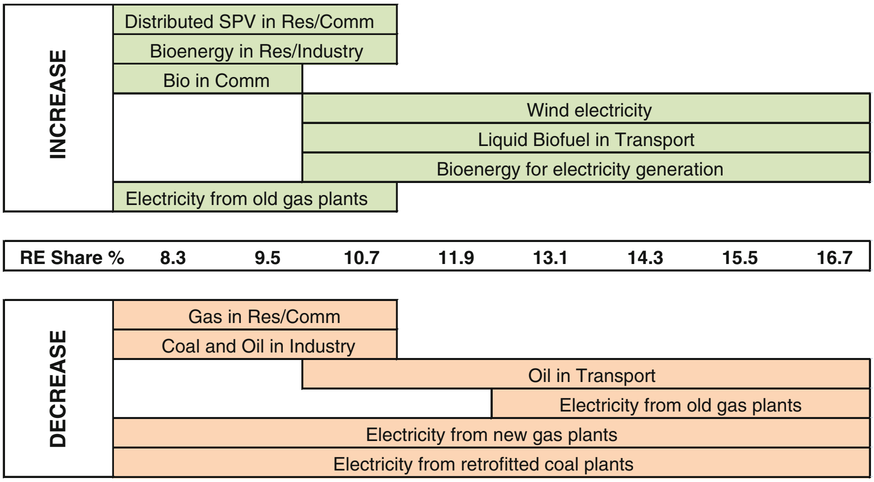

Fig. 8 RE technology options in the FACETS model

replace United States Environmental Protection Agency (EPA) compliant conventional coal (89 %), new nuclear (6 %) and advanced coal carbon capture and storage (CCS) (5 %). In contrast, the FACETS model chooses to rely on electricity production from old inefficient gas plants to support the variable renewable power generation production from distributed solar photovoltaics, and replace both new and old gas plants as the renewable energy share is increased. In the industry sector, the substitution choice is also different with the FACETS model replacing coal and oil, whilst the national experts replaced mainly natural gas usage.

3.3 Comparing Results: System Costs

The third indicator to compare the REmap results with the ETSAP models are the total system costs for a transition towards renewables. This comparison, however, should be made cautiously as:

- The REmap tool only examines the year 2030, and assumes linear deployment rates for RE deployment between 2010 and 2030;
- The REmap tool only examines the substitution costs of the renewable energy technologies, and does not consider the costs of energy efficiency improvements;
- The REmap tool does not consider costs in transmission and distribution networks, or other infrastructural investments, required to support the additional renewable energy deployment (Table 3).

The comparison at a global level shows that the estimated system costs are in the same order of magnitude, although it is clear from the limitations of the REmap tool that ETSAP models are better suited for an assessment of system costs. For the year

Table 3 Comparison of incremental systems costs over the Reference Case for the ETSAP models and the global REmap results

Model	Incremental system costs (USD_{2010})[a] (billion)	Discount rate (%)
Global REmap	1450	10
TIAM-ECN	1980	10
TIAM-WORLD	5582	5
TIMES-FR	58	10
Irish TIMES	1.8	6
TIMES-PT[b]	5.6	10
FACETS	865	5

[a] The costs are converted into USD_{2010} using the official exchange rates and consumer price indexes provided by the World Bank (http://data.worldbank.org/indicator/PA.NUS.FCRF and http://data.worldbank.org/indicator/FP.CPI.TOTL)

[b] For decentralized solar PV on residential rooftops, a discount rate of 17.5 % was used to reflect family decisions

2030, the REmap tool estimates total additional system costs of USD_{2010} 145 billion. An approximate level of additional system costs over the 2010–2030 period would be USD_{2010} 1450 billion assuming linear increasing deployment levels of renewables.[5] In comparison, the total additional energy system costs estimated by the TIAM-ECN model are around USD_{2010} 1980 billion, and for the TIAM-WORLD model USD_{2010} 5580 billion (discount rate of 5 %). The higher system costs observed in TIAM-WORLD are explained by the lower discount rate (system costs obtained with a 10 % discount rate are in the range of USD_{2010} 1340 billion.

The incremental system costs for the national models highly depends on the system size, national cost assumptions, absolute deployment levels as well as the different financial indicators used. More detailed information would be required to make a one by one comparison across the national results.

4 Comparing Insights

The second question is how the different insights derived from the ETSAP models and the REmap tools can be used to support policy makers, and when and where the REmap tool and ETSAP models are appropriate to use. One clear advantage of the ETSAP models is their ability to examine changes at each time step, whilst the REmap tool only provides results for a single year (essentially assuming that all

[5] For a proper comparison, additional assumptions would be required in terms of the energy commodity prices (oil, coal, gas, biomass, electricity, etc.), and capital and operational cost development for both renewable and conventional energy technologies over the 2010–2030 period.

system changes occur instantaneously). However, there are also a number of other features that are included in the ETSAP models but excluded from the REmap tool:

- The inclusion of infrastructural systems to examine the transition towards renewables (Sect. 4.1);
- The dynamic interaction and competition between different renewable energy technologies and resources (Sect. 4.2);
- The inclusion of both energy efficiency and renewable energy options (Sect. 4.3).

Furthermore, we explore the use of ETSAP models as input into the REmap tool.

4.1 Comparing Insights: Infrastructural Features

The REmap tool assumes that any costs associated with infrastructural investments that will take place in the Reference Case will also support the deployment of renewable energy options. In the ETSAP models, these infrastructural requirements can be explicitly modelled and taken into consideration. The results of the JMRT model show this most clearly (Hamasaki and Kanudia 2013). The model comprises 10 grids with weak inter-grid connections, using geographically specific resource data and GIS data to calculate distances to and from roads and grids, as well as seabed depth. In Japan, the greatest potential for onshore wind lies in the Northern regions, while the Southern region has great demand but limited potential, resulting in geographical supply-demand mismatch. Given the current state of Japan's power grids, the full potential of onshore wind in the north cannot be tapped without new interconnecting facilities.

Grid expansion changes the portfolio of renewable energy technologies selected under a 44 % renewable energy target. Onshore wind deployment levels increase and geothermal and offshore wind decrease (±10 % on deployment levels). The model also shows that despite the increased costs for the interconnecting facilities, the overall system costs will be marginally lower with grid expansion.

The impacts of infrastructure on the deployment levels of renewable energy technologies is an important insight for policy makers, especially since in the case of Japan they substantially alter perspectives for onshore versus offshore wind deployment. However, the JMRT model also shows that substantial model enhancements are needed to address these issues, including the introduction of subregions, increased data requirements and higher computing power.

In general, it seems that the inclusion of infrastructural constraints increases the insights provided by the ETSAP models, but the demand for model development and data requirements are also substantially higher than the REmap tools. As the renewable energy shares, especially those of wind power and solar photovoltaics, increase, the insights from the ETSAP models on infrastructural requirements and investments will become more important for policy makers.

4.2 Comparing Insights: Competition of Technologies and Resources

The REmap tool allows the national policy makers to identify additional individual renewable energy options to be deployed above and beyond the Reference Case. The deployment levels for these additional RE options should be based on an assessment of the available resources, energy demand, supply chain constraints and political barriers for each of the individual RE options. However, the REmap tool does not force the analyst to consider competition between different REmap Options, except for the fact the overall deployment levels are limited to the energy demand within a given sector.

In the ETSAP models, there is endogenous competition between the different RE technologies to satisfy the RE share that is set for the year 2030 most cost effectively. Figure 9 shows this competition for the case of TIMES-FR (Assoumou and Maïzi 2011). The results show the difference in deployment levels between the *Reference Case* to achieve a 27 % RE share, and higher RE shares. The results show increasing levels of solar heating deployed to satisfy the increasing shares of RE. However, beyond 36 % it becomes more cost-effective to deploy solar photovoltaics systems rather than solar water heaters. Due to space limitations associated with rooftops, this leads to a decrease in the deployment of solar water heaters. Similarly, the results show that to achieve higher shares of RE the deployment levels of biofuels in the transport sector drop in favour of biomass usage for heat and power. Furthermore, additional biogas production based on energy crops is used to increase biomass usage at higher renewable energy shares.

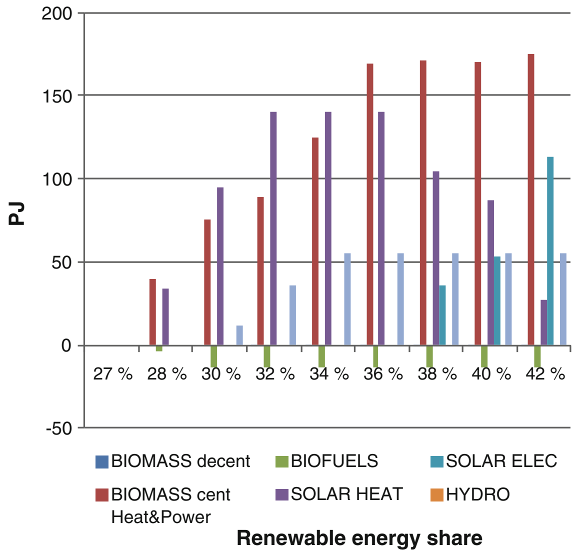

Fig. 9 Increase of renewables per source (vs. 27 % case) in TIMES-FR

Similar dynamics can be observed in the Irish TIMES model (Fig. 3). In that particular case, the deployment levels of biomass in the commercial sector decreases in favour of increased levels of biofuel usage in the transport sector as the renewable energy share increases from 30 to 32 %.

The competition between renewable energy resources and technologies is an important insight that can be gained from the ETSAP models, and that can inform the deployment levels of renewable energy technologies considered in the REmap tool. These insights seem to be particularly relevant for biomass, which is a renewable energy technology that can be used in the power sector as well as all of the end-use sectors. Consequently, countries that have high levels of biomass use should complement any REmap analysis with more detailed ETSAP models to understand how competition between the different end-use sectors may affect both the prices of biomass commodities as well as the deployment levels.

4.3 Comparing Insights: Energy Efficiency and Rational Use of Energy

Energy efficiency can substantially contribute to higher shares of renewables by reducing overall energy consumption. The REmap tool only considers energy efficiency measures that have been considered in the Reference Case, and as such determine the national energy balance in 2030. In contrast, the ETSAP models explicitly consider additional energy efficiency measures to increase the share of renewables.

All of the ETSAP models show that energy efficiency measures and the reduction of energy service demand are very important tools to increase the RE share, especially when RE shares are reaching levels above 30 %. Figure 10 shows such results at a national level for the TIMES-PT model created for Portugal (Simoes et al. 2008), whilst Fig. 11 shows the impact of energy efficiency options at a global level.

The results derived from a national model with elastic demand show that the total system costs decrease with an increasing share of renewables from 40 to 41 %. This is due to a reduction of energy service demand with impact in the total system costs. For other RE targets, this impact is not visible since other costs like investment costs are high enough to hide the effect of the reduction of services demand.

In Fig. 11, the contribution of renewable energy and energy efficiency options in each step increase of the RE share is examined. From 26 to 34 %, the share of RE increases primarily due to an increase in consumption of electricity and district heat generated from RE, which replace non-RE electricity. In this range of RE targets, we see a change in the generation mix on the supply side rather than substantial changes on the consumption side, including relatively small changes in the total final energy consumption. As a consequence, increasing RE supply outweighs demand-reduction-effects. With respect to the drivers for demand reductions, the model approach does not allow for a strict distinction between technology-related energy efficiency improvements, energy saving measures and demand reductions due to changes in the

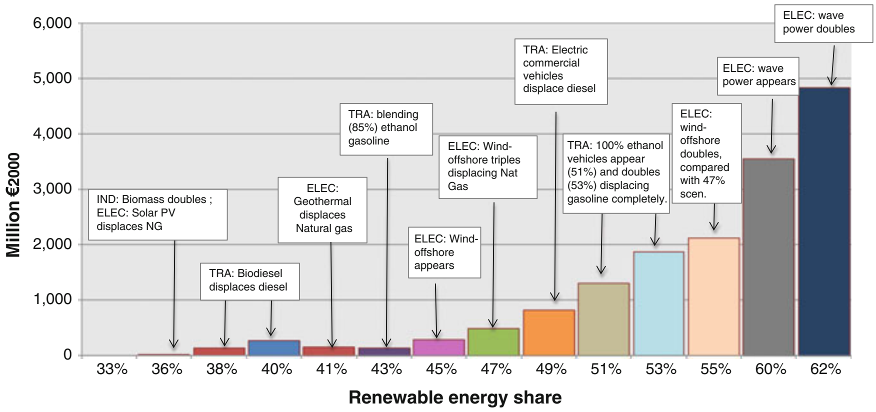

Fig. 10 National cost supply curve for Portugal from the TIMES-PT model

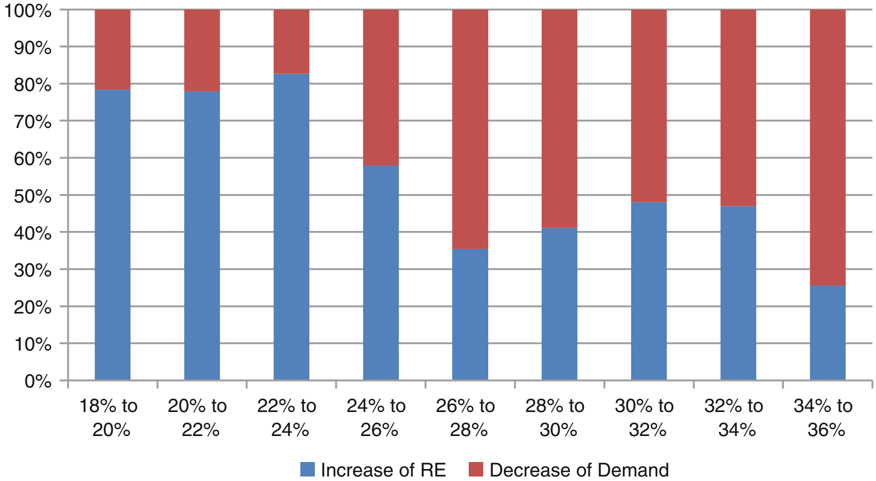

Fig. 11 Decomposition of RE and demand (TFEC) effects for each step to increase the RE share in the TIAM-ECN model

demand pattern. However, in general two thirds can be allocated to reductions in energy services demand, which also include energy saving measures, and one third to technology-based energy efficiency uptake.

In conclusion, the REmap tool seems to be sufficient to examine and explore deployment levels of renewable energy options up to around 30 % of TFEC. However, as countries are moving towards higher shares of renewables they simultaneously need to consider additional energy efficiency options available to decrease overall energy consumption and therefore increase the renewable energy share.

4.4 Comparing Insights: ETSAP Models as Input into the REmap Tool

An alternative way to use the ETSAP models is to populate the REmap tool. For the case of Italy, the TIMES-Italy model (Gaeta and Baldissara 2011) was used to estimate the substitution costs for individual renewable energy technologies (in EURO/GJ) by running multiple scenarios towards a set RE share in 2030, and removing or decreasing constraints on a specific RE technology group one at a time. For each scenario, the incremental system costs were computed, and attributed to the RE technology group. Figure 12 shows the results of this analysis.

These results show that the substitution costs per renewable energy option are comparable to the substitution costs identified in other REmap countries and at a global level. For example, Fig. 12 shows that the range of substitution costs between −10 and +50 USD/GJ in the case of Italy falls within the range of substitution costs from −20 to +60 USD/GJ identified in the REmap tool (Fig. 6). The renewables share at the x-axis does not include traditional biomass, as in the IRENA methodology.

In the case of Italy, where the ETSAP model is used to develop national renewable energy plans, it made sense to use the ETSAP results to populate the REmap tool. Subsequently, this allowed an aggregation of Italy at a global level. However, many of the more detailed insights of the ETSAP models are lost and substantial efforts are needed to run the multiple scenarios. Therefore, the use of ETSAP models to populate the REmap tool only makes sense if countries' national

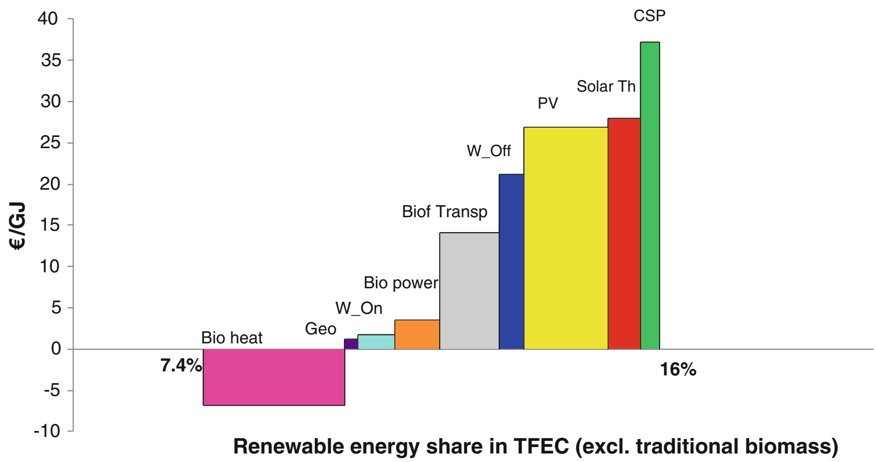

Fig. 12 Substitution costs of REmap Options by TIMES-Italy

renewable energy plans are based on ETSAP models and these plans need to be simplified to compare and aggregate at a global level.

5 Conclusions

In this chapter, we have examined a number of indicators to determine whether the simplified REmap tool creates comparable results with the more sophisticated ETSAP models, and to understand the appropriateness and complementarity of the usage of both the REmap tool and ETSAP models.

For the comparison of the results, we have examined the deployment levels, the substitution choices, and the system costs. The comparison of deployment levels of renewable energy options in 2030 shows that the results are similar. The major difference is in the deployment levels of solar photovoltaics, which could be explained by the reluctance by national REmap experts to envision radical changes in deployment levels. The comparison of substitution choices and the REmap cost supply curve shows that the REmap results correspond with the sequence in which the ETSAP models choose renewable energy options to satisfy an increasing RE share. The difference in results is mainly due to the political choices made by REmap experts. For example, in the case of the USA the national REmap experts choose to only substitute coal-fired power stations, whilst the ETSAP model chooses a mixture of conventional technologies depending on their economics. The results on system costs are far more robust for the ETSAP models than for the REmap tool, mainly because of the single time step (2030) used in the REmap tool. However, the difference in system costs between the two global ETSAP models also shows that system costs are highly affected by parameter choices, such as the discount factors.

From the comparison of results, it can be concluded that the REmap tool is a useful and appropriate tool to engage national experts and policy makers in the assessment and comparison of renewable energy options and renewable energy targets within and across countries. However, the REmap tool is not an appropriate tool for detailed national renewable energy planning. The results of the ETSAP tools show that they can provide far more detailed analyses, including the assessment of uncertainty, required to determine national renewable energy targets and associated policies. Furthermore, the comparison has demonstrated the value of multiple ETSAP model runs to examine progressively higher renewable energy shares as it demonstrates how a specific target may lock-in certain renewable technology options and infrastructures that are less economic for higher shares of variable renewables.

Considering the additional features of the ETSAP models, it is clear that they can provide more detailed insights than the REmap tool. In this chapter, the comparison considered three of these features: the infrastructure requirements for higher shares of renewables in the energy system, the role of competition between renewable energy technologies and resources, and the role of energy efficiency. For the specific case of Japan, the results show that infrastructural changes can have an important impact (±10 %) on the deployment levels of individual RE technologies considered. However, detailed analysis of grid infrastructure impacts requires the ability for inter-regional modelling, is data-intensive and is especially relevant for those countries with grid issues or with high shares of variable renewables.

The comparison also shows that the ability to provide insights on the role of competition between different renewable energy technology options and resource use among sectors is an important feature that is lacking in the REmap tool. In the REmap cost supply curve, the renewable energy options are presented as independent options to increase the renewable energy share within a country. Only through a qualitative discussion of the results can policy makers be informed about the possible interactions between these options. In the ETSAP models, the interaction and competition is made explicit, and this provides a valuable and important mechanism to support policy makers in their energy planning. The results show that this issue is particularly relevant for countries where there is competition for biomass in the different end-use sectors, and for examining different renewable energy options in the residential sector (rooftop photovoltaics versus solar thermal systems versus heat pumps).

The same applies for the insights that the ETSAP models provide on the competition and complementarity between energy efficiency options and renewable energy options to increase the overall RE share with an energy system.[6] Especially at higher levels of RE shares, the ETSAP models show that energy efficiency options become the dominant option to increase RE shares cost effectively.

The overall conclusion of this comparative analysis is that tools need to be geared towards the specific purpose of the exercise, but that it is important to collaborate between the different institutions that are supporting policy makers in their decision making process. The purpose of the REmap process is to explicitly engage national experts in the process of comparing and aggregating national renewable energy plans across a diverse set of countries. However, such an exercise should not be seen in isolation. For detailed national renewable energy planning, any use of the REmap tool should be complemented with ETSAP models as they provide a more flexible and robust tool to examine renewable energy options. In particular, the ETSAP tools can provide insights on system interactions, more detailed insights on the overall system costs, including possible investments in infrastructural changes, and provide insights on the competition of renewable energy options, renewable resources, and energy efficiency options once renewable energy targets have been set. The latter features become particularly relevant as countries continue to move to higher renewable energy targets.

[6] Please note that this competition is driven to achieve a certain renewable energy target, which is different from competition to satisfy greenhouse gas emission reductions.

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Energy Decisions in an Uncertain Climate and Technology Outlook: How Stochastic and Robust Methodologies Can Assist Policy-Makers

Maryse Labriet, Claire Nicolas, Stéphane Tchung-Ming, Amit Kanudia and Richard Loulou

Abstract Uncertain conditions may deeply affect the relevance of deterministic solutions proposed by optimization or equilibrium models as well as leave the decision maker in a quandary at the moment of defining policy. This chapter presents two applications of stochastic programming and robust optimization to climate and energy decisions using respectively TIAM-WORLD at the global level and MIRET in the case of France. At the global level, stochastic analysis demonstrates that the hedging strategy usually presents a smoother technology transition and is not equivalent to an average of deterministic solutions. Combined with a parametric analysis of the probability of the future outlooks, the approach produces a hedging strategy where the energy system prepares early for high mitigation even in the case of a low probability for such an outcome. Moreover, some technologies appear to be particularly appealing since they penetrate more in the hedging than in deterministic strategies; the penetration of gas power without carbon capture and sequestration in China, coal power plants with carbon capture in India, renewable electricity in Central and South America are examples of these "super-hedging"

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_4

choices. In the case of the French transportation sector, robust optimization illustrates the crucial role of biofuels as a robust mitigation strategy in both moderate and severe emission reduction cases.

1 Introduction

Uncertainty in the long-term energy, economy and climate outlook may deeply affect the relevance of the proposed solutions as well as leave the decision maker in a quandary at the moment of defining policy. The cause of uncertainty may be prediction error, affecting parameters of the model, as well as the absence of precise knowledge on the operation of certain processes or mechanisms, which forces modelers to use simplified representations of physical processes (Ben-Tal and Nemirovski 2002).

Many aspects of climate change and of energy systems are uncertain. First, the nature and extent of future climate change is not precisely known, as shown for instance by the uncertain parameters in the carbon cycle and the sensitivity of the climate to concentration of greenhouse gases (GHGs). Both the inherent variability of the climate system, that is, the natural fluctuations that arise in the absence of any radiative forcing of the planet, and the response of the climate system to changes in radiative forcing, are uncertain, and the level of uncertainty increases at the local or regional level (Hawkins and Sutton 2009). Moreover, greenhouse gas emission scenarios are uncertain, depending on techno-economic, development and policy choices, which depend themselves on climate changes, amongst other factors. Secondly, the actions to mitigate GHG emissions depend on the technical-economic characteristics of key technologies (efficiencies, investment and operation costs, which depend on research and development, economies of scale, spillover effects, etc.), the type of socio-economic development, the social willingness to modify behaviors as well as the dynamics of international negotiations and the time-horizon considered in the decision framework.

The most recent assessment report of the Intergovernmental Panel on Climate Change (IPCC) insists on the importance of considering uncertainties surrounding climate, technology, and social and political characteristics in supporting transitional adaptation and mitigation strategies, and recognizes the lack of consistent tools to deal with these uncertainties (IPCC 2013, 2014; Clarke and Jiang 2014; Kunreuther and Gupta 2014).

Optimal solutions elaborated with optimization or equilibrium models like TIMES are based on a complex, high cardinality set of exogenous assumptions (except to some extent in the case of endogenous learning) on the data populating the models. In short, optimization will sort technologies by decreasing economic merit order to meet various policy objectives in a cost efficient manner. Consequently, different sets of assumptions could yield different relative costs, and in turn to a different optimal technological portfolio. It could lead to an underestimation of the cost of the chosen strategies or to induce the policy maker into implementing a suboptimal policy.

To tackle these questions, *deterministic multi-scenario analysis* is a useful attempt to scope the range of impacts of key parameters on the possible climate adaptation and mitigation responses (Kunreuther and Gupta 2014). It constitutes a usual approach where alternative scenarios of plausible future developments are formulated. In such an approach, unknown parameters can be given extreme values, one at a time, with the intention of circumscribing the space of possibilities. The scenarios thus defined form *ensembles* of scenarios. Systematic ways of choosing parameter values to cover the space of possibilities efficiently are based on design of experiments. Amongst the different possible scenarios, "representative sets" may be identified and play a crucial role as guides for scenario analysis by the research community. In the climate change arena, multi-scenario analysis is frequent, as proposed by the scenarios of the IPCC or the modelling exercises of the Energy Modelling Forum (Weyant and Kriegler 2014), among others. Scenario/ensemble analyses can be performed without quantifying the uncertainty of the underlying unknown parameters. However, this also implies an unavoidable ambiguity in interpreting ensemble results since they tend to be used in a deterministic fashion without recognizing that they may have a low probability of occurrence and are only one of many possible outcomes (Clarke and Jiang 2014; Kunreuther and Gupta 2014). Moreover, such scenarios leave the policy adviser in a quandary as to *what policy to initiate now, given the often widely diverging courses of action solutions proposed by each of the alternative scenarios, even in the short term.*

Stochastic programming and *robust optimization* provide other rigorous frameworks applied on decision making models (Wets 1989). One of the main advantages of the stochastic programming approach is to obtain an explicit single hedging strategy while uncertainty prevails, contrary to classical multi-scenario analysis. Its main drawback is computational: it quickly leads to large-scale instances of the original model. Moreover, probability distribution have to be defined over the entire tree of events. Robust optimization offers parsimonious, computationally efficient ways of dealing with problems of high dimensionality requiring minimal information about the true probability distributions (Ben-Tal and Nemirovski 2002).

This chapter presents two different applications of stochastic programming (Sect. 2) and robust optimization (Sect. 3) to climate and energy decisions using TIMES models: TIAM-WORLD at the global level and MIRET in the case of France. Each section introduces the main principles of the methodology and describes results obtained in different cases.

2 Climate and Energy Decisions Under Stochastic Programming

2.1 Methodological Principles of Stochastic Programming

One key question facing policy makers is that of defining *one* course of action for example for the next 20 years, a time horizon relevant to energy investment, in a context of long-term uncertainties. From the viewpoint of a policy adviser, it is highly desirable to obtain a recommendation for a single *hedging strategy*, which strikes a good compromise between the costs of the many ways of "guessing wrong" (Kanudia and Loulou 1998; Loulou et al. 2009). The main objective is that there be no ambiguity as to *how to act now*, *before uncertainty is resolved*, thus alleviating the main defect of traditional deterministic scenario analysis which computes multiple strategies even prior to the resolution date, leaving the decision maker in a quandary.

This is the essence of decision under risk, and in particular of stochastic programming (Wets 1989). Stochastic programming produces an optimal single strategy, the hedging strategy, until the first date of resolution of the uncertain event (s). After that, the hedging strategy has as many *contingent* strategies as there are possible outcomes of the random event(s), each such strategy being a recourse against the corresponding outcome. Robust actions are those actions chosen in the hedging strategy. In fact, hedging is deemed relevant if decisions prior the resolution of uncertainty are different from those in the base case (i.e. the no-action scenario). Otherwise, "*wait and see*" is a good policy. But one of the most striking advantages of stochastic programming is that the hedging strategy is not necessarily an average of deterministic strategies and could represent solutions that could not easily be found otherwise.

Moreover, "super-hedging" actions can be identified, which are actions that penetrate more in the hedging strategy than in *any* of the perfect forecast strategies (i.e. strategies obtained from the traditional multi-scenario analyses). The existence of such actions seems counter-intuitive, since they lie outside the limits defined by the perfect forecast strategies, but their existence confirms that stochastic analysis of future climate and energy strategies may propose decisions that are beyond any combination or interpolation of the deterministic strategies (Kanudia and Loulou 1998).

Another very desirable property of the hedging strategy is that it greatly attenuates the well-known "razor edge" effect of Linear Programming (i.e. abrupt switches between two actions), as it tends to identify a robust portfolio of technologies instead of merely choosing the least-cost technology (Loulou and Kanudia 1999). It thus proposes a more diversified mix of technologies to attain the desired climate target, and that mix evolves more smoothly over time.

One of the computational drawbacks of stochastic programming is that it quickly leads to large-scale instance of the original model, whenever the number of random events and/or the number of outcomes of each event, become too large. Moreover, the probabilities associated with the different events are themselves not always easily available (Baker et al. 2007).

Our proposal to overcome this limit is to conduct a systematic exploration of the hedging strategies, while varying the probabilities of the expected outcomes. Such a parametric exploration constitutes a useful and original complement to the computation of hedging strategies and contributes to identify those technologies that are robust under a wide set of probabilities, and those that are not.

2.2 Mathematical Formulation of Stochastic Programming in TIMES Models

The detailed mathematical formulation is described in Loulou and Lehtila (2012). A typical stochastic linear program is written as in Eqs. 1 and 2, in the simpler two-stage case where all uncertainties are resolved at a single date θ, and where the optimization is done on the expected value of the total system cost (equivalent to maximizing total expected surplus).

$$\text{Minimize} \sum_t \beta(t) \sum_{s=1 \text{ to } S} C(t,s) \cdot X(t,s) \cdot p(s) \tag{1}$$

$$\text{Subject to: } A(t,s) \times X(t,s) \geq b(t,s) \tag{2}$$

and $X(t, 1) = X(t, 2) = \cdots = X(t,S)$, if $t <$ resolution date θ

where

- s represent the possible *states of the world* (sow), s = 1, 2, …, S
- $p(s)$ is the probability that sow s realizes
- C and b are respectively the cost and the right hand side (RHS) vectors of the Linear Program (LP). Their elements may also depend on s and t
- A is the matrix of LP coefficients under sow s at time t
- $X(t, s)$ is the vector of decision variables at time t, under state-of-the-world s.
- $\beta(t)$ is the discount factor.

Very many parameters of TIMES models that may be stochastic, such as: demand projections, bounds on total installed capacities, cumulative bounds on commodity production (net or not), seasonal distribution of a commodity, cumulative bound on an energy flow or on a process activity, process efficiency, process investment cost, seasonal availability factor, right hand side constant of user constraint, damage cost of net production of commodity, bound on maximum level of climate variable, climate module constants (climate sensitivity and thermal capacity of the atmosphere).

The current version of the TIMES implementation for stochastic programming is based on directly solving the above deterministic problem. This is the most straightforward approach, which may be applied to all problem instances. As this may lead to very large problem instances, stochastic TIMES models are in practice limited to a relatively small number of sow's.

In order to avoid the simplifying assumption of risk neutrality, two alternative candidates for the objective function have been proposed and used on TIMES models. In each, the objective function is replaced by a version that introduces varying degrees of risk aversion: expected utility criterion with linearized risk aversion and Minimax Regret (Savage) criterion (Loulou and Kanudia 1999). The first alternative has been fully implemented in the stochastic version of TIMES, providing a feature for taking into account that a decision maker may be risk averse, by defining a new utility function to replace the expected cost. The approach is based on a modified version of the classical E-V model (an abbreviation for Expected Value-Variance). In the E-V approach, it is assumed that the variance of the cost is an acceptable measure of the risk attached to a strategy in the presence of uncertainty (Loulou and Lehtila 2012). The second approach is also possible with TIMES, but requires a three step implementation of TIMES using the sensitivity analysis and the stochastic programming features of TIMES (Loulou and Lehtila 2012). Doing so requires substantial manual operations by the user.[1]

2.3 Applications in TIAM-WORLD

2.3.1 Overview of TIAM-WORLD

The TIMES Integrated Assessment Model (TIAM-WORLD) is a technology-rich model of the entire energy/emission system of the World split into 16 regions,[2] providing a detailed representation of the procurement, transformation, trade, and consumption of a large number of energy forms (Loulou 2008; Loulou and Labriet 2008).

It is an incarnation of the TIMES (The Integrated MARKAL-EFOM System) economic paradigm and computes an inter-temporal dynamic partial equilibrium on energy and emission markets based on the maximization of total surplus, defined as the sum of suppliers and consumers surpluses. In other words, the model finds optimal (cost-efficient) energy and technology mixes to satisfy demands for energy services like lighting, cooking, heating, cooling of houses, kilometers driven by cars, trucks, tons of aluminum, cement to be produced, etc. Each demand may vary endogenously in alternate scenarios, in response to endogenous price changes.

The model contains explicit detailed descriptions of more than 1500 technologies and several hundreds of energy, emission and demand flows in each region. Such technological detail provides a precise description of technology and fuel competition in the entire energy system, where changes in one sector may have direct and indirect impacts on other sectors. The model is set-up to explore the development of the World energy system until 2100. It is calibrated to 2005 energy statistics of the International Energy Agency (IEA 2013a, b).

TIAM-WORLD integrates a climate module for the modeling of global changes related to greenhouse gas concentrations, radiative forcing, and temperature increase. The module includes separate cycles for CO_2, CH_4, and N_2O, and also

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[1] Interested readers may want to consult the online forum of this topic at http://www.iea-etsap.org/forum/forum_posts.asp?TID=95.

[2] Africa, Australia, New Zealand, Canada, United States, Mexico, Central and South America, China, India, Japan, South Korea, Other Developing Asia, Middle-East, Europe of 27 + Switzerland, Norway and Iceland, Other East Europe, Russia, Central Asia and Caucasia + OPEC and Non-OPEC disaggregation when relevant.

accounts for the additional forcings introduced by other causes, natural and anthropic. The total atmospheric forcing is then introduced into equations that simulate the changes in mean temperatures of two layers: surface, and deep ocean. The climate module provides a very useful means of simulating scenarios with specific climate targets, be they on concentration, forcing, or temperature.

2.3.2 Uncertain Climate Context

Climate variability is one of the many elements of uncertainty involved in energy planning and decision-making. Assessing the vulnerabilities of energy systems and incorporating them into long-term energy planning and operation is becoming imperative for the development of policies that aim to cope with climate change but also to better understand the possible impacts of climate change on the energy system in terms of timing and sequencing of decisions. This section focuses on cases where the future mitigation level is considered as a random event.

First, in order to explore the uncertainties associated with the climate sensitivity (*Cs*) of the climate module of the model, defined as the equilibrium response of global surface temperature to a doubling of the equivalent CO_2 concentration, Labriet et al. (2009) considered four possible values of *Cs* with respective probabilities (between brackets) as follows, and according to Yohe et al. (2004): 1.5 °C (25 %), 3.0 °C (45 %), 5.0 °C (15 %) and 8.0 °C (15 %). It is assumed that the uncertainty on *Cs* will be fully resolved in 2040. The research focuses on climate strategies to keep long-term temperature increase below the 2.5 °C target. One of the findings of the study is that when *Cs* = 1.5 °C, the base case as modeled with this version of the model satisfies the climate target at all times. In other words, the Perfect Foresight scenario with *Cs* = 1.5 °C and a climate target of 2.5 °C is identical to the Base Case. Moreover, additional hydroelectricity, sequestration by forestry and the shutdown of coal power plants without carbon capture are identified as hedging decisions. While carbon capture penetrates early in the most pessimistic PF with *Cs* = 8.0 °C, it penetrates much later in the hedging strategy. In the end-use sectors, fuel switches in industry (to biomass and gas), biomass in residential buildings, and methane abatement actions are identified as super-hedging actions: they penetrate more in the hedging than in any PF strategy.

Second, Loulou et al. (2009) is part of a multi-model study sponsored by the Energy Modeling Forum, which suggests three scenarios, each with a specific alternative value for total forcing (2.6, 3.7 and 4.5 W/m^2). The study proposed a probabilistic interpretation of these three PF scenarios by converting the problem into a stochastic problem with a *single target* on long-term global temperature change (2.45 °C), while assuming that three possible values of the climate sensitivity were possible, each with a specific probability: 2.0 °C (50 %), 2.9 °C (35 %), 5.0 °C (15 %). Greenhouse gas emissions in the hedging are close to those in the PF scenario with a 2.6 forcing target, showing the strong influence of this severe target on the hedging strategy. The composition of the electricity supply shows that the amount of electricity produced with carbon capture and sequestration (CCS) in the hedging strategy is higher than in any deterministic strategy in year 2040, but not so in preceding periods. Overall, the hedging strategy presents a smoother transition from the initial electricity mix to a radically different one in 2040, than the PF strategies with 3.7 or 2.6 forcing targets. This “smoothing” property was also observed in Labriet et al. (2009), as described above. Usually observed in hedging strategies, such a smooth transition is one great advantage of hedging strategies and is easier to implement in practice.

Finally, another manner to explore climate uncertainties is to define uncertain climate targets to be respected in the long term. Based on this approach, TIAM-WORLD was used to analyze the impact of two contrasted climate outlooks with a severe (450 ppm CO_2 equivalent) and a loose (650 ppm CO_2 equivalent) climate target imposed on the energy system. Due to the expected impacts of climate change, heating and cooling needs as well as the price of bioenergy are also considered uncertain, and were defined based on the coupling of TIAM-WORLD and respectively a climate model, PLASIM-ENTs (see chapter by Labriet et al. at the end of this book), and a land-use model, MAgPIE (Leimbach et al. 2013). All the other parameters of the models remain unchanged. Since the probability of each of the two proposed climate target remains fully unknown, a systematic exploration of the hedging solution is proposed with probabilities of the second state of the World varying from 0 to 1, in 0.1 increments. The two runs where the probability is equal to 0 or to 1, correspond to perfect forecasts of the future climate outlook (Fig. 1).

The scenario naming convention is as follows: The first 3 digits represent the probability of the High Mitigation scenario, the next 3 digits represent the probability of the Low Mitigation scenario, * represents the High Mitigation branch after bifurcation.

As already discussed, the main value of stochastic analysis is to assess the decisions made in the hedging, prior to the definition of the uncertain parameters. Total net CO_2 emissions help understand how the hedging varies between the two perfect foresight scenarios when the probability of scenarios varies (Fig. 2): the

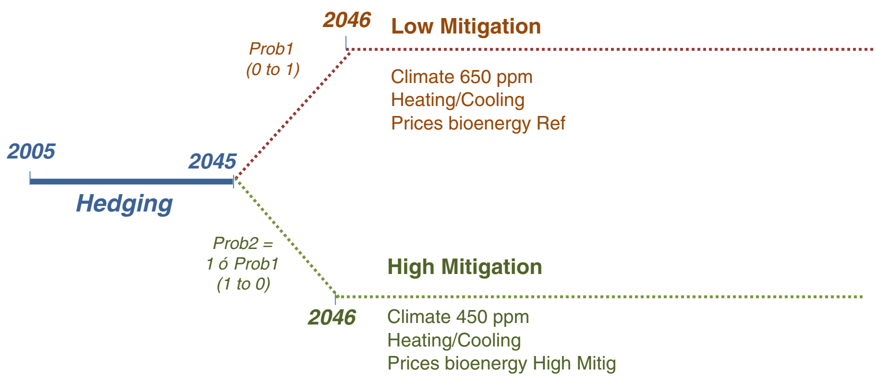

Fig. 1 Stochastic event tree based on climate uncertainty

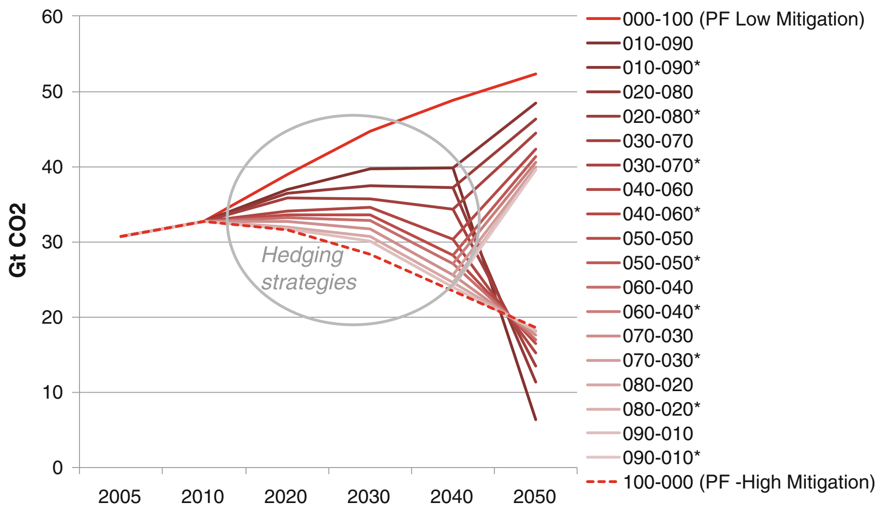

Fig. 2 Net CO_2 emissions under each of the 11 cases

hedging does not vary uniformly within the range defined by the two perfect foresight cases; a small probability of high mitigation (10 %—scenario 010–090) forces the energy system to adopt decisions quite different from the "PF Low Mitigation". In other words, some energy decisions deserve an early implementation "in any case".

The analysis of the capacity mix of power plants in 2030 shows that significant changes occur in most regions as soon as the probability of the High Mitigation case reaches 10 % (Fig. 3): coal and gas are substituted by wind, hydro and nuclear. This implies that the 2030 electricity system fully prepares for the high mitigation scenario even if the latter has low (but non zero) probability. Other changes, specific to some regions, are observed around 30–40 % of probability of High Mitigation, such as the penetration of CCS in China and India, or the increase of the share of renewables in Central and South America. In 2040, just before the state of the world is revealed, significant changes also occur when the probability of High Mitigation goes from 0 to 10 %, but some "clusters" also appear in several regions (Fig. 4). Amongst them, three levels of electrification of the economy are observed in China (with changes observed for a probability of the High Mitigation of 40 and 70 %), the role of coal power plants with CCS only for intermediate probabilities in India, while gas power plants with CCS, which is cleaner but more expensive, starts gaining share with 70 % probability and is preferred to coal + CCS at the end. This peaking of coal power plants with CCS at intermediate probabilities in some regions reveals a unique value that the stochastic approach adds over deterministic scenario analysis: coal CCS penetration in India, as well as in Japan and Russia (not shown here) is higher around 40–50 % probability of high mitigation compared to either perfect foresight cases; such a mitigation option is a "super-hedging".

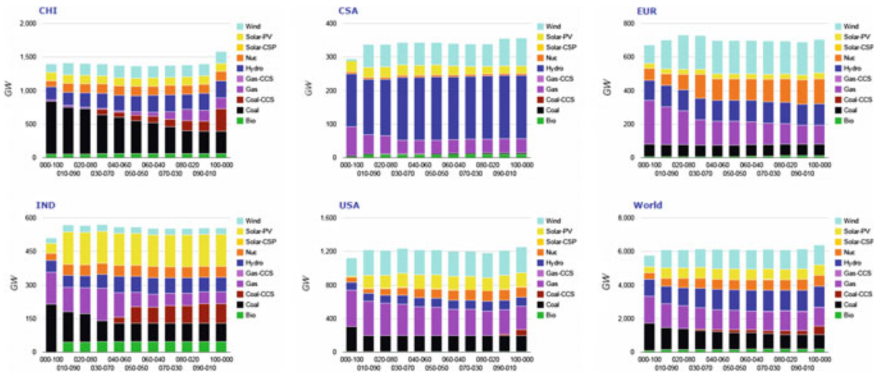

Fig. 3 Power plant capacity in 2030. The first 3 digits of scenario names on the x-axis represent the probability of the high mitigation scenario, the next 3 digits represent the probability of the low mitigation scenario (results for other regions are available upon request)

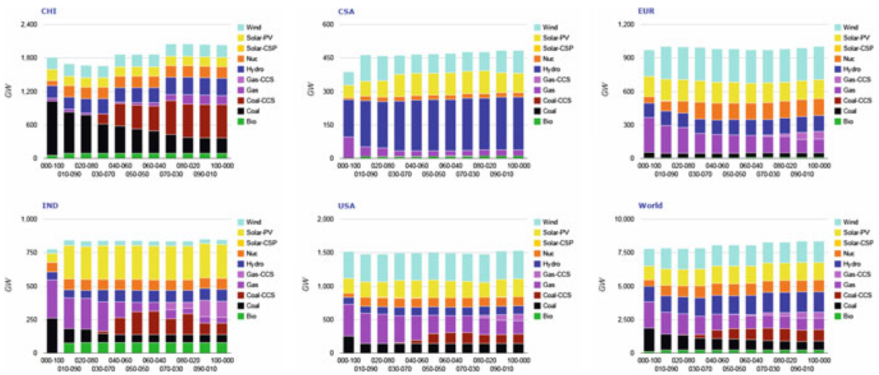

Fig. 4 Power plant capacity in 2040. The first 3 digits of scenario names on the x-axis represent the probability of the high mitigation scenario, the next 3 digits represent the probability of the low mitigation scenario (results for other regions are available upon request)

2.3.3 Uncertain Technology Outlooks

The impacts of the long-term technology context on the optimal evolution of the World energy system are now explored in a stochastic framework where the availability and characteristics of future technologies are uncertain, and the level of mitigation is no longer modelled as a random event, but rather as a discrete parameter on which sensitivity analysis is performed (targets of 2.6 and 3.7 W/m^2).

Two contrasted sets of assumptions are made on the future energy system of the World are considered after 2040: one (the Renewable Outlook) is focused on renewable energy and improvement of the energy intensity of the economy, while CCS and nuclear power are assumed not to play an important role; the other one

(Conventional Outlook) is centered on fossil (with or without CCS) and nuclear energy, where renewable energy is expected to be more expensive, biomass potentials and improvements of the energy intensity lower (Labriet et al. 2012). This dichotomy is of course a simplified view of the various technological futures since it is not at all clear that the technologies included in each state of the World are so well correlated that they can be lumped together in a single state of the World. Probabilities of each branch varied from 0 to 1 in 0.05 increments.

Analysis of the hedging strategies in the case of a stringent climate target (2.6 W/m^2) shows that mitigation actions are quite stable when probabilities vary from the Conventional Outlook to the Renewable Outlook (Fig. 5 top). In other words, for stringent targets, the need for rapid de-carbonization severely restricts the set of effective options, and the most effective mitigation actions are used in the mid-term almost irrespective of the values of future probabilities of technology outlooks.

For the moderate climate target (3.7 W/m^2), the degree of uncertainty of the technology outlook has a larger impact on mid-term hedging energy decisions (Fig. 5 bottom). Indeed, mitigation scenarios are much milder but more volatile, reflecting a lower robustness of actions across the range of probabilities associated to the technology outlook. Without the pressure of a rapid decarbonization required by a severe climate target, mitigation remains moderate and quite flexible, and the nature of the mitigation options is highly dependent on the nature of the technology outlook.

Regional results show that natural gas appears as an appealing options in several countries, such as in China, in an uncertain technology context. Its use in power plants without CCS is even considered as a “super-hedging” mitigation option, penetrating more in the hedging solution than in any of the deterministic scenarios (Fig. 6). In other words, when the future availability and characteristics of key energy technologies is uncertain and long term emissions must be reduced in a moderate manner (3.7 W/m^2), power plants without CCS is a good “install-now” strategy and allows “wait-and-see” for other options given its relatively low emissions and the low capital cost of associated technologies. By implementing such a technology option, the policy maker keeps a middle-of-the-road position that does not emit too much GHG and that can be modified without too much “regret” in terms of economic losses, when uncertainty is resolved on the more effective options.

3 Robust Optimization

3.1 Methodological Principles of Robust Optimization

One drawback of stochastic programming is that probability distributions, possibly parameterized, have to be defined over the entire tree. When whole probability distributions are defined for the uncertain events, Monte-Carlo type of analysis may ensue: in such a case, sets of values are randomly sampled from the distributions, and series of deterministic runs are performed (MIT 2011). However, both

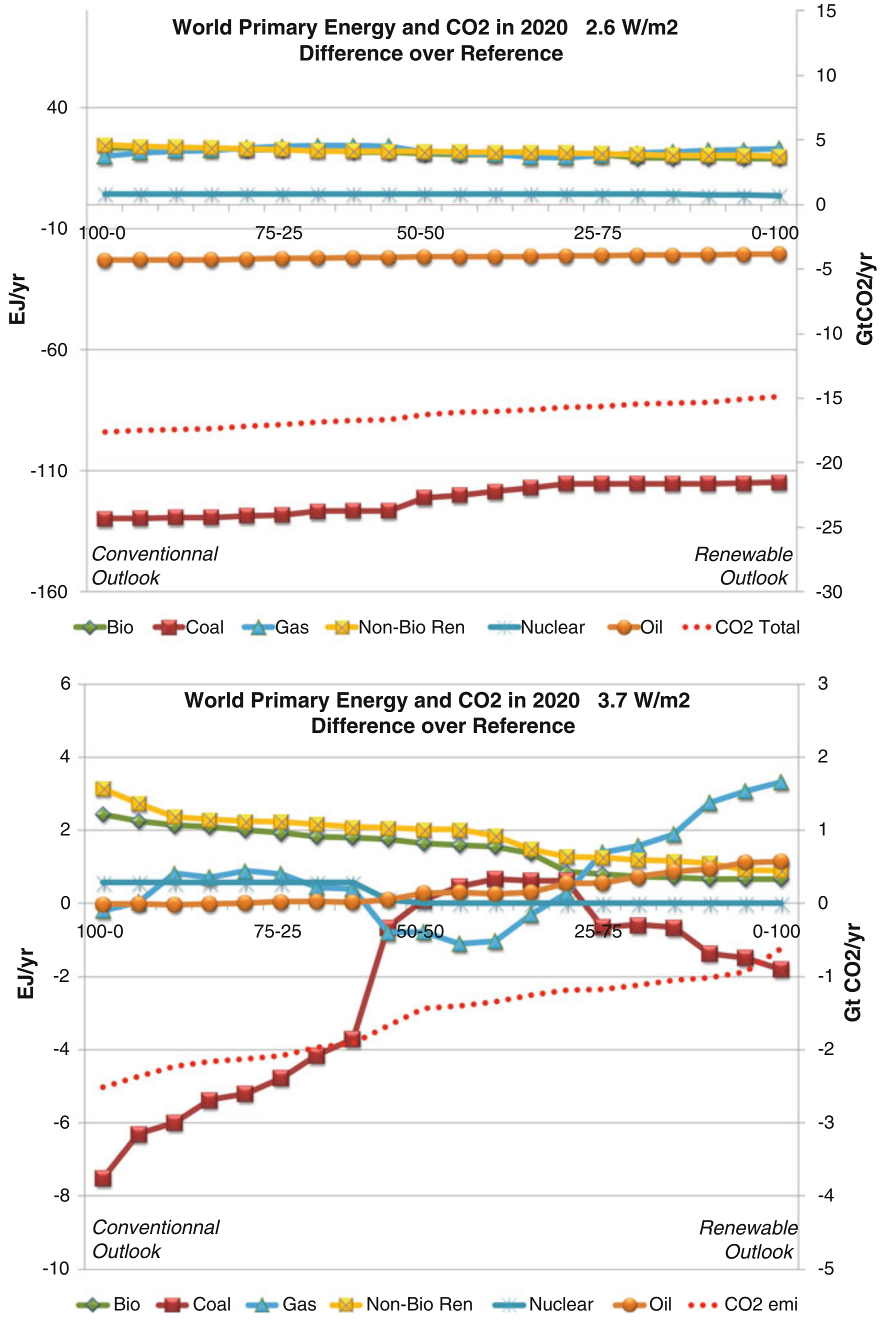

Fig. 5 Mitigation options in the power sector in 2030 at the world level in two climate cases (*top* 2.6 W/m^2; *bottom* 3.7 W/m^2), measured as the difference over the reference case. The first 3 digits of scenario names on the x-axis represent the probability of the conventional outlook, the next 3 digits represent the probability of the renewable outlook

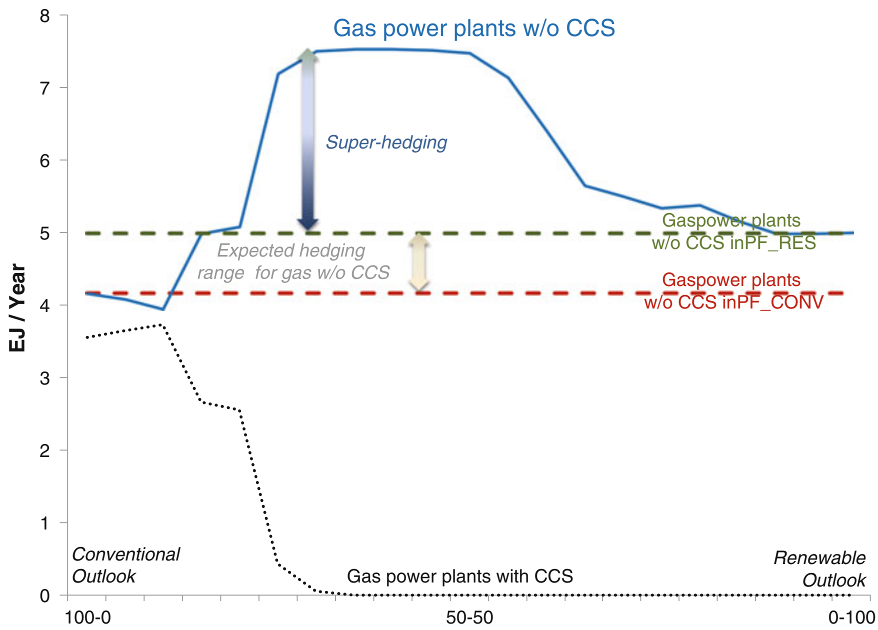

Fig. 6 The role of gas power plants without CCS as a super-hedging strategy in China, 2030, 3.7 W/m^2. The first 3 digits of scenario names on the x-axis represent the probability of the conventional outlook, the next 3 digits represent the probability of the renewable outlook

techniques are rapidly confronted with the intractability issue in numerical computations as problem size grows. Robust optimization (RO) is an alternative approach for coping with uncertainty. RO formulations offer parsimonious ways of dealing with problems of high dimensionality, requiring minimal information about the true probability distributions.

Early developments of RO date back to Soyster (1973) who initiated an approach for obtaining relevant (i.e. feasible) LP solutions when matrix coefficients are inexact. RO has known many developments in the last 15 year by generalizing Soyster approach (Bertsimas and Sim 2004) or using different formalisms (Ben-Tal and Nemirovski 2002; El Ghaoui et al. 1998). Its applications to energy and environment problems are currently emerging as a promising technique for practitioners. For example, Babonneau et al. (2011) applied it to the TIAM-WORLD model to study the security of supply to the European energy system.

The general principle of RO consists in immunizing a solution against adverse realizations of uncertain parameters within a given *uncertainty set*. The basic requirement for a robust solution is that constraints of the problem are not violated whatever the values of the parameters in that set. The main modelling issue then consists in identifying, depending on the model class and the nature of the uncertainty region, computable robust counterparts for the initial optimization program. Ben-Tal et al. (2014) and Bertsimas et al. (2010) review techniques for building such robust counterparts (RC) in general cases. One particular case of interest for TIMES modelers is the case of a linear program combined with a polyhedral uncertainty set, for which the RC is itself a linear program. The application presented below is based on this principle.

3.2 Mathematical Formulation of Robust Programming in TIMES Models

As mentioned above, while stochastic or Monte-Carlo frameworks require the definition of probability density functions, the principle of RO consists in set-based descriptions of uncertainties. As such, only the *extent* to which parameters are likely to vary needs to be known (although this information may be itself difficult to acquire), but not its likelihood. This corresponds to the support of the density functions.

To introduce the mathematical representation of RO, we follow Bertsimas and Sim (2004) and consider the following linear problem (Eq. 3):

$$(\mathrm{P})\begin{cases}\min\ c^T x\\ \text{s.t. } Ax \leq b\\ x \in \mathbb{R}^+\end{cases} \tag{3}$$

We assume that the uncertainty only affects the coefficients $a_{i,j}(i \in I, j \in J)$ of the matrix A. The coefficients can vary in a symmetric range: $a_{i,j} \in \left[\overline{a_{i,j}} - \widehat{a_{i,j}}, \overline{a_{i,j}} + \widehat{a_{i,j}}\right]$ where $\overline{a_{i,j}}$ is the nominal value of the parameter and $\widehat{a_{i,j}}$ the uncertainty set half-length. No specific probability distribution is needed.

We can now introduce the parameter $\Gamma \in [0, |I| + |J|]$ named the budget of uncertainty whose role is to adjust the robustness of the methodology against the level of conservatism of the solution.

By writing $a_{i,j} = \overline{a_{i,j}} + z_{ij}\widehat{a_{i,j}},\ z_{ij} \in [-1, 1]$ we can reformulate the problem (P) and write its robust counterpart ($\mathrm{P_{rob}}$) as shown in Eq. 4:

$$(\mathrm{P_{rob}})\begin{cases}\min\quad c^T x\\ \text{s.t.}\quad \sum_j \overline{a_{i,j}}x_j + \max_{z_{ij}} \sum_j z_{ij}\widehat{a_{i,j}}x_j \leq b_i \quad \forall i \in I, j \in J\\ z_{ij} \in [-1, 1] \quad \forall i \in I, j \in J\\ \sum_{i,j} |z_{ij}| \leq \Gamma \quad \forall i \in I, j \in J\\ x \in \mathbb{R}^+\end{cases} \tag{4}$$

More generally, by limiting the number of parameters allowed to deviate, Γ represents the degree of pessimism on the problem parameters. When $\Gamma = 0$, the robust problem is identical to the nominal one and when $\Gamma = |I| + |J|$, it is equal to the "worst case" problem. The concept of the uncertainty budget is based on the fact that it is highly unlikely that all the parameters take their worst case value at the same time.

Using strong duality, the maximization problem in the constraint becomes a minimization problem which can be reinjected into the original problem. Hence, the robust counterpart of the problem is still a linear programming problem (a little bit bigger) and conserves the good properties of this class of model in terms of tractability and computational time (Bertsimas and Thiele 2006).

The robust counterpart of the initial problem includes variables that traduce the deviations of the worst-case parameters with respect to their nominal values (the number of potentially deviating coefficients being controlled by the uncertainty budget).As an outcome, the solution of the problem is immune to variations of the uncertain parameters within their set. Moreover, it has nice connections with attitudes of the decision maker towards risks (Bertsimas et al. 2010), and provides probabilistic guarantees of constraints violation.

3.3 Application in MIRET

3.3.1 Overview of MIRET

As a TIMES instance, the MIRET model (Lorne and Tchung-Ming 2012) is a technology-explicit, sectoral model of the French energy-transport sector. It describes in detail the supply of primary energy (fossils, agricultural and woody biomass), energy conversion through detailed refinery modeling, first and second generation biofuel production units, biogas, and a simple model of the electricity sector. Transport end-uses are detailed through a hundred of vehicle technologies for passenger and freight road transport, rail transport, air transport and navigation. Its scope is continental France, and the time horizon is 2050, with 2007 as a calibration year; it works as a long-term, dynamic inter-temporal partial equilibrium model. The version used here was built as a partial equilibrium model, including demand-side reactions to the endogenously formed energy services prices.

3.3.2 Scenarios: Meeting Transportation Abatement Objectives Under Cost Uncertainty

One major issue arising from the many possible uncertainties of the techno-economic parameters of the model is the following: *how robust is an optimal technological trajectory to* (*which*) *techno-economic assumptions*? In other words, decision makers may wish to analyze solutions that are immune to adverse realizations of these parameters.

To illustrate the methodology, we built two alternate sets of normative scenarios: reductions of 50 % (Cap1) and 66 % (Cap2) of GHG emissions are imposed in the

Table 1 Parameters affected by uncertainty

Scenario component	Sector	Uncertainty source
Primary energy supply	Fossils (oil, coal, gas)	Price (maximum: +10 % above nominal value)
	Biomass (agricultural, wood)	
Energy conversion	Oil refining	None
	Biofuels	Investment cost (maximum: +10 % above nominal value)
	Electricity generation	
End-use	Road transport (passenger cars, buses, trucks)	
	Rail transport (all trains)	

French transport sector in 2050 compared to 2007. For each of these emission caps, we conduct a sensitivity analysis on the uncertainty budget. This application is particularly helpful to better understand the impact of cost uncertainties in the definition of mitigation policies in the French transportation sector.

The uncertainty set is as follows. We assume that the investment cost of new technologies available from 2020 and beyond is not known with certainty. For each of these technologies, the uncertainty model consists in assuming that the investment cost can rise by 10 % above its nominal value. On top of that, it is assumed that the unit costs of primary energy are also subject to uncertainty. This concerns fossil primary energy (crude, natural gas and coal), biomass (agricultural crops, imported vegetable oils, dedicated energy crops and agricultural and forest residues). These assumptions are summarized in Table 1. Because of the number of costs involved in this exercise, we do not distinguish between the fuels and processes and we use the same value (10 %) to create the uncertainty set of costs. We are aware that the investment cost for mature technologies is much less uncertain than the one of new technologies. In that sense, the threshold is to be understood as a sensitivity experiment, rather than an attempt to calibrate uncertainty bounds for all affected technologies.

The overall uncertainty set comprises around 120 parameters, including technology investment costs and energy prices. Under the uncertainty model chosen, this makes a total of around 900 constraints to be added to the original model. The original TIMES modeling framework does not include such equations; consequently, they were added manually. In the sequel, the uncertainty budgets at each period are varied proportionally: if $\Gamma = (\Gamma_t)_{t \geq t_0}$ is the vector of uncertainty budgets over time, then we vary $h \in [0, 1]$ such that $\Gamma_h = h\Gamma$.

3.3.3 Results

Results are presented for the two carbon caps imposed in the transport sector. The uncertainty budget Γ corresponds to the number of coefficients allowed to vary; it is between 0 (no coefficient deviates from the nominal value: this is the deterministic case) and the maximal value of around 120 (all coefficients can deviate from the nominal value). Results are presented as percentages of this maximal uncertainty budget. For example, the scenario Cap 1–10 % corresponds to the −50 % carbon cap (Cap1), and allowing 10 % of the cost and price coefficients to drift from their nominal value.

What is the cost of robustness? Figure 7 presents the evolution of the objective function for the two emission cap scenarios and for different ratios of the uncertainty budget. We observe the usual increasing concave shape of the objective function. Total cost increases by up to 11 % over the case without uncertainty in both Cap1 and Cap2 (absolute total cost is of course higher in the case of Cap2 given the more severe emission reduction imposed in this scenario). The main part of the additional cost is the *additional cost of using uncertain technologies/energy sources*; it is due to limitations in substitution options: even if the price of oil is 110$/bbl rather than 100 $/bbl, some fossil fuels will still be used in the transportation sector and the price increase will directly impact the objective function. Another part of the cost corresponds to the *additional costs of technical substitution*, due to changes in the relative costs of technology which induce different technology investment paths. For example, if the apparent price of oil is 110$/bbl instead of 100$/bbl, some diesel or gasoline vehicles may be replaced by gas vehicles or fossil fuels may be substituted with biofuels. When the uncertainty budget reaches 30 %, the objective function is almost stable. Indeed, the costs and prices impacting a lot the objective function have already deviated and the technical substitutions have been done or even undone (when lots of costs can vary, the relative cost of technologies does not vary hence the investment trajectories are not necessarily impacted).

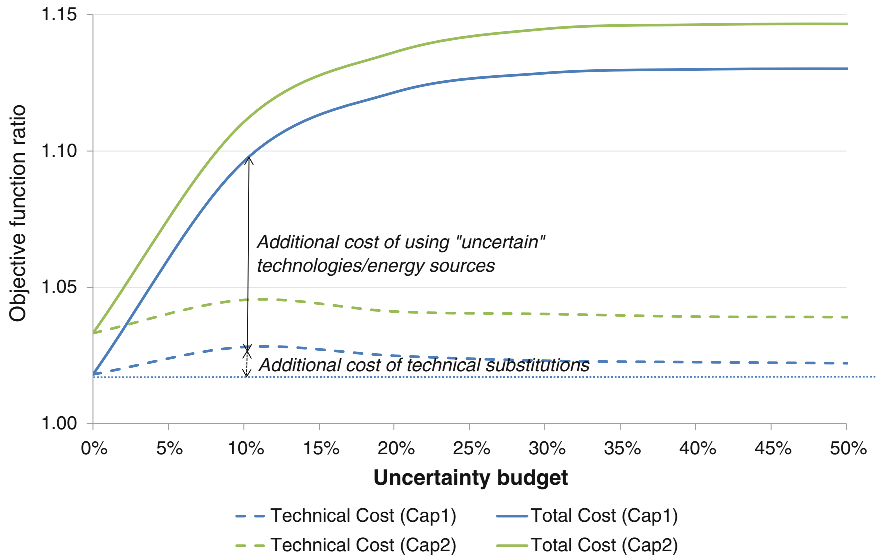

Fig. 7 Objective function value ratio (change over reference case)

What are the main technological hedges in the transportation sector? Figures 8 and 9 highlight some of the hedging strategies for the two caps and uncertainty budgets until 50 % (no major changes occur after this threshold). In Cap1 and for low uncertainty budgets, hedging consists in raising the share of gasoline and diesel in transport to replace natural gas (Fig. 8). The share of gas increases again for higher uncertainty budget. The underlying biofuels incorporation consists in adding more ethanol into gasoline and in blending more hydrotreated vegetable oil in diesel (Fig. 9). The 10 % uncertainty budget corresponds to the highest integration of biofuels in the energy mix of transport in absolute terms; this is consistent with the peak observed in the trajectory of cost of technical substitutions (Fig. 7). In Cap2 scenarios, gasoline substitutes diesel in all cases (Fig. 8). This substitution is motivated by a higher blending rate with ethanol, as observed in Cap1 scenarios. In Cap2 scenarios, this strategy is accompanied by a strong substitution of hydrotreated vegetable oil by biomass-to-liquids biodiesel in the low uncertainty budget. In Cap2–10 %, the decreasing market share of diesel vehicles in the fleet impacts the consumption of biofuels for diesel car, leading to a small decrease of biofuel consumption compared to Cap2. In both emission cases, using more biofuels appears to be a robust strategy to hedge against uncertain costs. Results also show that the fuel diversity increases under uncertainty, more particularly when the uncertainty budget constraint is more stringent. This confirms the common conclusion among model users working with uncertainty: diversification is a good hedging strategy.

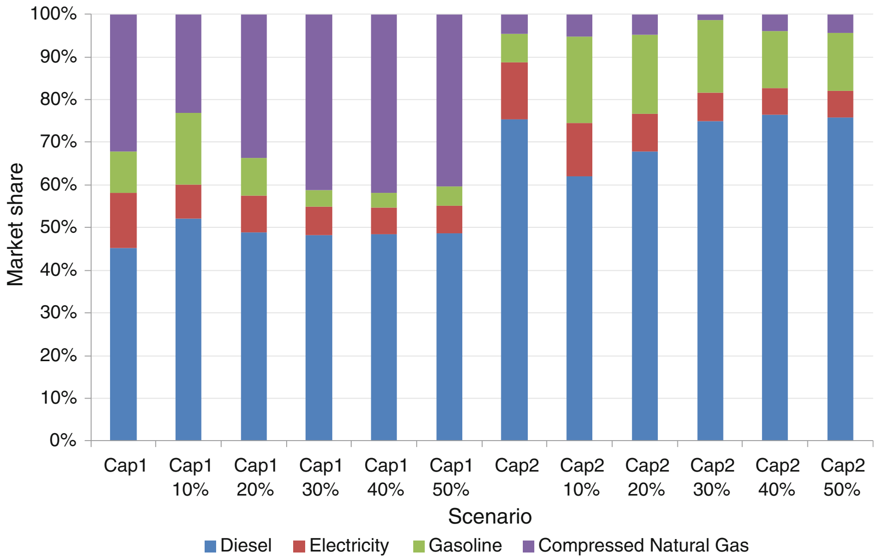

Fig. 8 Fuel mix in the French transport sector in 2050

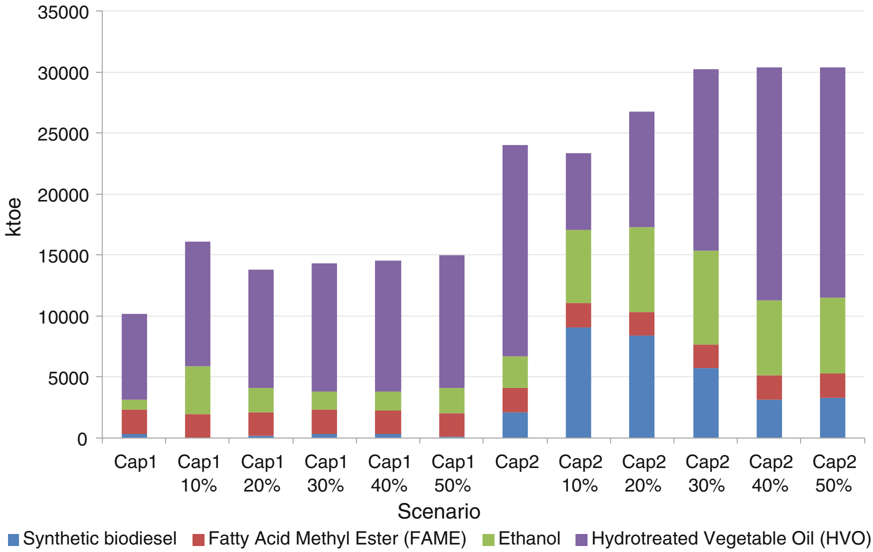

Fig. 9 Biofuels mix in the French transport sector in 2050

Finally, and consistently with the evolution of the objective function, the integration of pathways which are sensitive to the level of uncertainty does not vary monotonically: the use of substitution is higher for low uncertainty budgets—where relative costs are perturbated most.

Which costs are the most critical? Table 2 illustrates the most critical costs, for a 10 % uncertainty budget and the two emission caps. The 10 % uncertainty budget is particularly interesting since it corresponds to the most important technological hedging (Fig. 7). The technologies and fuels in Table 2 are those whose cost variation impacts most the objective function. They were sorted by decreasing

Table 2 Most critical costs in the two scenarios

	Cap1 10 %	Cap2 10 %
1	Crude oil import	Crude oil import
2	Natural gas import	Medium diesel car
3	Medium diesel car	Natural gas import
4	Diesel light utility vehicle	Biodiesel light utility vehicle
5	Small gasoline car	Diesel light utility vehicle
6	Jet fuel import	Small gasoline car
7	Small diesel vehicle	Small diesel vehicle
8	Medium electric vehicle	Medium electric vehicle
9	Naphtha import	Jet fuel import
10	Small CNG vehicle	Electric car battery

shadow value of the robust counterpart of the energy problem: the higher the shadow value, the higher the impact on the optimum objective function of the maximization sub-problem is. The most impacting costs are related with primary energy, which is not surprising. Indeed, the most sensitive technologies and fuels can be either those whose costs/prices are low and which are used in large quantities, or those with high costs/prices, and used in small quantities. Oil-based fuels correspond to the former case; this shows the difficulty of reducing oil dependency in the transportation sector. Other critical costs are those of the most used transportation technologies such as diesel or gasoline cars. Costs of electric mobility technologies also appear as important, which shows that technological progress on electromobility will be important in the costs of decarbonizing the transportation sector. The ranking of most technologies and fuels varies slightly according to the level of the emission cap, but the main result is that in any case, costs of biofuels technologies or feedstocks do not show up as the most critical, except for Light Utility Vehicles in the case of more stringent emission cap, but light utility vehicles represent only a small fraction of the mobility demand. This result is consistent with the use of biofuels as substitution options in uncertain scenarios.

4 Relevance for Policy-Making

Stochastic programming and robust optimization are crucial to support decision-making in an uncertainty context.

Stochastic programming produces an optimal single strategy, the hedging strategy, providing outcomes about how to act now, before uncertainty is resolved, thus alleviating the main defect of traditional deterministic scenario analysis which leaves the decision maker in a quandary. The hedging strategy is not necessarily an average of deterministic strategies and could represent solutions that could not easily be found otherwise; "super-hedging" actions can even be identified, i.e. actions that penetrate more in the hedging strategy than in *any* of the perfect forecast strategies. For example, natural gas in power and industrial sectors appears as an appealing robust option in several countries, being even considered as a "super-hedging" mitigation option; in other words, gas is a good "install-now" strategy given its relatively low emissions and the low capital cost of associated technologies; it allows policy makers to keep a middle-of-the-road position that does not emit too much GHG and can be modified without too much "regret" in terms of economic losses, when uncertainty is resolved on the more effective options.

Since probabilities of future outlooks are usually unknown, a parametric exploration of the hedging strategies with varying probabilities constitutes a useful complement to identify those technologies that are robust under a wide set of probabilities, and those that are not. For example, results show that the electricity system should fully prepare for the high mitigation scenario even with a less than even chance of the latter. The need for rapid de-carbonization severely restricts the set of effective options, and the most effective mitigation actions are used almost irrespective of the values of future probabilities. At the opposite, for moderate climate targets, mitigation scenarios are much milder but more volatile, reflecting a lower robustness of actions across the range of probabilities associated to the technology outlook.

Implementing RO principles in full-scale energy models also offers useful insights for policy-makers. From a normative systems analysis standpoint, it may not be obvious to identify the most influential technological parameters to reach a given policy objective (emission reduction targets, financing constraints, etc.). RO offers a parsimonious way to do so. Conversely, some parameters may have a far smaller role than could be anticipated. Hence, (i) key technologies to specific policy objectives are easily identified (ii) optimal technology mixes for these policies are made robust to random realizations in the techno-economics of the key technologies. In short, potential risks and hedging potentials of future technologies can be assessed all at once, within a technology mix that remains compliant with modeled objectives. In the case presented in this chapter, insights for policy makers include the interest in relying on a more diversified use of biofuels when future costs are uncertain. Finally, the policies and targets may themselves be subject to uncertainty. Making solutions robust to these uncertainties is particularly relevant, and should be part of future research agendas.

5 Conclusion

Understanding the sensitivity of short-term mitigation decisions to the long-term technology and climate outlook is of particular interest for the decision-makers in order to define relevant climate and energy policies in the context of uncertainty. Stochastic programming combined with a systematic exploration of the hedging strategies while varying the probabilities of the possible futures is particularly interesting to identify preferred energy and climate strategies in an uncertain context, which may even penetrate more in uncertain scenarios than in deterministic ones, as well as clusters of decisions valid for a large range of probabilities.

Robust optimization is illustrated with an example where uncertainty weighs on costs. From the theoretical viewpoint, it allows to manage large uncertainty sets while preserving linearity and tractability. The application in energy system models can prove useful in elaborating robust long-term strategies, and help identify what combinations of parameters are the most critical, or conversely do not really impact solutions. The technique may be relevant to study other sources of uncertainty in models. An on-going research consists in applying it to climate model parameters of the TIAM model. In this context, robust optimization will contribute to better know the most sensitive parameters, whether and how the uncertainty affects the mitigation strategies as well as the mitigation cost increment induced by uncertainty.

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Schemes for the Regional Allocation of Emission Allowances under Stringent Global Climate Policy

Tom Kober, Bob van der Zwaan and Hilke Rösler

Abstract In this chapter we investigate burden-sharing regimes for the allocation of greenhouse gas emission reduction obligations under a 2 °C long-term climate policy framework, and present our findings derived from an integrated energy-economy-climate assessment. In our analysis we focus on two different allocation schemes: a per-capita-based scheme, and a scheme aiming at equalising the climate policy costs among the world regions with respect to their economic capability. We find that, under a per capita based burden-sharing scheme, the amount of carbon certificates traded on the carbon market yields a cumulative capital transfer of 20 trillion US$ between 2020 and 2050, which is on average 680 billion US$/year. The main certificate selling regions are Africa and India and the main buyers South America and the Middle East. Conversely to the per capita based scheme, a burden-sharing regime that aims at equalising regional climate policy costs leads to a cumulative carbon market capita flow until 2050 of about one quarter with average annual certificate transactions worth 180 billion US$/year, with China and Other Developing Asia being the major certificate sellers and Western Europe the main buyer. Comparing both burden-sharing schemes with regard to the compensation of non-OECD countries' climate change mitigation efforts via revenues from the global carbon certificate market reveals an advantage of the scheme based on climate policy costs over the per capita scheme, because the policy cost related

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_5

scheme covers 12 % of the non-OECD's climate policy costs of the first half of this century, whereas 4 % under the per capita scheme only.

1 Introduction

At the 19th Conference of the Parties (COP-19) of the United Nations Framework Convention on Climate Change (UNFCCC) in 2013 in Warsaw governments decided on further important steps towards a new binding climate change agreement as successor to the Kyoto Protocol. To reach such an agreement policy makers from developed and developing countries will have to negotiate their countries' contribution to the world's climate change efforts taking an equitable allocation of emission reduction obligations into account.

In this chapter we present our work on the cost and carbon certificate trade impacts of two different regimes of inter-regional burden-sharing for the allocation of GHG emission reduction obligations needed to reach stringent global climate change stabilisation. This work, among other research topics, was conducted in the context of the LIMITS project which focussed on the main world regions.[1] Project results regarding burden-sharing schemes are described as a cross-model comparison study in Tavoni et al. (2013) and for one model in particular in Kober et al. (2014). Compared to the latter publication, this chapter reports more regionally detailed results and provides additional insights for selected countries as to the implications of the different burden-sharing schemes.

We focus our investigation on the distribution of emission allowances and carbon certificate trade effects, as well as carbon market capital flows emanating from the introduction of equitable burden-sharing between regions that undertake collective effort in mitigating global climate change. In Sect. 2 we provide a brief characterisation of the model that we apply, as well the approach and main assumptions used. In Sect. 3 we highlight our main results regarding the main dynamics of the two emission allocation schemes analysed here, including their main differences in terms of certificate trade and carbon market capital flow. In Sect. 4 we report our overall conclusions and reflect upon these in the light of implications for policy makers.

[1] The LIMITS project was funded by the European Union Seventh Framework Programme FP7/2007–2013 under grant agreement no. 282846. Further information on the project is available under www.feem-project.net/limits.

2 Approach and Socio-economic Assumptions

The analysis of regional burden-sharing schemes under stringent climate policy control is conducted through a scenario analysis using a global energy system model.

2.1 TIAM-ECN Energy System Model

TIAM-ECN is the global TIMES Integrated Assessment Model (TIAM) of the Energy research Centre of the Netherlands (ECN). Its general structure is similar to the ETSAP-TIAM model, as well as the linear optimisation algorithm, in which the total discounted energy system costs are minimised over whole time horizon until 2100. For its 15 regions it contains the abstracted structure of the entire energy economy from resource extraction to energy end use. It features many region-specific details associated to energy resource availability, conversion and demand. As a technology-rich bottom-up model, it contains many possible fuel transformation and energy supply pathways, and encompasses technologies based on fossil, nuclear and renewable energy resources. According to the technologies' economic and energy system constraints the models determines the most cost-efficient energy transformation pathways in order to satisfy energy demand. Regarding the representation of GHG emission reductions, the model covers abatements options for carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) related to energy conversion, industrial processes and other GHG emission sources, such as agricultural activities. More detailed model descriptions and examples of the application of TIAM-ECN can be found in Rösler et al. (2011, 2014), Keppo and van der Zwaan (2012), van der Zwaan et al. (2013a) and Kober et al. (2014), as well as several references therein. Although the model has been applied to the time horizon to 2100 in order to reflect the very long-term dynamics of selected GHG emissions, we focus our investigation around burden-sharing schemes on the first half of this century as this period better corresponds to the scope of the current climate policy debate.

The demand of useful energy in TIAM-ECN is derived based on socio-economic parameters. For the global development of the gross domestic product (GDP)[2] we assume more than a tripling of over four decades, from 68 trillion US$ in 2010 to 247 trillion US$ in 2050 while the world population grows to 9 billion persons in 2050. This population development is based on the medium fertility projections of the United Nations (UN 2011), with a particular strong growth in Africa, India and Other Developing Asia with a population in 2050 of 2.1, 1.7 and 1.4 billion respectively. China's population is expected to peak at 1.4 billion people around

[2] GDP is expressed in terms of purchasing power parity (PPP) and monetary values in US$ (2005), if not indicated otherwise.

2025, and to decline thereafter to 1.3 billion people in 2050. For most of the countries of the Organisation for Economic Cooperation and Development (OECD) the population remains comparably stable, with a total average increase of 0.1 %/ year for the period 2010–2100. The number of households, which has an impact on the demand for space heating for instance, is assumed to increase more rapidly than the population due to changes of the living patterns towards smaller household sizes. The total number of households doubles from 2 billion to 4 billion households between 2010 and 2050. Further model assumptions and a description of model input data, including the availability of future energy technology, can be found in Kriegler et al. (2013), van der Zwaan et al. (2013b) and Kober et al. (2014).

2.2 Burden-Sharing Regimes

An energy system that allows the provision of energy services while attaining deep GHG emission reductions in order to mitigate climate change is more costly compared to a system not subjected to GHG emission reductions if one neglects damages to the energy system due to climate change. To achieve stringent climate policy targets as cost-effective as possible, substantial expenditures are required in all regions worldwide, independent of their economic development status. These additional cost vary across regions due to various reasons, and in some regions there may exist more low-cost GHG abatement options than in others. To unlock the world's least-cost GHG mitigation options, some regions may need to disproportionally contribute to global climate change mitigation efforts, for which they would need to be compensated. Regional compensation mechanisms, also named burden-sharing schemes, aim to establish a more equitable distribution of the financial burdens associated with climate change mitigation by shifting costs attributed to GHG emission reduction across regions. Examples of burden-sharing mechanisms are the emission reduction targets of the member states of the European Union (EU), which are subjected to emissions not covered by the European Emissions Trading Scheme (EU 2013), and the intra-EU burden sharing of the 2010 EU target under the Kyoto Protocol based on the "Triptych approach" (Phylipsen and Blok 2013). Burden-sharing schemes that have different indicators in common, which can be based on socio-economic variables, energy- and emission's parameters and/or cost factors, are used to formulate the equity principle underlying each scheme and to determine a region-specific allocation of emission allowances. Through exchange of these allowances on a carbon certificate market, both cost-efficient allocation of GHG emission reductions and financial compensation of regions can be realised. The literature provides studies of many different burden-sharing schemes which have been analysed over the past. An overview is compiled in Tavoni et al. (2013). This publication also explains the methodological background of two burden-sharing schemes that we use for our study. Tavoni et al. (2013) also provide the outcomes of the LIMITS cross-model comparison study on the two burden-sharing schemes. Further comparative assessments of different burden-sharing principles can be found, for instance, in den Elzen et al. (2008), Hof et al. (2008), Jacoby et al. (2008) and Ciscar et al. (2013).

Our study concerns two different burden-sharing schemes. The first scheme, which we refer to as "resource-sharing" scheme uses a population based indicator, and the second scheme, the so-called "effort-sharing" scheme, considers climate policy costs and economic development. The resource-sharing scheme describes an allocation mechanism for emission permits according to the level of GHG emissions allowed per capita. For this scheme we assume a transition phase for the period 2020–2050 in which the regional per capita emissions converge from status-quo towards the global average while the global average converges according to the GHG reduction obligation in order to achieve stringent climate targets. For an explanation of the terminology 'contraction and convergence' see Meyer (2000). The goal of the effort-sharing scheme is to equalise the mitigation costs across regions with the paradigm that all regions should incur the same climate change control costs in percentage terms of their GDP after emissions trading. Hence, revenues or expenses from carbon certificate trade are included in climate change control costs. Starting in 2020, the regions' shares of total climate change mitigation costs should be equal to the world average. This implies that regions with higher relative mitigation costs compared to the global average receive additional carbon certificates. Each region gains revenue from the carbon market through the sale of excess carbon certificates, which provides compensation (at least partly) for their mitigation costs. This effect leads to an equalisation of climate change mitigation efforts across regions. Conversely to contraction and convergence under the resource-sharing scheme, we assume no transition phase under the effort-sharing scheme.

The two burden-sharing schemes are investigated under a framework of stringent climate policy goals achieving a long-term stabilisation of the global mean temperature increase at 2 °C with respect to the pre-industrial level. For the calculation of the regional allowance allocation we apply a 2 °C climate stabilisation scenario in which the regional allocation of GHG emission certificates corresponds to the regional emissions under a global least-cost GHG reduction pathway. This scenario is referred to as the 'reference' scenario. In both burden-sharing schemes the amount of worldwide available emission allowances equals the reference scenario in each period. The duration of one trading period is 10 years while banking or borrowing between trading periods is not allowed.

The model implementation of the burden-sharing schemes, which is described in more detail in Kober et al. (2014), is realised through pre-optimisation procedures for the calculation each region's overall allocations of permits. The calculated certificate quantities are introduced as user constraints to the optimisation problem. Key input parameters for the calculation of the allocation of emission allowances under the resource-sharing scheme are the population development assumptions, the regional GHG emissions per capita in 2020 and the future evolution of the global average of per capita GHG emissions. For the calculation of the regional per capita emissions in 2020 and the global average specific emissions from 2020 onwards, we used those derived from the reference scenario. Each regions' per capita emissions contract beyond their respective starting points in 2020 and converge in subsequent decades by 2050. Under the effort-sharing scheme target policy costs are calculated for every region and period. These regional costs are the product of the world total climate change control costs as percentage of global GDP and the GDP of the respective region. The difference between all regions' effort-sharing target policy costs and their policy costs under global least-cost climate change mitigation is divided by the global carbon certificate price for each period. The resulting quantity per period is added to the regions' emission levels calculated under least-cost mitigation criteria, which then equals the regional effort-sharing certificate allocation.

3 Results

We focus the presentation of our results on the time period to 2050. Nevertheless, long-term energy system effects past 2050 are considered in our study due to our model approach with perfect foresight for the time horizon until 2100.

3.1 GHG Emissions Development and Associated Costs in the Reference Scenario

The reference scenario is characterised through a GHG emissions reduction pathway with fragmented weak national climate policies in the near-term that reflect the unconditional Copenhagen pledges. For the period after 2020 we anticipate a global coordinated action to achieve climate stabilisation at 2 °C average atmospheric temperature increase, which is implemented through a maximum radiative forcing level of 2.8 W/m^2 in 2100.[3] A detailed description of the policy framework and assumptions of this scenario can be found in Kriegler et al. (2013).

The GHG emissions of the reference scenario are displayed for the 15 model regions disaggregated by emission source in Fig. 1. The development of the regional emissions in 2020 mimic the countries' Copenhagen pledges as described in Kriegler et al. (2013). Global level GHG emissions reach their maximum in 2020 with 51 $GtCO_2e$ and decrease afterwards to 21 $GtCO_2e$ in 2050. Undoubtedly, industrialised countries and emerging economies have to reduce their GHG emissions drastically in order achieve the global 2 °C climate change control target at

[3] This forcing target refers to all anthropogenic radiative agents with the exception of three agents: nitrate aerosols, mineral dust aerosols, and land use albedo changes. According to our model approach we adjusted the forcing target to be applied to the three GHG emissions represented in the TIAM-ECN.

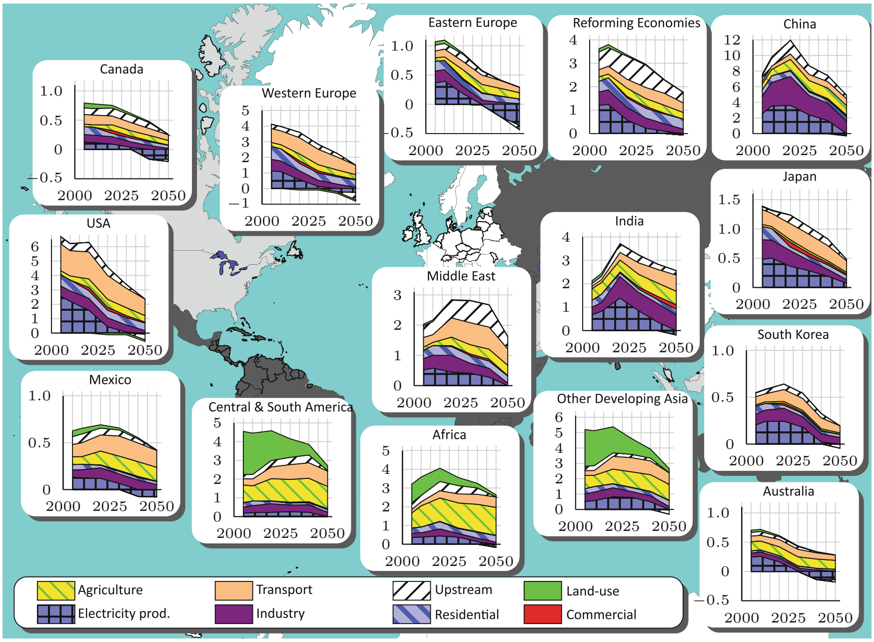

Fig. 1 GHG emissions by sector in the reference 2 °C climate change control scenario with least-cost long-term GHG mitigation (units in $GtCO_2e$)

least costs. For most of the industrialised regions GHG emissions never exceed 2010 emission levels. Deepest emission reductions in relative terms are realised in Eastern and Western Europe, Canada and Australia where 2050 emission levels are at least 80 % below 2010 emissions. In most of the non-OECD regions, which are characterised by either a strong economic growth and/or a significant increase of population, GHG emissions continue to increase until 2020 and decline rapidly afterwards. A modest increase of emissions in the two regions Central and South America and Other Developing Asia towards 2020 can be observed as a result of compensation of increasing emissions from fossil fuel combustion and agricultural activities by decreasing emissions from land-use and land-use change and forestry (LULUCF). The emissions from LULUCF follow a declining trend which can partly be attributed to policy measures due to the benefits related to conservation of natural area and biodiversity. There are only four out of the 15 regions with emission reductions in 2050 compared to 2010 of less than 40 %, which are Africa, Central and South America, India and the Middle East.

In general, we observe most of the GHG emission reductions being realised through abatement of CO_2, in particular in the upstream sector and in the power sector which in some regions even allow for negative net emissions. Negative emissions occur when biomass is converted in technologies with carbon dioxide capture and storage (CCS), e.g. for the production of electricity, biofuels or hydrogen. For instance, in Eastern and Western Europe, the USA, Canada and

Australia, negative GHG emissions of the electricity and upstream sectors offset emissions of sectors with more costly abatement options. Compared to the power sector and the upstream sector, GHG emission reductions in agriculture, e.g. for food production, and in the transport sector, are more expensive and in some cases have very limited mitigation potential. For insights in the global, regional and sectoral emission reductions and the deployment of low-carbon technology we refer to van der Zwaan et al. (2013b), Calvin et al. (2013) and van Sluisveld et al. (2013) who provide their findings in the light of the same scenario framework as presented in this publication. In our study we assume a broad availability of GHG mitigation measures, such as renewable energy, CCS technology and alternative fuel conversion technologies in the demand sectors that are necessary to realise the transition to a decarbonised energy system. Future technology deployment is associated with a various uncertainties which have been investigated by van der Zwaan et al. (2013b) related to the availability and cost of low-carbon technology, and by Keppo and van der Zwaan (2012) related to CCS technology in particular.

Looking at the regions' specific per capita emissions, displayed in the left panel in Fig. 2, this indicator is highest in 2020 in Australia, Canada and the USA with around 20 $MtCO_2e$/capita and lowest in Africa and India with 3 $MtCO_2e$/capita, while on global average 7 $MtCO_2e$ are emitted per capita in 2020. The global average per capita emission declines to 2 $MtCO_2e$/capita in 2050. This global average in 2050 represents the convergence target for the emission allocation under the resource-sharing scheme. The regional per capita emissions in 2050 range from 6 $MtCO_2e$ per capita for Reforming Economies to less than zero for Eastern Europe.

The carbon certificate price that corresponds to the emission trajectory in order to attain the 2 °C climate target increases from 70 US$/$tCO_2e$ in 2020 to

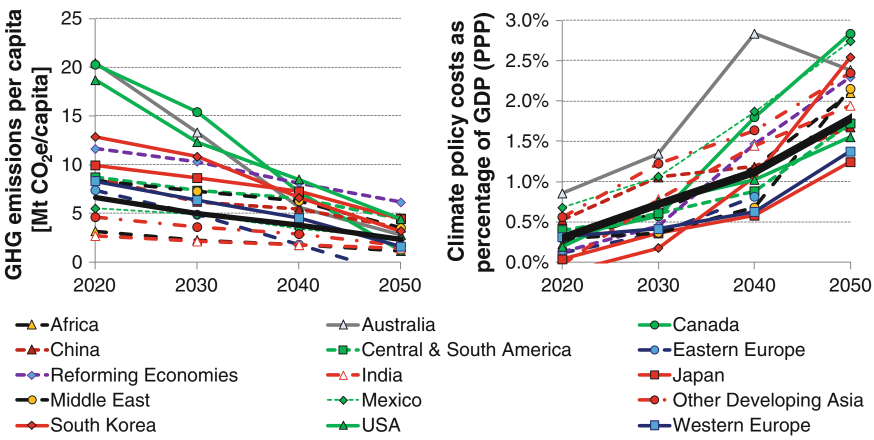

Fig. 2 Regional GHG emissions per capita (*left panel*) and GHG emission intensity of GDP (*right*) in the reference 2 °C climate policy scenario

130 US$/t$CO_2$e in 2030, and to 390 US$/tCO_2e in 2050. According to our model approach, this price path represents the marginal overall GHG emission abatement cost, and it applies to all regions and sectors of the global energy system. In 2020 the certificate prices are strongly influenced by the stringent Copenhagen/Cancun pledges we imposed, and prices in the long-run are determined by the availability and cost of the GHG mitigation measures. These abatement prices are in line with the prices stated by other models which span a range between 200 and 900 US$/t$CO_2$e in 2050 with a median at 200 US$/t$CO_2$e (see Kriegler et al. 2013). The Global Energy Assessment reports a CO_2 price above 110 US$/t$CO_2$e that is associated with a global GHG emission reduction down to about 25 GtCO_2e by 2040 (GEA 2012). The worldwide aggregated energy system costs (including costs to avoid non-energy related GHG emissions), to which we refer as 'climate policy costs',[4] accumulate to 77 trillion US$ for the entire first half of the century with 0.3 trillion US$ in 2020, and around 4 trillion US$ in 2050. In 2020, the highest costs occur in China (90 billion US$), followed by Western Europe (50 billion US $). For India in 2020 we observe a slightly positive cost effect due to reduced fossil energy imports under climate policy. In absolute terms, China faces highest climate policy costs throughout the whole first half of the century, with about one fifth of the global costs in 2050, and India's costs grow substantially in this timeframe that India becomes the country second highest climate policy costs by 2050 (16 % of the global costs).

For the effort-sharing scheme of particular importance, we provide the climate policy costs in relative terms to GDP in the right panel in Fig. 2, which shows that these costs on global level correspond to 0.3 % in 2020 and 1.7 % in 2050. Australia faces comparably high costs until 2040 due to the fact that the country undergoes a substantial change of its domestic energy supply structure and its revenues from coal export decline drastically as a result of reduced coal demand under climate change policy. After 2030/2040 this effect applies also to the Middle East, Reforming Economies and Canada, which experience extensive net fossil fuel exports under absence of climate policy and possess few local GHG reduction potential. Under stringent climate policy their fossil fuel exports reduce significantly in the long-run associated with a decline of their revenues from the oil and gas markets, which consequently leads to an increase of their climate policy costs. In China until 2030 and in Mexico and Other Developing Asia over the whole period, relative policy costs are higher than the world average, which results from the large expected increases in their respective energy demands and thus massive investment requirements in renewable energy for power production and energy efficiency improvements on the demand side. Western Europe and Japan are

[4] Policy costs in the context of our bottom–up modelling approach refer to undiscounted costs for the entire energy system, including expenditures for technology investments, operation and maintenance, other variable costs as well as costs associated with changing demand patterns. Policy implementation and transaction costs are excluded. Climate policy costs are calculated as the difference between the total costs under certain policy conditions and the costs in the reference case.

regions with relative climate policy costs below the global average for most of the time until 2050, which is driven by their low energy intensity of GDP, their reduction of energy imports under climate change policy and their good potentials to deploy low-carbon technology. This includes for both regions the continuation of electricity production from nuclear power until 2050 with an installed power plant capacity at around 2005 level.

3.2 Allocation of Emission Allowances

Based on the development of GHG emissions in the reference scenario and the burden-sharing schemes' calculation methods, regional allowance endowments are determined as displayed in Fig. 3. Independent of the burden-sharing scheme China is the region which receives most of certificates equivalent to cumulative emissions for the period 2020–2050 of about 250 $GtCO_2e$. The figure also illustrates that for the majority of the regions the allocation according to the effort-sharing deviates less from the regions' cost-optimal GHG emission trajectories than the distribution under the resource-sharing scheme.

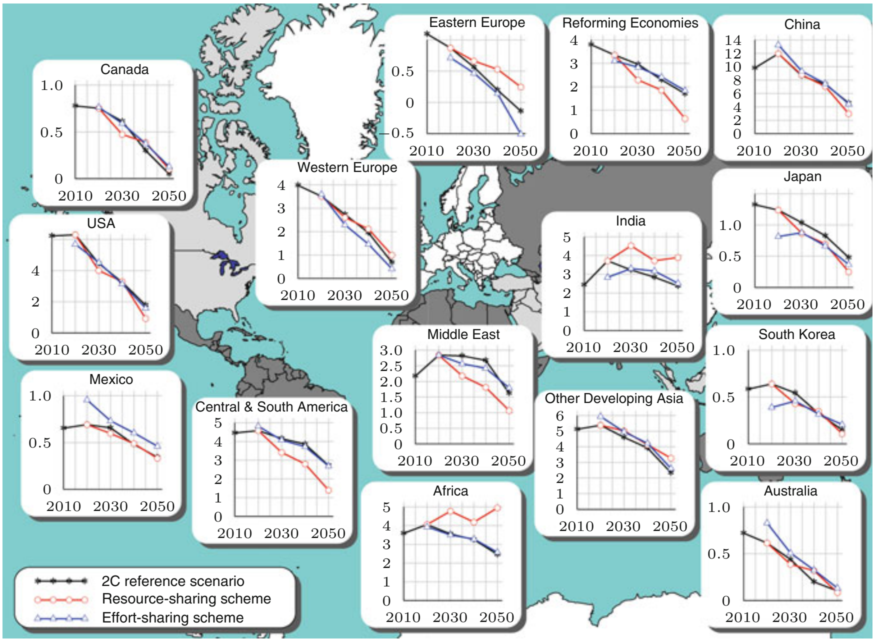

Fig. 3 GHG emissions in the reference scenario and emission allowances allocation under the two burden-sharing regimes (units in $GtCO_2e$)

The resource-sharing method favours regions with a high population growth, such as Africa and India. For both regions the amount of emission permits increases from 2020 to 2030, and for Africa also from 2040 to 2050. All other regions receive less certificates in the periods past 2020. The endowment of certificates to Other Developing Asia is higher than the emission reductions of the reference pathway as a result of the initially low per capita emissions in 2020 and the high population growth in this region. In regions with low or even negative population growth rates, the number of emission rights of regions declines drastically in particular when the initial number of GHG emissions allowances is high, such as for China, Japan, the USA, Central and South America and Reforming Economies.

The effort-sharing scheme favours regions which are characterised by comparably high costs for GHG emission reduction with respect to their overall economic capability. China receives emission permits between 2020 and 2050 of cumulatively 256 $GtCO_2e$, which exceeds the reference GHG emissions by 14 $GtCO_2e$ (6 %). Also Other Developing Asia, Mexico and Australia can profit from additionally available certificates worth about 18 $GtCO_2e$ until 2050. In contrast, Western Europe and Japan as a region with a high expected GDP and moderate climate policy costs get 16 $GtCO_2e$ less allocated in the same timeframe compared to its reference emission pathway.

When comparing the certificate allocation under the two burden-sharing schemes, significant differences can be observed for Africa, India, Latin America, the Middle East and Reforming Economies. Africa, for example, receives under the resource-sharing allocation in total 34 $GtCO_2e$ more emission permits until 2050 than under the effort-sharing scheme. The different endowments affect the carbon certificate trade and hence the extent to which the regions are compensated for their climate change mitigation efforts.

3.3 Carbon Certificate Trade

Emission certificate trade allows a return from an initial certificate allocation to the overall cost-optimal mitigation pathway, if one assumes the existence of a perfect carbon certificate market (as we here do). The traded quantities are determined by the allocation of GHG emission rights and the region's technological potentials to reduce GHG emissions. The trade of certificates in the resource-sharing scheme starts after the year of grandfathering in 2020. A cumulative amount of certificates equivalent to 83 $GtCO_2e$ is traded until 2050 under the resource sharing scheme. 60 % (50 $GtCO_2e$) less certificates are traded under the effort-sharing scheme in the same period due to the fact, that the allocation under the effort-sharing regime comes closer to each regional cost-optimal GHG emissions reduction pathways than under the resource sharing scheme.

Under the resource-sharing regime the total annually traded quantity of emission rights reaches its maximum with 6 $GtCO_2e$ in 2050, which represents about a quarter of the global GHG emissions and half of the global CO_2 emissions in that year. Most of the emission certificates are sold by Africa and India (Table 1). These two regions combined sell emission rights equivalent to a cumulative amount of 63 $GtCO_2e$ until 2050, which corresponds to about 80 % of all certificates sold in this period. Around 80 % of the tradable permits in this time frame are bought by Central and South America, China, the Middle East and the Reforming Economies due to their rapidly increasing GHG emissions and modest or even negative population growth rates.

Table 1 Emission certificate trade and carbon market capital flow cumulative between 2020 and 2050 for the two burden-sharing schemes

Resource-sharing scheme			Effort-sharing scheme		
	Certificates sold ($MtCO_2e$)	Revenues from the carbon market (billion US$)		Certificates sold ($MtCO_2e$)	Revenues from the carbon market (billion US$)
Certificate selling regions					
Africa	33984	8473	China	13873	1327
India	29375	6574	Other Dev. Asia	10620	1831
Other Dev. Asia	10937	2809	Mexico	3883	693
Eastern Europe	6233	1614	Australia	3171	505
Western Europe	1870	797	Canada	951	290
Australia	586	165	India	366	788
	82984	20432		32865	5435
Certificate buying regions					
South America	−24549	−5854	Western Europe	−10272	−2151
Middle East	−17850	−3823	Japan	−5899	−936
Ref. Economies	−16432	−3905	USA	−4461	−760
China	−9632	−3605	Middle East	−4207	−553
USA	−8403	−2150	Eastern Europe	−4139	−1022
Japan	−4146	−953	South Korea	−1902	−106
South Korea	−1119	−174	South America	−1087	−366
Mexico	−569	−79	Ref. Economies	−627	272
Canada	−283	112	Africa	−273	186
	−82983	−20432		−32866	−5435

Associated to the trade of emission allowances is the capital transfer on the global carbon market, which is determined by the amount of certificates traded and the corresponding price of emission certificates. As a result of the exponential increase of the carbon certificate price, the carbon market capital flow is increasingly determined by the certificate price, rather than by the traded quantities. Under the resource-sharing scheme the total carbon market capital flow accumulates to 20 trillion US$ until mid of this century with annual capital transfers of 400 billion US$ in 2030 to 620 billion US$ in 2040 and to 2200 billion US$ in 2050 (Table 1). Over the entire timeframe Africa and India receive together 70 % of the worldwide generated revenues from sales of certificates. Conversely, Central and South America's spends about 30 % of the total global expenditures for certificate purchases, and the Middle East, Reforming Economies and China about 20 % each.

Comparing the global capital flows of the carbon certificate market under the resource-sharing scheme with the climate policy costs associated with the 2 °C climate stabilisation target, reveals, that the cumulative carbon market capital flows represent 30 % of the global policy costs during the first half of the 21st century (Fig. 4). Of course, this indicator deviates regionally. For the group of non-OECD countries, in total 4 % of the policy costs can be compensated by revenues from the carbon market until 2050. Looking at single regions, we can observe for Africa on the one hand total cumulative revenues from the carbon market of 8.5 trillion US$ which is almost 2.5 times the cumulative climate policy costs (3 trillion US$) in the

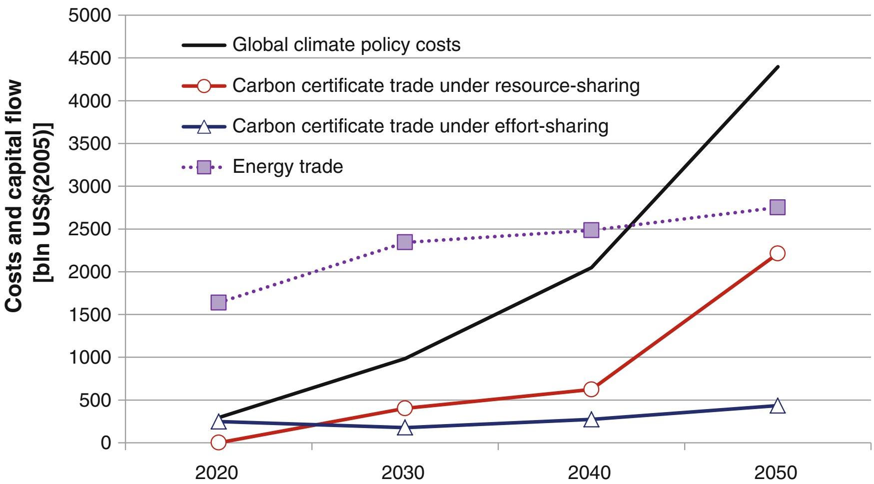

Fig. 4 Climate policy costs and capital flows for trade of carbon certificates, energy and captured CO_2 under the resource-sharing scheme (based on Kober et al. 2014) *N.B.* Capital flows refer to trade among the 15 regions represented in the model. Market capital volumes would increase if results are shown based on a higher geographical resolution

period to 2050. On the other hand, Reforming Economies' expenses for certificate purchases are about 50 % higher than their climate policy costs in the reference scenario for the period 2020 to 2050. These two cases indicate that the resource-sharing regime analysed in this study is unsuitable to compensate all developing and transition countries at once. This underpins the drawback of the resource-sharing scheme, which refers to the allocation regardless of each region's capabilities to reduce GHG emissions. Especially, if a regions' population growth is rather moderate, or even negative, and emission abatement measures are costly, the region is hardly compensated for their cost to mitigate climate change. The case of Africa also shows that the resource-sharing scheme might also over-compensate the financial efforts of GHG emission reduction measures of selected emerging regions. This finding has also been observed by Jacoby et al. (2008).

Under the effort-sharing scheme certificate trade reaches its maximum with almost 3 $GtCO_2e$ in 2020 and declines in the subsequent periods until 2050 to about 1 $GtCO_2e$ annually. The resulting annual carbon market volume ranges between 170 and 270 billion US$ in the period 2020 until 2040 and peaks at 430 billion US$ in 2050. The corresponding cumulative capital flow until 2050 (5 trillion US$) represents one quarter of the volume under the resource-sharing scheme. China and Other Developing Asia are prime certificate selling regions under the effort-sharing regime, and receive 30 and 40 % respectively of the total global carbon market revenues until 2050. China is particular important in the near-term with a share of global certificate sales values of 50 % in 2020 (95 billion US$). In the decades beyond 2020, China's carbon market revenues decline, and towards mid-century China's position on the market changes from a net selling region to a net buying region. The main selling regions in 2050 are Other Developing Asia, the Middle East, Reforming Economies and India, which receive each more than 50 billion US $. Western Europe is by far the main buyer of emission certificates with cumulative expenditures of 2.2 trillion US$ in the first half of this century and a maximum annual capital requirement of 110 billion US$ in 2050. Eastern and Western Europe combined spent up to 250 billion US$ in 2050 for purchases of permits, and hence for compensation of other regions for their climate change control costs.

The capital volume of the carbon certificate market as percentage of the global climate policy costs is about 10 % for the period 2020–2050 under the effort-sharing regime. The development of this share over time reveals a declining trend from 70 % in 2020 to 10 % in 2050. Comparing these global shares, with those of the resource-sharing scheme, however, is insufficient to assess both burden-sharing schemes with regard to their ability to reach a fairer distribution of the region's costs for mitigating climate change. Our model results show significant regional differences between the two burden-sharing schemes with respect to the regions revenues or expenditures on the carbon market versus their climate policy costs. In 2020, China and Central and South America are able to recover almost all their climate policy costs through revenues from the carbon market, and Other Developing Asia at least 30 %. Overcompensation, as observed for Africa under the resource-sharing scheme, is less significant under the effort-sharing regime. The effort-sharing regime allows all non-OECD countries combined, to cover 12 % of their climate policy costs using revenues from the carbon certificate market during the first half of the century, with a maximum of 27 % in 2020 and a minimum of 9 % in 2040. Comparing the two burden-sharing schemes we conclude, that the effort-sharing regime is better capable to compensate less developed economies for their costs under a global 2 °C climate policy framework. The effect of burden-sharing—generating generally higher policy costs for the cluster of OECD countries and lower ones for non-OECD countries—is larger for the effort-sharing scheme than the resource-sharing scheme.

The certificate exchanges and associated capital volumes to realise either of the two burden-sharing schemes indicate the importance of the existence of an appropriate carbon certificate market to cost-efficiently reach climate change mitigation goals. In particular under the resource-sharing scheme, the capital transfer of the carbon market would almost reach the level of energy market capital flows around the middle of the century (Fig. 4). For the assessment presented here we assumed perfectly functioning markets for both carbon certificates and energy commodities. It might be difficult, to establish perfect carbon market conditions, and market distortions of many different types could arise. For an analysis of the impacts of an imperfect carbon certificate trade we refer to Kober et al. (2014), who investigate in particular effects related to timing issues, regional trade implications, certificate price effects, and global climate policy costs.

4 Conclusions

In this study we analysed the two different regional burden-sharing schemes for the allocation of GHG emission allowances, the resulting carbon certificate trade, and carbon market capital flows under a 2 °C climate policy regime. To achieve this climate target at least-cost, global GHG emissions must reduce by half between 2010 and 2050, which is in line with recent publications (see Kriegler et al. 2013; IPCC 2014; IEA 2014). Thereby sectors in which abatement is costly, such as agriculture, industry and transportation, would be compensated by extensive emissions reductions in other sectors which even become negative net emitters in selected regions around the middle of the century.

We investigated a population-based certificate allocation regime (resource-sharing) versus a scheme which aims at equal distribution of the economic burden across regions (effort-sharing). We find that under the resource-sharing regime the regional allocation of emission certificates deviates more from the region's emission trajectories under a global least-cost reference mitigation pathway than observed under the effort-sharing scheme. Consequently, significant differences between the two burden-sharing schemes occur regarding the amount of certificates traded on a global certificate market, and the resulting carbon market capital flow. Between 2020 and 2050 under the resource-sharing scheme almost three times more certificates are traded than under the effort-sharing scheme. Establishing a proper functioning of a global carbon certificate market is essential when implementing burden-sharing schemes, as it allows the unlocking of a regions' least cost GHG mitigation potential. If carbon certificate trade possibilities are limited global costs to attain the 2 °C climate target might even increase by 20 % (Kober et al. 2014).

The resource-sharing method favours regions with a high population growth, such as Africa and India. Both regions are net seller of certificates on the certificate market with cumulative sales of permits equivalent to 63 $GtCO_2e$ until 2050 which corresponds to an aggregated capital flow of 15 trillion US$. With these revenues from the carbon market, both regions combined can cover their climate policy costs until 2050. The most important certificate-buying regions until 2050 are Central and South America, the Middle East, Reforming Economies and China due to their low or even negative population growth.

The effort-sharing scheme favours regions which are characterised by comparably high costs for GHG emission reduction with respect to their overall economic capability. China and Other Developing Asia face comparable high climate policy costs in the near-term and receive excess emission permits which they sell on the carbon market and gain combined revenues worth 140 US$ in 2020. These revenues offset the regions' climate policy costs in that year. Towards 2050 China becomes a net buying region as a result of its strong economic growth and comparable advantage in terms of its GHG emissions reduction potential. An important determinant of climate policy costs in the long-run are changes in fossil fuel trade, which occur as consequence of global fuel shifts towards low-carbon energy and demand reductions to meet the stringent climate targets. This increases climate policy costs of traditional fossil fuel exporting regions (Middle East, Reforming Economies and Australia) because of substantial reductions of their import revenues from fossil fuel trade. Western Europe, which has relatively low climate policy costs as percentage of its GDP, is the main buyer of emission certificates with cumulative expenditures of 2.2 trillion US$ in the first half of this century and a maximum annual capital requirement of 110 billion US$ in 2050.

Comparing both burden-sharing schemes, with regard to the compensation of non-OECD countries' climate change mitigation efforts via revenues from the global carbon certificate market, reveals an advantage of the effort-sharing scheme over the resource-sharing scheme. Under the effort-sharing regime, for all non-OECD countries combined, about 12 % of their climate policy costs can be covered by revenues from the carbon certificate market during the first half of the century, with a maximum of 27 % in 2020. The average annual capital needed to realise this compensation until 2050 amounts to about 140 billion US$. Comparing these means, with the 100 billion $US\$_{2020}$ targeted to be mobilized by the Green Climate Fund under the Copenhagen accord by 2020, (UNFCCC 2014) advocates for continuation of this financial instrument in future and to increase its budget, if a higher compensation of less developed economies is aimed for.

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Assessment of Carbon Emissions Quotas with the Integrated TIMES and MERGE Model

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Abstract The success of climate change mitigation depends on the modalities for the extension of the Kyoto protocol after 2020. This refers to the appropriate level of GHG reduction imposed as emissions quotas in line with the 2 °C commitment. We perform a parametric analysis where increasingly stringent cumulative and global emission quota bounds are applied using the integrated TIMES and MERGE model (ITMM). The model integrates in one set of equations two hybrid top-down and bottom-up models both able to analyze technological change. The study assumes efficient policies and measures where all world regions accept a binding protocol in 2020 while mitigation policies will start already in 2015. However, this early introduction of efficient policies needs capital transfers for a fair burden sharing in favor of countries with low income and in that sense the model assumptions are critical. Marginal cost of carbon control of these optimistic policies are high (600–1000 \$/t of carbon by 2050) but global GDP losses remain moderate and below 1.5 % per year.

1 Introduction

The Copenhagen Conference of Parties (COP15), as endorsed by the COP16 in Cancun, reached an agreement described in the so-called Copenhagen Accord (CA) (UN-FCCC/CP/2009). The accord aims to combat global warming with differentiated reduction targets of greenhouse gas emissions and by mobilizing resources supporting adaptation and carbon-free technology in developing countries. Unfortunately, both conferences and the subsequent ones failed to negotiate a binding

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_6

agreement to combat global warming. The COPs approved to negotiate and to arrange by 2015 the initiation of such legal binding commitment from 2020 onwards. Nevertheless, the final outcome on mitigation depends on the modalities for the extension of the protocol. Therefore, the legitimate question is which levels of GHG reduction would be sufficient to serve as a Post-Kyoto policy framework aiming to stabilize GHGs concentration at levels that would prevent dangerous anthropogenic interference with the climate system (UNFCCC Art. 2).

Also, as such an agreement will start with global commitments in 2020, while the Kyoto protocol is not supported by significant countries like USA, Canada and eventually Japan and Russia, it is justified to question if it is not already too late to sustain global warming below 2 °C. This is especially the case, in a period following the economic recession of 2008, where governments and markets become increasingly hesitant to mitigate global warming supporting a globally binding agreement. On the other hand, the CO_2 concentration and the mean temperature in the earth atmosphere and the oceans are increasing. These are the overarching questions of the present study. The analysis is based on MERGE (Manne et al. 1995) integrated with the TIMES-MACRO model of USA (Remme and Blesl 2006) both being able to analyze technological change. Emphasis is given to model US, a key player for mitigation policy, as we need to analyze details of technological change including among others the end-use markets not available in MERGE.

A significant study that helps to quantify the probability to sustain global warming below 2 °C as function of cumulative GHGs reduction bounds has been published in Nature (Meinshausen et al. 2009). This study, based on comprehensive probabilistic analysis, claims that cumulative emissions up to 2050 are robust indicators of the probability that twenty-first century warming will not exceed 2 °C relative to pre-industrial temperatures. Limiting cumulative CO_2 emissions over 2000–2050 to 273 GtC yields a 25 % probability of warming exceeding 2 °C—and a limit of 392 GtC yields a 50 % probability—given a representative estimate of the distribution of climate system properties. Similarly, an intermediate probability level is obtained by limiting emissions to 316 GtC (33 % probability) while a limit of 242 GtC yields a 20 % probability. Therefore the results of Meinshausen et al. (2009) may serve as an acceptable benchmark to define cumulative targets for our analysis. Finally, for comparison we refer to the Synthesis Report of the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC). This report estimates a similar value of 273 GtC as the remaining amount of carbon emissions quotas from 2011 onwards for a global warming below 2 °C with a probability of 66 % and 355 GtC for a 50 % probability.

As part of the Copenhagen Accord, Annex I Parties (industrialized countries) and non-Annex I Parties (developing countries) have submitted reduction proposals (pledges) and mitigation actions to the UNFCCC secretariat. Based on these pledges and some extra assumptions compiled by Labriet (2010), emissions for 2020 are estimated to be around 39 $GtCO_2$ (10.64 GtC) and have been adopted in our analysis. This level is lower than the ranges discussed in Den Elzen et al. (2011). Then, for the subsequent periods between 2020 and 2060, we run scenarios postulating different levels of carbon emissions quotas, aiming to assess the feasibility and the implications of the Durban COP17 outcome. Simultaneously the global target of CO_2 emissions in the period 2015–2020 remains free but below the level of 39 $GtCO_2$.

2 The Baseline

The baseline development considered in MERGE is based on the assumptions made in the EU project ADAM, Edenhofer et al. (2010), fine-tuned with the baseline scenario development generated by the TIMER model (Van Vuuren and van Ruijven et al. 2006; Magné et al. 2010) for that project. The baseline excludes any consideration of climate policies or damages due to climate change. The MERGE regions refer to the WEUR (European Union), EEFSU (Eastern Europe and former Soviet Union), CANZ (Canada, Australia and New Zealand), MOPEC (Mexico and OPEC), China, India, Japan and ROW (rest of world). USA which is the ninth world region, is analyzed based on the assumptions and database of the IEA-ETSAP TIAM project (Loulou and Labriet 2008a, b).

ITMM is a large scale NLP model that maximizes the Negishi weighted regional utilities of all world regions. It is solvable directly with only one TIMES region represented explicitly, in our case this is USA. Similar analysis can be done with the global TIMES model but concentrating on the energy system policies without considering the macro-economic feed-backs and implications of such policies. Studies with a model like ITMM can put emphasis either on the global dimension of the issue or could focus on the national consequences of global policies or both, as in this study.

In the baseline, electricity production increases (as a consequence of population and economic growth with a moderate improvement in energy intensity), from 19.2 PWh in 2010 to 62 PWh in 2050, while the annual primary energy use increases from 455 EJ in 2010 to 976 EJ in 2050. Existing fossil fuel-based thermal plants are progressively phased out and replaced initially by a combination of pulverized coal and natural gas combined cycle (NGCC), followed then by integrated gasification combined cycle coal (IGCC) plants due to their outstanding high efficiency and low fuel cost. Next to IGCC, wind turbines followed by nuclear reactors are the most competitive power generation systems. Wind power complements the power supply up to 27 % of overall electricity generation. Primary energy is mainly provided by coal followed by renewable energy forms and biomass, complemented with gas and oil. As a consequence, energy and industry related carbon emissions reach a level of 15 GtC while the atmospheric concentration of CO_2 becomes 545 ppmv in 2050 (642 ppmv, if all Kyoto gases are included). This moderate increase of CO_2 in the atmosphere is the consequence of learning by doing (LbD) and learning by research (LbS) options available in the model. These options refer to wind, solar PV, nuclear, advanced coal and gas with carbon capture and sequestration, biofuels, hydrogen and synthetic fuels. See also Barreto and Kypreos (2004) and Kypreos (2007). These options reduce the specific investment cost (eventually to the level of their floor cost) as function of experience and research spending, making for example wind energy a competitive baseline option.

Next we perform a parametric analysis with different cumulative CO_2 emission reduction targets aiming to restrict temperature change below 2 °C for different probabilities. This policy goal was initially accepted by the European Parliament (European Commission 2007) and has been confirmed in Cancun. The MERGE model describes the emissions of all other Kyoto GHGs based on a baseline development and their marginal abatement supply curves while TIMES defines an explicit treatment of mitigation technologies for CH_4 and N_2O. We have concentrated on the CO_2 cumulative emissions as this was the most demanding part in the cumulative integral of GHGs in the study of Meinshausen et al. (2009).

3 Global Emissions Quotas, Concentrations and Marginal Costs

In this section we present different results obtained, in particular: the level of emission reduction and the associated probabilities to exceed the 2 °C of post-industrial warming; the implied global carbon taxes; and finally the economic implications for USA and other world regions in respect to the baseline developments. The description of the induced changes in the primary energy use and power production and the related technology implications follow afterwards. All scenarios are estimated with a descriptive utility discount rate of 3 %.

3.1 Global Remaining Emissions Quotas

Figure 1 illustrates the emission levels estimated when different cumulative budgets are imposed for the period 2020–2060 guided by the four emission budgets of Meinshausen et al. (2009) between 242 GtC (20 % probability) and 392 GtC (50 % probability). Simultaneously another constraint ensures that at least the global annual emissions of CO_2 emissions by 2020 remains below the level of 39 $GtCO_2$ (10.64 GtC). Otherwise, the model was free to select optimal emission levels for the period of 2010. As consequence of this flexibility, when stringent cumulative CO_2 bounds are imposed the global emission level for 2020 becomes less than the total level of the Copenhagen pledges of 39 $GtCO_2$. This implies an optimistic view assuming that the signatory countries of the extended Kyoto protocol will opt for policies consistent with the stringency of this constraint already by 2015. Another possibility would have been to simulate the COP17 decisions and force the Copenhagen pledges for 2020 in all scenarios. But this would give high levels of emissions for 2020 making it more difficult and expensive to satisfy the sustainability targets afterwards.

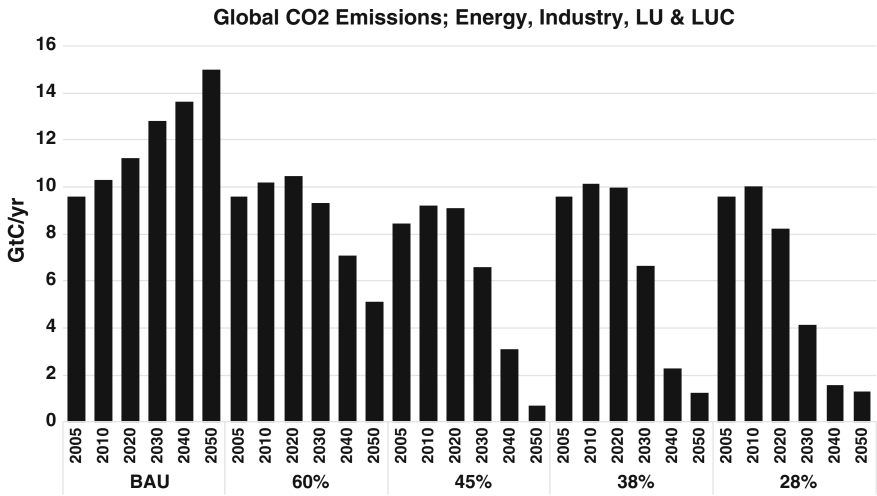

Fig. 1 Annual carbon emissions for the baseline and under different cumulative emissions quotas with 60, 45, 38 and 28 % probability of exceeding 2 °C

Examining the column of cumulative emissions 2000–2050 of Table 1 estimated by multiplying the annual emission levels with 10 (years per period), we confirm that cumulative emissions are above the levels proposed by Meinshausen et al. (2009). Also the probability to exceed 2 °C associated with the cumulative emissions is between 60 % and 28 %. This is a consequence of the optimization freedom given for the years 2010–2020 and the bounds from 2020 to 2060. Results given in Fig. 2 indicate that: (a) the associated shadow prices in our parametric analysis are becoming quite high when approaching low probability levels. For example the marginal costs for 2050 increase above \$1000/tC for the 28 % probability case starting from \$400/tC in the 60 % case (b) emission in 2020 follow the stringency of the cumulative constraint while there are doubts that the potential signatory countries of the Kyoto protocol and the less developed countries will reduce emissions to the levels estimated in the model for the period 2010–2020. See for example the conclusions of the FEEM report of Bosetti et al. (2011).

Table 1 Model estimates of global CO_2 emissions from energy, industry, land use and land use change in GtC/year; cumulative emissions quotas 2000–2050 for the scenarios analyzed and their corresponding probability for not exceeding 2 °C

2010 (GtC/a)	2020 (GtC/a)	2030 (GtC/a)	2040 (GtC/a)	2050 (GtC/a)	2000–50 (GtC/a)	Probability obtained (%)
10.28	11.23	12.8	13.62	14.99	593	
10.20	10.47	9.32	7.10	5.14	436	60
10.13	10.13	7.74	4.15	1.58	369	45
10.12	10.0	6.65	2.27	1.25	336	38
10.02	8.23	4.13	1.58	1.28	286	28

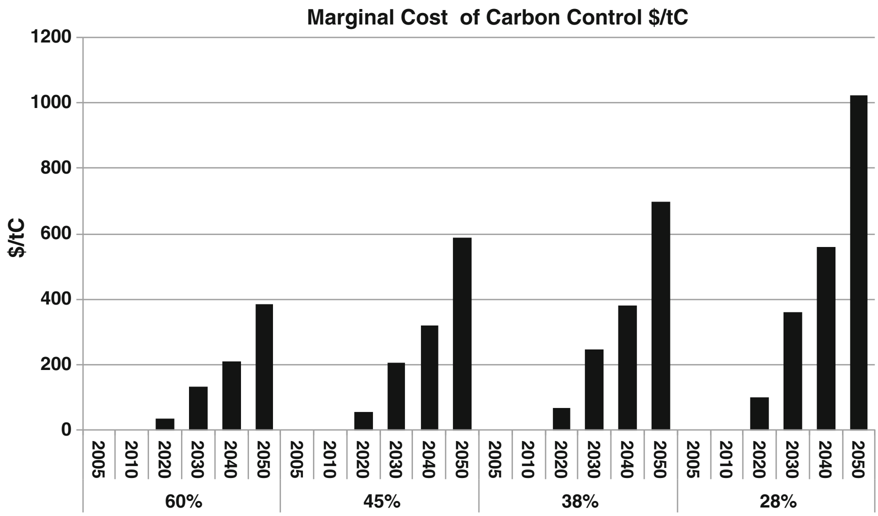

Fig. 2 Marginal cost of carbon control estimated with ITMM under cumulative and global emission for different probabilities of exceeding 2 °C

Finally, as the results demonstrate the benefits of early mitigation policies (e.g., the feasibility to meet the policy target at low economic cost), we have decided not to repeat the estimations lowering the cumulative bounds until to reach the exact probabilities of Meinshausen et al. (2009). Notice that our probability level for three scenarios is below 50 %.

3.2 Emissions and Concentrations

Figure 2 presents the marginal costs that correspond to the imposed cumulative constraints. The emission profiles for the low probability cases indicate significant reductions for the year 2020 already which needs the initiation of effective policies by the year 2015. The CO_2 concentration for the 28 % probability case is 410 ppmv while the other unconstrained GHGs add another 100 ppmv of CO_2eq. It is expected that imposing global constraints in form of CO_2 equivalent emissions could move the global GHGs concentrations to 450 ppmv by 2050 at similar marginal emission reduction cost, as given for example by Den Elzen in his default case (2010).

3.3 GDP Development and Economic Burden by Region

Most of the economic growth in the future will take place in the less developed countries. These countries will also consume more energy having higher shares of carbon emissions than the industrialized countries.

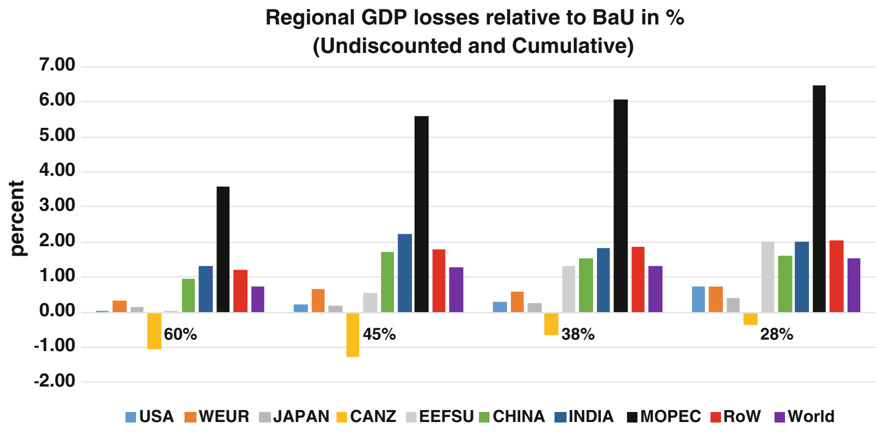

Fig. 3 Regional cumulative and undiscounted GDP losses relative to BAU

Figure 3 defines the undiscounted GDP losses for the period of 2010–2050. The cumulative constraint on CO_2 emissions defines efficient solutions across time and regions but is not considering any compensation transfers as in the case of Cap and Trade policies or in the case of technology protocols to counter balance these losses.

The estimated global GDP losses relative to baseline development for the different scenarios are low. However the impacts are significant for some developing world regions (e.g., the oil exporting countries), as shown in Fig. 3. The losses for the OPEC regions have a maximum of 6.5 % as not only oil and gas exports are reduced but also their prices. The cost for the industrialized world is a fraction of the cost for the other world regions with CANZ having a net benefit mainly due to the use/export of domestic resources. This explains why the now less developed countries are reluctant to join a globally binding protocol without compensation measures. On the other hand a full compensation of economic losses will conclude to very high capital transfers from the industrialized countries (Jacoby et al. 2009). Notice that the undiscounted GDP losses of the global and cumulative economic output for the period of analysis are low (1.2–1.5 %). The net losses are even lower as secondary benefits from reduced local pollutions (due to lower fossil fuel use) and the reduced damages due to lower temperature increase are not assessed in the analysis.

3.4 Primary Energy and Power Generation

This section presents the primary energy consumption (PEC) and power generation for the baseline and the carbon constrained cases. We have already realized (Figs. 1 and 2) that the strong emission reduction obtained for the 28 % probability case is associated with high marginal cost above 1000$ per ton of carbon. The high marginal cost induces significant levels of energy conservation (Fig. 4) and substitution for fossil fuels presented in the subsequent Figs. 4 and 5.

The carbon constraint induces a significant change in energy use equivalent to 1/3 of the baseline's consumption for the 38 % and the 28 % probability cases. Also the use of oil is below 10 % of the total primary consumption or in absolute terms is reduced below 100 EJ/year. Gas consumption is also reduced but to a lesser extent. Consequently the market shares of renewable, biomass and nuclear are increased over the baseline.

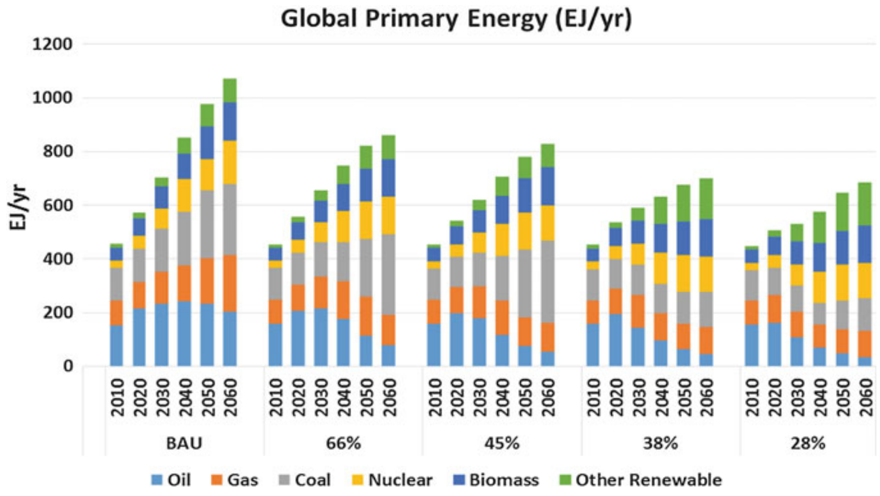

Fig. 4 Global primary energy consumptions for all cases and the BAU

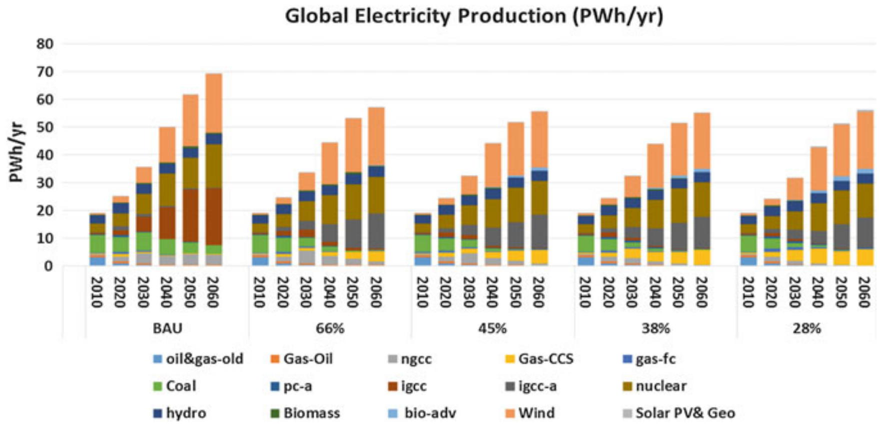

Fig. 5 Global electricity production for all cases analyzed

The level of electricity production is reduced by about 7 PWh/year or by 10 % relative to baseline for the three most stringent constrained cases. The production changes in power generation are drastic as carbon free options are becoming mature dominating the market while the level of production is reduced following the stringency of the carbon constraint. Winners are wind energy, nuclear energy and coal based on IGCC and gas combined cycle (GCC) with carbon capture and sequestration (CCS) options. Advanced biomass systems with CCS options having negative carbon emissions begin to penetrate in 2040.

4 Specific Results for USA

The previous sections explained the consequence of global and binding carbon constraints to the energy system necessary to restrict temperature change below 2 °C. The bounds and the induced carbon prices act as driving forces for technological change needed to establish a carbon free world. The last part of this report (Figs. 6, 7, 8 and 9) presents and discusses the implications of the global constraint to the national USA energy system and carbon emissions.

The reduction of carbon emissions in USA follows the general pattern that appears on the global level where the industry and transport sectors are less efficient to reduce emissions than the power generation industry and the households where

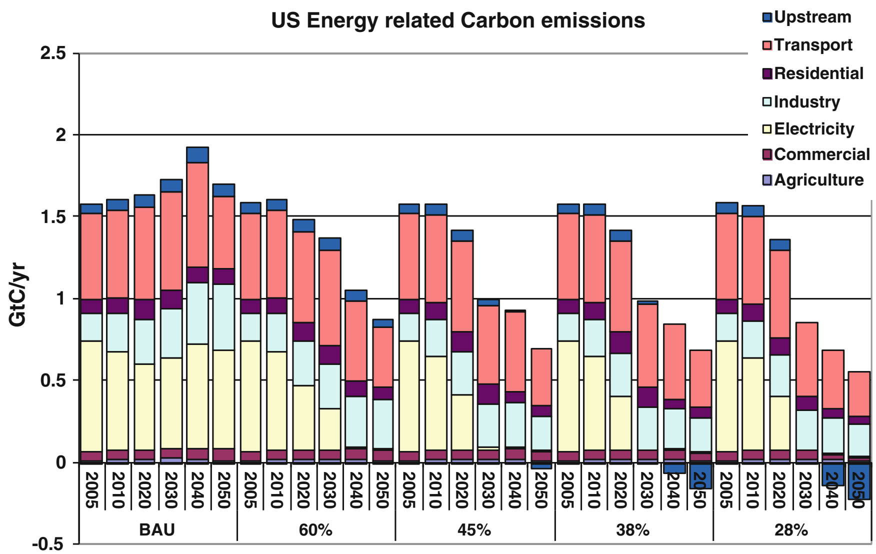

Fig. 6 US energy related carbon emissions by sector. Notice the negative emissions for the most stringent policy cases taking place in the power generation sector (biomass-advanced systems with CCS)

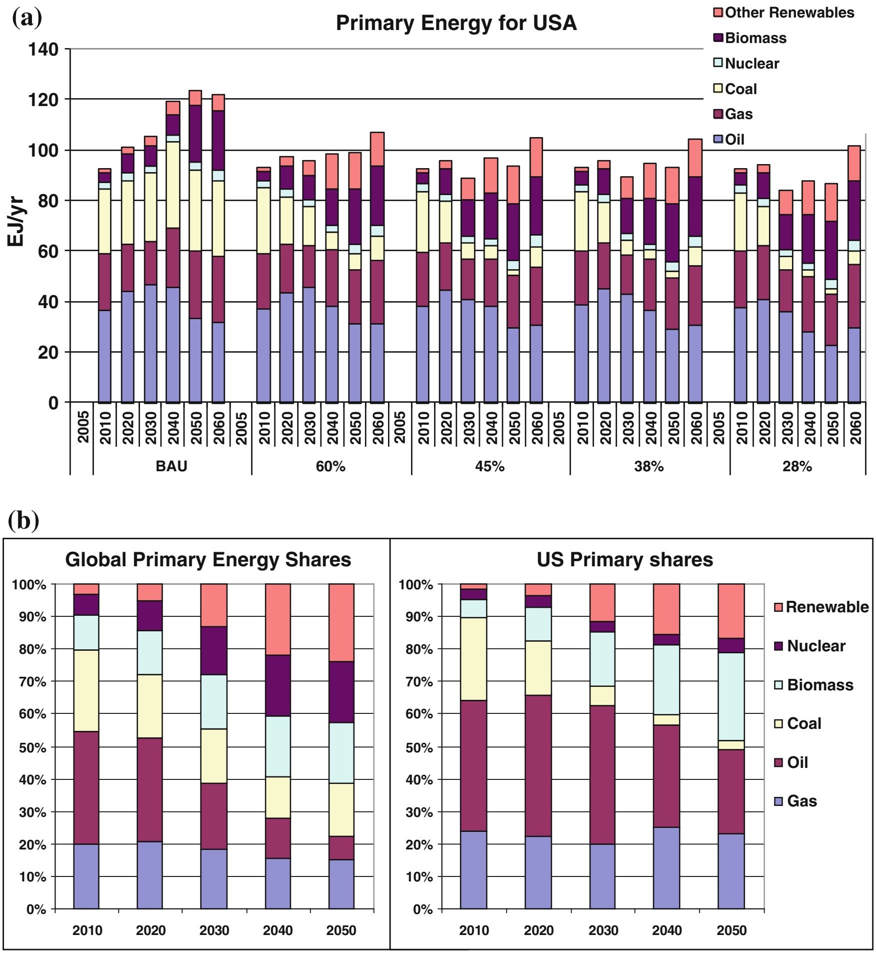

Fig. 7 **a** US primary energy consumption for all cases analyzed and the BAU. **b** Global and US relative shares of PEC for the 28 % CO_2 case

carbon emissions are totally eliminated or drastically reduced. Interesting is anyhow the strong reduction of carbon emissions in the baseline for the period of 2050 that is associated with a dramatic increase of biomass use (alcohol fuels) and wind for power generation. It is a consequence of learning by doing, the key driver of technological change which is further enhanced in the case of active carbon policy.

As a consequence of price differences among the global model and USA the PEC shares in the US (Fig. 7b) and for the most stringent cases, differ significantly from the corresponding global shares. For the US, oil and gas share covers 50 % of PEC followed by biomass (27 %) and renewable (16 %) while coal (3 %) and nuclear (4 %) are almost insignificant. At the global level oil and gas cover only 22 % while IGCC, coal with CCS and nuclear attain significant market shares

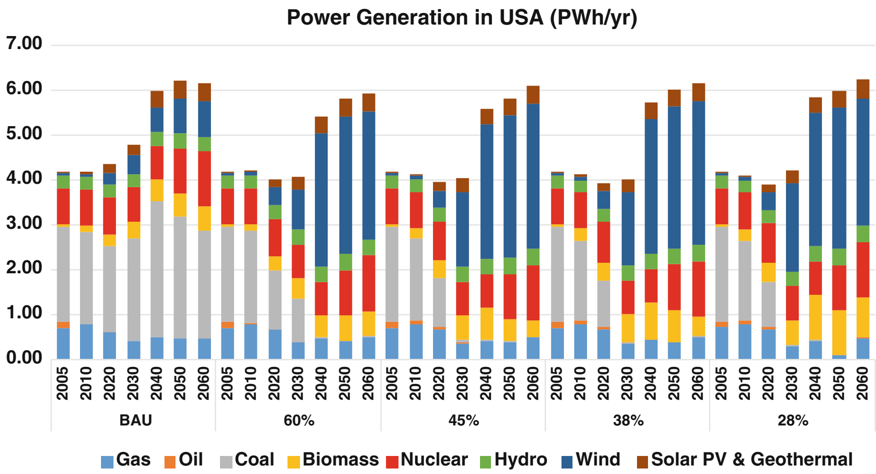

Fig. 8 US electricity generation for the constrained cases and the BAU

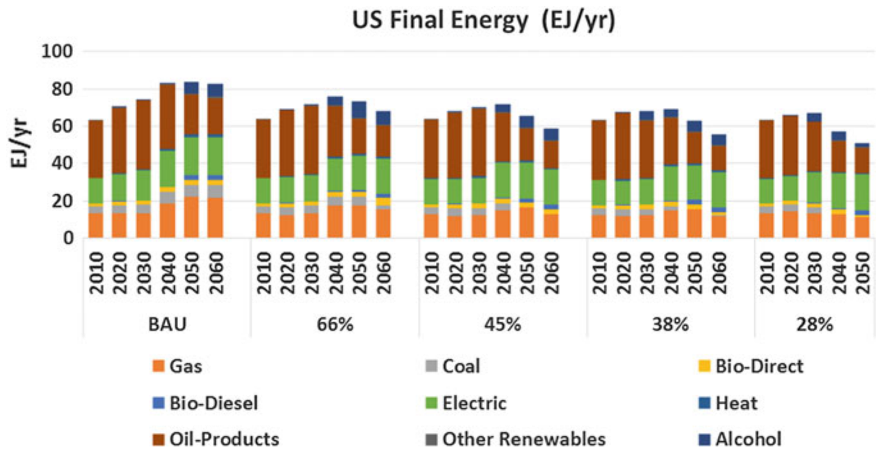

Fig. 9 US final energy use by fuel for all cases and the BAU

complemented with biomass and other renewables. PEC in USA is increased over time by 1/3rd in the baseline case (Fig. 7a) following the economic growth but remains almost stable in the carbon constrained cases. Thus coal substitution by renewable is significant, oil and gas defend their market position while nuclear energy is not free to recover market shares.

Again in the power generation sector (Fig. 8) coal is substituted by wind followed by biomass and nuclear energy under the carbon constraint. Most of the cases show a stabilization in production for the first decades followed by strong penetration of renewable electricity in the last decades as electricity substitutes for fossil use. Geothermal options and solar PV are also introduced in the last periods of analysis. Wind covers more than 53 % of electricity generation and solar PV another 2 % and this could be critical for the load management in the future if production will be based on intermittent systems. As consequence of the substitution effects under the carbon constraint, power generation becomes carbon-free in the US.

In Fig. 9, we notice that electricity, alcohol fuels and bio-diesel contribute to the substitution of coal and oil products and therefore to the reduction of carbon emissions. The use of electricity is significantly increased in the last two decades to substitute for fossil fuels. As the relative prices of energy services and fossil fuels increase, following the high marginal cost of carbon control, consumers reduce their demand for energy services by e.g., driving less, while in the long run are investing in more capital intensive but efficient devices. As a consequence, the final energy use in the stringent scenarios is reduced by 27 % while efficient end-use devices like electric heat pumps and electric cars as well as bio-fuels penetrate the market. Efficient devices and conservation measures together with electricity substitution for oil, contribute to the de-carbonization of the US economy for the stringent scenarios in the last decades.

5 Conclusions

All recent UN Conferences of Parties failed to arrange a global and binding agreement to reduce GHG emissions other than to postpone the initiation of such agreement. Thus the most critical COP will take place in Paris in 2015 where decisions have to be made. Most importantly, global carbon emissions in the recent years continue to grow such that the feasibility of policies for a warming below 2 °C is questionable. The present study defines scenarios and derives conclusions on the economic impacts and this feasibility question, with the help of a new integrated assessment approach merging TIMES-MACRO (a hybrid model) for critical world regions, with the MERGE model for the remaining regions. Conclusions can be summarized as follows:

- The study assumes efficient policies and measures where all world regions accept a binding protocol in 2020 while policies could be initiated already in 2015. However, this needs compensation transfers for countries with low income and in that sense the model assumptions for the early periods are critical. Further delays beyond 2015–2020 or low participation to the protocol will make the goal of 2 °C warming a difficult, but not impossible task, as efforts are postponed towards the second half of the century. This leads to higher marginal prices and costs (see also Den Elzen et al. 2010). These extra costs are related to the inertia of the infrastructures in the energy system that locks-in conventional production technologies and the foregone learning by doing cost reductions. Obviously moderate targets can be satisfied at lower cost but at higher risks of damages.

- Some carbon-free technologies like wind and advanced nuclear reactors together with more efficient end-use devices like conventional but advanced vehicles are contributing to the reduction of carbon emissions already in the baseline. Other systems like solar PV and advanced carbon capture and sequestration options for power generation and transportation fuels need the introduction of high carbon taxes or other instruments to become better competitive.
- Bio-fuel production and advanced power generation based on biomass with CCS options with negative carbon emissions appear already in the 2040s and have the potential to become one of the key future technological options to mitigate carbon emissions and reach the 2 °C constraint.
- Conservation options in buildings and the transportation sector together with efficiency improvement are key end-use policy options contributing to the reduction of carbon emissions as shown implicitly in Fig. 9 in the case of USA. We notice also the importance of electricity, alcohol fuels and bio-diesel for the substitution for coal and oil products in the end-use markets.
- Although the net undiscounted GDP reduction on the global level and for the most stringent carbon constraint remains below 1.5 %, the impact of the carbon constraint in the oil exporting regions and non-OECD regions is significant, asking for counterbalancing actions and measures and a fair burden sharing.

There is work remaining for the scientific community as almost 22 years after the Earth Summit in Rio de Janeiro in 1992 or after 20 years with the Framework Convention on Climate Change into force in 1994, we are neither successful in reducing global emissions nor able to emphasize enough the uncertainties and risks in the physics and economics of climate change convincing the public and politicians to take serious actions. Better scenario analyses with differentiated emission reductions focusing on the historical responsibility of the industrialized world must be balanced with the expected projections of future emissions of developing countries to prepare better UN Conferences and negotiations. Scientists should quantify better not only the mitigation strategies but also the expected damages and the cost of adaptation options in order to improve the allocation of capital and technology transfer between word regions and among mitigation and adaptation options.

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Integrating Policy Instruments into Energy System Models—From Theory to Application to Germany

Birgit Fais and Markus Blesl

Abstract This chapter provides an overview of the use of bottom-up energy system models to evaluate the long-term effects of energy and climate policy instruments. The major benefits of this type of model for policy evaluation are the inclusion of all interactions within the energy system as well as the high level of technological detail. Progress, on the other hand, needs to be made in terms of the representation of the decision-making behavior of different economic agents and the inclusion of macroeconomic feedbacks. Flexible, endogenous modelling approaches for two important instrument categories are then outlined and applied to a case study on the German energy system: emissions trading systems and different support systems for renewable electricity. This scenario analysis shows how the explicit modelling of policy instruments in energy system models can provide quantitative policy insights, e.g. to analyze the interaction between different types of instruments or to compare alternative policy mechanisms which can be applied for the same political target.

1 Introduction

Over the last two decades energy policy has grown more and more complex. Ambitious and, in some cases, conflicting targets have been established regarding climate change, energy security, the affordability of energy and the deregulation of energy markets. Especially in the area of climate policy, the introduction of a large variety of new policy instruments on different regional levels could be observed in recent years. In this process, policy makers need to have the possibility to back up

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_7

their decisions with comprehensive and scientifically sound research on ex-ante and ex-post evaluation of policy instruments in order to arrive at a consistent and efficient policy framework.

Technology-rich, bottom-up energy system models have been used for a long time to represent and analyze complex systems in an understandable form as well as to determine cost-efficient technological pathways to reach energy savings or emission reduction targets. The aim of this chapter is firstly to assess the usefulness of such models for the quantitative evaluation of the long-term impact of climate policy instruments on the energy system and the interaction between various policy tools. In addition, modelling approaches for the explicit representation of two central types of policy instruments are outlined briefly: emissions trading systems and different support mechanisms for renewable electricity. Using the German energy and climate policy as a case study, a comparative scenario analysis is then conducted to explore the interaction between these two instruments and to contrast the long-term effects of alternative renewable support systems.

2 Current State of Research: The Use of Energy System Models for Policy Evaluation

Energy system analyses have for a long time played a crucial role in supporting the political decision-making process by identifying sustainable technology pathways and contrasting the impacts of alternative energy futures. In order to assess the suitability of energy system models for the evaluation of specific policy instruments, the approach initiated by Jaccard et al. (2003) provides a valuable starting point. It identifies three attributes that an ideal model should comprise when used for the assessment of different types of policy instruments: (1) technological explicitness; (2) microeconomic realism (i.e. representation of consumer behaviour); and (3) macroeconomic completeness.

The main advantage of bottom-up engineering models is easily identified in their high level of technological detail. Hence, it is the only approach that can be applied to evaluate the effect of technology-specific measures and, even more importantly, to incorporate the impact of new technologies and technological breakthroughs for which no historical data is yet available (Hoffman and Jorgenson 1977). Bottom-up energy system models also provide the possibility to model technology competition and learning.

However, conventional bottom-up energy system models have often been criticized for their representation of the decision-making behaviour of different economic agents, since strong emphasis is put on financial costs as the key decision variable for technology choice assuming that technologies that provide the same energy service can be regarded as perfect substitutes (Jaccard 2009). However, in reality investment decisions by households or firms depend on a large variety of parameters which can explain why the most cost efficient option is not always chosen.

In recent years, various attempts have been made to improve the representation of consumer behaviour in energy system models. A basic approach to model investment barriers has consisted for a long time in using high implicit discount rates, also referred to as hurdle rates (Mundaca et al. 2010). A more sophisticated method has been developed for the hybrid model CIMS. To account for behavioural aspects, the calculation of the market shares of competing technologies is not only based on financial costs but also on additional parameters: the weighted average time preference rate, a cost term representing intangible costs, and a market heterogeneity parameter (Jaccard 2009). Within the scope of the optimising energy system model SOCIO-MARKAL, the effect of awareness campaigns is modelled by introducing “virtual technologies” which include the cost of the awareness campaign and, if used, directly have an effect on the investment decision (Nguene et al. 2011). Another example is the TIMES-Household model where a variety of household types are differentiated to account for household behavior and heterogeneity (Cayla and Maïzi 2015).

Apart from the shortcomings in terms of behavioural realism, the limited consideration of macroeconomic feedbacks is often highlighted as the second shortcoming of energy systems models when used for policy evaluation. A first comparatively simple step to increase the economic flexibility consists in assigning own-price elasticities to the different demand categories in the model such that the economic agents can react more flexibly to changes in the scenario assumptions (Loulou et al. 2005). However, it has to be pointed out that in order to account for all macroeconomic feedbacks, some sort of coupling with a macroeconomic model is necessary (Böhringer and Rutherford 2005): either through a soft-link with an existing large-scale macro-model (e.g. Schäfer and Jacoby 2006), or by hard-linking an energy system model with a reduced from representation of a computable general equilibrium (CGE) model (cf. for example Loulou et al. 2004).

A more detailed discussion on the theoretical background of modelling policy instruments in energy system models can be found in Götz et al. (2012a).

3 Modelling Approaches to Represent Policy Instruments in Energy System Models

In the following chapter specific modelling approaches are briefly outlined for two important instrument categories: emissions trading systems and support schemes for renewable electricity generation.

3.1 Emissions Trading Systems

In general, the modelling of a cap and trade system in an energy system model is straightforward by putting a constraint on total emissions in the participating sectors. The optimization approach of the model then ensures that, as in a trading system, the most cost efficient way of fulfilling the cap is realized. The dual variable of the user constraint representing the cap equals the marginal costs of the last (most expensive) unit of emission abated to fulfil the constraint. It can be therefore interpreted as the certificate price that would arise in the trading system under the modelled conditions (Remme et al. 2009).

However, due to computational and data constraints in most cases, models with limited regional scope are applied for policy evaluation. The challenge therefore often consists in the fact that the modelled region does not cover the entire trading region (31 countries in the case of the EU emissions trading system (EU ETS)). So far this issue has usually been addressed in two manners: either by setting a fixed emission reduction path for the respective country (e.g. Anandarajah and Strachan 2010), or by integrating fixed certificate prices into the model (e.g. Unger 2010). In the first case the drawback consists in the fact that the emission trade with the remaining trading region is neglected, while in the second case the influence of changing national framework conditions on the certificate price is ignored.

To overcome these shortcomings, a modelling approach has been developed that makes it possible to determine both the emission reduction in the national (in this case German) ETS sector and the ETS certificate price endogenously within the model. With this procedure, the cap can be put on total EU ETS emissions instead of on Germany alone. While the emission mitigation in the German ETS sector is still determined endogenously within TIMES-D based on the explicit modelling of technologies within the reference energy system, the reduction options in the rest of the countries participating in the EU ETS are added to the model with the help of a CO_2 abatement cost curve, modelled as a step function containing the CO_2 reduction potentials in the ETS sectors outside of Germany at different certificate price levels. Through the optimization approach, marginal abatement costs for Germany and the rest of the ETS sectors are equalized and a uniform certificate price for the whole system will be determined as the shadow price of the upper bound on total ETS emissions.

To implement this modelling approach, comprehensive data on the emission reduction potentials at different certificate price levels in the ETS sectors outside of Germany are required. This information can be either obtained by an extensive literature research, by conducting a quantitative model analysis at European scale or by aggregating the results from several national model analyses. For the case at hand, a version of the Pan-European TIMES model—TIMES PanEU (Blesl et al. 2009, 2010)—which comprises of 30 regions (EU-27 plus Switzerland, Norway and Iceland) with a less detailed time resolution (12 time slices) and less sectoral detail than TIMES-D, is applied. The basic model assumptions, i.e. on energy prices or technology parameters, are harmonized between the two models. In order to determine the various steps of the abatement cost curve, several model runs with different ETS certificate price levels are executed in the Pan-European model. The difference in emission abatement between one model run and the next represents the reduction efforts that would occur in the entire ETS sector at the corresponding allowance price level. When using an abatement cost curve for the remaining trading region, one has to keep in mind that one specific cost curve represents the reduction potentials under a specific set of assumptions. If it is assumed that the framework conditions in the remaining trading region change, the cost curve needs to be adjusted.

Further information on the technical details of modelling supranational emission trading system in national energy system models is provided in Götz et al. (2012b).

3.2 Support Systems for Renewable Electricity

Specific support schemes for the deployment of renewable electricity technologies form an integral part of the climate policy of many countries. However, in energy systems modelling so far the effects of such instruments have in most cases only been taken into account in an indirect and inflexible way by exogenously setting the expected minimum amounts of electricity produced from different types of renewable energies without making reference to the characteristics of a specific support system (e.g. Capros et al. 2010; Blesl et al. 2010). This, however, clearly reduces the flexibility of the model as generally no changes in the electricity generation from renewable sources will occur when the scenario assumptions are altered and the effects on electricity prices are often not accounted for. Some first attempts have been made in recent years to incorporate renewable electricity generation in the optimisation approach and to explicitly represent specific support instruments (cf. the Green-X model (Ragwitz et al. 2007), the PERSEUS-RES-E model (Möst and Fichtner 2010), and the simulation model in Frontier Economics (2012)). However, renewable electricity generation is in most cases analysed in an isolated manner, i.e. electricity prices are set exogenously such that no interactions with conventional power generation are considered and the effects on the demand side are neglected. Apart from that the support systems for renewable electricity are generally modelled in a very simplified and abstract manner without keeping in mind the often complex structure of the real-world application of such instruments.

In the following, methodological approaches for the explicit representation of the most important support mechanisms for renewable electricity, fixed feed-in tariffs (FIT), tradable green certificate (TGC) systems as well as tendering procedures, in energy system models are presented. Further information on the modelling of instruments to promote renewable electricity is provided in Götz et al. (2012c).

3.2.1 Feed-in Tariff Systems

To illustrate the modelling approach for a FIT scheme, the example of the German system is used which since the year 2000 offers fixed, technology-specific tariffs and has been highly successful in promoting renewable electricity generation raising its share in gross final electricity consumption from 6 % in 2000 to 23 % in 2012. The methodology is divided into the modelling of the payment side (e.g. the tariffs) and the cost side (e.g. the FIT surcharge, a levy on retail electricity prices).

From the point of view of the renewable plant operator, the tariffs can be understood as a subsidy on the renewable electricity generation. They are therefore integrated into the model by using the TIMES parameters developed to display subsidies such that for each unit of electricity generated a subsidy (equal to the real-world tariff, expressed as a negative cost factor in the model) is assigned to the renewable generation process. Moreover, the modelling approach takes into account a number of distinctive features of the German FIT system, as these have a substantial impact on the competitiveness of renewable electricity generation: the payment period is limited to 20 years, tariffs decrease as a function of the vintage year and tariffs remain constant in nominal terms which results in a reduction in real terms over the years.

After integrating the tariffs into the model, one has to bear in mind that this only constitutes one part of the FIT system. The tariffs are not a subsidy by the state, but are financed through a levy on retail electricity prices (the FIT surcharge). The level of this surcharge depends on the actual expansion of renewable electricity, i.e. on the model results for the generation side. Therefore, subsequent to the first model run, where only the tariffs are implemented, the FIT surcharge is calculated and integrated into the model framework (as additional costs on final electricity demand). Afterwards, as the integration of the FIT surcharge and the associated increase in end-use electricity prices causes modifications in the electricity consumption and consequently also in electricity generation, an iterative process of several model runs is needed to adjust FIT payments and the FIT surcharge to one another.

The main advantage of this methodology lies in the fact that both the amount of renewable electricity generation and the effects on the demand side are determined endogenously within the model.

3.2.2 Quantity-Based Support Schemes for Renewable Electricity

In comparison, modelling tradable green certificate schemes and tendering procedures in an energy system model is much more straightforward, as this type of instrument establishes the quantity of renewable electricity to be produced rather than its price. Target values for relative shares of renewable energies in electricity generation (either technology-specific or -unspecific) can be easily integrated in the model with the help of user-defined constraints. As it would be the case in the trading system for green certificates or the tendering process, in the optimization process the cheapest generation options to fulfil the quota are chosen. The shadow price of such a user constraint is equivalent to the difference between the generation costs of the most expensive generation technology required to fulfil the quota and the electricity price (given in the model as the dual variable of the electricity commodity balance) and can therefore be interpreted as the certificate price in the trading system or bidding process. Furthermore, it directly impacts electricity generation costs and electricity prices in the model. Generation costs of conventional plants (outside of the quota) increase by the costs that arise from the purchase of green certificates, while generation costs of renewable plants decrease through the selling of certificates (cf. Remme et al. (2009) for further information on the interpretation of dual solutions in a TIMES model).

4 Scenario Analysis on the German Energy and Climate Policy

In order to illustrate how the explicit modelling of policy instruments can benefit the long-term evaluation of policy impacts on the energy system, the results of a scenario analysis focusing on Germany will be briefly outlined in the following section. This analysis uses the national energy system model TIMES-D which depicts the entire German energy system with high technological detail from primary energy supply to energy services demand (for further information see Götz et al. 2013).

The scenario analysis focuses on two important issues of the German energy and climate policy based on the scenario shown in Table 1. Firstly, in order to explore the interactions between the EU ETS and the German FIT system for renewable electricity, three scenarios with varying assumption on these two policy instruments are contrasted. The reference case (REF) combines the currently implemented EU ETS target of −21 % until 2020 compared to 2005 with the present version (as of 2012) of the German FIT system, while the other two scenarios only consider one of the two instruments (ETS_Only and FIT_Only).

Secondly, to compare the current German FIT scheme with different types of alternative support schemes for renewable electricity, the scenario REF is contrasted against three additional scenarios which represent different renewable support instruments and are set up such that one specific effect relevant in the

Table 1 Scenario overview

<table>
<tr><th>Scenario</th><th>Renewable support</th><th>ETS target</th></tr>
<tr><td>REF</td><td>Current German FITs (2012 version)</td><td rowspan="2">−21 % until 2020 compared to 2005; −1.74 % p.a. afterwards</td></tr>
<tr><td>ETS_Only</td><td>–</td></tr>
<tr><td>FIT_Only</td><td>Current German FITs (2012 version)</td><td>–</td></tr>
<tr><td>FIT_Neut</td><td>Technology-neutral feed-in tariff system reaching the same absolute amount of renewable electricity as in the reference case</td><td rowspan="3">−21 % until 2020 compared to 2005; −1.74 % p.a. afterwards</td></tr>
<tr><td>TGC_Neut</td><td>Technology-neutral quota system reaching the targets for the renewable share in gross electricity consumption of the German Energy Concept</td></tr>
<tr><td>TGC_Spec</td><td>Technology-specific quota system reaching the same shares for each renewable source in gross electricity consumption as in Qu_Neut</td></tr>
</table>

comparison of these instruments can be quantified with each of them. First of all, a technology-neutral FIT system (scenario FIT_Neut) it used to explore the impacts of promoting only the most cost efficient technologies as opposed to the current technology-specific variations in the support level without changing the absolute amount of renewable electricity generated (technology effect). In the next step, the FIT systems are contrasted with quantity-based tradable green certificate schemes which have the advantage that compliance with the previously set political targets can be guaranteed (quantity effect). In the scenario TGC_Neut, a technology-neutral quota is put on the entire renewable generation reflecting the official government target values of the German Energy Concept (BMWi and BMU 2011). In contrast, in the scenario TGC_Spec a technology-specific TGC system is implemented (using the cost efficient shares from the scenario TGC_Neut) which allows to evaluate the advantages of a technology-specific scheme in terms of limiting the profits of renewable generators (windfall effect). It needs to be pointed out that all scenarios account for the historical development of the FIT system, i.e. it is assumed that all plants installed until the end of 2012 remain in this system and continue to receive the fixed tariffs.

4.1 Interaction Between European Emission Trading and the German Support Scheme for Renewable Electricity

The impacts of introducing a support instrument for renewable electricity on a national level while having a supranational emissions trading system in place become clearly visible when looking at the emission reduction in Germany under the different scenario assumptions (Fig. 1). Due to the strong expansion of renewable sources in electricity generation, overall emission mitigation efforts in the German ETS sectors are higher for the reference case in which the FIT system is in place. Hence, the implementation of a national support instrument affects the burden sharing within the EU trading system with German contribution to the 21 %-target in 2020 varying between 26 % (REF) and 13 % (ETS_Only). On the EU level, however, the national scheme does not stimulate any additional emission abatement, but results in a system-wide decrease of the ETS certificate price. Given that Germany is responsible for almost a quarter of total ETS emissions, the model results indicate quite substantial price differences of up to 6 €/t CO_2 until 2030 between the scenarios REF and ETS_Only.

Additional insights on the interaction effect can be gained by looking at the development of the German electricity sector (Fig. 2). With the FIT system in place renewable generation is further increased to almost 46 % in 2020 and 54 % in 2030 to gross electricity consumption such that the targets of the German energy concept of 35 and 50 % are clearly exceeded. In the scenario without the FIT system, the extension of renewable electricity generation remains rather limited (shares of 25 % in 2030), underlining the fact that supporting renewable electricity generation does

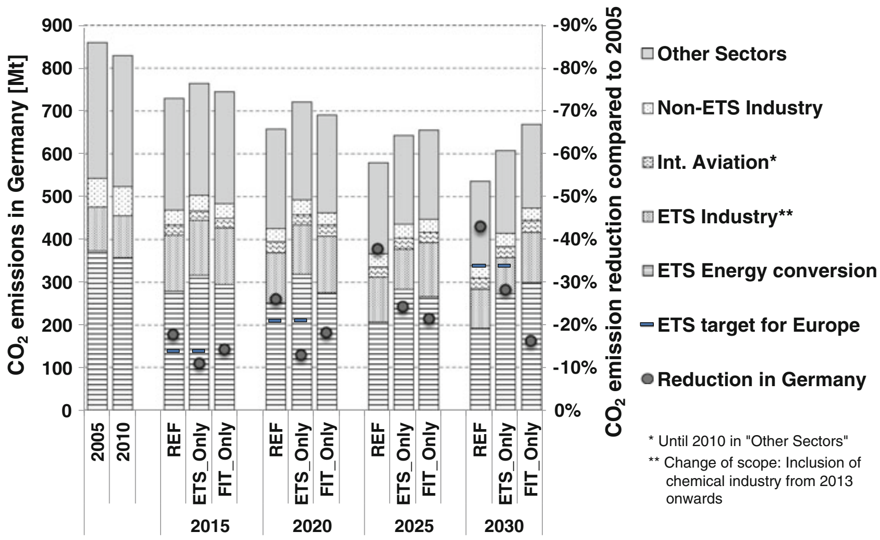

Fig. 1 CO_2 emissions in Germany and emission burden sharing under different assumptions regarding the FIT scheme and the EU ETS (based on Fais et al. 2014a, cf. www.tandfonline.com)

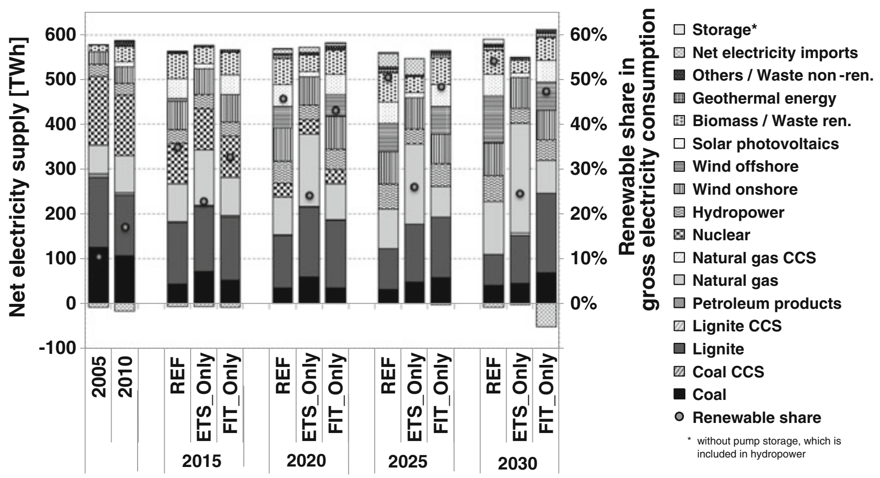

Fig. 2 Net electricity supply in Germany under different assumptions regarding the FIT scheme and the EU ETS

not constitute a cost efficient emission abatement strategy for Germany. Under the premises that only the FIT system but not the EU ETS is implemented (FIT_Only), renewable electricity generation in Germany still rises considerably until 2020. After that, however, growth rates slow down significantly when compared to the reference case indicating that in the long term the EU ETS has a supporting effect on the expansion of renewable electricity in Germany by raising the generation costs for fossil fuel plants.

With respect to electricity prices, various interaction effects need to be taken into consideration. First of all, raising the share of renewable electricity generation has a dampening impact on wholesale prices as it replaces the conventional generation with the highest generation cost (merit-order effect, cf. Sensfuß et al. 2008). Furthermore, the influence of the emissions trading system on electricity prices is lowered with the implementation of the feed-in tariffs as ETS certificate prices decline. These two effects lead to a decrease in wholesale electricity prices in the scenarios with the FIT system of up to 22 %. In the case of end-user electricity prices, the extra costs of the FIT surcharge need to be accounted for such that on the whole, household electricity prices are up to 23 % higher in the reference case than in the scenario ETS_Only.

In terms of system-wide costs, cost savings for ETS emission certificates of €57 billion need to be contrasted with the differential costs of the FIT system (i.e. the FIT payments minus the market value of the FIT electricity generation) of €320 billion in the reference case compared to the scenario ETS_Only (cumulated from 2013 to 2030). Thus, the scenario analysis shows that the additional support mechanism for renewable electricity deteriorates the cost efficiency of emission mitigation in Germany and affects the EU-wide carbon price. Hence, even though these measures might be justified by additional policy targets, most importantly technology promotion and the realization of substantial learning effects, their impact on emission mitigation needs to be taken into account when setting the long-term ETS targets to avoid a weakening of the CO_2 price signal.

4.2 Comparison of Alternative Renewable Electricity Support Schemes for Germany

The quantitative scenario analysis contrasting the current FIT system in Germany against alternative price-based and quantity-based support schemes provides insights in terms of impacts on renewable electricity generation, costs of the support system, and total energy system cost.

In the reference case, the significant increase in renewable generation is strongly based on comparatively costly technologies, (especially solar PV and offshore wind) for which the tariff level is comparatively high. Switching to a technology-neutral support system (scenario FIT_Neut) leads to significant shifts in the structure of renewable generation, as heavier reliance is put on comparatively low-cost technologies (especially onshore wind in less favourable locations and large-scale biomass plants) (Fig. 3). With the quantity-based support systems, the targets of the German energy concept are precisely complied with, such that renewable electricity generation drops by a quarter (66 TWh) in 2020 and by 11 % (36 TWh) in 2030 compared to the reference case. With respect to the composition of renewable electricity generation, some similarities with the scenario FIT_Neut are

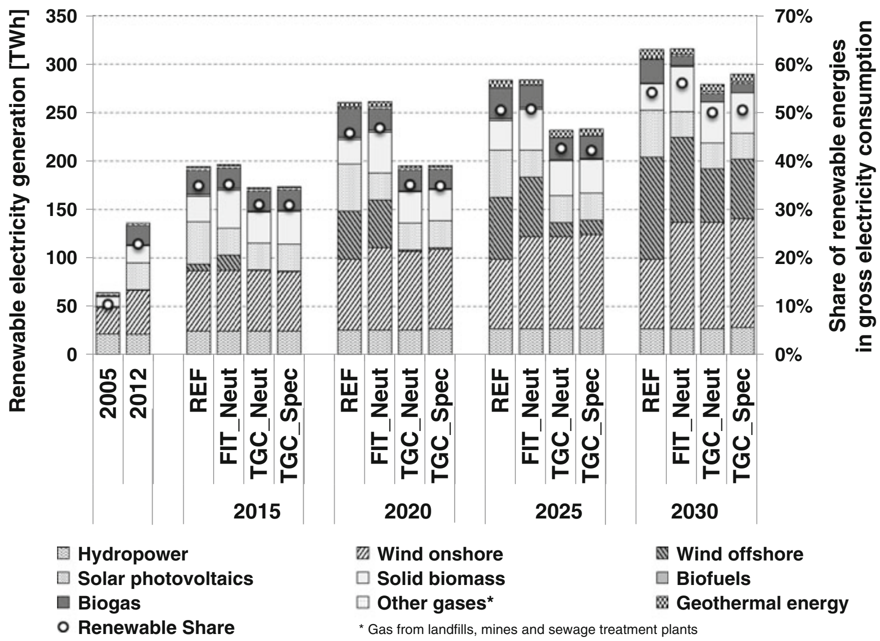

Fig. 3 Comparison of renewable electricity generation in the scenarios with different support schemes for renewable electricity

discernible. The lower overall generation level affects in particular the development of offshore wind energy. However, even when reducing renewable generation to the policy target levels, an exploitation of relatively costly technologies like offshore wind energy is still required under the chosen scenario assumptions.

The stronger emphasis on cost efficiency under the technology-neutral support system is reflected in a reduction of cumulated generation costs for all renewable generation units installed between 2013 and 2030 of €117 billion in the scenario FIT_Neut in relation to the reference case. If, in addition, the amount of renewable generation is lowered to the policy targets (scenarios TGC_Neut and TGC_Spec), this cost difference sums up to €208 billion.

The additional costs that arise under the different support systems are best represented by their differential costs. Here, a general difference in the remuneration level caused by technology-neutral and -specific systems needs to be kept in mind: uniform remuneration tends to lead to an over-subsidisation of less costly technologies resulting in high profit margins for producers, while technology-specific tariffs that reflect disparities in generation costs of renewable technologies can limit the producer surplus and the additional costs for consumers (Ragwitz et al. 2007).

Accordingly, considerable increases in differential costs for renewable technologies with relatively low investment costs can be observed in the scenarios with technology-neutral support systems (Table 2). This leads to a rise in cumulated differential costs of almost €33 billion between 2000 and 2032 in the scenario

Table 2 Cumulated differential cost under different support schemes for renewable electricity

Cumulated differential cost, 2000–2032 (Bn €)[a]	Hydro-power	Wind onshore	Wind offshore	Solar photovoltaics	Biomass[b]	Geothermal energy	Total
REF	5.5	47.2	40.5	126.6	86.9	13.1	319.7
FIT_Neut	13.5	84.1	52.9	110.1	87.3	4.7	352.5
Difference to REF	7.9	36.9	12.4	−16.5	0.4	−8.4	32.8
TGC_Neut	11.3	76.5	13.9	109.3	74.9	3.8	289.7
Difference to REF	5.8	29.3	−26.6	−17.3	−12.0	−9.3	−30.0
TGC_Spec	3.4	51.7	14.7	109.3	69.3	3.4	251.8
Difference to REF	−2.2	4.5	−25.8	−17.3	−17.6	−9.7	−68.0

[a] The costs arising from the current FIT system for units installed until the end of 2012 are included for all scenarios
[b] Incl. gas from landfills and sewage treatment plants

FIT_Neut and only a limited decline of €30 billion in the scenario TGC_Neut in spite of the considerable savings in terms of generation costs compared to the reference case. Based on the differentiation in the tariff structure, higher cost savings of €68 billion are realized under the technology-specific quota system. A different picture arises when looking at total energy system costs. System-wide cost savings can be achieved under all alternative support schemes (from €94 billion in the scenario FIT_Neut to €416 billion in the scenario TGC_Spec compared to the reference case, cumulated from 2013 to 2030). It needs to be pointed out, however, that energy system costs do not contain any information on the distribution of these costs across the system.

Thus, the scenario comparison at hand indicates that when strictly adhering to the principle of cost efficiency the long-term development of renewable electricity in Germany would change considerably and generation costs could be lowered significantly. However, it is also shown that it is not guaranteed that consumers benefit from a technology-neutral support system that promotes the most cost efficient renewable technologies.

5 Conclusion

This chapter has given an overview on the use of bottom-up energy system models to assess the long-term impacts of energy and climate policy instruments by explicitly including such instruments in the modelling framework. For further information on the two applications for the German energy system see Fais et al. (2014a, b).

Using flexible, endogenous modelling approaches for policy instruments in bottom-up energy system models provides several contributions to policy evaluation, most importantly: (1) explore how changing scenario assumptions, for example on fossil fuel prices, affect the outcomes of a certain policy instrument; (2) evaluate the interactions between different policy instruments and (3) compare alternative policy instruments which can be applied for the same political target.

Some general lessons can be drawn from this modelling exercise:

- The real-world application of climate and energy policy instruments often differs substantially from the abstract, theoretical representation in textbooks. This additional complexity has to be accounted for in the modelling approach to arrive at a realistic depiction of the policy impact. This means that generally a highly detailed model, comprising a large variety of technologies, is required.
- Quantity-based measures, like emissions trading systems or tradable green certificate schemes, are generally much more straightforward to model than price-based instruments like FITs as in the latter case additional cost terms have to be introduced.
- When using a comprehensive energy system model for policy evaluation, one has to make sure that all effects that a policy instrument causes are included in the modelling approach. For example, when modelling a FIT system for renewable electricity, the impacts on electricity demand as well as on the electricity grid and the required storage capacity need to be taken into consideration.
- Finally, it has to be noted that when using energy system models for policy evaluation entails a change in perspective. Traditionally, such models assume the perspective of a social planner simultaneously minimizing total discounted costs of the entire system using a social discount rate (Keppo and Strubegger 2010). For policy evaluation, however, the individual perspectives and decision-making behaviour of the various economic agents need to be taken into consideration.

If the aim consists in integrating all effects of a certain measure into the model in an endogenous manner, the modelling approach can prove to become relatively complex. So, it needs to be highlighted that the choice of the modelling tool and the sophistication of the methodology should always depend on the specific research question that is analysed.

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Improving Efficiency in Kazakhstan's Energy System

Aiymgul Kerimray, Kanat Baigarin, Aidyn Bakdolotov, Rocco De Miglio and GianCarlo Tosato

Abstract Kazakhstan is one of the most energy-intensive countries in the world, almost 4 times higher than the world average and 7 times higher than the OECD average. There are various reasons for inefficiencies in Kazakhstan's energy system: administrative and economic (statistical double counting of energy flows, above normative losses and low profitability), geographic (the extremely continental climate and low population density) and technical considerations (high share of coal in generation mix, high wear on main and auxiliary equipment in energy intensive sectors, high wear on electric lines, dilapidation of housing stock, and an absence of control systems for energy savings) all contribute to the high energy intensity. This study explores energy efficiency potential by analyzing the evolution of the Kazakh energy system. All the technical inefficiencies have been taken into consideration through the explicit representation of existing inefficient technologies/chains in a TIMES-based model. Under the assumptions of a market-oriented development of the economic system, even without specific policies (Business as Usual), the model suggests significant energy efficiency improvement: 22 Mtoe (million tons of oil equivalent) by 2030 and a 40 % reduction in energy intensity of GDP by 2030. The more ambitious policy target of reducing energy intensity of GDP by 40 % by 2020 also appears easily achievable via economically viable solutions.

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_8

1 Introduction

The high energy intensity of the Republic of Kazakhstan can be explained better by deconstructing the fuel-energy balance—as published by the Committee on Statistics of the Republic of Kazakhstan (2013) and the International Energy Agency (2013). For the present analysis, the fuel-energy balances of the Committee on Statistics were reclassified according to the IEA format, cross-checked with available information on technology and infrastructure and compiled with other local sources of information.

The total primary energy supply of Kazakhstan was 64.5 Mtoe in 2011 (million tons of oil equivalent): almost half of which was consumed by the energy sector (including losses). The International Energy Agency reported an energy intensity of GDP of 0.93 toe/thousand USD (at 2005 prices) in 2011, 3.7 times higher than the world average and 6.6 times higher than the OECD average.

As represented in Fig. 1, the ratio of total final consumption over total primary energy supply (TFC/TPES) is significantly higher in other countries, 55 % in Kazakhstan. The world average is 69 %, while the share is 64 % in the Russian Federation and 79 % in Canada (IEA 2013).

Power plants' transformation losses account for 15 Mtoe: 23 % of the country's total primary energy supply (TPES). This is explained by the fact that most power plants were inherited from Soviet Union days, and that 41 % of generating capacity have been operating for more than 30 years (ME RK 2010). Efficiency at the largest coal fired electric power plants is no more than 40 % while that at heating plants does not exceed 65–70 %. The introduction of new heating plants may increase efficiency by up to 85–90 %. Coal is the most commonly used fuel at power plants, accounting for 67 % of total generating capacity.

Another 8 % of TPES (4.8 Mtoe) is attributed to losses, most of which are heat losses (1.9 Mtoe). According to the Ministry of Energy of the Republic of Kazakhstan (ME RK 2010), between 2010 and 2011, 37 % of generated heat was lost. The country's severe climatic conditions require high consumption of heat since the average winter temperatures are −19 °C in the North and −5 °C in the South.

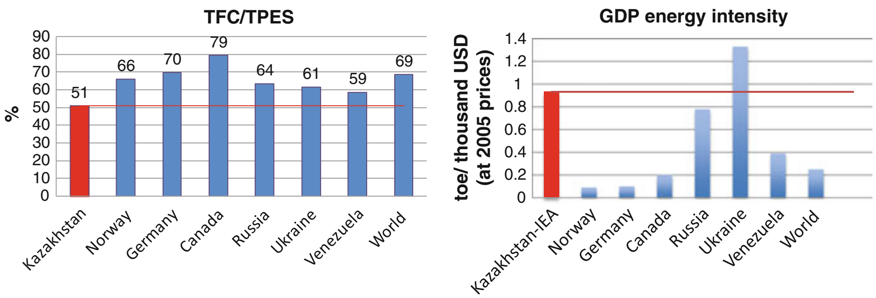

Fig. 1 Benchmarking analysis of TFC/TPES and TPES/GDP

Heating networks have deteriorated, with more than 60 % of components in use for over 20 years. Electricity losses are also high, at 9.3 % of total generation, due to long distance transmission and severe climatic conditions, and wear and tear is significant, at 50–60 %.

There are significantly high rates of self-consumption in the oil and gas sector—4.6 Mtoe (7 % of TPES). Kazakhstan is a net exporter of crude oil and natural liquids: 71.3 Mtoe in 2011 (110 % of domestic TPES). Gas is also exported, at lower volumes—most recently, 10.1 Mtoe. Power plants's self-consumption account for another 2 Mtoe: 11 % of the electricity generated.

On a demand side, industry is the biggest consumer in Kazakhstan—12 Mtoe (19 % of TPES). The energy efficiency of industry in Kazakhstan is low, at 45–60 %, as equipment is old and worn out. Until recently, there were no energy efficiency policies or programmes. Also, the prices of energy commodities were too low to result in reduction of energy consumption. Industry in Kazakhstan is mainly represented by energy intensive and heavy industries.

The residential sector is the second largest consumer of energy in Kazakhstan—9.7 Mtoe. Climatic conditions force households to use 2.3 Mtoe of heat, 2 Mtoe of coal, 2 Mtoe of gas and another 1.6 Mtoe of oil products, mainly for heating purposes. The Ministry of Energy of the Republic of Kazakhstan reports that, on average, buildings consumed 270 kwh/m^2 of heat in 2010: 1.5–2 times higher than in other countries with a similar climate (ME RK 2010).

Kazakhstan has significant potential for improving its energy efficiency and reducing its GHG emissions across most sectors of its economy. The Government of Kazakhstan has already taken steps to reduce its energy consumption through the direct and indirect policies discussed in the next section. The main aim of this chapter is to investigate the energy efficiency potential of Kazakhstan, using techno-economic modeling instruments.

2 Policies and Measures in Energy Efficiency in Kazakhstan

On 12th January 2012, the Law on Energy Saving and Improving Energy Efficiency (2012) was adopted. It covers the creation of the State Energy Register, and mandatory energy audits on major industrial sites and public services. In 2014, the Government planned to establish voluntary agreements on energy saving with industrial companies. The residential sector is affected by a law promoting metering, with differentiated pricing of district heating depending on the availability of metering devices. Provision of heat, electricity and gas is prohibited to new sites unless meters are fitted, and sales and production of electricity consuming devices are prohibited unless class of efficiency is indicated. Sales and production of incandescent lamps are also now prohibited.

In 2013, the Concept of the Republic of Kazakhstan for Transition to a Green Economy (2013) was approved. It sets concrete targets for six key sectors: water resources, agriculture, energy efficiency, the power sector, air pollution and waste utilization. It aims to ensure that renewable energy and nuclear power account for half of all electricity generation by 2050. The plan is also for gas fired power plants to account for 30 % of total electricity generation by 2050. This requires investment into gas infrastructure across the Northern, Eastern and Southern regions of the country.

To realize these ambitious targets, the Energy Saving—2020 programme was adopted in 2013 (ME RK). This defines strategies to improve energy efficiency across the industry, transport and residential sectors, and electricity and heat distribution systems. The final target is to reduce energy intensity of GDP use by 40 % by 2020 (compared to 2008 levels).

3 Approaches to Modelling of Improving Energy Efficiency

3.1 Energy Efficiency Chains

The model of the Kazakh energy sector (TIMES-KZK), calibrated to the reclassified national energy balances of 2009–2012 and further broken-down by end-uses in each demand sector, makes explicit the stocks and technical characteristics of existing technologies, as well as the energy flow through the system, resulting emissions, and associated costs, thereby reproducing the present inefficiencies in Kazakhstan.

The TIMES-Kazakhstan single region model represents all steps in the energy chain: from extraction of primary resources to their supply to primary energy markets; from transformation of primary energy carriers to their transmission and distribution to the final energy sectors (residential, commercial, industry, transport, agriculture); and from the use of final energy commodities to the satisfaction of end users demand for energy services (space heating and cooling, water heating, lighting, private and public mobility, iron and steel production, etc.). This process-oriented model provides a consistent framework with which to explore various paths towards energy efficiency within the coming 15–20 years.

Energy efficiency improvements (EEI) are virtual commodities of the model, representing energy not consumed whenever an existing technology is substituted with something better, at extra cost (Sarbassov et al. 2013). Equations 1 and 2 make explicit the efficiency gaps (EG) between an existing reference technology (ET) and the new ones (NT) available for the same energy sector/service (j), as well as the virtual savings due to the use of more efficient technologies (Q(NT)). Alternative options (NT) are included in a technology repository and characterized by an additional attribute representing the efficiency gap. Per each unit of output of the new technology (i), $EG_{i,j}$ units of improvements (units of losses avoided) are generated.

$$EG_{i,j} = \left(EFF(NT_i)_j - EFF(ET)_j\right) \quad (1)$$

$$EEI_{i,j} = EG_{i,j} * Q(NT_i)_j \quad (2)$$

EG efficiency gap
NT new technology
ET reference technology
EFF energy efficiency of the technology, which can be expressed as a ratio between energy output of the technology to its input
EEI energy efficiency improvement
Q savings
i indicator for a generic new technology
j energy service

EEI index must be intended as an approximate measure of efficiency improvement due to the chain of commodities and technologies before and after the system point where each measure applies. In terms of primary energy supply equivalent, the amount of avoided losses is greater; in terms of final energy consumption it is slightly lower.

In particular, new-generation electricity consumption meters are explicitly described through investment costs (US$2 at prices of 2000 per GJ per activity) and savings potential (up to 4 % of the unnecessary electricity consumption, based on authors estimation), while the installation of heat meters (with automatic regulation of the radiator temperature) could reduce the consumption by about 35 % (Sarbassov et al. 2013) with reference to the present situation, at a cost of about US$25 at prices of 2000 per GJ per activity.

The main technical causes for inefficiencies have been taken into consideration in current analysis, through the explicit representation of existing inefficient technologies and chains, as well as of some more efficient alternatives for the future development of the Kazakh system. To reduce tampering, which causes the above normative losses, the possible installation of meters has been considered. Thus, the model is able to track improvements in electricity, heat and natural gas transmission/transport and distribution, as well as in the oil, coal and gas transformation and uses.

The development of demand toward 2030 is driven by assumed population, and GDP (a medium variant projection by the Committee on Statistics of the Republic of Kazakhstan). From 2009 to 2030, the population is predicted to grow by 30 % (at 1.25 % pa), while GDP is assumed to rise at an annual rate of 6 % pa until 2020, followed by 5 % pa later on (300 % growth by 2030).

3.2 Internalising Energy Policy Instruments

Energy efficiency improvements result from investments into upgrading, affecting primary energy supply and resulting emissions. Through tracking technologies and energy flow, analysts can determine improvements in efficiency across the system, checking where specific measures bring cost-effective changes.

Standards and carbon taxes are often considered in order to reduce consumption across energy systems, and such regulatory-based and market approaches are usually combined in a multi-policy instrument, aiming to enhance additive energy and carbon reducing effects. Moreover, the explicit modelling of existing and new technological options allows for the use of subsidies (directly stimulating energy efficiency improvements), by applying an incentive per unit of loss avoided. Such a new instrument, generally called energy efficiency feed in tariffs—EEFiTs, has not been used for the scenarios presented in this paper, but it is fully embedded in the last version of the Kazakhstan model.

The present study aims to test two alternative approaches across the entire system: targeting energy intensity of GDP (a regulatory-based approach), and testing a CO_2 tax (a market-based approach).

4 Scenarios and Results

Two scenarios were run for this study, to quantify the potential for energy efficiency improvements in the Kazakhstan's system, subject to two types of energy measures. The first envisages reducing energy intensity of GDP by 40 % by 2020 (compared to the 2008 level) as set in the Energy Saving-2020 programme (ME RK 2013). The second offers an incentive of US$20 (at 2000 prices) per ton of CO_2 equivalent reduced starting from 2020 (CO_2TAX). The results, presented in Fig. 2, show the strong impact of energy intensity on reducing TPES (which is the denominator of the indicator, the reduction is due largely to improved efficiency in the coal chain), and the relevant impact of CO_2 taxation on emissions and the penetration of natural gas.

The Business as Usual (BaU) scenario doubles TPES by 2030, with coal remaining the dominant fuel (57 % of TPES). Assuming rigid GDP growth[1] (inelastic energy service demand), the target for GDP energy intensity would lower TPES by more than 22 Mtoe both in 2020 as well as in 2030, almost halving the coal supply compared to BaU. The overall efficiency of the system (the amount of energy consumed per unit of energy supplied) will reach 72 %: comparable to the levels in

[1]Domestic GDP is strongly tied to oil and gas export volumes. In the present analysis, all the scenarios share the same assumptions about export increases, which are consistent with the assumed GDP growth rate.

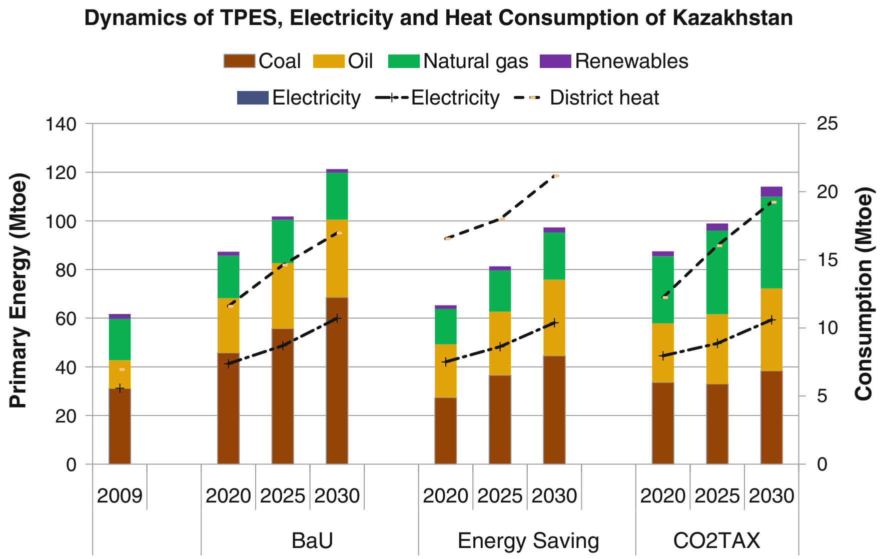

Fig. 2 Dynamics of TPES, electricity and heat consumption

Norway and Germany. The impact of CO_2 taxation[2] on TPES is less evident. The total supply in 2020 would be almost the same as in the BaU case, with reduction by 2030 to around 7 Mtoe.

In terms of reducing emissions, regulatory-based measures are much less effective than taxation-based measures. The dynamic of CO_2 in the former case is very similar to the BaU dynamic, while the latter produces an evident reduction in emissions (more than 25 %). Such a reduction is mainly due to the strong penetration of natural gas (from 19.5 Mtoe to 37.5 Mtoe in TPES) in the generation and final consumption sectors, and to the significant improvement of the efficiency of natural gas-fired stations, as shown in Figs. 3 and 4. Reducing the growth of CO_2 emissions in Kazakhstan—from the average annual 12–8 %—would require significant change in the configuration of the energy system and the involvement of gas. Currently, most of the gas extracted is reinjected; therefore, issues on gas production, processing and transportation should be resolved, to provide additional gas to the domestic market.

Figure 3 shows that even in the BaU case, energy savings may reach 10 Mtoe by 2020 and 22 Mtoe by 2030—mainly through more efficient coal transformation and electricity end-use sectors. This scenario reduces energy intensity of GDP by 18 % by 2020 and by 40 % by 2030 (compared to current levels). Meanwhile, the

[2]Such an approach simulates policies and measures already announced, for instance in the Concept of the Republic of Kazakhstan for Transition to a Green Economy (2013), and (more in general) aims to stimulate a market-based renovation and improvement of those technologies which become competitive at a low CO_2 price.

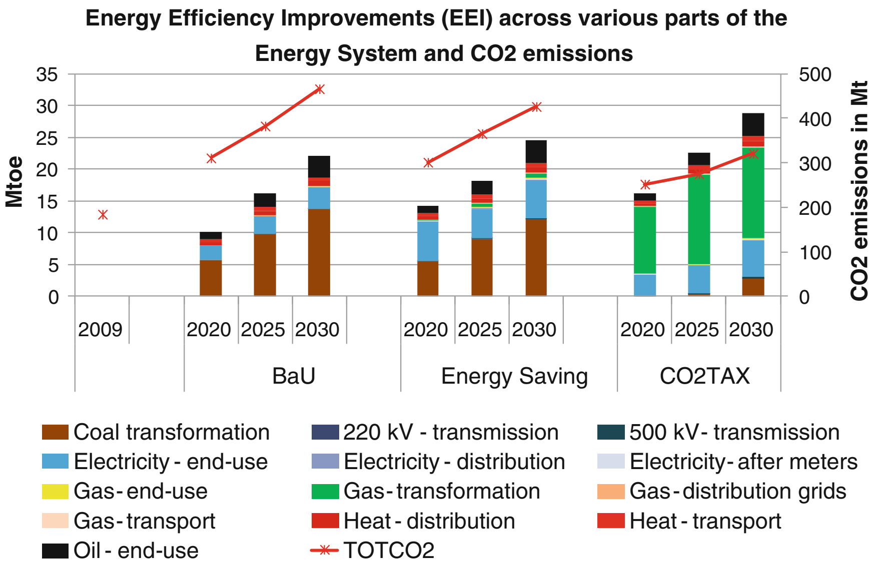

Fig. 3 Energy efficiency improvements across various parts of the energy system and CO_2 emissions

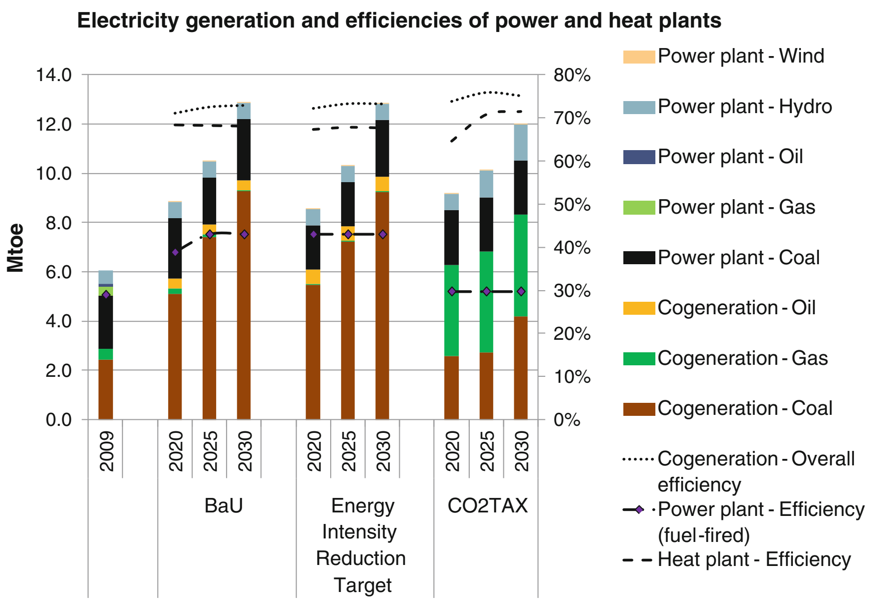

Fig. 4 Electricity generation and efficiency of power and heat plants

TFC/TPES indicator rises to 62 % by 2030. This means that most energy efficiency improvements are economically feasible and can be easily achieved once administrative and regulatory barriers are eliminated.

For all considered scenarios, most improvements are due to higher efficiency of generation (mainly coal-based in the BaU and in the Energy Intensity Reduction Target scenario, and mainly gas-based in the CO_2TAX case). Also, improvements are evident in the substitution of old electrical appliances with more efficient options, and new vehicles for the transport sector.

By 2030, the efficiency of CHP plants will rise by 9 % (maximum) while that of heat plants rise by 7 %. Figure 4 also demonstrates that CHP plants prevail in the new capacity-mix, rather than fuel fired pure electricity plants—mainly because climatic conditions force high demand for heating (as well as increasing levels of housing stock per capita). This is consistent with the recent Energy Saving Law, which aims to increase the use of cogeneration plants.

In absolute terms, the effects of the two efficiency-oriented alternative measures are hardly distinguishable in the demand side, as the total final consumption is almost the same over the three scenarios (slight reductions of 5 and 6 Mtoe compared to the BaU case for 2030), although the share of resources shifts, with natural gas partially replacing coal for heating.

5 Conclusions

The BaU case suggests significant energy efficiency improvement, meaning some significant cost-effective improvement (in particular regarding generation) can be gained, even without a specific energy policy to reduce (eliminate) market barriers (low priority of energy issues, incomplete markets for energy efficiency, distortionary fiscal and regulatory policies, and insufficient, or inaccurate information).

More than 50 % of energy efficiency improvement in the BaU case can be obtained by replacing old, coal-fired stations with modern coal plants. The efficiency of the energy system (TFC/TPES) increases from the current level of 55–62 % in the BaU scenario and to 72 % in the Energy Intensity Reduction Target scenario, by 2030, reaching the current level of Norway and Germany.

The reduction of energy intensity of GDP by 40 % by 2020 (compared to the 2008 level) can be achieved with economically viable options and without significant structural changes to the energy system: using timely technology updates and no market barriers. On the contrary, reduction of CO_2 would require significant efforts to increase the share of gas in the fuel mix.

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Ex Post and Prospective Analyses of Renewable Policies in Spain

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Abstract In this work, socioeconomic and environmental impacts associated to energy technologies in the current and future Spanish Energy System have been estimated. This information has provided the base from which to conduct two kinds of analyses. First, an Ex post analysis of renewable policies in Spain, where the net impact on social welfare associated to the progressive introduction of those energies in the energy system has been assessed using a partial cost-benefit analysis. Then, a prospective analysis of the Spanish energy system where the optimum energy mix, which leads to the largest social welfare under different energy scenarios, taking into account a medium-long term time horizon (2035), has been estimated using the national energy optimization model TIMES-Spain. The results of the Ex post analysis of the period 2005–2012 show an increase on social welfare due to the introduction of renewable energies. Nevertheless, when assessing the total expenditure of renewables support policies, the results show this support exceeds the

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_9

economic value of the socioeconomic and environmental externalities calculated in this work. The prospective analysis results for the period 2010–2035 definitely recommend a support for renewable electricity generation technologies and the redesigning of renewables support policies to better reflect their external benefits with respect to the fossil alternatives.

1 Introduction

This work has been carried out within the framework of the INER project, funded by the Spanish R+D Plan. INER stands for Study of the Net Social, Economic and Environmental Impacts of the Promotion of Renewable Energies in the Spanish Energy System. The aim of INER was to estimate the socioeconomic and environmental impacts associated to the introduction of the renewable energy technologies in the current and future Spanish Energy System.

The first Plan of Promotion of Renewable Energy in Spain, PPER 2000–2010 (IDAE 1999), started in 2000 to strengthen the energy policy objectives of security and quality of electricity supply and environment protection in order to meet Spanish international commitments. Afterwards, a reviewed plan was published, Plan of Renewable Energy, PER 2005–2010 (IDAE 2005), whose main indicative targets were to reach 12.1 % of total energy consumption with renewables and to contribute 30.3 % to the total gross electricity production by 2010. This objective was fully met with a share of 35.4 % of renewable electricity (REE 2011). Biofuels would account for 5.83 % of the gasoline and diesel consumption in transport. The total investment needed by the plan was estimated in 23,598,641 Million Euro. After PER 2005–2010, a new plan, PER 2011–2020 (IDAE 2011), was elaborated with new objectives by 2020.

Besides fiscal support of investments and tax exemptions, the successful deployment of renewable technologies in the electricity system has been mainly due to a feed-in tariff scheme (FIT) which has been working in Spain from 1998. This scheme, regulated by Royal Decrees 2818/1998, 436/2004, 661/2007, 1578/2008 and 1565/2010, has facilitated the penetration of renewables in the electricity market and their technological development until 2012 when the Government, in an attempt to reduce the growing high electric tariff deficit, approved Royal Decree-Law 1/2012 suspending the remuneration pre-assignment procedure and removing incentives for new electricity installations.

Despite this growth experienced by renewables, there is still a high foreign energy dependence which strongly affects the sustainability of our energy system (SEE 2013). Among others, in addition to not meeting the greenhouse gas emissions reductions committed in the Kyoto Protocol (SEMA 2014), the country, with high external energy dependence, is very vulnerable to fossil fuel price fluctuations and faces serious risks in energy supply security. In the current energy market, where only private generation costs are taken into account, fossil energies are more cost competitive than renewable energies and thus, keep their dominant role in the energy system. However, renewable energies have other advantages that should be taken into account. They contribute to the diversification and continuity of energy supply and the reduction of environmental impacts, and represent a good alternative way of generating prosperity and employment and facilitating the access to energy in isolated rural areas. Therefore, the competitiveness of renewables improves substantially when, besides the private costs of the technologies, their externalities are also considered. For that and to also guarantee a sustainable energy system which maximizes the society welfare, policy makers should make use of economic instruments to internalize externalities and to design energy policies which take into consideration social welfare.

In this context, this work performs a cost assessment of the most recent energy policies in Spain, not only considering the private cost of electricity production but also the environmental and socioeconomic costs. First, external costs have been quantified and monetized so that the total cost of electricity has been estimated for all the technologies in the Spanish electricity system. Two main results have been obtained from this analysis: the net impact on the social welfare associated to the progressive substitution of fossil technologies by renewable technologies up to 2010, and the optimal electricity system in the medium and long term under different scenarios.

2 Total Costs of Current and Future Electricity Technologies

First of all, a comprehensive literature review was carried out to identify relevant publications on socioeconomic impacts of energy technologies. Then, a data gathering task was performed regarding the different components of the total cost of energy technologies, such as private costs, environmental burdens and damages, direct employment, etc. For this purpose, national and international data sources were consulted.

2.1 Levelised Electricity Costs

Levelised electricity costs (LEC) and their projections were calculated from investment and operation and maintenance costs data (IDAE 2011; IEA 2010; BCG 2011) for the different technologies in the Spanish electricity system, according to the IEA methodology (IEA 2010). Results showed that, in 2010, most of the renewable technologies were not cost competitive compared with conventional ones. Only LEC for hydropower was close to LEC for nuclear and fossil technologies (Fig. 1).

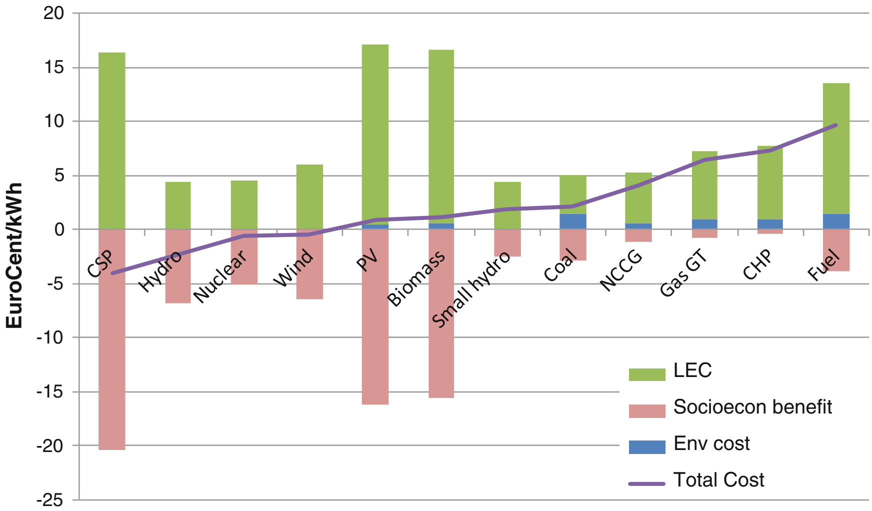


Fig. 1 Disaggregated total cost by technology in 2010 (Caldés et al. 2014)

Nevertheless, over the next periods, LEC for fossil and nuclear technologies is expected to increase. In the case of fossil technologies, this is due to increasing prices for CO_2 and emission allowances as well as fuel prices (Kost et al. 2013). In the case of nuclear technologies, such a trend is due to the longer construction times and changes in regulatory requirements in nuclear (IAEA 2013). On the other side, LEC for renewables is expected to reduce, except for hydropower. It should be noted that there is a relevant change in the LEC for solar technologies which will drop by up to 40 % by 2030 mainly due to the effects of increased learning.

2.2 Environmental Externalities

Data from the CASES project (Cost Assessment for Sustainable Energy Systems, 6th FP), where ExternE methodology (EC 2005) was applied, has been used to estimate the environmental external costs of the technologies. Environmental damages have been estimated from the inventory of emissions of the different technologies during their whole life cycle and using damage factors for the main global and local atmospheric pollutants adapted to the Spanish conditions. The environmental costs for renewable technologies, as can be seen in Fig. 1, are lower than those from conventional fossil ones, with the highest costs attributed to coal and oil technologies. Among renewables, the lowest environmental costs correspond to hydro and wind technologies while the highest costs correspond to biomass technologies.

2.3 Socioeconomic Externalities

The domestic impact on economic activity of the main electricity technologies in Spain has been estimated using the Input-Output table for 2009 from the WIOD project (Timmer 2012) and real data on investment and operation and maintenance costs for each technology. The domestic direct and indirect economic activity generated by each technology has been calculated, as a way to estimate the impact on Value Added. As with the environmental externalities, renewable technologies present the largest socioeconomic external benefits. This result is especially positive taking into account that renewable energy projects are usually located in rural areas with a lower socioeconomic development than cities. It has been considered that all the goods and services have been produced in Spain. If this assumption is relaxed, for instance due to an increase in solar panels imports from China, the socioeconomic positive impacts of renewables would be substantially reduced. To account for such effects, a sensitivity analysis on this subject will be carried out in future studies.

3 Impact of the Renewable Penetration on the Social Welfare

All the previous results have been integrated into a partial Cost-Benefit Analysis (CBA) to evaluate the total costs of electricity generation during the period 2005–2010, when the first PER was in force. Factors considered in the analysis are shown in Table 1.

For this purpose, three scenarios have been considered: (i) BASE scenario, which considers the actual RES deployment, (ii) PER scenario, where the Spanish energy mix matches the PER objectives for RES, and (iii) NoRES scenario. In this last scenario, it has been assumed that the renewable capacity installed in 2004 remained constant over the whole period and that the demand not met with renewables would have been met with natural gas combined cycle plants.

The total electricity system cost has been estimated for the three scenarios adding the external costs and benefits to the private costs.

The scenario without renewable growth (NoRES) presents the highest total costs. It is followed by the BASE scenario where the difference in the generation costs of renewables is compensated by higher external benefits. Finally, the scenario where PER is met presents the lowest total costs. Comparing BASE and PER scenarios, the higher cost in the first is mainly due to a huge installation of solar technologies, which in 2008 surpassed in 2500 MW the installed capacity foreseen in the PER.

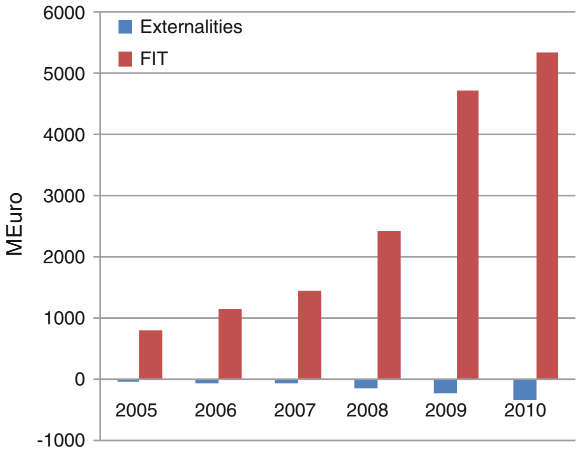
Once the total cost of the electricity system was calculated for each scenario, the difference between BASE and NoRES scenarios was estimated. This comparison provided the net impact associated with renewable technologies penetration in terms of private costs, and environmental and socioeconomic externalities.

Table 1 Factors considered in the partial CBA (Caldés et al. 2014)

Relevant factor	Cost or benefit for society	Measurement indicators	Monetized (monetization method)	Considered in this CBA?
Electricity generation costs	Private cost	Levelised electricity cost	Yes	Yes
Economic activity	Socio-economic externality	Value added	Yes	Yes
Local environmental effects	Environmental externality	Various environmental impact indicators/kWh	Yes (Extern-E and Cases)	Yes
Global environmental effects	Environmental externality	CO_{2equiv}/kWh	Yes (Extern-E and Cases)	Yes
Renewable support expenditures	Public cost	Feed in tariffs expenses	Yes	Yes
Employment	Socio-economic externality	Jobs created	Yes	Estimated but not included
Tax revenues	Public benefit	Tax revenues from energy related activities	Yes	No
Fossil fuel imports	Public benefit	Oil and gas imports	Yes	No
Other renewable support polices	Public cost	Tax exemption, investment subsidies, etc.	Yes	No
Transaction costs	Public costs	Not measured	Not measured	No
Merit order effects	Public and private benefit	Not measured	Not measured	No
Increase in RES exports	Private benefit	Not measured	Not measured	No
Rural development	Public benefit	Not measured	Not measured	No

The differences in total external cost between renewable and non-renewable technologies have been compared with the cost of the renewable support policies in the power generation sector (feed-in tariffs) for the years between 2005 and 2010. The results (Fig. 2) show that the cost of the feed-in tariff system exceeds the net environmental and socioeconomic externalities. From this result it can be concluded that the feed-in tariff scheme should have been designed in such a way that private costs and social benefits of renewable were better balanced and therefore result in lower policy costs.

Fig. 2 Costs for feed-in tariff and total externalities for renewable technologies



Other benefits that could be incorporated in future analysis include the savings in fossil fuel imports, tax revenues, merit order effects and job creation, which could be monetized. Additionally, there are also other benefits derived from the support for renewable energies in this period worthy of mention such as the increase in technology exports resulting from the market leadership of some Spanish companies.

An alternative scenario to NoRES scenario was considered for sensitivity analysis purposes. Under this alternative scenario, the demand not met with renewables would have been met with coal instead of gas. Results show that the total cost for the scenario with gas is higher than that for the scenario with coal. Looking at the total cost components, although the coal has higher environmental costs it also presents higher socioeconomic benefits mainly because coal consumed is an indigenous resource while gas is imported and most of its associated economic activity stimulation takes place outside of Spain's borders and has not been evaluated. In addition, coal also has lower private generation costs.

4 Optimum Energy System in the Medium and Long Term

TIMES-Spain is a national energy model part of the Pan European Times model (PET) developed within the NEEDS project (New Energy Externalities Development for Sustainability, 6th FP) in 2004. From then, TIMES-Spain has continuously been updated and improved within the framework of several European Commission and national projects such as RES2020 (Monitoring and Evaluation of the RES directives implementation in EU27 and policy recommendations for 2020, IEE) (Labriet et al. 2010), REACCESS (Risk of Energy Availability: Common Corridors for Europe Supply Security, 7th FP), COMET (Towards an infrastructure for CO_2 transport in the Western Mediterranean, 7th FP) and INER.

In this work, TIMES-Spain has been used to model the Spanish energy system, with special focus on the electricity generation, within the 2010–2035 time horizon under different renewable energy scenarios.

4.1 Modelling the Spanish Energy System in 2020–2035

After the update, recalibration and validation of the model with the energy consumption and production data for 2010, a first scenario has been built, the BASE one, which gathers all the national and international energy and environmental policies and commitments.

Regarding national policies, BASE scenario includes the feed-in tariff scheme from 2005 to 2012 when this instrument was abolished for new renewable, CHP and residues facilities (Decree-Law 1/2012). The BASE scenario also considers subsidies to investments on renewable technologies in the commercial and residential sectors.

As far as international commitments are concerned, BASE scenario includes the commitments in force related to Directive 28/2009/EC on the promotion of the use of energy from renewable sources, Directive 29/2009/EC to improve and extend the greenhouse gas emission allowance trading scheme of the Community, and Directive 2001/81/EC on national emission ceilings for certain atmospheric pollutants. Those commitments set by 2020 have been kept at the same level until the end of the time horizon. Such Directives are included as a constraint in the model setting a series of objectives such as 20 % renewable energy from final energy consumption and a maximum emission of 258.4 Mt of CO_2 by 2020, and SO_2 and NOX emission ceilings up to 746 and 847 kt respectively from 2015 to 2035.

The inclusion of those policies leads to renewable technologies reaching 44 % share of electricity generated by 2020 (39 % when electricity from industry is considered), and 100 % in 2035 (97 % including electricity from industry). The robustness of this result should be further analysed. The model includes average availability factors for each seasonal time slice. A higher level of disaggregation should be considered to properly assess this point. The highest contribution among renewables in 2020 corresponds to wind power. Later on, particularly by 2030, there is a considerable penetration of solar technologies which, by 2035, generate 38 % of the total electricity. For simplicity reasons, in this exercise, impacts on the electricity grid, storage requirements and Demand Side Management (DSM) have not been taken into account.

Comparing the objectives of PER 2011–2020 (IDAE 2011) with the results of the optimization, some discrepancies have been found (Fig. 3). It should be noted that PER 2011–2020 estimations were done under an optimistic demand projection. According to the results of the modelling exercise, electricity with biomass does not enter the Spanish electricity system, in fact the objective for this technology in PER is quite modest. Additionally, there is a delay in wind offshore which participates in the system with a negligible share of 0.08 % by 2020 and reaches 0.4 % in 2035.

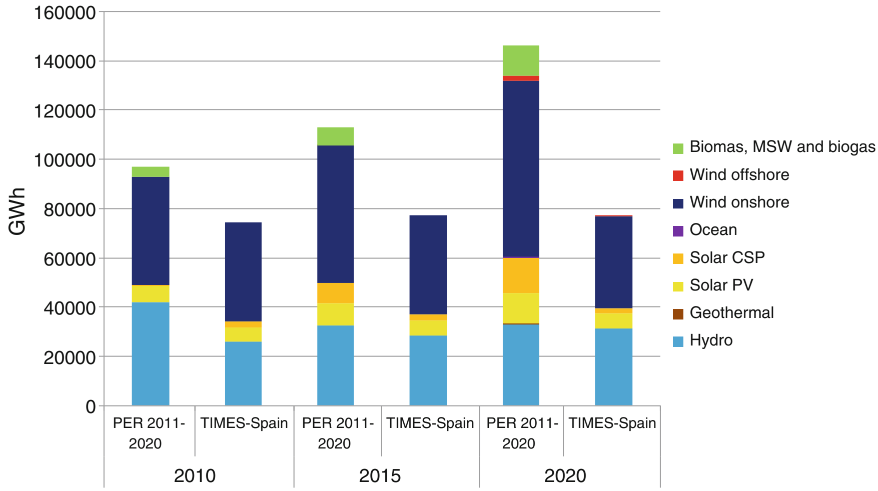


Fig. 3 RES forecasted penetration in BASE scenario versus PER 2011–2020 objectives

4.2 Energy, Environmental and Socioeconomic Scenarios

In addition to the BASE scenario, two alternative scenarios have been built:

- ZERO scenario, which considers the evolution of the energy system when there are no restrictions or targets to emissions and renewable technologies penetration set by the policies in force.
- INTER scenario, which considers the internalization of the environmental and socioeconomic external costs for all the electricity technologies estimated in the previous sections. Socioeconomic externalities have been calculated as an increase in economic value added into the Spanish economy associated to technology investment and operation. They resulted only in benefits (Fig. 1). They have been introduced in the objective function by reducing the investment and operation and maintenance costs of each technology from the amount of the socioeconomic externalities. Environmental externalities have been introduced in the model as an additional variable operation and maintenance cost. As in ZERO scenario, INTER scenario does not include any restriction or target either.

Results of the ZERO scenario show a mix with a huge participation of fossil technologies, a high share of coal (also via CHP) and a lower but still relevant share of renewables in 2020 (33 %) and 2035 (25 %), mainly hydro and wind technologies.

Penetration of renewable technologies in the final energy consumption in the INTER scenario is higher than in the BASE scenario (62 % in 2020 and 68 % in 2035). The electricity production with natural gas disappears from the system in 2015 and is replaced by renewable electricity, mainly wind and solar power. This

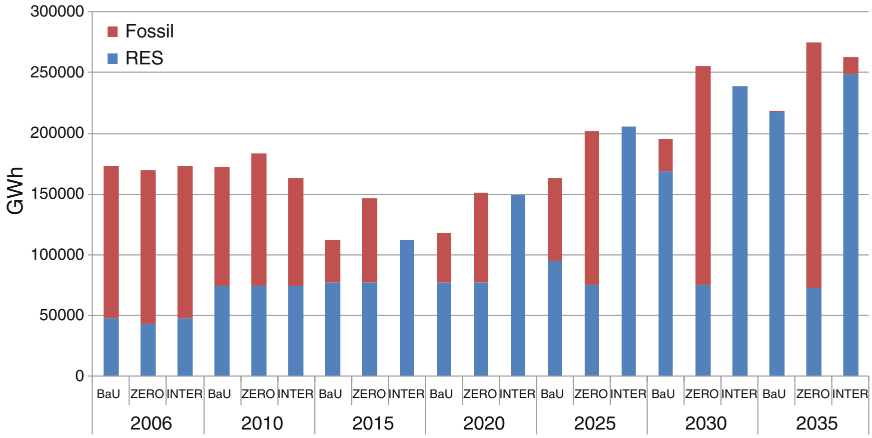


Fig. 4 Fossil and renewable technologies production in the three scenarios

result might appear unrealistic because of the large investments in natural gas combined cycle (NGCC) plants made in Spain over recent last years. However this is what is actually happening as many NGCC plants are producing at 10 % of their capacity or even in standby because of the high penetration of renewable electricity into the system. At the end of the time horizon, both scenarios present an electricity mix almost completely renewable with the rest being produced with gas through CHP in the BASE scenario, and CHP and NGCC in the INTER.

Figure 4 shows the production of electricity with fossil technologies (except for CHP) and renewables.

5 Conclusions and Recommendations

Based on the results from the partial Cost-Benefit Analysis some conclusions have been drawn. The positive impact on social welfare associated to the renewable energies is higher than the impact associated to fossil energies. Thus, the Government should restart the promotion of the penetration of renewable technologies in the national electricity mix by means of support policies, as in the past. Nevertheless, this support has to be well designed and diversified in order to avoid past imbalances. Various policies such as public support to R+D in less mature but promising renewable technologies and a well-designed investment incentive system (e.g. feed-in tariffs and tenders) should be put in place. Also, the expansion of technologies in the system should not overpass the target assigned to them, which could be estimated as the amount of capacity that maximizes the welfare of the society. Besides, the magnitude of socioeconomic benefits associated to renewable energies is very sensitive to the origin of the components and services. Consequently, industrial policies should be designed to strengthen the domestic production of those goods and services. Finally, there was a huge growth of renewable technology installation from 2005 to 2010 which resulted in a capacity expansion for some technologies well above the objectives set by the PER 2005–2010. This led to an unexpected increase in the support policy costs which over-passed the associated environmental and socioeconomic benefits. A more accurate design of the level of feed-in tariffs and a limit to the new capacity installed according to the PER estimates could have reduced the costs of those support policies.

Regarding the modelling exercise, the main conclusion is that it is possible to meet the objectives of renewable technologies penetration and emission reductions set by the European Directives internalizing the external costs and benefits of electricity technologies. Thus, renewable support policies through financial instruments which reflect the external benefits with respect to fossil technologies should be reestablished.

Acknowledgments This work has been carried out within the framework of the INER project, co-funded by the Spanish R+D Plan.

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Modelling Pathways to a Low Carbon Economy for Finland

Tiina Koljonen and Antti Lehtilä

Abstract Concretizing the roadmaps outlined for moving to a low carbon economy by 2050 into detailed policies is a challenging task. Using ETSAP-TIAM as the central modeling tool, we have analyzed the implications of low carbon policies within Europe, with a special focus on the Finnish energy system. The main objective of the work was to identify cost-effective pathways for moving into a low carbon economy by 2050, by creating a set of different storylines for the future society and economy. The analysis involved also linking the energy system model to an applied general equilibrium model and a forest sector partial equilibrium model for estimating the impacts on the overall economy as well as land-use change and forestry. The scenario results indicate that Finland has good opportunities for achieving its low carbon targets by 2050 due to its large natural resources. The major uncertainties are related to the application of carbon capture and storage (CCS) and possible sustainability criteria for biomass.

1 Introduction

The Government of Finland adopted the Foresight Report on Long-term Climate and Energy Policy in 2009 setting a target to reduce Finland's greenhouse gas (GHG) emissions by at least 80 % from the 1990 level by 2050 as part of an international effort (PMO 2009). Finland's long term climate target is in line with the strategies and emission targets set by the European Commission for achieving the low carbon economy by 2050 (EC 2011a, b). The government of Finland established a Parliamentary Committee on Energy and Climate Issues on summer 2013 with the task of preparing an energy and climate roadmap for Finland up to

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_10

2050. The Energy and Climate Roadmap 2050 report was published on October 2014 (MEE 2014) which builds up strategic guidelines for Finland in order to achieve a low carbon society.

The central supporting research and analysis work for the Energy and Climate Roadmap preparation was a scenario building and modelling of alternative low carbon pathways for Finland, which was assessed by the multidisciplinary research project Low Carbon Finland 2050 platform (LCFinPlat) in collaboration with VTT Technical Research Centre of Finland, the Government Institute for Economic Research (VATT), the Geological Survey of Finland (GTK), and the Finnish Forest Research Institute (Metla). The analyses presented in this paper are based on the results of the LCFinPlat project (Koljonen et al. 2014), which included integrated assessments with energy system, general equilibrium, and sectoral models for mining industry, building sector, and forest sector. The scenario building and analysis included large and multidisciplinary consultation between industries, non-governmental organizations (NGOs), scientists, and policy makers. Also, interview of 1000 private energy consumers were carried out to analyze the motivation and potential barriers for GHG mitigation.

The primary focus of this paper is on energy system modelling of alternative low carbon scenarios for Finland with TIMES-VTT model. The impacts of low carbon emission targets on national economies and the use of natural resources are also shortly reviewed. The modelling and analysis of low carbon targets on Finland's, Nordic, and EU's energy systems with TIMES-VTT model were partly based on earlier work (Koljonen et al. 2012; IEA 2013; Knopf et al. 2013) but in the LCFinPlat project a new setup of scenarios and more detailed modelling of forest and mining industries were included. The paper is structured as follows: Sect. 2 describes the alternative low carbon pathways and Sect. 3 the modelling methodology. In Sects. 4 and 5 the modelling results of alternative low carbon scenarios and selected sensitivity analysis are presented, including a summary of the impacts on national economy and the use of natural resources of Finland. Section 6 concludes the analysis presented and gives some recommendations for future work.

2 Senario Definition

Five low carbon scenarios were created: Continued growth, Stagnation, Save, Change, and Base-80 %. The scenario matrix for the first four scenarios was formulated according to Jim Dator, who has compressed the range of futures into four archetypes—continued growth, collapse/decline, conserver/disciplined society, and high tech transformation. The Base-80 % scenario was built around the Baseline scenario defined in the National Energy and Climate Strategy (MEE 2013). The low carbon societal scenarios are based on both narrative storylines (Table 1) and systematic modelling (Sect. 2 and Table 2).

The development and analysis of scenarios aimed at broad-based utilization of viewpoints of different interest groups and consumers, and, on the other hand,

Table 1 Characteristics of the low carbon scenario storylines

Scenario	Main characteristics from Finland's perspective
Baseline	"Business as usual", including existing national and EU's energy and climate policies, like EU's and Finland's 2020 targets. No major changes to industrial or community structures. Conservative development of technologies
Base-80 %	Similar assumptions as in the Baseline, despite the minimum 80 % emission reduction target by 2050 for Finland and the rest of the EU region
Continued growth "smart society"	Global agreement on 2 °C climate target, economic prosperity, internationalizing, open society, rapid development of technology, structural change in industry, increasing density of urban and regional structures
Stagnation "climate crisis"	Rise of global mean temperature of over 4 °C ⇒ economic crisis, closed society, slow development of technology, current industrial structure, current urban and regional structures
Save "modern oil crisis"	Delayed global agreement on 2 °C climate target ⇒ forward-leaning climate policy of the EU, conservative development of technology, emphasis on energy and material efficiency, current industrial structure, current urban and regional structures
Change "smart consumer"	Global agreement on 2 °C climate target, radical innovations emphasized, developments in economic structure ⇒ role of services emphasized, intertwining work and leisure time, internationalizing, open society, slight dispersal in urban and regional structures, major changes in industrial structure

utilizing the assessments of sustainable use of natural resources. The interactive platform was implemented by a series of seminars, workshops, consultations between different interest groups and between experts, as well as a broad questionnaire targeted at private consumers, contributing as a whole to the target of interactivity. As a result of these viewpoints, a set of quantitative inputs were formulated by the broad group of experts, including VTT's experts on technologies, foresight and energy systems, VATT's and Metla's economists, Metla's experts on forestry, and GTK's geologists.

The central assumption for the scenarios is set by a globally binding climate agreement reflecting the 2 °C climate change mitigation target. In the Save scenario, it is assumed that the global climate agreement is delayed and the EU takes a lead in climate policies by setting the 80 % mitigation target by 2040. In the Stagnation scenario, global climate policies fail and the global mean temperature rises of over 4 °C.

The development of new low carbon technologies and changes in industrial as well as urban and regional structures vary between the scenarios as central drivers of future development. In the Continued growth and Change scenarios optimistic development and implementation of new technologies were assumed while in the other scenarios base (i.e. more conservative) assumptions were used. In the Continued growth and Change scenarios the urban and industrial structures were also

Table 2 Main assumptions of the low carbon scenarios modeled (in the TIMES-VTT model, EU is approximated by the group of six European regions included)

Scenario characteristic	Base-80 %	Growth	Save	Stagnation	Change
Climate policy	EU—80 % by 2050 global 2 °C	EU—80 % by 2050 global 2 °C	EU—80 % by 2040 global 2 °C	EU—80 % by 2050 regional, ~4 °C	EU—80 % by 2050 global 2 °C
GDP growth	Good	High	Moderate	Slump	High
Industrial structure	As in official Baseline[a]	Focus on value added	Conventional	Focus on traditional strengths	Focus on value added and services
Technology development	Normal	Rapid for all sectors	Focus on end-uses[b]	Slow	Very rapid
Nuclear power in Finland	2 new plants + refurbishments	≤5 GW in 2050	≤7.2 GW in 2050	≤3.4 GW in 2050	Moratorium
CCS availability	EOR/EGR	Full potential	Full potential	EOR/EGR + depleted fields	EOR/EGR + depleted fields
Buildings	Conventional	Low energy concepts	Focus on renovation	Slow improvements	Low energy concepts
Transport	Slow technological changes	Rapid technological change	Modal shifts, new infra, savings	Mostly conventional	Rapid technological change

[a] Refers to the Baseline of the 2013 updated national energy and climate strategy of Finland (MEE 2013)
[b] High investments and deployment of energy efficiency measures assumed

assumed to change from the current development path. In the Change scenario urbanisation is high, which provide industrial innovations in information and communication technologies (ICT) and related industry. In the Change scenario more local, small scale industries are assumed to emerge, and regional structure moves in a more decentralized direction enabling distributed energy solutions to emerge.

In addition to the four low carbon scenarios, a Baseline scenario corresponding to the main characteristics of an updated national energy and climate strategy (MEE 2013) until 2025 was analyzed. Furthermore, the Base-80 % scenario, including similar assumptions as the Baseline, despite the 80 % emission reduction target by 2050, was analyzed. The scenario assessments also include sensitivity analyses with respect to the most essential uncertainties. Table 1 summarizes the main characteristics of the alternative low carbon scenarios for Finland while the main assumptions of the low carbon scenarios modeled in the TIMES-VTT are described below in Sect. 3.2 and Table 2.

3 Modeling Methodology

3.1 Models Used

In the low carbon scenario analysis we employed five different models, of which the TIMES-VTT energy system model was the core tool. The four other models were soft-linked with the TIMES model, as illustrated in Fig. 1.

The energy system model TIMES-VTT is a global multi-region model originally developed from the global ETSAP-TIAM model (Loulou 2008; Loulou and Labriet 2008). It is based on the IEA TIMES modeling framework (Loulou et al. 2005), and is characterized as a technology-rich, bottom-up type partial equilibrium model. TIMES-VTT model consists of 17 regions, which include four regions for the Nordic countries (Denmark, Finland, Norway, Sweden), Western Europe, Eastern

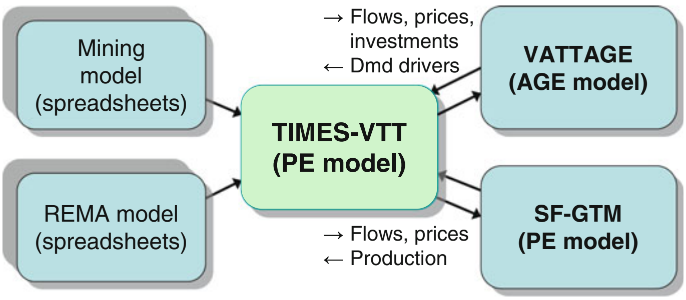

Fig. 1 The linked models used for analyzing the scenarios. *PE* Partial equilibrium, *AGE* applied general equilibrium

Europe, CIS (Former Soviet Union excluding the Baltic countries), Africa, the Middle East, India, China, Japan and South Korea, Other Developing Asia, Canada, the USA, Latin America, and Australia and New Zealand. For the Nordic regions, the district heat production and demand is divided into four sub-regional areas for better modeling of the heat networks in these countries (Koljonen et al. 2012; Lehtilä et al. 2014).

The time horizon of the model is flexible, and can be extended to 2100 or even beyond. For the low carbon scenarios, we used a horizon extending to 2065, divided into successive periods of 5–10 years duration, each representing an average year of the period. To reflect seasonal and diurnal variations in supply and demand, each year is divided into five seasons and two daily time segments.

For gaining further insights into the macroeconomic impacts of the low carbon pathways, the VATTAGE applied general equilibrium model, developed at the Government Institute for Economic Research (VATT), was soft-linked with the TIMES model (Honkatukia 2009). A detailed spatial partial equilibrium model of the Finnish forest sector, SF-GTM, was linked for obtaining more detailed results concerning the LULUCF (i.e. Land Use, Land Use Change and Forestry) effects and the use of regional biomass resources (Kallio et al. 2013). Furthermore, spreadsheet models are used to provide input data for the modeling of various sectors. Two such models were specifically used for the low carbon scenarios, namely, a long-term mining sector model developed by the Geological Survey of Finland (GTK) for modeling the developments in the mining industries (Tuusjärvi et al. 2014), and the bottom-up REMA model for estimating the energy use in various segments of the building stock (Tuominen et al. 2014).

The TIMES model incorporates also an integrated climate module, with a three-reservoir carbon cycle for carbon dioxide (CO_2) concentrations and single-box decay models for the atmospheric methane (CH_4) and nitrous oxide (N_2O) concentrations, and the corresponding functions for radiative forcing. Additional forcing induced by other natural and anthropogenic causes is taken into account by means of exogenous projections. Finally, the changes in mean temperature are simulated for two layers, surface, and deep ocean (Loulou et al. 2010).

3.2 Scenario Assumptions

The scenarios analyzed can be divided into base cases and sensitivity cases. The base cases include a Baseline scenario, with only present policies related to the EU 2020 climate and energy package and other national policies (MEE 2013), and five low carbon scenarios corresponding to the storylines depicted in Table 1. The actual modeling of the low carbon storylines involves a large amount of input data, which cannot be described in any detail in this paper. The data used for each scenario have been tailored to the storylines with respect to the demand drivers for all sectors, assumptions on technological development, constraints on the deployment of certain technologies (e.g. nuclear power, carbon capture and storage, bio-refineries), and development of building standards. The main assumptions in the low carbon scenarios are summarized in Table 2.

As in bottom-up models in general, by far the largest amount of input data is required for the various existing and new technologies available in the energy system. The technology data have been collected from numerous sources, and have been classified into base estimates and optimistic ones. In the scenarios with rapid technological change, optimistic estimates have been used for the technical and economic development of many key technologies for achieving a low carbon society, such as wind and solar power technologies, new bioenergy technologies and end-use technologies in different sectors (Koljonen et al. 2012; MEE 2014).

A second important category of input data is related to energy resources and potentials, which are also based on numerous literature sources as well as the ETSAP-TIAM database (Loulou 2008; Koljonen and Lehtilä 2012; IEA 2013). For these data, assumptions are not varied across scenarios but base estimates are used for all scenarios. However, due to differing projections for the forest industries and agricultural production, biomass potentials implicitly vary across scenarios.

The sensitivity cases are variants of the base case scenarios, where the assumptions concerning certain key assumptions have been changed in order to see how much they affect the solution. Within our project, we have mainly considered the assumptions regarding nuclear power, biomass sustainability criteria and the commercial availability of carbon capture and storage (CCS) for the sensitivity cases, which were assumed to be the most critical uncertainties for Finland based on the stakeholder interviews. These cases are described in more detail later in this section.

The global climate policies of at most 2 °C global temperature increase, as shown in Table 2, have been modeled by limiting the total radiative forcing to at most 3 W/m^2 until 2100, in line with the median estimates by Meinshausen et al. (2009). The Stagnation scenario has been modeled assuming no new global agreements on climate change policies, but only regional climate policies according to the pledges presented by various countries, leading roughly to about 4 °C increase in the global temperature (De Cian et al. 2013).

In the scenario analysis, we assumed only the EU-wide targets binding, and that they must be reached solely by reductions within the EU. The so-called flexible mechanisms, where measures outside the EU could also be credited, were thus excluded from consideration. Moreover, changes in emissions related to land use, land use change and forestry (LULUCF) were also excluded from the EU-wide emission targets in the energy system model runs, and were only assessed separately with the SF-GTM forestry sector model (Kallio et al. 2013, 2014). However, we did take into account BECCS (i.e. CCS integrated to biomass fired energy production, pulp and paper industries, and 2nd generation liquid biofuel production) as an option for reducing emissions, as it has already been accepted in the inventories submitted to the UNFCCC (IEA 2011).

4 Results from the Basic Scenario Variants

4.1 Energy and Emission Scenarios of the Alternative Low Carbon Pathways

Like most European countries, Finland has also a national GHG reduction target for 2050, which is the same as the EU-wide target, i.e. 80 % compared to the 1990 level, and it concerns all greenhouse gas emissions of the Kyoto protocol. The results from the basic scenario variants indicate that the EU-wide emission target for 2050 would lead to closely comparable emission reductions in Finland, as illustrated in Fig. 2. In the Baseline scenario (current policies, the proposed EU's 2030 climate and energy targets not included), total emissions would be reduced only by about 30 % by 2050. On the other hand, in the low carbon scenarios the EU-wide targets would entail reductions in Finland amounting to 67–85 % of the 1990 emission levels by 2050. The Stagnation scenario is the only one clearly left behind the national targets, while in the Growth, Save and Change scenarios the national targets related to a low carbon society appear to become well achieved also in Finland.

In Finland, the total primary energy consumption was about 1500 PJ in 2010, of which 52 % consisted of fossil fuels, including peat. The use of renewable energy is already at a high level, close to 30 %, and the role of nuclear energy is also considerable, about 18 %. In the low carbon pathways the contribution of fossil fuels decreases steeply, dropping to around 20 % in 2050, while the share of renewable energy increases to 44–60 % of total primary energy (Fig. 3a). In all

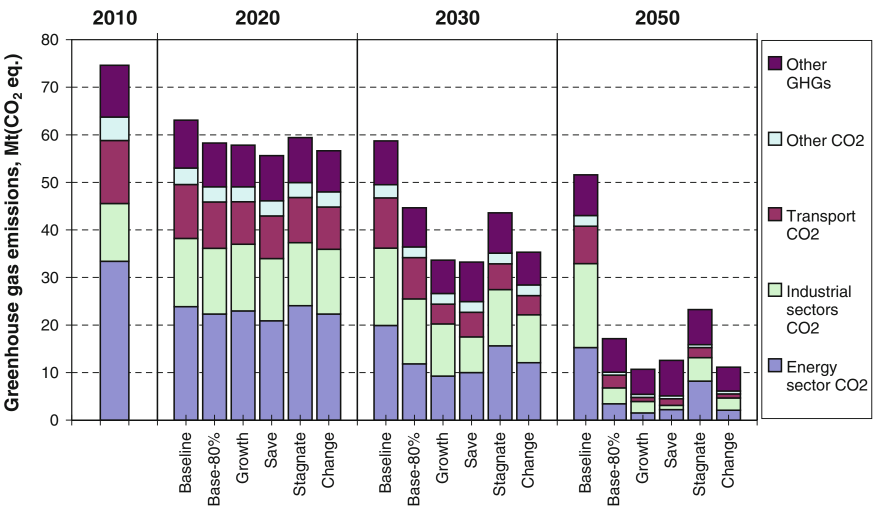

Fig. 2 Development of GHG emissions in Finland in the base scenario variants (other CO_2 includes CO_2 emissions in all other sectors)

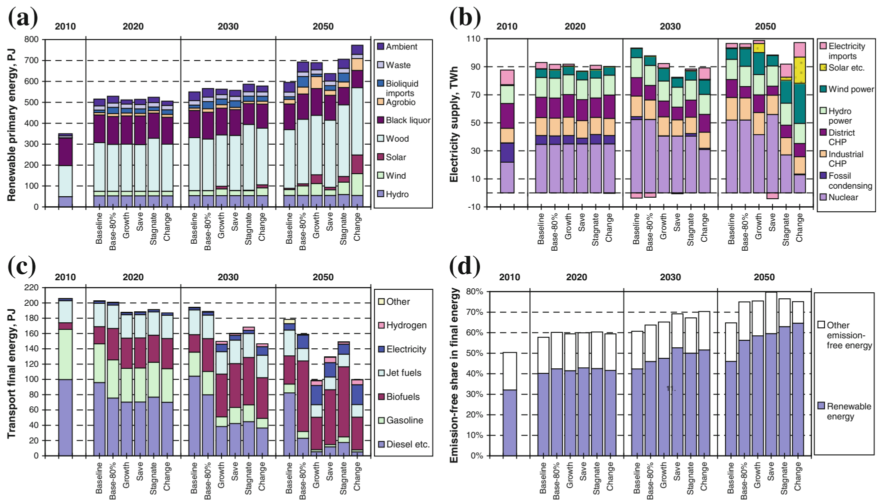

Fig. 3 Development of electricity supply (**b**), renewable primary energy (**a**), final energy in transport (incl. aviation) (**c**), and emissions-free final energy (**d**) in the base variants of the low carbon scenarios considered

scenarios bioenergy remains the most important renewable energy source in Finland.

The development of electricity supply is illustrated in Fig. 3b. The results clearly illustrate that in the low carbon economy electricity generation should become practically free of GHG emissions. That appears to shrink the economic potential for combined heat and power (CHP) and district heating, which may seem somewhat unexpected in view of the high efficiency of CHP generation. However, because basically all thermal generation should be based either on biofuels, carbon-free synthetic fuels, or fossil fuels with CCS, it tends to become both logistically difficult and uneconomical to maintain a very high share of CHP generation. According to the results CCS may indeed become competitive also in CHP plants producing district heat for large urban areas, especially combined with oxyfuel combustion technology, as it enables maintaining high total energy efficiency in CHP generation. The Change scenario depicts a high penetration of solar power, which may be realistic only under the optimistic assumptions concerning energy storage technologies in this scenario.

In final energy consumption the impacts of continued electrification, which are pronounced in the low carbon pathways, are clearly seen in the results. Along with high efficiency improvements e.g. in the building and transport energy use, the share of industry in final energy consumption tends to increase in the case of Finland. As an example, the average specific energy consumption for heating and hot water decreases by up to 60 % in the scenarios, compared to the present levels.

Concerning the transport sector, our scenario results indicate that along with second generation liquid biofuels and electrification in the longer term, the obstacles to achieving deep emission cuts also in this sector will be much reduced. Figure 3c illustrates the development of the final energy in transport, the corresponding emissions being already shown in Fig. 2. Even though in some scenarios up to 40 % of the transport biofuels would have to be imported, domestic production becomes significant in all scenarios, and to a large extent equipped with carbon capture. The Change scenario even shows net exports of liquid biofuels after 2030. Electrification becomes dominant by 2050 in those scenarios with rapid technological change, turning the market share of liquid biofuels eventually downwards.

The share of renewable energy in total final energy was in Finland about 32 % in 2010, and the target for 2020 is set at 38 %. As shown by the results in Fig. 3d, the target is well achieved, and in the low carbon scenarios the share reaches 60–65 % by 2050. Including all GHG emissions-free final energy (excluding fossil CCS) the total share of carbon-neutral final energy increases to 75–80 %.

Of the main sectors causing GHG emissions, agriculture turns turn out to be the one where achieving substantial reductions is the most difficult. In our scenarios, the decrease in agricultural emissions were at the highest 44 % in the Change scenario, but that was to a large extent due to the assumed decrease in agricultural production in that storyline, and only to a lesser degree through advanced technical abatement measures or changes in fertilizer use and cultivation practices. The decrease in domestic production was based on the assumed favorable development of global trade.

As the emission targets were EU-wide, the GHG emission prices were the same for all European countries. According to the results, the marginal prices would rise to 100–125 €(2010)/tonne (CO_2 eq.) in 2050, depending on scenario. The prices are within the range of carbon values (85–264 €(2010)/tonne) reported in the assessment of the EU 2030 climate and energy policy framework (EC 2014).

As practically no suitable geological CO_2 storage capacity has been identified within the territory of Finland, the transportation and storage related to CCS applications in Finland have been estimated by assuming that the storage site is located either in the North Sea or the Barents Sea (Teir et al. 2010). Despite the considerable costs for CO_2 transportation, the results indicate that CCS could still have a notable role in Finland, if the storage technology will be commercialized on a wide scale. That was assumed to take place in the Base-80 %, Growth and Save scenarios, which also show the highest proportions of emission reductions occurring within the emission trading sectors. The scale of the emission abatement by CCS is illustrated in Fig. 4 for the basic scenario variants.

One of the characteristics of the Finnish energy system is the use of biomass for large-scale energy conversion, currently mainly within the pulp and paper industry and in public power and heat generation, but in the future also in bio-refinery plants producing liquid biofuels. Due to the substantial forest resources, this opens up the possibilities for negative emissions via BECCS, thereby facilitating deeper cuts in overall emissions. According to the results, BECCS accounts for the majority of the

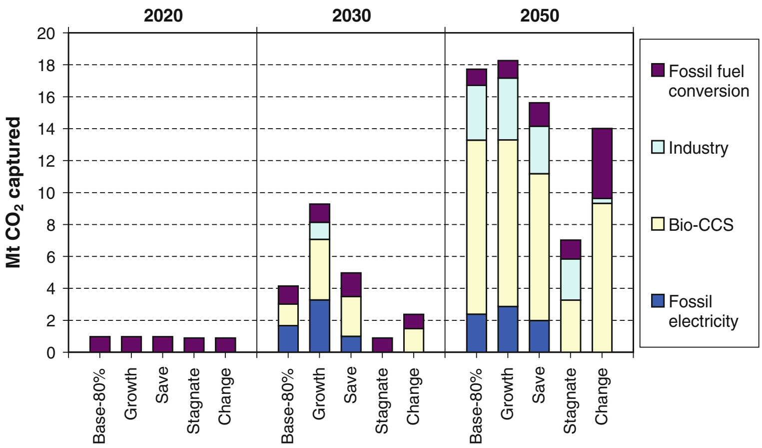

Fig. 4 Emission abatement by CCS

CCS potential in Finland, and appears to be a particularly attractive option in bio-refinery plants, where carbon can be captured from an almost pure CO_2 stream. The potential for fossil-based CCS appears to be limited, and is mostly related to large multi-fuel CHP plants using also biomass, as well as hydrogen production. Within industry, the most promising CCS option appears to be enhanced blast furnace process with top gas recycling and oxygen injection.

4.2 Impacts on the National Economy

The build-up of the LCFinPlat scenarios on the national economy did not directly aim at comparability. The Base, Base-80 %, Save, and Stagnation scenarios show similarities from an economic viewpoint. Compared to Baseline, the 80 % emission reduction does not imply a major decrease in gross domestic product (GDP), partly due to the moderate reduction of emissions already in the Baseline, partly due to the fact that majority of the reductions can be implemented by new technology, which was assumed to be commercially available, when needed. On the basis of the Baseline and Base-80 % scenarios, the macroeconomic effect of 80 % emission reduction is mild: the growth of GDP is lower by less than 1 % in comparison to the Baseline in 2050. Assuming slow technological development and thereby the need for increased supports for new technology implementation the GDP losses will increase. Climate policy has also an impact on the structure of the economy by slightly diminishing the external balance—that is, the share of exporting sectors decreases compared to the Baseline (Honkatukia et al. 2014).

4.3 Impacts on the Use of Forest Resources

The annual amount of carbon dioxide sequestered by forests in Finland equals approximately half of the greenhouse gas emissions from other sectors. Opportunities to employ forest sinks to offset the emissions from the other sectors are, however, very limited in the Kyoto Protocol and in consecutive agreements. Therefore, the increase in forest sinks does not give additional benefits for Finland to meet its climate obligations. Thus, the increase of forest sinks was not considered in the LCFinPlat project as an emission mitigation measure even if their development was investigated. Opportunities to use wood biomass for the production of energy and processed products is one of Finland's advantages in the transition towards a low carbon society. Since the use of wood begins to grow stepwise, the felling potential[1] of forests will still be underutilised during the next two decades. Because the planned use of wood is below the growth, the volume of Finnish forests keeps on growing. This also contributes to a growth of carbon sinks. That is, forests store carbon from the atmosphere more than it is emitted back due to felling and the decaying process of natural mortality. By 2050 the carbon sinks could be more than doubled compared to current levels (70–90 Tg CO_2/a in 2050), indicating the net carbon sinks might be much larger than Finland's GHG emissions (Kallio et al. 2014).

5 Results from the Sensitivity Cases

The low carbon pathways depicted by the scenarios contain many inherent uncertainties that require further sensitivity analysis with respect to the key factors influencing the results. In addition, as the scenario storylines were also quite different from each other, sensitivity analysis can also help identifying the main similarities and differences between scenarios to arrive at robust conclusions regarding the low carbon pathways. As mentioned above, we analyzed sensitivities to three significant uncertainties the stakeholders identified important for the Finnish energy system: (1) new nuclear power (N), (2) biomass sustainability (B), and (3) the commercial availability of CCS (C). Lastly, we also looked into the case where these three uncertainties are applied simultaneously (R). Selected results from the sensitivity analyses are shown in Fig. 5 for the Save and Growth scenarios.

In the first sensitivity analysis case (N), we assumed that no new nuclear power plants would be installed in Europe after those currently under construction. As there have been plans for several new plants in the relatively small energy system of Finland, the uncertainties related to nuclear power have a particularly high impact on the low carbon pathways in Finland.

[1] The felling potential corresponds to the sustainable harvesting potential of roundwood, which is estimated from harvesting suggestions obtained from the national forest inventory.

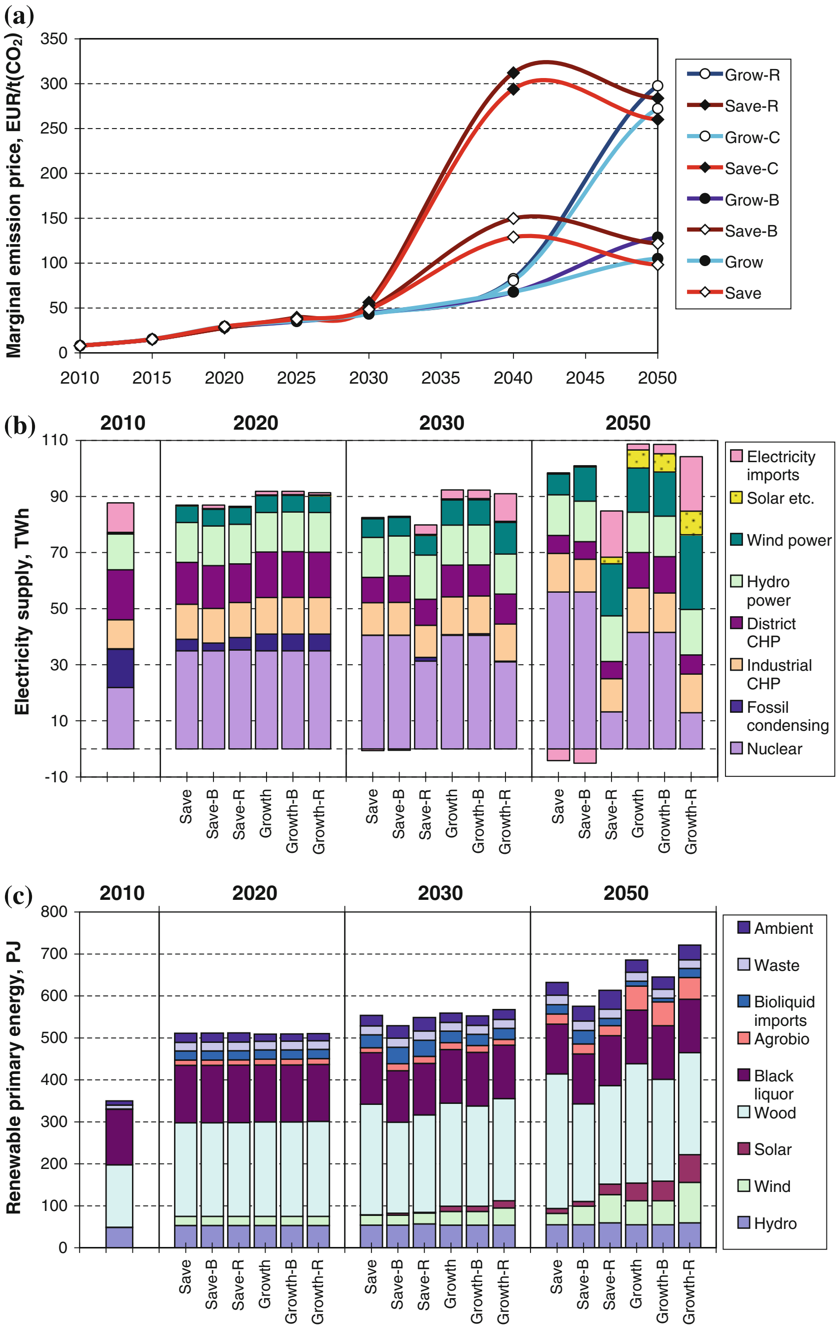

Fig. 5 Marginal GHG emission prices (**a**), electricity supply (**b**) and renewable primary energy (**c**) in Finland in the Save and Growth scenarios, with sensitivity variants B and R

As expected, the nuclear power case (N) shows its strongest impacts on the electricity system. Perhaps the most significant impact is seen in the role of combined heat and power (CHP), which now becomes much more prominent in the low carbon pathways by 2050. At the highest, CHP would cover 40 % of the total electricity supply, and would mostly be based on biomass but also on fossil fuels with CCS in large scale pass-out turbine plants. Other substantial changes include a notable decrease in electricity demand due to higher prices, and larger penetration of wind and small scale hydro power in the N case. However, it turns out that the impacts on the marginal costs of GHG emission reduction remain quite small.

Sustainability criteria for biomass supply represent a second important factor of uncertainty for the Finnish energy system. As seen from the base case results, in all of our scenarios, bioenergy remains the most important renewable energy source, and plays a very important role in attaining the low carbon targets. The second sensitivity analysis case (B) thus attempts to find out, how the pathways might change if new criteria for biomass sustainability would be implemented in future. To simulate conceivable stricter criteria, we applied a CO_2 emission factor of 65 kg/GJ for the forest biomass produced from stumps and thinnings, as well as a factor of 25 kg/GJ for all other forest chips, and 20 kg/GJ for energy crops. The emission factors were based on GWP (i.e. Global Warming Potential) estimates presented in literature (for example in Pingoud et al. 2012).

As expected, the use of biomass for energy decreases considerably in the sensitivity analysis case B. However, in this case the changes in electricity supply remain quite small. CHP loses some of its competitiveness and wind power gains some. The impacts are most clearly shown in the primary energy mix and production of liquid biofuels from woody and grassy biomass, where the use of the least sustainable biomass fractions reduces sharply. Interestingly, there is also some increase in electricity consumption due to electrification in this case. The marginal GHG emission prices rise about 25 % in 2040–2050 compared to the base cases.

For the third sensitivity case considered (C), the commercial availability of CCS, we assumed that CCS would not become a commercial option in Europe, due to various issues related to long-term storage, like public acceptance, or for some other reason. The use of CCS was therefore restricted to enhanced oil and gas production, where it has been already commercially applied.

Until 2030, the results in the sensitivity analysis case C show only minor differences compared to the base cases, as the CCS option was assumed to become widely available only after 2030. By 2050 substantial differences do emerge, because without CCS, fossil fuels and peat are no longer competitive in electricity generation, except during times of peaking demand and for reserve capacity. This in turn reduces the competitive potential of CHP generation in general, as the supply of non-fossil fuels is more limited and has high transportation costs over long distances. The decreasing fossil-based generation is mostly compensated by increases in electricity imports and larger wind and solar power production. However, the demand for electricity is not reducing, because the opportunity costs related to electrification remain favorable. The strength behind these impacts can be understood by looking at the marginal GHG emission prices, which are in this case more than doubled, rising over 250 €/tonne. The impacts on bioenergy use are two-fold: higher marginal costs increase it, while the unavailability of CCS reduces it. Yet steeper increases in marginal costs of GHG reduction have been reported earlier by Remme and Blesl (2008).

Finally, to see the combined effect of the three factors described above, we also ran the scenarios assuming that all the three main uncertainties described above are simultaneously applied. The results from this case (R) indicate the availability of CCS being indeed the most significant uncertainty for the low carbon pathways. The results are in many respects similar to the sensitivity case (C), and the marginal abatement costs are only 10 % higher. However, in the (R) case the demand for electricity is now in many scenarios notably lower than in the base cases, as the incentives for demand reduction are finally exceeding those of electrification. Note that in case (R) investment in nuclear power was prohibited in Finland only and not in the rest of the EU. In the case (N) new nuclear power was prohibited in Europe as well.

It may also be of interest to look at the impacts of the sensitivity cases on the projected European-wide electricity supply due to EU-wide cap of GHG emissions and, on the other hand, due to the increasingly integrated electricity markets within the EU. The results for some of the cases are illustrated in Fig. 6, where the base case results are shown for the Save and Growth scenarios, and the sensitivity cases B, C and R for the Growth scenario. From the results one can clearly see the high importance of wind and solar power for reaching the low carbon targets on the European level, as well as the influence of CCS availability on the results. Without CCS, fossil fuel based generation should become practically negligible also on the

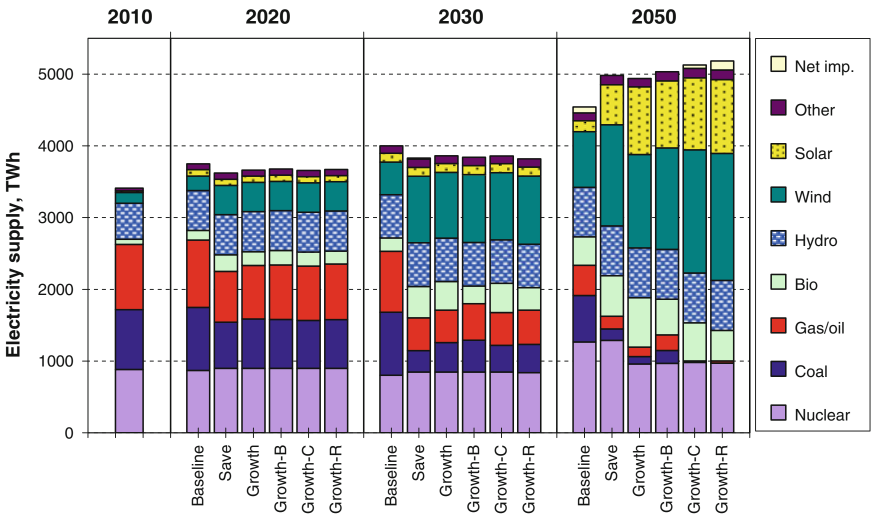

Fig. 6 Electricity supply in Europe in the baseline, save and growth scenarios, with sensitivity cases B, C and R for the growth scenario

European level, leading to yet higher and more costly dependence on variable renewable generation. But with CCS, one can see BECCS having potential also on the wider European scale.

6 Conclusions

The recently published Energy and Climate Roadmap 2050 for Finland (MEE 2014) builds up strategic guidelines in order to achieve a low carbon society. The modelling and analysis work by the LCFinPlat project formed the basis of the low carbon strategies for the government. An important part of the LCFinPlat project was also the established interactive platform, which was implemented by a series of seminars and workshops held during the project, consultations between different interest groups and experts, as well as a broad questionnaire targeted at private consumers, contributing as a whole to the target of interactivity. The platform served policy makers through the whole period of formulation of the Energy and Climate Roadmap 2050 for Finland and also policy makers gave feedback on preliminary results of the impact assessments. The platform proved to be an essential part of the whole scenario building and modelling framework because of large uncertainties related to long term scenarios. The consultations, seminars and workshops through the project period also increased the transparency and common understanding of the challenges and opportunities of the transition to a low carbon society. On the other hand, it was also shown that multidisciplinary and systematic modelling of alternative low carbon pathways is needed to identify the major uncertainties, risks, opportunities, and strengths of alternative low carbon pathways and to build up robust strategies in achieving the assessed climate targets.

The TIMES-VTT model, built on the ETSAP energy system modeling tools, was the core model in our low carbon scenario analysis. The combined use of several other models linked with TIMES has demonstrated the flexibility of the TIMES modeling framework. The open and user-extensible GAMS code facilitates the interfaces and tailored processing of both input and output data for soft-linking with other models, and the VEDA-FE user shell provides powerful tools for efficient handling of various scenarios and sensitivity analysis cases. Nonetheless, from our experience there seems no doubt that an integrated multi-sector, multi-region general equilibrium model could bring substantial further added value to the set of ETSAP tools, as managing the data exchange and iterations between soft-linked models with different disaggregations can be time-consuming.

The analysis of the LCFinPlat project did not aim at defining the "best" pathway to be followed until the year 2050. Therefore, it is important to broadly map possible development paths and recognize factors and risks common for all the pathways potentially emerging from the choices in the following decades. The modelling and scenario analysis with TIMES-VTT model showed that Finland has good opportunities to achieve the low carbon society because of its large natural resources. However, in the Stagnation scenario Finland didn't reach its own 80 %

GHG reduction target expect by buying emission allowances indicating, that at least EU level and preferably global level climate target should be agreed before implementing national low carbon targets and policies. In all the low carbon scenarios bioenergy remains the most important renewable energy source, and plays a very important role in attaining the low carbon targets. Therefore the impacts of possible future sustainability criteria for biomass was analyzed with sensitivity analysis, which showed that the marginal GHG emission prices rose about 25 % in 2040–2050 compared to the base cases. However, both the stakeholder consultancy and sensitivity analysis showed that commercialization of CCS represents the major uncertainty: the marginal GHG emission prices more than doubled, rising over 250 €/tonne if we assumed that CCS would not be available as a mitigation option. Without CCS, fossil fuel based generation should become practically negligible also on the European level, leading to yet higher and more costly dependence on variable renewable generation. But with CCS, one can see BECCS having large potential in Finland but also on the wider European scale.

In many impact analyses of low carbon policies, alternative technology portfolios and technology learning rates have been considered (EC 2011b; Knopf et al. 2013). On the other hand, alternative scenarios for the changes in the community structures, industrial structures, or economy structures are usually not considered at all, expect in the more detailed sectoral analysis. In the LCFinPlat project it was shown that there is a clear advantage of analyzing these to create robust scenarios and to better identify risks and opportunities in the transition to the low carbon society. It also important to integrate multidisciplinary expertise in formulating and analyzing alternative low carbon pathways even though more resources and time would be needed to create common low carbon visions and strategies.

Acknowledgments The work presented in this paper was based on research work of above twenty researchers from VTT, VATT, Metla and GTK. The impacts of low carbon policies on national economics was analysed by Juha Honkatukia from VATT and the impacts on the use of forest resources was analysed by Maarit Kallio and Olli Salminen from Metla. The authors greatly acknowledge collaboration between the whole research group and the financial support from Tekes—the Finnish Funding Agency for Technology and Innovation, VTT, VATT, GTK, and Metla.

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Part II
Focussing on Specific Aspects of Supply and End-Use

Methodological Significance of Temporal Granularity in Energy-Economic Models—Insights from the MARKAL/TIMES Framework

Ramachandran Kannan, Hal Turton and Evangelos Panos

Abstract One of the key attributes that distinguishes bottom-up energy modelling frameworks is the temporal depiction. In any given bottom-up model, the depiction across two dimensions—viz. model time horizon and intra-annual time resolution—has an implicit meaning for the framework and research questions to be answered. There are also tradeoffs between these two temporal dimensions in model design driven by computational resources, solver algorithm capabilities, data availability and methodological limitations. In the TIMES framework, the option to apply a higher intra-annual time resolution offers the potential to generate additional powerful insights into the electricity sector where fluctuations in supply and demand are significant, even though this feature alone is still less suitable for analyzing fully the dynamics of the sector. Nonetheless, the TIMES integrated system approaches offer additional capabilities which are not available in single-sector modeling approaches. This chapter provides a broad overview of temporal features in the MARKAL/TIMES energy modelling framework. The significance in terms of higher time resolution, along with trade-offs and benefits of an integrated system approach are discussed with a set of scenarios from the Swiss TIMES electricity and energy system models.

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_11

1 Background

Energy models have emerged as a useful methodology for energy research aimed at evaluating future energy supply options and generating insights for policy design. Energy models covering a wide range of analytical approaches have been developed for specific objectives with a predefined methodological scope and limited applications (Kannan and Turton 2013; Foley et al. 2010; Pfenninger et al. 2014). One of the key attributes that distinguishes bottom-up energy modelling frameworks is temporal representation, among others. It has two dimensions viz. time horizon and intra-annual time resolution. The time horizon is often important to explore the evolution of the energy system over multiple years/decades while the intra-annual granularity can accommodate variability in demand and supply. Both of these temporal dimensions have an implicit meaning for the framework and research questions to be answered. In addressing long-term policy goals, e.g. climate change mitigation and increasing integration of renewable energy sources, requires analytical approaches that combine a sufficiently long time horizon and an appropriate level of intra-temporal resolution. In practical terms, the tradeoffs between these two temporal dimensions are driven by a range of factors such as: computational resources; solver algorithm capabilities; data availability; and methodological limitations. Nevertheless, advances in computational power and solver algorithms have facilitated the emergence of modelling frameworks with the potential to combine a long time horizon and detailed intra-annual time resolution for representing electricity load curves. For instance, the TIMES framework has the capacity to represent any number of intra-annual timeslices and time periods. To some extent, combining these features enables analysis of the long-term evolution of energy system along with energy balancing mechanisms in a single model. We describe the application of the Swiss TIMES electricity and energy systems models, denoted as STEM-E and STEM respectively, with an hourly timeslice resolution and a century-long time horizon.

Section 2 provides a broad overview of the temporal significance in energy modelling frameworks with their strengths and shortcomings. Insights from two scenarios analysed using the STEM-E and STEM models are presented as a case study to support the discussions in Sect. 3. A summary of approaches for improving model development in MARKAL/TIMES frameworks are highlighted in Sect. 4 with conclusion in Sect. 5.

2 Temporal Dimensions in Energy Models

The following subsections describe the two temporal dimensions of bottom-up energy modelling framework.

2.1 Time Horizon

The time horizon in energy models is defined according to the number of periods represented and the number of years in each period. Frameworks have either a predefined period definition, a choice of fixed (equal) period lengths, or options for unequal period length. The choice of model time horizon depends on the research and policy questions to be answered. The long time horizon is critical when the research is concerned with long-term energy challenges such as resource depletion, technology spillover effects, climate change mitigation, investment cycles and evolution of long-lived infrastructure (e.g. power plants, gas pipelines, electric grid) and so on. Given that integrated energy system models are often applied to explore these issues, almost all employ a long time horizon of multiple years and decades. Clearly, uncertainties affecting the energy system increase over longer time horizons, as underlying driving factors like economic growth and technology development become less certain. In some modelling frameworks like TIMES, the long-term uncertainties can be represented while maintaining a greater focus on near- to mid-term developments, through the definition of unequal time periods in the model, describing the near term in a higher level of temporal detail.

2.2 Intra-Annual Time Split

The inter-annual time split is the number of daily, weekly and seasonal time splits within a year. A high level of intra-annual time resolution is very important when the balancing of demand and supply of time-dependent energy commodities is likely to have a large impact on energy system technology options development. For example, electricity is a highly time-dependent energy commodity because both energy (e.g. kWh) and capacity requirements (e.g. MW) must be met at every instant. In sectoral electricity modelling approaches, the intra-annual resolution is often high and covers intervals ranging from seasons to a few minutes. These approaches have been used for scheduling electricity dispatch and planning and operation of power system (e.g. Deane et al. 2014; IAEA 2001; Energy Exemplar 2014).

2.3 Trade Offs

Figure 1 illustrates two key temporal dimensions in energy model applications. Energy system models conventionally adopt a long time horizon because their primary application is to assess long-term issues (e.g. climate change mitigation, resource depletion, etc.). In most of these models (as well as in integrated assessment models), the intra-annual resolution is simplified and electricity demand is

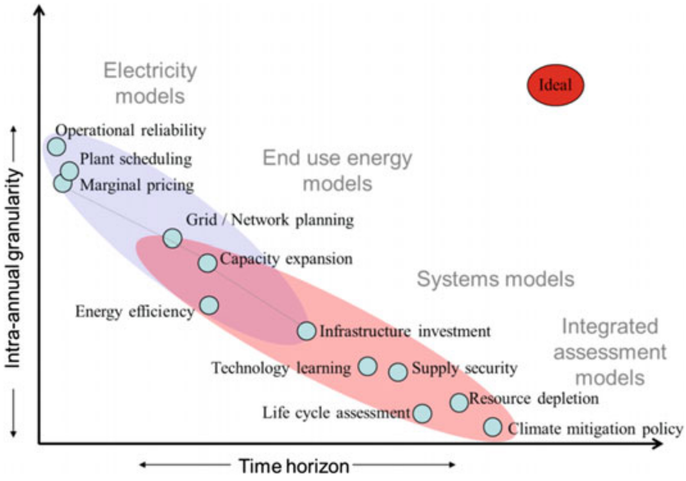


Fig. 1 Temporal representation in bottom-up energy models

often tracked by annual flows, and therefore dynamic electric peaks are not fully accounted. This intra-annual simplification is often due to the already-high level of computational complexity required in these models to represent the entire energy system and multi-year and decadal time horizons. In some energy system models like LEAP, MARKAL, TIMES, POLES and NEMS a simplified algorithm is included to represent some of the basic intra-annual features (e.g., approximate capacity demands), but they are not comparable to power sector specific models [e.g. WASP (IAEA 2001), PLEXOS (Energy Exemplar 2014)]. In comparison, sectoral energy models and electricity dispatch models often have high levels of intra-annual time resolution because they aim to represent balancing mechanisms and/or assess inter-temporal variations. However, even in sectoral (i.e., single sector) modelling approaches, intra-annual details may also need to be simplified with longer modelling time horizons because of computational and data issues (Kannan and Turton 2013).

Ideally, models of energy system development should combine a sufficiently long time horizon and an appropriate level of intra-temporal resolution for the given analysis—all in one model. In practical terms, the tradeoffs between these two temporal dimensions are driven by a range of factors, including computational resources and data availability. Importantly, these modelling tradeoffs could also affect model solutions, and thus it is important to find the right balance given the practical constraints and the specific analytical policy application. Some approaches combine two or more modelling frameworks to integrate the two temporal aspects (Chaudry et al. 2009; Johnsson 2011; Welsch et al. 2014).

2.4 MARKAL/TIMES Framework

MARKAL and TIMES have a long track record of policy and academic research. In the early application of MARKAL models, the year is divided into six timeslices using two indices: three seasonal (Winter, Summer and Intermediate) and two diurnal (Day and Night). Only electricity and heat are tracked via these six intra-annual timeslices whereas all other energy-commodities are tracked via annual flows. A "flexible timeslicing" feature was introduced in the MARKAL framework, enabling more detailed representation of variations in energy demand and supply, including operating characteristics of specific technologies. This flexible timeslicing was first implemented in the UK MARKAL model (Kannan 2011).

The TIMES framework—the successor to MARKAL—has the capacity to represent any number of intra-annual timeslices and unequal time periods, which enables a wide range of additional applications of energy system modelling. A Swiss TIMES electricity systems model (STEM-E) was developed with an hourly timeslice resolution and a century-long time horizon with unequal time periods (Kannan and Turton 2012a). The primary objective of developing STEM-E was to understand the long-term evolution of the Swiss electricity system. At the same time, it is intended to provide insights into electricity generation scheduling.

2.4.1 Swiss TIMES Electricity Model

STEM-E is a single-region model, covering the entire Swiss electricity system from resource supply to end use electricity demands. It has a time horizon of 110 years (2000–2110) in 14 unequal time periods. The time periods are specified to a length of 2 years in the short term and between five and 20 years in length in the medium and long term. The intra-annual resolution depicts four seasonal, three daily and 24 hourly timeslices. Thus the model has 288 timeslices for each year (or, technically for the milestone year in each period). Electricity demands are given exogenously and the model then selects (via the optimization process) across a range of existing and new electricity generation technologies to satisfy demands. Temporal factors affecting the generation from each of these technologies is represented across the 288 timeslices (e.g., hydro availability, solar irradiance, wind). Given the importance of electricity trade in Switzerland (including the import of cheap off-peak electricity, pumped storage, and export during other periods), electricity import and export interconnectors with neighboring markets are also modeled in STEM-E. We analysed an extensive number of electricity supply scenarios using STEM-E (Kannan and Turton 2012b). To showcase the incremental insights provided by the high intra-annual resolution, we compared the basic version of STEM-E with a second version of the model in which the 288 timeslices are aggregated[1] to a level

[1] The 288 hourly timeslices of STEM-E are aggregated into eight timeslices (two diurnal timeslices viz. Day and Night in four seasons and the representation of different days of the week is removed).

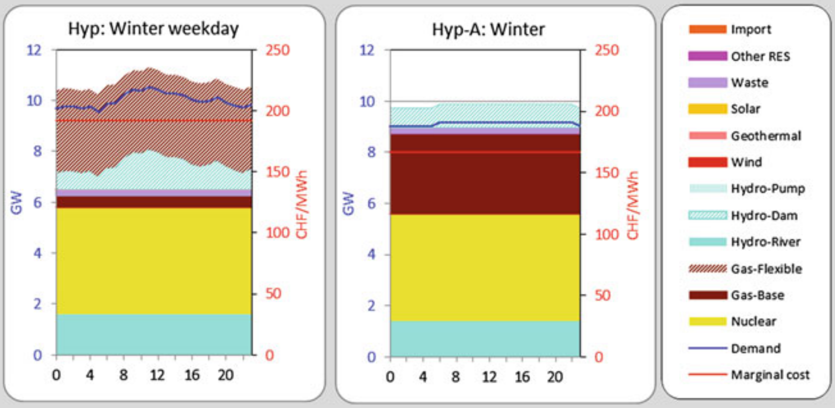
similar to most TIMES/MARKAL models (Kannan and Turton 2013). All other inputs, e.g. technology characterization, demands and cost data remain the same in both models. The objective of this aggregated model was to illustrate the differences between the solutions of the two models, and thus the potential influence of temporal factors on optimal energy technology deployment.

This comparative analysis identified the risk that models with an aggregated intra-annual time resolution may overestimate the potential contribution of large base-load power plants (Box 1), and underestimate the need for supply-demand management and storage (because the aggregation is liable to smooth peaks and troughs in supply and demand). Thus, it appears to be a significant value added by the higher intra-temporal resolution available in the TIMES framework, in providing an enhanced representation of load-balancing in the electricity system.

Box 1: Aggregated and disaggregated intra-annual time splits in STEM-E

The STEM-E model was applied to analyze the potential strengths and shortcomings of a disaggregated hourly model compared to an aggregated model. Although STEM-E is a model of the Swiss electricity sector, for this illustration we analyzed a hypothetical electricity system excluding some of the unique features in Switzerland in order to derive insights into the wider applicability of a TIMES model for dispatch modelling. We analyzed two scenarios with this hypothetical system—the *Hyp* scenario using STEM-E with the disaggregated 288 timeslices, and an otherwise identical *Hyp-A* scenario using an aggregated version of STEM-E.

The figure below shows the electricity schedule in 2048 (mid-year of period 2041–2055) on a winter day for the *Hyp* scenario (with the 288 disaggregated timeslices) compared to the aggregated *Hyp-A* scenario. The figure shows that the hourly model deploys a large capacity of flexible gas plant, whereas the aggregated model chooses a large deployment of base-load gas generation. For example, the total capacity of base-load plants in 2048 is 10.8 GW in the hourly model compared to 14 GW in the aggregated model. This occurs because the dynamic load curve in the hourly model is most cost-effectively managed with new investments in flexible (i.e. dispatchable) gas plant, whereas in the aggregated model the smaller variation in demand is more readily supplied with (cheaper) base-load gas plants and existing dam hydro plants. The flexible gas plants are scheduled only during winter weekdays and therefore have a low capacity factor. Resource cost is significantly higher in the hourly model compared to the aggregated model because of the flexible gas plant with relatively low efficiency. Electricity system cost differs ($\sim$8 % in 2048) between the two models. The higher system cost in the hourly model is also attributable to the need for additional installed capacity to manage the higher peak compared to the aggregated model. Some additional scenarios analysed with both models are discussed in Kannan and Turton (2013).



Electricity generation schedules on a winter day from both models in 2048

3 TIMES Versus Other Modelling Approaches

3.1 TIMES Versus Traditional Dispatch Models

It is evident that a higher time resolution can provide powerful insights into the generation schedule and choice of technology. However, the current TIMES framework cannot account for reliability and stochastic characteristics of the electricity system, or probable unserved energy or loads, which are typically represented in electricity dispatch models (e.g. WASP, PLEXOS). For example, in the TIMES framework, technology is assumed to be available on average throughout the year up to its availability factor. However, in real-world operation some generation capacity may be completely unavailable during planned and unplanned outages. Similarly, time required for start-up, shut-down, unit commitment, are inadequately represented.

3.2 TIMES Integrated System Approach

Although the TIMES framework does not account for some features available in typical electricity dispatch type models, its integrated system approach is complementary. For example, dispatch models represent only the electricity sector and are generally static in terms of generation stock. Thus, they are not intended for analysing dynamics and emerging energy system developments in other sectors that affect the electricity sector. TIMES's integrated system approach is suitable for analysing dynamics in other sectors that affect the electricity sector. This energy 'system' approach has numerous advantages over sectoral or dispatch type models to address a wide range of policy objectives, because demand and sectoral allocation of different energy carriers is determined endogenously (most notably for electricity), whereas sectoral models are unable to account for interactions with other sectors. For example, electric mobility may provide a decarbonisation pathway for the transport sector. However, the impact of electric vehicles on the electric network (demand) cannot be analysed with dispatch models without assumptions on exogenous demand and charging profiles. For such a complex system development, TIMES's energy system approach is powerful because it endogenizes key system characteristics such as the electricity demands and load profile/curve. To exploit these advantages, we extended the scope of STEM-E to develop a whole energy system model—the Swiss TIMES energy system model (STEM). To illustrate the TIMES integrated approach, we present two scenarios focusing on interaction between e-mobility and the electricity sector.

3.2.1 Swiss TIMES Energy System Model

The Swiss TIMES energy system model (STEM) is the full energy system—an extension to STEM-E to include all end-use energy service demands (ESDs), and calibrated to the Swiss national energy statistics (Kannan and Turton 2014). However, due to computational complexity of representing the entire energy system, the number of timeslices was aggregated to 144 (weekdays and weekends in three seasons) from the 288 timeslices in STEM-E. Figure 2 shows the temporal structure of STEM.

A selection of scenarios have been analysed using STEM and the input assumptions and results are described in Kannan and Turton (2014). In this chapter we highlight insights from two scenarios to illustrate the significance of combining the TIMES system approach with a high intra-annual time resolution. Figure 3 shows car fleet technology mix from two low-carbon scenarios, which achieve a 60 % reduction in CO_2 emissions by 2050 with and without options to invest in centralised natural gas combined cycle power plants—denoted as *LC60* and *LC60-NoCent* respectively. In the *LC60* scenario, plug-in hybrid electric vehicles (PHEVs) and full battery electric vehicles (BEVs) penetrate from 2035 and 2050 respectively. The car fleet is nearly decarbonized on a tank-to-wheel basis in 2050.

Figure 4 shows the electricity supply mix in the two scenarios. The existing nuclear power plants are gradually replaced by natural gas turbine combined cycle (GTCC) power plants (reflecting government policy precluding new investment in nuclear). By 2035, one third of the electricity supply is from GTCC plants. Renewable electricity generation contributes 22 % of the total supply by 2050, with

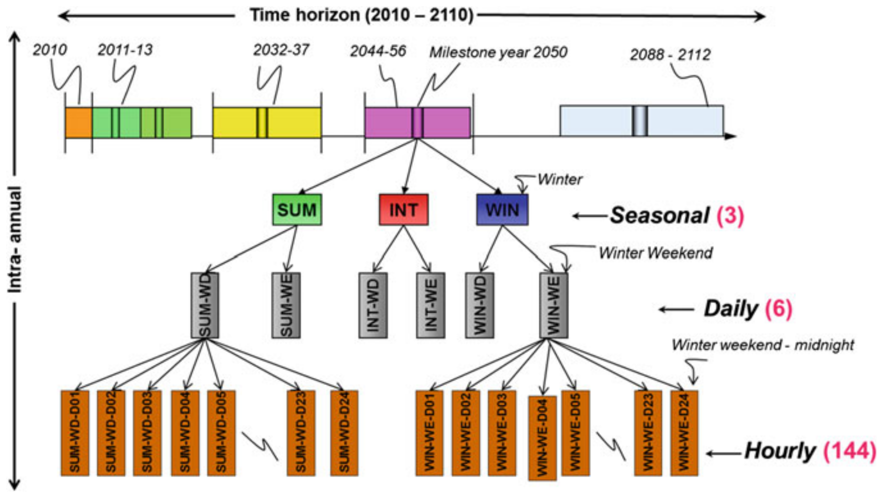


Fig. 2 Temporal depiction in STEM. *SUM* summer, *INT* intermediate, *WIN* winter, *WD* weekday, *WE* weekends

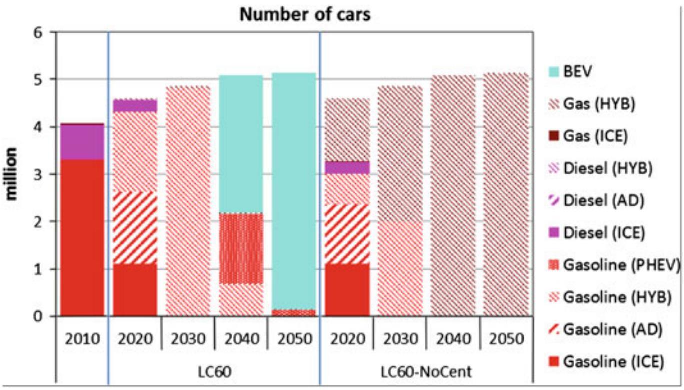


Fig. 3 Car fleet in *LC60* and *LC60-NoCent* scenarios. *BEV* Full battery electric vehicle, *HYB* hybrid vehicle, *PHEV* plug-in hybrid electric vehicles, *ICE* internal combustion engine, *AD* advanced ICE

almost all of the domestic renewable potential exploited. Despite the carbon cap in the *LC60* scenario, centralised gas power plants are deployed to facilitate increased electrification to enable decarbonisation of the car fleet (and other end-use applications, e.g. space heating through heat pumps). However, in the absences of centralized gas electricity supply (*LC60-NoCent* scenario) the car fleet switches to natural gas hybrid vehicles (Fig. 3) due to the absence of additional alternative low-

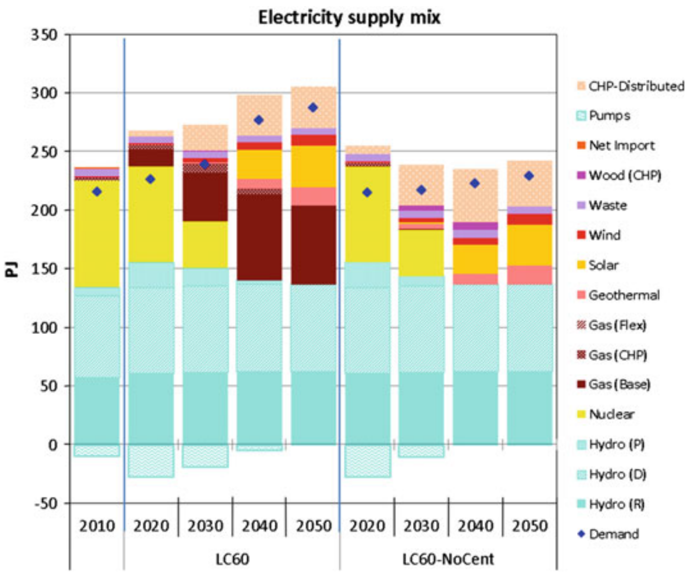


Fig. 4 Electricity supply mix in *LC60* and *LC60-NoCent* scenarios

carbon sources of electricity, i.e. renewable potentials are assumed to be finite and net imports[2] of electricity are assumed to be unavailable.

Figure 5 shows the generation schedule on a representative winter weekday in the scenarios. In the *LC60* scenario the demand peaks in the morning due to charging of BEVs (shown in purple shades in the Export plot) using cheap imported (See Footnote 2) electricity assumed in this scenario. Electricity imports are attractive during morning and the imported electricity is stored in BEVs. The centralized gas plants support the deployment of BEVs whereas without centralized gas plants (*LC60-NoCent*), natural gas is cost effective in car transport. These results illustrate some of the additional insights generated from the integrated system approach in TIMES.

As can be seen from the above illustrations from STEM, a novel feature of the integrated model with higher intra-annual time resolution is that it has the potential to provide insights into electricity demand and supply balancing mechanisms across sectors. Unlike electricity models, for which the electricity demand and profile are exogenously given, the integrated system framework, like MARKAL and TIMES, determines both the demand and its profile endogenously based on end-use technology choice, even though the demand (or user) pattern of ESDs is itself exogenously given (Kannan 2011). This feature enables the exploration of different electricity demand trajectories through demand reduction or peak shaving

[2] A self-sufficiency constraint is introduced requiring that net electricity trade is roughly in balance over the year, but the timing of electricity trade is left unconstrained.

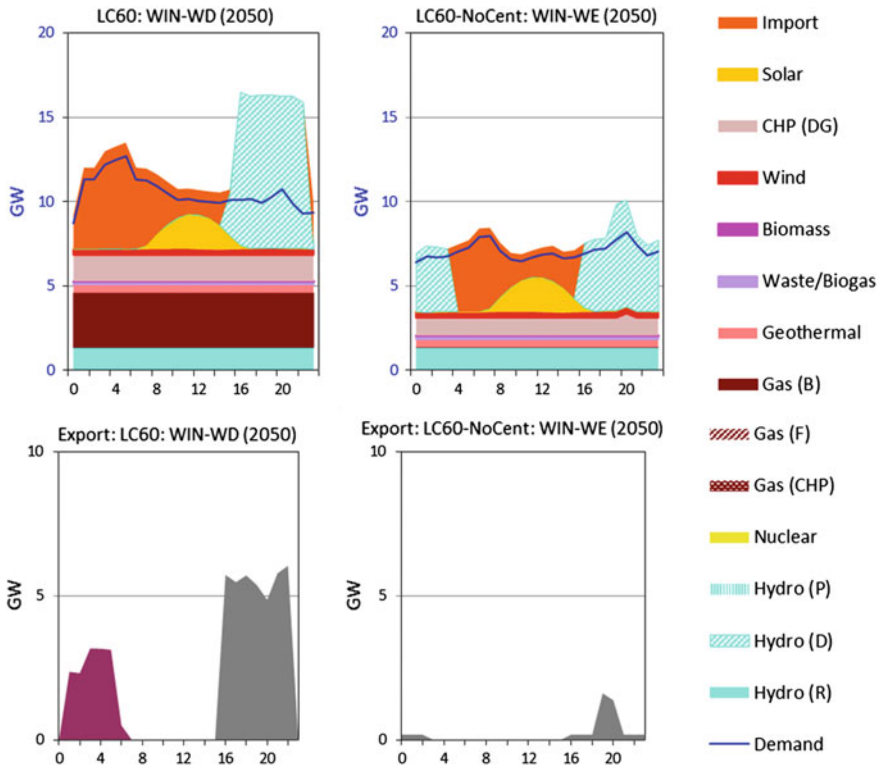


Fig. 5 Electricity generation schedule on winter weekdays

measures. To illustrate this feature, Fig. 6 shows the electricity demand profile for a set of scenarios from STEM. Depending up on technology and/or carbon constraints, the electricity demand diverges across scenarios (Kannan and Turton 2014 for more detail). Compared to a daytime peak in 2010, demands peak during early morning hours in the *LC60* and *BAU* scenarios because of charging of BEV using cheap electricity.[3] On the other hand, without centralised gas power plants (*BAU-NoCent* and *LC60-NoCent*), demand is lower because there is less electrification (neither heat pump or BEV) of end uses. This demonstrates the strength of the integrated modelling framework with flexibility to adjust electricity demands endogenously.

[3] It should be noted that the availability of cheap electricity during the early morning is an assumption applied in the analysis (based on historical electricity import prices), which may change if the demand profiles in electricity trading partners were to vary substantially (for example, as a result of charging of BEVs).

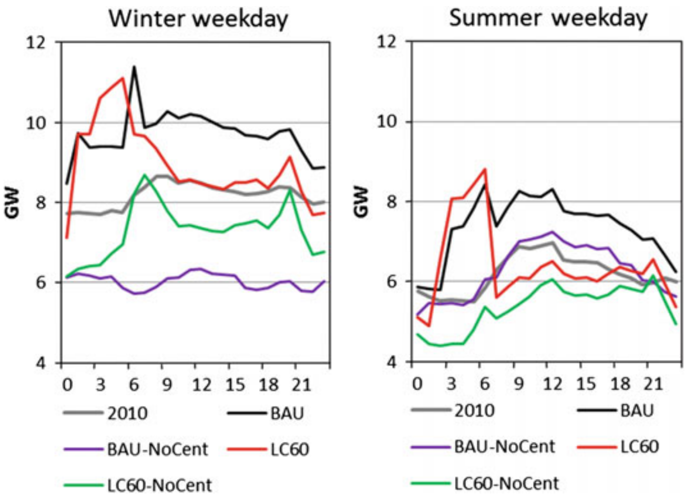


Fig. 6 Electricity demand profiles of 2050

4 Challenges and Solutions

4.1 Data Requirements

Clearly, the high intra-annual resolution in STEM is demanding in terms of data requirements—e.g. performance of demand technologies, load profile of ESDs, resource availability, etc. at the same resolution as that of the intra-annual timeslices. Such data are not commonly available in many countries, meaning that a large number of assumptions and approximations may be needed, which risks undermining the reliability of the detailed intertemporal model. Therefore, the availability of input data is one of the key determinants in choosing an appropriate intra-annual resolution. If the data availability is poor or subject to high uncertainty, an aggregated model could be a more suitable choice. Again, the choice of timeslices also depends on the energy system in question, and the policy and research applications of interest. For some applications, an aggregated model can still provide some robust insights (Kannan and Turton 2013).

4.2 Computational Complexity

The large number of timeslices considerably increases computational resource requirements. Therefore, introducing a high time resolution in a model with an already large number of equations and variables requires careful choice of timeslices and use of an appropriate solver; and involves trade-offs in terms of

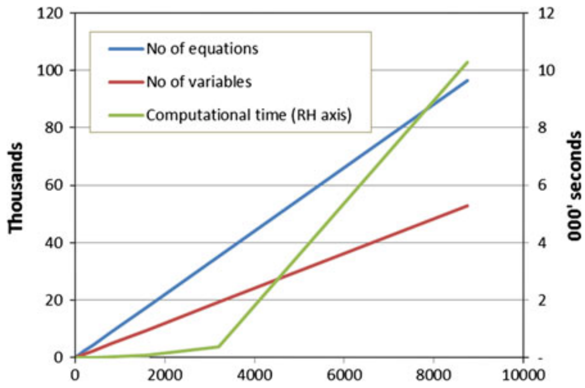


Fig. 7 Timeslice versus matrix size and computational time in TIMES framework

representing other features such as lumpy investment or endogenous technology learning. Figure 7 shows some simple correlations between the number of timeslices and the number of variables and equations in a TIMES framework. It is based on a highly simplified reference energy system with one typical process and two commodities fully characterised for one period; variables and equations relevant for storage, inter-regional exchange, user constraints and vintage are not generated and have been excluded. The model matrix size grows approximately linearly with number of timeslices, but computational time[4] is increasing nearly exponential.

The computational complexity is not only limited to the solution time, but memory and numerical problems may also arise. To reduce computational time in linear programming (LP) formulations, interior point algorithms such as CPLEX/Barrier can be used (Wright 2004; Dantzig and Thapa 2003) at the expense of memory.[5]

4.3 Alternative Approaches

To address the computational and data availability issues, a number of alternatives are possible to approximate some elements of a more detailed load curve in a conventional energy system model to improve electricity sector depiction. Most of

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[4] The computational time includes both model generation and solution time using CPLEX solver in 8-cores Intel processor with 24 GB RAM.

[5] For example, some specific CPLEX/Barrier options for improving the performance of the algorithm includes *BarColz*, *BarEpComp*, *BarOrder*, *BarStartAlg*, etc. However, the use of CPLEX/Barrier requires large memory, which can be addressed with solver options like *MemoryEmphasis*, *Names*, *WorkMem* to conserve memory (GAMS 2014). Numerical difficulties can occur during the optimisation if large LP problems are ill-defined due to large differences in the magnitude of coefficients in an equation. In such a case, the solver reports the problem as unscaled infeasibility. This can be diagnosed by *GAMSCHK* option described in Bruce (2013) and accordingly input data has to be adjusted to avoid large numerical differences in coefficients.

these involve diverging from conventional approaches of defining timeslices based on usual seasonal classification or electricity tariff-based definitions of day and night. Instead, timeslicing should be based on real data on intertemporal variations in the electricity demand (load) curve; availability of energy resource supply options; and the research question to be answered. There is no rule of thumb in timeslicing, but the following are some guidelines (also see Kannan and Turton 2013 for an extended discussion).

- If a specific domestic resource is seen as the key electricity supply option (e.g. hydro, solar, wind), or if there is a strong policy interest on a specific technology or resource, then the choice of timeslices could be based on characteristics of the technology/resource in question so that their operational characteristic can be realistically modelled.
- When the number of intra-annual timeslice is small, this leads to an averaging of capacity demands and thus underestimates the real demand peak. This can be partly addressed by defining the timeslices in a way that ensures a better representation of the peak, such as with:
  - An uneven seasonal time split to capture some of the seasonal variations in demand and/or resource supply.
  - A non-uniform diurnal time split. For example, a time split that defines 'day' according to the peaking hours in each season could be chosen, or according to daylight hours if solar PV has a significant potential.
- An alternative to ensure the impact of large variations in demand is represented in the choice of base-load and dispatchable generation technology, is to introduce a share constraint for base-load and dispatchable technologies. This could be determined from the highest and lowest electricity demand hours in each season. However, any such constraint could have negative implications for future years.
- Similarly, a non-conventional electricity reserve margin (Kannan 2011) could be applied based on the differences between the average capacity demand and hourly peak demand. This reserve margin would need to be larger than prevailing rule-of-thumb values used by electric utilities to cover the instantaneous peak and spinning reserves. However, while this approach may ensure a more appropriate representation of total capacity requirements, it does not represent generation and dispatch at the peak.
- In some countries, weekly (weekdays vs. weekends) demand variations are more significant than seasonal variation (e.g., in tropical countries) which imply additional limitations on the operation of large base-load plants (operational control in case of nuclear plants and part load efficiency penalty for fossil fuel plants). In such cases, a time split can be applied at the weekly level.
- Insofar as an hourly TIMES model can represent some features of electricity dispatch model, it cannot fully replace an electricity dispatch model. Therefore approaches have been explored to soft-link integrated energy system model with

aggregated timeslices and detail electricity model to generate issues specific to the electricity system such as reliability and stochastic characteristic of technologies (Chaudry et al. 2009; Deane et al. 2014; Welsch et al. 2014).

5 Conclusions

We used the TIMES framework to develop models of the Swiss electricity and energy systems combining detailed technology pathways, an hourly load curve and a long model horizon. The long time horizon facilitates the analysis of long-term goals and challenges, and accounts for the long lifetimes of energy-related capital infrastructure. The high level of intra annual detail in this model provides richer insights into the operational schedule of power plants. Despite the computational and data intensity of this model, the higher time resolution leads to solutions that appear to be more realistic from a technical and 'real-world' standpoint compared to an equivalent aggregated intra-annual model. Therefore, there are considerable benefits in investing in data collection and exploiting developments in computational and solver power. Nonetheless, there is no one-size-fits-all approach for intra-annual timeslicing. The ideal number of timeslices to represent in a model depends on energy system characteristics, the research question to be answered and, most importantly, the availability of data at the timeslice level. TIMES models can represent some of the features of electricity dispatch, but cannot fully replace such models, and instead can be viewed as providing complementary insights and inputs. However, the TIMES framework's integrated system approach and flexible temporal depictions are equally important for the application of this framework in supporting policy and other decision makers; and exploring different strategies for the long-term development of the energy and electricity systems.

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Improved Representation of the European Power Grid in Long Term Energy System Models: Case Study of JRC-EU-TIMES

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Abstract This chapter describes a methodology to integrate DC power flow modeling and N − 1 security into JRC-EU-TIMES, a multiregional TIMES energy system model. It improves the accuracy of modeling cross-border transmission expansion especially for energy systems with higher penetration of renewable energy sources (RES). We describe three grid representations with increasing accuracy of modeling power flow constraints: (1) basic trade flow without DC power flow, (2) DC power flow with fixed line characteristics and (3) DC power flow with a discretization algorithm, endogenous grid characteristics and N − 1 contingency analysis. The last approach uses the newly developed Integrated

The views expressed are purely those of the authors and may not in any circumstances be regarded as stating an official position of the European Commission.

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_12

TIMES–NEPLAN Software (ITNS) that couples JRC-EU-TIMES energy system modeling with NEPLAN-based electricity grid modeling. To evaluate the improvement of the JRC-EU-TIMES modeling mechanisms, the three grid representations are compared. We conclude that cross border transmission expansion is cost efficient regardless of the grid representation. The impact of power flow constraints is limited for the analyzed case study under the assumption of perfect markets. However, integrating these constraints is leading to slightly higher cross-border capacities for most countries mainly in periods with limited availability of variable renewable electricity. This occurs when grid extensions and peaking power in some strategic countries are more competitive than local peaking power for each country. This is possible without a substantial increase in model running time.

1 Introduction

The combined generation and transmission expansion planning (CGTEP), also called composite or coordinated, or integrated resource planning, is a very complex non-linear and non-convex optimization problem (El-Debeiky and Hasanien 2000; Alvarez Lopez et al. 2007; Roh et al. 2007; Tor et al. 2008; Sepasian et al. 2009; Bent et al. 2011; Hemmati et al. 2013b). The large integration of renewable energy sources (RES) into modern power systems has made the CGTEP problem even more challenging, because the greatly increased uncertainties introduced often require new transmission lines in order to maintain a satisfactory level of power system security and adequacy (Contaxi et al. 2012; Orfanos et al. 2013). CGTEP is typically split into generation expansion planning (GEP) (Kabouris and Contaxis 1991; Zhu and Chow 1997; International Atomic Energy Agency 2001; Chuang et al. 2001) and transmission expansion planning (TEP) (Romero et al. 2002; Georgilakis 2010; Hemmati et al. 2013a) to improve computational tractability. Comprehensive reviews on CGTEP, GEP, and TEP can be found in Zhu and Chow (1997), Hemmati et al. (2013a, b), respectively. However, in planning for RES, the complete decoupling of the two problems is not necessarily the best approach. The potential to generate energy is highly dependent on where the generators are built and the distances to connect RES to existing systems bring the relative costs of transmission and generation closer in scale.

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Examples of a coupling between energy model and electrical network model can be found in UKERC (2009), REALISEGRID (2010), Sakellaridis et al. (2011), Deane et al. (2012), Hamasaki (2014). More specifically, the MARKAL-MED energy model is combined with the WASP GEP (International Atomic Energy Agency 2001) model and a combined gas and electricity network model in UKERC (2009) in order to assess how the UK system can move to a secure and low-carbon energy system over the period to 2050. The combined use of MARKAL, WASP and Cost (Stochastic modeling tool) for the analysis of the electricity system under high RES penetration is presented in Sakellaridis et al. (2011). The use of TIMES and Stochastic Analysis for the analysis of the electricity system under high RES penetration is also presented in Sakellaridis et al. (2011). TIMES is used to model the energy system and a tool is developed for planning cross-border transmission capacity expansion in REALISEGRID (2010). Geographical information system (GIS) gathered renewable energy potential data are coupled with a multiregional TIMES energy system model to study the effect of feed-in tariff (FIT) in the development of wind turbines for the Japanese electricity system (Hamasaki 2014). A soft-linking methodology that employs detailed simulation outputs from a dedicated power systems model to gain insights and understanding of the generation electricity plant portfolio results for the electricity sector from a separate energy systems model is presented in Deane et al. (2012).

The previous analysis has shown that there is an open challenge to establish a link between an energy system model and an electricity network model. This challenge is even bigger, if the objective is to create a link between a well-established energy model and a widely used network analysis model. The work presented in this chapter is designed so as to fill the above mentioned gap, because the objective is to provide interfaces for the integration of TIMES-based energy system modeling with NEPLAN electricity grid modeling.

The TIMES energy system model is a long-term energy planning model that finds the least-cost solution of the evolution of a specific energy system in terms of time resolution and of a Reference Energy System simulating the real energy system (Loulou et al. 2005). TIMES is a bottom-up, partial equilibrium energy model based on maximizing total societal surplus. Main inputs in TIMES are the evolution of the economy resulting in scenarios of useful energy demand, a forecast of international fuel prices and technology roadmaps including specific costs and efficiencies for a time period of several decades.

The TIMES model does not consider in detail the analysis of the electrical power system. It includes a rather elementary approach for dispatching generation, use of transmission and integration of non-dispatchable renewable generation. As a result, the optimal technology mix computed by TIMES may not be optimal when considering the geographically specific transmission grid investments resulting from that technology mix. In addition, renewable investments economic analysis should normally include costs related to transmission grid expansions necessary for penetration in geographical areas with a high potential of renewables, and costs related to balancing measures required due to variations of renewable generation, such as pumped storage plants, gas turbines.

NEPLAN is a well-established software tool to analyze, plan, optimize and simulate electrical, water, gas and district heating networks (BCP Busarello+Cott +Partner Inc. 2014). The NEPLAN Programming Library (NPL) allows to access NEPLAN data and calculation algorithms through a C/C++ written program (BCP Busarello+Cott+Partner Inc. 2014). NPL allows developing user defined algorithms.

This chapter proposes a methodology for the integration of DC power flow modeling into a multiregional TIMES energy model. More specifically, the chapter proposes an Integrated TIMES–NEPLAN Software (ITNS) that provides interfaces for the integration of TIMES-based energy system modeling with NEPLAN-based electricity grid modeling. Among others, the ITNS allows more accurate estimation of maximum permissible penetration of RES in a system.

The ITNS incorporates economical and technical parameters of transmission grid expansion planning to the solution of TIMES and modifies its solution in order to include transmission line investment costs. These parameters are either incorporated in the TIMES solver directly or are incorporated through available loading coefficients of the transmission lines. In this sense, constraints and costs imposed by transmission system operators when determining an expansion plan of the transmission grid are taken into account and affect the generation expansion planning proposed by TIMES. Thus, the solution calculated through ITNS is more realistic than the basic TIMES solution as it incorporates costs of transmission investments, which cannot be evaluated otherwise, since network reinforcements depend on the generation expansion plan. Reversely, cost of these reinforcements should be weighed against a more expensive dispatching that demands fewer investments in transmission network. This interaction may be modeled only with an integrated approach.

The ITNS software incorporates the $N - 1$ security criterion[1] to the expansion planning determined by TIMES. Although the optimality of the solution is not guaranteed, the solution exported by ITNS can be considered at least near-optimal, thanks to an iterative optimization algorithm, which is the core innovation of ITNS. Major constraints are incorporated in the objective function, while other constraints can be accounted for by a fine tuning and do not affect significantly the TIMES solution. The ITNS and its optimization algorithm have been fully adopted by EU-JRC within the JRC-EU-TIMES model. Application results of JRC-EU-TIMES indicate the value and the usefulness of the proposed approach.

To evaluate the improvement of the JRC-EU-TIMES modeling mechanisms, three grid representations are compared in scenarios with free and fixed transmission expansion.

[1] The $N - 1$ criterion for system operation requires that the system is able to tolerate the outage of any one component (line, generator, transformer) without disruption of the operation of the electrical system.

2 Methodology

2.1 General Description of the JRC-EU-TIMES Model

The JRC-EU-TIMES model represents the EU28 energy system plus Switzerland, Iceland and Norway (hereafter EU28+) from 2005 to 2050, where each country is modeled as a single region. Each year is divided into twelve (12) time-slices that represent an average of day, night and peak demand for every one of the four seasons of the year.

The materials and energy demand projections used in JRC-EU-TIMES for each country are differentiated by economic sector and end-use energy service, using as a starting point historical data of 2005 and macroeconomic projections from the GEM-E3 model and in line with the values considered in the EU Energy Roadmap 2050 reference scenario. From 2005 till 2050 the exogenous useful energy services demand grows by 32 % in agriculture, 56 % in commercial buildings, 28 % in other industry, 24 % in passenger mobility and almost doubles (97 %) in freight mobility. On the other hand, the exogenous useful energy services demand for residential buildings is 12 % lower in 2050 than in 2005 due to the assumptions on energy efficiency improvements in buildings.

Energy consumption data from Eurostat is used to derive country and sector-specific energy balances, which determine the characterization of energy technology profiles for supply and demand technologies in the base year. Beyond the base year, new energy supply and demand technologies are compiled in an extensive database with detailed technical and economic characteristics. The model considers power plants in operation and under construction as well as plants to be decommissioned and built, allocating a specific vintage to each electricity generation technology. Cumulative CO_2 storage capacity is derived from the GEOCAPACITY research project,[2] and does not include national policy decisions restricting storage possibilities, such as only storing in offshore sites, or no storage. We consider country-specific wind and solar annual availability profiles for an average year for the 12 modeled time-slices.

Regarding electricity grids, in its basic configuration, JRC-EU-TIMES considers both import/export processes regarding the existing infrastructures (capacity and flows) and possible new investments both within EU28+ and with the rest of the world. In the basic JRC-EU-TIMES configuration there are three levels of electricity voltage and conversion between levels, while no DC power flow is considered. Transmission grids have an associated cost of in euros/kW based on the electricity transport tariff for 2011 for each country from Eurostat.

In this section as well as in Sect. 2.2 certain procedures of the methodology will be presented. The overall methodology will be presented in Sect. 2.3.

2 http://www.geology.cz/geocapacity.

2.2 *Incorporating DC Power Flow Equations and Power Flow Scenarios Formulation*

2.2.1 DC Power Flow Equations into TIMES and Regional Interconnection Costs

A special version of the TIMES model generator developed by CRES, VTT, NTUA and JRC incorporates Power Flow Analysis into the calculations of TIMES. This version is applicable to all TIMES models and was also implemented in JRC-EU-TIMES. In particular, a linear (DC) power flow algorithm, which is a linearized approach of the Power Flow problem and calculates power flows of a rather aggregated transmission grid of the studied system, was incorporated into TIMES. The grid used for the power flow analysis is not necessarily identical to the region split used in a multiregional TIMES model. For example, Fig. 1 presents a simplified network where R1–R4 represent the regions in which the energy system is split in the TIMES model. As it can be seen, each region of TIMES may include several network nodes.

Trade (transactions between regions) and internal flows within a region should comply with the restrictions imposed by network capacity. The equations to calculate the power flow in each power line of the network are Eqs. 1 and 2 (Seifi and Sepasian 2011).

For every bus (node) i:

$$P_{G,i} - P_{L,i} = P_{T,i} \quad i = 1, \ldots, N \tag{1}$$

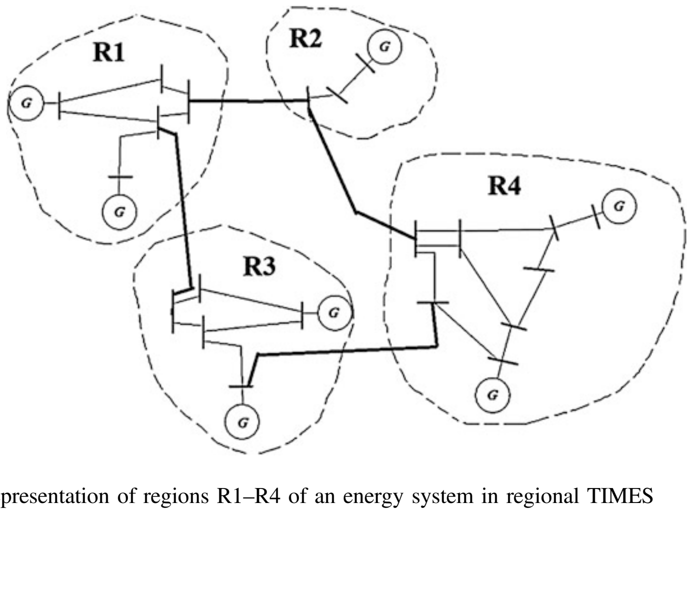

Fig. 1 Representation of regions R1–R4 of an energy system in regional TIMES

and

$$P_{T,i} = \sum_{j=1}^{M} P_{flow,ij} = \sum_{j=1}^{M} B_{ij} \cdot \left(\delta_i - \delta_j\right) \quad i = 1, \ldots, N \tag{2}$$

where

N	the total number of nodes
M	the number of branches that are connected with node i,
$P_{G,i}$	active power injected into node i by generators
$P_{L,i}$	active power withdrawn in node i by loads
$P_{T,i}$	total active power injected into node i
P_{flowij}	branch active power flow between nodes i and j
B_{ij}	susceptance of the branch connecting nodes i and j
δ_i	voltage phase angle of node i with respect to a reference angle

Rewriting the nodal active power balance equations, in matrix notation:

$$[B_r] \cdot [\delta] = [P_T] \tag{3}$$

where

B_r is the reduced admittance matrix by the line and column corresponding to the slack bus—(N − 1) × (N − 1),

δ is the nodal voltage angle vector (except for slack bus)—1 × (N − 1)

In addition, the branch power flow equation is

$$\left[\tilde{B}\right] \cdot [\delta] = [P_{flow}] \tag{4}$$

where

P_{flow} is the matrix of power flows in every power line,

$\tilde{B}$ being the flow admittance matrix—M × N

$$[P_{flow}] = \left[\tilde{B}\right] \cdot [B_r]^{-1}[P_T] \tag{5}$$

where

P_{flow} is the power flow in every power line,

P_T is the power injection in every bus except for the slack bus—(N − 1) × 1.

Regional interconnection costs are given as exogenous input by the user, in terms of cost per unit of power transmission capacity (euros/MW). It should be noted that investments calculated by TIMES are indicative as they do not correspond to actual line types, as it will be explained in detail in the next sections.

2.2.2 Allocation of Additional Capacity, Generation and Demand

The solution of TIMES results in the total quantity (in terms of energy) of generation and demand of electricity for each type of generation technology (CCNG, wind, PV, etc.) or demand category (industry, households, etc.) for each time slice modelled. In addition TIMES results define the capacity of electricity production plants in every region for every generation technology. Based on these information, power flow scenarios are formed for each time slice.

First of all energy quantities (generation and demand) are translated into power, based on the duration of each time slice. The following step is the allocation of these quantities to the grid nodes. As it is referred in Sect. 2.2.1 multiple nodes may be included in a single region. Thus, the aggregated quantities (generation, demand and capacity of power plants) should be allocated to the existing nodes for every region. The allocation of generation and demand can be performed based on a set of criteria:

- The first is to use a predefined distribution scheme based on statistical data, for the nodes of each region. For example, if the solution of TIMES show industrial load to increase in a region, there should be a predefined distribution of industrial load among the region's nodes. Therefore, certain nodes near industrial areas will undertake the additional loads, while others in urban or mountainous areas will not. This approach is used in order to allocate electricity demand.
  The same criterion is also used in allocating the capacity of distributed generation plants. This procedure is also based on statistical data derived from suitable sites for expansion of distributed plants ensuring that development of new distributed power plants (e.g. wind, solar or CHP) will take place in sites with high RES or CHP potential.
- The second criterion is applied for (non-distributed) generation expansion allocation and is to mark predetermined sites for new plants. This applies mostly to conventional plants, for which sites for a new power plant of a certain type (e.g. coal, nuclear) inside a region can easily be determined in advance.

2.2.3 Synchronous and Asynchronous Connections

Before analyzing synchronous and asynchronous connections, it is necessary to define the notion of a corridor. In a transmission network, multiple circuits may link the same network nodes. In the current analysis, every group of such circuits is merged and substituted by one equivalent line, which is called "a corridor". In case that the circuits of a corridor operate at different voltage levels, transformers at both ends of the circuit together with the circuit are substituted with an equivalent admittance.

Depending on the type, a connection may be synchronous (AC connections) or asynchronous (DC connections). Asynchronous connections are capable of controlling power flow due to the converter stations that exist at both ends of the line. DC connections are usually used in interconnections between countries or isolated areas. Since power flow is controlled, the flows in asynchronous connections are considered in TIMES as normal trade processes. In the power flow problem, asynchronous lines are omitted from the network and substituted with a positive power injection in one end and an equal negative power injection in the other end of the line.

Power injection at synchronous connections is not controlled. Power flow in these lines is calculated through DC power flow equations, based on the network admittance matrix. However, in the realization of the algorithm a third category of lines arises, which are radial connections. Radial connection is a connection between two nodes, that if it is opened, one node becomes isolated from the rest of the power grid. In such connections, the flow depends only on positive or negative injections of power from generation and load demand. Thus, the excess of production or load of a radially connected node equals the power flow in the connection line. These circuits are considered as DC connections (predefined power flow).

In Fig. 2, a simplified network of Western Europe is shown as an example of the method that has been used with the JRC-EU-TIMES model. United Kingdom (UK) and Ireland (IR) are connected through DC lines, while Spain (ES) and Portugal (PT) are radially connected through AC lines.

The corridor PT-ES is radial and therefore flow in this corridor is determined by the excess or the shortage of power generation comparing to the demand in nodes of PT and ES. Asynchronous and radial connections have been modeled with the traditional trade approach and synchronous with the flow based methodology developed.

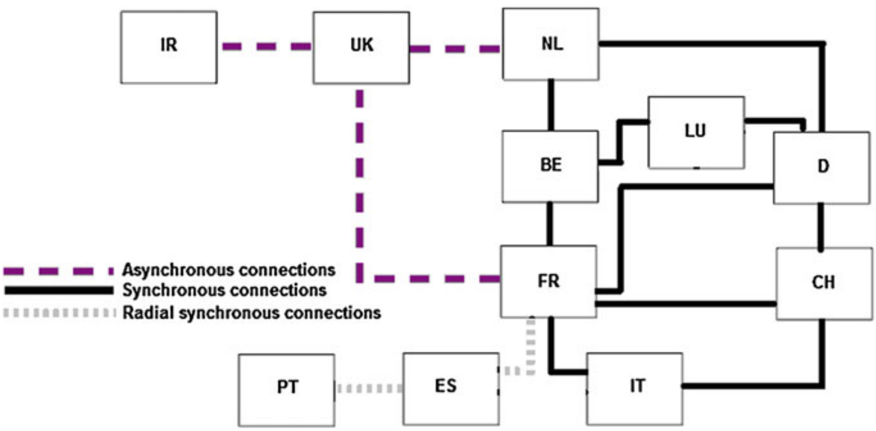

Fig. 2 Simplified network

2.3 Incorporating N − 1 Security Constraints Integrating TIMES with NEPLAN

Incorporating N − 1 security constraints in TIMES directly is not possible as this would make the problem non-linear. Therefore, N − 1 security analysis is performed indirectly using a usability coefficient (ε) which determines the acceptable loading of a corridor. The basic concept is that through this coefficient it is possible to limit the loading of a corridor in N (normal) state—which is modeled in TIMES through DC power flow—so as to avoid overloading in N − 1 (emergency) conditions. In particular, incorporation of the N − 1 security constraint is being performed using an iterative method through which the value of the usability coefficient (ε) is determined. This coefficient expresses the percentage of acceptable loading for a certain corridor in N state in order to fulfill N − 1 criterion. This acceptable loading depends on the characteristics of the corridor, as well as on the surrounding network. The initial value of the usability coefficient is determined by Eq. 6:

$$\varepsilon_{ij} = \begin{cases} \dfrac{\min\left\{\sum_{n_{ij}-1} \mathrm{P}_{\mathrm{k}}^{\max}\right\}}{\sum_{n_{ij}} \mathrm{P}_{\mathrm{k}}^{\max}}, & \text{if} \quad n_{ij} > 1 \\ 0.9, & \text{if} \quad n_{ij} = 1 \end{cases} \tag{6}$$

where $\mathrm{P}_{\mathrm{k}}^{\max}$ is the transfer capacity of circuit k of corridor *ij* and n_{ij} is the number of circuits constituting corridor ij.

Equation 6 expresses the acceptable loading of a corridor so that after a trip of the circuit with the maximum transfer capacity, the corridor will not be overloaded. In other words, by applying this criterion we assure that if power flows do not change after a circuit trip, the loading of corridor ij will be within predefined limits. As it is well known, a modification of a network, such as a circuit trip, modifies all power flows in the network. Yet, this is an approximate way of determining the initial value of the usability coefficient ε. For corridors that consist of only one circuit, the initial value of usability coefficient ε is taken equal to 0.9.

2.3.1 N − 1 Contingency Analysis

The N − 1 contingency analysis is performed through an iterative procedure that uses NEPLAN and eventually calculates usability coefficients (ε). As it is described in Sect. 2.2 for every time slice a corresponding power flow scenario is formulated and used as an input in NEPLAN with a more detailed network model, which includes individual circuits. This procedure uses network data imported into NEPLAN, along with power flow data calculated through the procedures described in Sect. 2.2.2 and performs N − 1 security check using NEPLAN functions.

The overloading of a circuit computed through NEPLAN has to be translated into a restriction for the loading of the corresponding corridor, in order to be used by TIMES (usability coefficient). Through this procedure a correction factor of the initial value of usability coefficient is calculated.

Suppose that for the m contingency (i.e., the contingency of circuit m), circuit k gets overloaded. The overload indicator L_{km} is then computed as follows (Eq. 7):

$$L_{km} = \begin{cases} \frac{P_{km}}{P_k^{\max}}, & \text{if} \quad P_{km} \geq P_k^{\max} \\ 0, & \text{if} \quad P_{km} < P_{km}^{\max} \end{cases} \tag{7}$$

where

L_{km} overloading indicator of circuit k under the contingency of circuit m
P_{km} loading of circuit k under the contingency of circuit m
P_k^{max} upper limit of loading (capacity) of circuit k

For each overloaded circuit and for each contingency, we compute the indicators I_m and J_k as follows (Eqs. 8 and 9):

$$I_m = \sum_{k=1}^{n_{lines}} L_{km} \tag{8}$$

$$J_k = \sum_{m=1}^{n_{cont}} L_{km} \tag{9}$$

where

n_{lines}, n_{cont} total number of circuits and total number of contingencies, respectively.

In practice, indicator I_m is the total overloading that appears in all circuits under contingency m. Similarly, indicator J_k is the total overloading of circuit k under all contingencies.

The overloading of circuit j is computed by selecting the maximum value of J and the value of the maximum J as follows (Eq. 10):

$$J_j = \max_k \{J_k\} \tag{10}$$

We compute the contingency i with the maximum I and the value of the maximum I as follows (Eq. 11):

$$I_i = \max_m \{I_m\} \tag{11}$$

Using these two parameters, we calculate the value of the correction factor K_c for each corridor. The correction factor K_c for each corridor indicates the required reduction of the value of usability coefficient ε according to the N − 1 security analysis results. In other words, the correction factor K_c reduces the acceptable loading of a corridor in case it is overloaded when a contingency occurs.

There are two cases of correction requirements:

Case 1: $J_j \geq I_i$, which means that circuit j (belonging to corridor c) has to be reinforced. In this case, the value of K_c for the corridor c is computed as follows (Eq. 12):

$$\mathrm{K_c} = \frac{1}{\mathrm{L_{ji}}} = \frac{1}{\max\limits_{\mathrm{m}} \{\mathrm{L_{jm}}\}} \tag{12}$$

$$L_{ji} = \max_{m}\{L_{jm}\} = \max\{L_{j1}, L_{j2}, \ldots, L_{ji}, \ldots, L_{jn_{cont}}\} \tag{13}$$

where L_{ji} denotes the overloading of circuit j during the contingency i.

Case 2: $J_j < I_i$, which means that in this case we have to avoid contingency i, i.e., we have to reinforce the corridor c in which the circuit i belongs, the outage of which results in the contingency i. In this case, in order to force TIMES to add a new circuit in the corridor c, the value of K for corridor c is defined as (Eq. 14):

$$\mathrm{K_c} = 0.5 \tag{14}$$

The new value of the usability coefficient is calculated through Eq. 15:

$$\varepsilon_{ij}^{new} = K_{ij}\varepsilon_{ij}^{old} \tag{15}$$

2.3.2 Discretization of Line Investments

Corridor reinforcements indicated by the TIMES model solution is a continuous variable (since TIMES gives a linear programming solution). A mixed integer programming solution with discrete investments can be calculated, however this will considerably increase the computational time. Since investment costs depend on the types of circuits constructed or upgraded, there is a need for a discretization algorithm, which rationalizes the reinforcements and associated investments indicated by the TIMES solution.

As mentioned in Sect. 2.2.3, every corridor consists of several circuits of different capacities. In the methodology used it is assumed that each corridor may be reinforced by a predefined type of circuit, based on certain criteria (e.g. topological features of transmission grid). In other words, the characteristics of each corridor indicate acceptable reinforcements and investments. If the additional capacity requirement calculated from the TIMES solution exceeds a predefined percentage of the capacity of the predefined reinforcement, the investment is approved by the algorithm. Otherwise the investment is not approved, and the network is not reinforced.

2.4 *Iterative Process Coupling JRC-EU-TIMES with Neplan (ITNS)*

The individual procedures analysed in Sects. 2.2 and 2.3 are assembled in a process that constitutes ITNS, the overall methodology of coupling between JRC-EU-TIMES and NEPLAN and is analysed in the current section. This coupling is performed through an iterative process, which allows both models to approach a minimum cost solution, taking into account the transmission expansion costs. A simplified flow chart of the algorithm is shown in Fig. 3 and the steps that should be followed are:

First step: This step includes three elements. First of all it includes an external procedure that imports the initial values of all parameters and variables into the JRC-EU-TIMES model (e.g. circuit admittance, cost, network parameters). The second element is the execution of JRC-EU-TIMES and the third is an external function that extracts the results of JRC-EU-TIMES into ASCII files. The extracted results are the generation and demand of electricity for every region, the generation and load type as well as the generation capacity expansion.

Second step: This is performed in an external function that formulates power flow scenarios. Demand, generation and generation expansion are allocated at the nodes of each region of JRC-EU-TIMES for every time slice. Thus, for every year, a load flow scenario is formulated, for each time slice (instances of grid operation). In addition, new circuit investments are calculated in JRC-EU-TIMES and then they are discretized according to method presented in Sect. 2.3.2.

Third step: This step is similar to the first step. Updated data from the second step are imported into JRC-EU-TIMES through an external procedure. These data are the adjusted allocation factors for generation and demand and the line investments calculated through the discretization process presented in Sect. 2.3.2. These grid reinforcements are imported as fixed line investments.

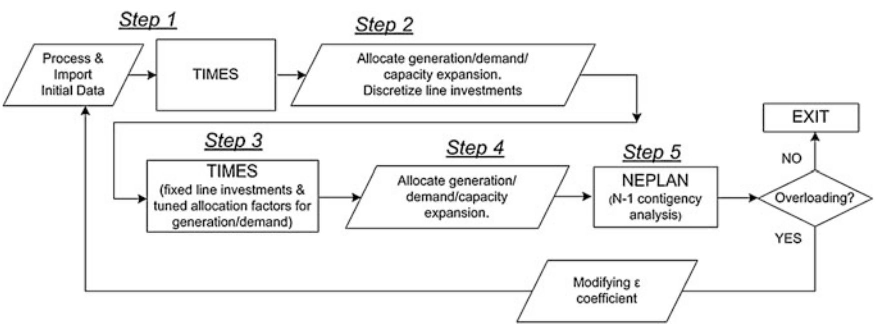

Fig. 3 Flow chart of the coupling between JRC-EU-TIMES and NEPLAN software (ITNS)

JRC-EU-TIMES is re-executed with the updated values calculated in the second step and the new results are extracted in ASCII files.

Fourth step: This step is similar to the second step. It is an external procedure that uses the JRC-EU-TIMES results produced in step three and reallocates demand, generation and generation expansion to the nodes of every region of TIMES for every time slice and for every year studied.

Fifth step: This step consists of three procedures. The first procedure imports data into the NEPLAN software (circuit investments which is the discretization output, injections of generation and demand). The second procedure is the N − 1 security analysis, which is performed using NEPLAN, and the calculation of the overloading of circuits under all contingencies. The third procedure is the calculation of the correction factor of usability coefficients (K_c) through an external procedure (see Sect. 2.3.1).

Sixth step: This is an external procedure that is a logic check for the termination of the iteration. If the solution of NEPLAN does not indicate overloading calculated through the N − 1 contingency analysis, the iterations are terminated. In the opposite case, the iteration starts again from step 1. The execution of JRC-EU-TIMES is performed with new epsilon coefficients calculated by multiplication of the initial ε with the K_c coefficients using Eq. 15.

In Fig. 3, the flow chart of the overall methodology is presented. Every iteration presupposes that NEPLAN detects overloading of circuits under N − 1 conditions. Usability coefficients are then reduced (through K coefficient). Thus, in every iteration the JRC-EU-TIMES solution reduces the loading of corridors. This may be accomplished by modifying the dispatch of electricity (allocation of generation to the different nodes), or by reinforcing the electricity network. The reduction of circuit/corridor loading after each iteration, leads to the convergence of the algorithm.

2.5 Power flow representation in JRC-EU-TIMES

The simplified grid of the European electricity system for the base year of study is presented in Fig. 4. The asynchronous and radial connections are simulated like a trade process in TIMES. The synchronous connections are modeled using the DC Load Flow algorithm in TIMES. The synchronous grid is represented with 13 nodes and 23 synchronous connections. Each node represents a country of the former UCTE 1st synchronous zone of the West and Central Europe.

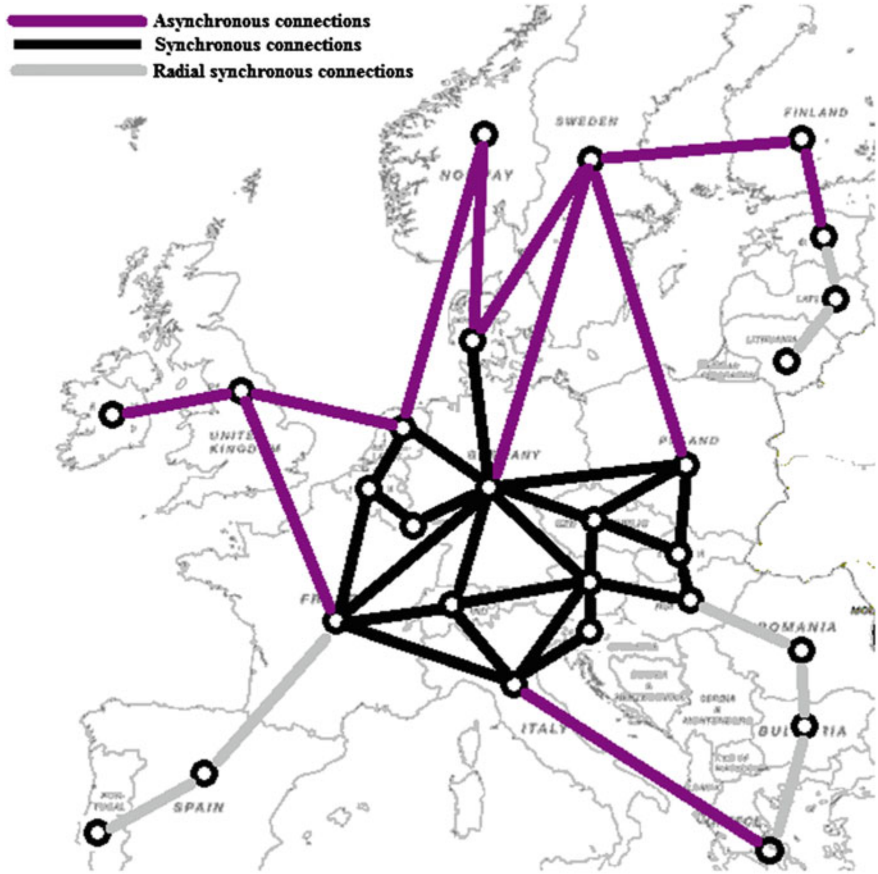

Fig. 4 Simplified model of European grid at the base year of study

3 Scenarios to Assess Integrating Grid Constraints in JRC-EU-TIMES

To assess both the impact of DC Power flow modeling and ITNS in JRC-EU-TIMES results, we developed four scenarios as shown in Table 1. To determine the effect of the different grid representations we compare the optimal solutions of the basic TIMES code with the more advanced approaches. Asynchronous and radial connections are always modeled with the traditional trade approach. However, synchronous connections have been modeled with both the traditional trade approach as well as with the new flow based methodologies. The three grid representations are compared in the scenarios TRADE, DC and DC_Neplan where the transmission expansion is free after 2025. The last scenario, DC_FixGrid, has a fixed transmission expansion up to 2050.

Table 1 Scenario description

Scenario	Grid representation of synchronous connections	Grid expansion
TRADE	Trade based (basic TIMES)	Endogenous grid expansion (after 2025)
DC	TIMES DC power flow with fixed grid characteristics	
DC_Neplan	TIMES DC power flow with discretization algorithm, endogenous grid characteristics and N − 1 contingency analysis via the ITNS	
DC_FixGrid	TIMES DC power flow with fixed grid characteristics (as DC scenario)	Fixed grid expansion (fixed up to 2050)

In an optimization model scheduled electricity flows are equal to the physical flows as optimal price signals exist so that the market solutions fully represent the physics. However, this can only be implemented if the physical flows are represented properly. More details for each scenario are provided as follows:

- The TRADE scenario corresponds to the solution of JRC-EU-TIMES without incorporating the DC Power flow algorithm (i.e. it is the basic TIMES model). Energy transactions between regions in the European system are calculated like normal trade functions in TIMES.
- The DC and DC_FixGrid scenarios refer to using the JRC-EU-TIMES model in the versions with the incorporation of DC power flow, where power flows between regions are more accurately estimated. However, ITNS loops are deactivated, and thus corridor reactances and allocation factors are not updated after the definition of the initial investment plan.
- The DC_Neplan scenario refers to the execution of the complete TIMES-NEPLAN integrator software (ITNS), including discretization algorithm, endogenous grid characteristics and N − 1 contingency analysis.

In all scenarios an 80 % CO_2 emission cap was considered compared to 1990 values. Moreover, all scenarios have in common the following assumptions: (i) No consideration of specific policy incentives to RES (e.g. feed-in tariffs, green certificates); (ii) three additional constraints to ensure: (1) sufficient reserve capacity, (2) realistic representation of variable RES generation and (3) sufficient storage charging capacity. Variable RES (wind, solar, PV and ocean) cannot operate during the winter peak time slice to account for reserve capacity considerations; and (iii) countries without nuclear power plants (NPPs) will not have these in the future (Austria, Portugal, Greece, Cyprus, Malta, Italy, Denmark and Croatia). NPPs in Germany are not operating after 2020 and Belgium NPPs are not operating after 2025.

The main objective of the case study is to evaluate the improvement of the JRC-EU-TIMES modeling mechanisms by including grid related constraints. Note that when looking into the results of our case study regarding the impact on the power system there are several limitations, such as that the insights that are gained from the current configuration are most useful when the consumption and production of electricity are similar to the assumed averages of the 12 time slices. Ideally, one would include a higher number of time slices, regions as well as the national grids to represent different conditions for power plant availability, weather conditions and volatility of fuel prices. This allows including in JRC-EU-TIMES representative day patterns with much more combinations of normal and more extreme events as well as regional differences in renewable availability. Moreover, more differences will be visible when more disruptive situations are modeled based on less perfect circumstances.

4 Results

In the JRC-EU-TIMES model, cross border transmission expansion is cost efficient regardless of the grid representation. The most important factors determining cross border electricity flows as well as the cost efficiency of transmission expansion are (1) the electricity price difference between the countries strongly driven by technology specificity, (2) the transfer capacity limits active in the model and (3) storage possibilities in JRC-EU-TIMES. The results show that a more accurate representation of the grid is possible and worthwhile in a large energy system model. However, we observe that the impact of DC Power Flow is limited for the analyzed case study. Figure 5 shows the net electricity export in 2035 for the four scenarios. The large export from Norway is notable as well as the export from France in the scenario with limited grid expansion (DC_FixGrid). At this level of detail, there are very limited differences between the three grid representations TRADE, DC and DC_Neplan.

Remarkably, unscheduled flows do not appear in the DC scenario because the physical grid limitations are fully internalized in JRC-EU-TIMES. The TRADE scenario does not have grid constraints so unscheduled flows, deviations between scheduled flows and physical flows, take place. Including DC Power Flow triggers

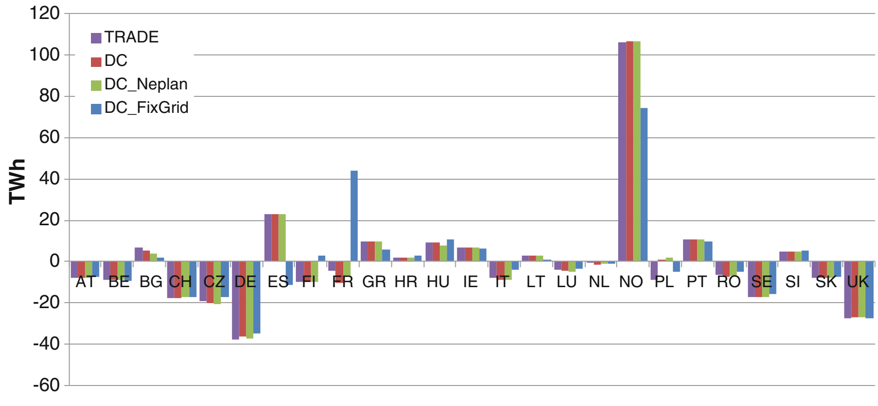

Fig. 5 Net electricity export in 2035

grid extensions but also a shift in generation and consumption to make the physical flows stay in the limits of the grid network. As we compare a market that does not have physical limitations (copper plate) except net transfer capacity with a market that has physical limitations (grid with power flow constraints) one could consider the changes of generation and consumption as some kind of redispatch, however based only on limitations of interconnectors.

In the JRC-EU-TIMES model the Summer Day and Summer Peak represent times with vast amounts of available solar energy. In fact, because of the limited number of time slices, the Summer Day and Summer Peak show a homogenous high level of solar energy across the regions. The Winter Peak represents times without any contribution from variable renewables. Under these somewhat disruptive circumstances we observe increased investments in interconnection capacity.

First, we look at the impact of summer solar electricity production. In the TRADE scenario, the DC scenario as well as the DC_Neplan scenario, more than 10 GWe cross-border capacity is built between Spain and France. This allows transferring electricity from Spain and Portugal in the summer to Northern Europe. As a consequence, we observe a reduced use and capacity of nuclear power plants in France when compared to the DC_Fixgrid scenario that has limited grid expansion possibilities. Interestingly, when the grid expansion is limited, there is an increased deployment of electric cars in Spain. The reason is that in the year 2035, there is a trade-off between storing part of the solar electricity into the batteries of electric cars and using the grid to export. We conclude that the impact of DC Power Flow and NEPLAN is low although the summer solar production induces grid expansions.

In the Winter Peak no variable renewable electricity is available. This a somewhat extreme assumption—not all countries will be without wind, solar and ocean activity at the same time—which leads us however to an interesting finding. As Fig. 6 shows, in the Winter peak time slice important flows occur making Poland, Belgium, Italy and UK exporting electricity to mainly Switzerland, Sweden and

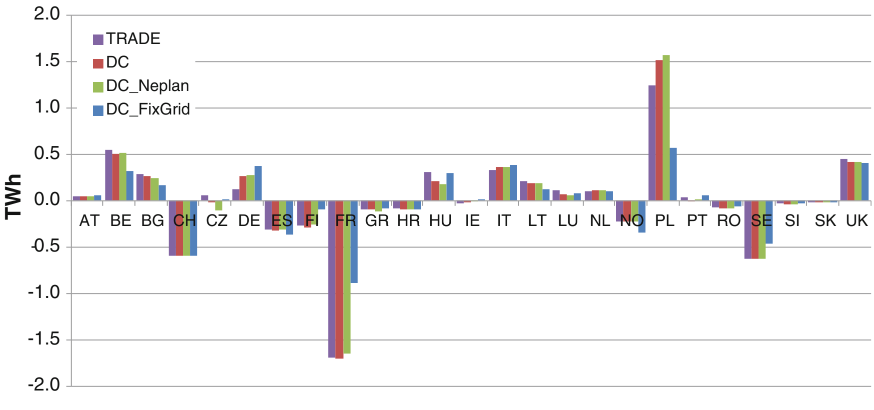

Fig. 6 Net electricity export in the Winter Peak hours (110 h) without availability of variable renewable electricity in the year 2035

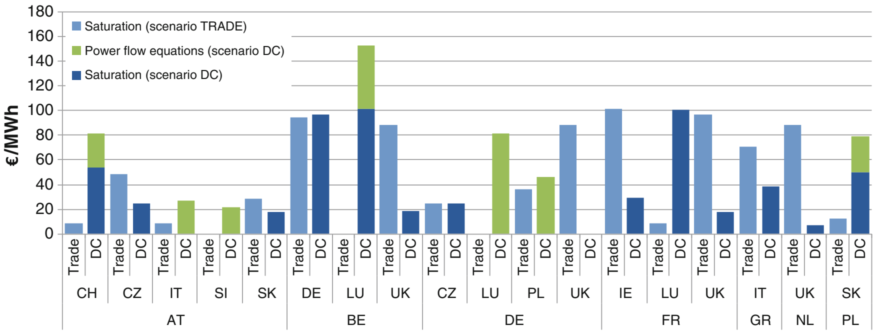

Fig. 7 Electricity price difference between countries in the scenarios TRADE and DC and decomposition for the Winter Peak in 2035

France. Also, the representation of the grid has an impact on some countries such as Germany and Poland.

The electricity market in JRC-EU-TIMES is optimal in this way that it does not have external costs when DC Power Flow is included and it implements nodal pricing in each of the 13 nodes of the synchronous central European grid. The market value of the transmission connection is with nodal pricing equal to the price difference between the areas arising from differences in marginal production cost as well as from congestion costs. Figure 7 shows for the situation in 2035 without available variable renewables the electricity price differences between countries. In the TRADE scenario, electricity price differences are only based on marginal production costs. In contrast, the DC grid representation has another component arising from the power flow constraints. In some connections like Austria-Italy or Germany-Poland it only has the component of power flow constraints.

The traditional representation of the grid, the TRADE approach, uses the network as optimal as possible with the only limitation that the sum of the inflows and outflows in a node is zero. With such a representation, many possible combinations of trade are possible for a given consumption and production in each node. However, the DC power flow approach represents also the physical electricity flows, directed by the grid characteristics. With a given consumption and production in each node (country in our case) and with given trade in radial and asynchronous connections, only one solution of the electricity flow exists in the synchronous grid and investments in new lines are triggered by a combination of regional cost of electricity production and physical limitations. The added value of DC power flow is that it models the physical flow of electricity. This usually leads to higher investments in grid lines than in the TRADE approach.

When the price difference is large enough for a sufficient long period, this can cause a grid expansion at least when this grid expansion is not too costly. Figure 8 shows most of the grid expansions for the three scenarios where investments are free. Most of the connections have higher cross-border capacities when power flow constraints are included such as Austria and Slovakia with all its neighboring

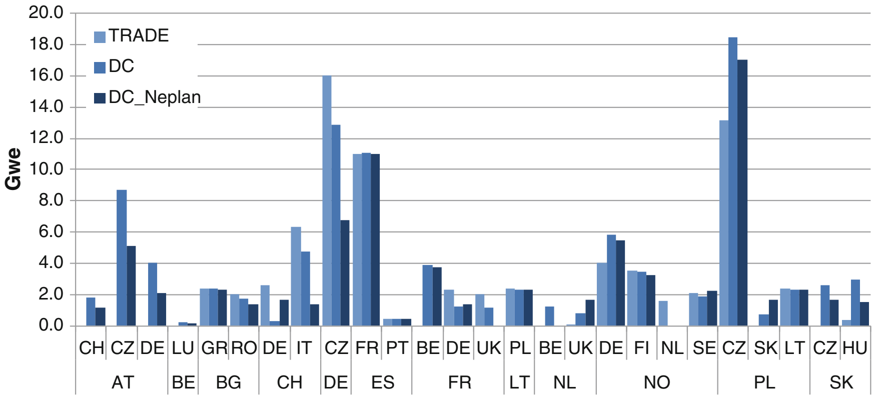

Fig. 8 Electricity grid expansions between countries in the scenarios TRADE, DC and DC_Neplan

countries but also the connection Germany-Norway and Poland-Czech Republic. The main driver for the optimal electricity path is the cost of the combined grid expansions. Typically this cost of the grid expansion is a factor 10–100 lower than the value of the traded commodities. However, the impact of the price component of the power flow constraints is often even smaller than the cost differences between possible grid expansions. Because of this reason the model will typically not drastically change the grid expansion as there are preferred routes based on the cost of these interconnections. We conclude that power flow constraints have an impact on optimal grid expansion and that the accuracy of the grid expansion costs is crucial for proper grid flow analysis.

We evaluated the improvement of the JRC-EU-TIMES modeling mechanisms by including grid related constraints. No substantial increase in modeling time was observed when static DC power flow equations are added to the JRC-EU-TIMES model. However, mainly the discretization loop of the ITNS is time consuming. Depending on the number of new investments, the total ITNS cycle needs 10 up to 100 iterations.

5 Conclusions

To evaluate the improvement of the JRC-EU-TIMES modeling mechanisms, three grid representations are compared in scenarios with free and fixed transmission expansion. We conclude that the impact of power flow constraints is limited for the analyzed case study. However, integrating these constraints has a relevant impact on the value of future possible grid expansions mainly in periods with limited availability of variable renewable electricity, without a substantial increase in model running time and leading to slightly higher cross-border capacities for most countries.

Future research can define restrictions based on the output of the total ITNS cycle so to prevent the iterative procedure of the soft coupling of TIMES with NEPLAN. Further work can also include increasing the number of regional differences such as renewable availability as well as stochastic generation or consumption. This would trigger more disruptive situations that are necessary to understand the true value of grid extensions. We conclude that the perfect foresight assumption of JRC-EU-TIMES requires special attention of the modeler. Indeed, some of the robustness of the JRC-EU-TIMES should be removed in order to get a possibly less optimal distribution of power plants and consumption patterns, as we observe today in many members states. We expect to see more differences between the three grid representations for situations that are more disruptive and less perfect.

Under these conditions, we conclude that the decision making process on transmission expansion can strongly be affected by tools like JRC-EU-TIMES as there is a strong competition between grid extension, storage options, local peak power as well as demand side management.

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Highly Detailed TIMES Modeling to Analyze Interactions Between Air Quality and Climate Regulations in the United States

Evelyn Wright and Amit Kanudia

Abstract This chapter describes highly detailed modeling of existing coal-fired units in the US power sector within the FACETS TIMES model. Such detailed modeling is necessary wherever the existing stock plays a key role in determining policy cost. The soon-to-be-implemented Mercury and Air Toxics (MATS) regulation imposes unit-level emissions rate constraints on nearly 1100 coal-fired units, forcing retrofit or retire decisions at a large portion of the existing fleet. Covered emissions and retrofit costs depend in a detailed way on unit configuration and coal quality, forcing development of new techniques to handle the enormous expansion in model size and detail. These retrofit/retire decisions are being made under uncertainty about future carbon policies for the sector. FACETS was used to compare "foresight" scenarios in which the model could "see" both the MATS requirements and a power sector clean energy standard (CES) to "myopic" scenarios in which the MATS decisions made in the Reference scenario are fixed in the model solution up through the MATS compliance window in model year 2018, after which the model is free to begin responding to the CES. The overall national costs of myopia were found to be small, except when the carbon policy ramps up very quickly after air quality compliance decisions are made, but significant regional heterogeneity exists. Stranded asset costs from retrofitted units that must be underutilized or abandoned later range from \$2 to 8 billion in the myopic cases. Substantially fewer retrofits are undertaken in the foresight cases, reducing stranded asset costs in some regions by up to 100 %.

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_13

1 Introduction

Carbon policy is slowly becoming a reality in many parts of the world. As this happens, analysis needs are evolving from abstract consideration of goals, timing, and high-level strategies to rigorous evaluation of the costs, incidence, and risks of specific policy designs. In the United States power sector, a key determinant of the economic impacts of carbon policy is the fate of the substantial existing stock of coal-fired units.

Over the next few years, these units are subject to implementation of historic new air emissions regulations, including a tightening of standards for sulfur dioxide (SO_2) and nitrogen oxides (NO_x), as well as new standards under the Mercury and Air Toxics (MATS) rule for air toxins including acid gases, mercury, and other heavy metals (US EPA 2014a). The MATS standards differ from most major regulations recently implemented (and modeled) in an important way. These pollutants are subject to toxic hot spots, and thus the standards impose unit-level emissions rate constraints, not regional cap and trade budgets. Each of the country's nearly 1100 coal-fired units above 25 megawatts (MW) capacity faces the requirement to individually comply with these standards or retire.

At the same time, the stringency and timing of future carbon regulations for the sector remain uncertain. Although the Obama administration has recently proposed standards under the Clean Air Act (US EPA 2014b) prohibiting new coal plants without carbon capture and storage (CCS) and imposing moderate medium-term emissions rate reductions on existing plants, it remains unclear whether these proposed rules will survive legal challenge, and in any case they are expected to serve as only a prelude to eventual new, dedicated climate legislation.

The MATS compliance deadline is 2015, with possible extensions through 2017, so owners of non-compliant units will need to make costly decisions to retrofit or retire these units without certainty about how much longer these units will remain economic to operate under future carbon policy. The cost of carbon policy, in turn, depends on the decisions made regarding MATS compliance: how large is the existing stock of vulnerable units, and how significant are recent stranded investments in air compliance equipment when carbon policy becomes stringent enough to start forcing these units to retire.

Of equal importance is the *regional distribution* of carbon policy cost impacts. Previously analyses (Pizer et al. 2009; Rausch et al. 2011; Wright and Kanudia 2014) have shown that cost impacts may vary several-fold across the US, and it appears that these differences have played at least some role in the difficulty reaching consensus on a federal carbon policy (Wheeler 2008). The stock of coal-fired units, and their age, size, and existing emissions control equipment, are distributed unequally around the country, so the interactions between air quality and carbon policy can be expected to impact different regions more significantly than others.

Because air toxin emissions depend in quite a detailed way on unit configuration, coal quality, and existing emissions control equipment, it has been necessary to model the stock of existing units and their many retrofit options in a highly detailed, unit-level manner. These challenges are described in the next section. In addition to presenting this analysis, this chapter is designed as an illustration of how the TIMES platform can be used to analyze problem spaces that are much more highly detailed than has been common previously. Thus the modeling discussion in Sect. 3 assumes some familiarity with VEDA-FrontEnd[1] and interest in the details of the technique. Some new features have been developed to deal with the volume of data required, but much of the work has been done by using existing features in new ways. We hope this discussion will be useful to other modelers who are also wrestling with the need for incorporating more detail into their analyses. Other readers can feel free to scan or skip this section, as the remainder of the discussion does not depend on it.

To investigate the interaction between air quality compliance demands and carbon policy uncertainty, and demonstrate the application of these modeling techniques, the FACETS US TIMES model (Wright and Kanudia 2014) was used to compare "foresight" scenarios in which the model could "see" both the MATS requirements and a power sector clean energy standard (CES) that imposes a national cap and trade program forcing a reduction of the carbon intensity of generation over time to "myopic" scenarios in which the MATS decisions made in the Reference scenario are fixed in the model solution up through the MATS compliance window in model year 2018, after which the model is free to begin responding to the CES. Three versions of the CES policies with different stringency ramping rates were tried.

Section 4 presents this analysis, including the scenarios assessed, and the resulting system configurations, costs, and emissions results at national and regional levels. The chapter concludes with a discussion of the implications of the results, and considers the recently proposed Clean Power Plan carbon regulations for existing units in light of our findings.

2 Challenge of Modeling MATS Emissions and Compliance

MATS requires each unit to meet standards for several toxins. Three of the most significant were modeled here: an acid gas standard, using emissions of hydrochloric acid (HCl) as the measurement proxy; a mercury standard; and a standard for non-mercury metal toxins using filterable particulate matter (PM) as a surrogate for compliance measurement. Emissions of HCl and mercury depend on boiler type, coal quality, and emissions control equipment, and several compliance routes may be available to each unit. This section describes the rule's requirements and the emissions control retrofit options made available in the modeling.

[1] http://www.kanors-emr.org/VedaSupport/.

The acid gas standard requires emissions below approximately 0.002 pounds per million British Thermal Unit (lb/MM BTU) of coal consumed.[2] HCl emissions are a function of the chlorine content of coal and emissions control equipment for SO_2. The higher ash content of subbituminous and lignite coals neutralizes much HCl before emission, leading to an effective range of uncontrolled emissions among US coals ranging from 0.281 pounds per million BTU (lb/MM BTU) to 0.0015 lb/MMBTU, or more than two orders of magnitude, implying that between zero and more than 99 % reduction is necessary to comply, depending on the coal type used.

Plants can retrofit to reduce HCl emissions with either flue gas desulphurization (FGD) or direct sorbent injection (DSI). Capital and operating costs depend on unit size and existing emissions control configuration, as DSI requires a fabric filter (FF) in place, but in general, FGD is a high capital cost, low operating cost technology, whereas DSI requires a lower upfront capital cost, but three-fold higher variable operating and maintenance (O&M) cost. FGD removes a much higher percentage of the HCl (99 vs. 90 %), providing more coal type flexibility. As discussed below, FGD also makes a contribution to mercury removal, and may provide an important compliance route for the mercury standard, depending on a unit's other characteristics. Table 1 summarizes retrofit device cost and performance assumptions for all devices made available in the modeling.[3]

Mercury emissions depend on the mercury content of the coal burned along with boiler type and emissions control equipment for SO_2, NO_x, PM, and an optional dedicated activated carbon injection (ACI) for mercury removal. The latter also requires the unit to have either an electrostatic precipitator (ESP) or FF. The mercury standard requires emissions below approximately 1.2 pounds per trillion BTU of coal consumed.[4] As coal mercury contents range from 1.8 to 34.7 lb/TBTU, removal of 33–97 % of the mercury content is required.

Many different unit configurations will lead to compliant mercury control for units burning bituminous coals. For example, most boiler types will achieve 90 % reductions when equipped with FGD and selective catalytic reduction (SCR) and burning bituminous coal, and a fluidized bed unit with FF achieves a 95 % reduction. Non-ACI controls are less effective at removing mercury from subbituminous and lignite coals, but ACI will remove 90 % of incoming mercury content from any coal type. Overall, 510 units, or nearly half, achieve 90 % or greater mercury reductions under their existing configurations when burning bituminous

[2]The standards for HCl and mercury are given in mass per electricity generated for units below a heat rate threshold of 10,000 BTU per kilowatt-hour (kWh) and mass per unit of coal combusted for units above, in order to provide some flexibility for high heat rate units. Thus the precise standard is dependent on the characteristics of each unit. The threshold values are used here to provide an approximate sense of the requirements of compliance. The unit-specific standards were used in the modeling described below.

[3]Characteristics derived from US EIA (2011a) and US EPA (2010, 2011a, b).

[4]For plants burning bituminous or subbituminous coals. Plants burning lignite are subject to a different standard, which was implemented in the modeling but neglected here for simplicity of discussion.

Table 1 Emissions control retrofit options and characteristics

Equipment	Capital cost ($/kW)[a]	Addition to fixed O&M ($/kW years)	Addition to variable O&M (mills/kWh)	Removes	Removal rate
FGD	378–662	5.9–18.0	1.9	SO_2	95 %
				HCl	99 %
				Hg	Depends on configuration
DSI alone	30–110	0.4–2.0	5.9	SO_2	70 %
				HCl	90 %
DSI plus FF	154–291	0.4–2.0	5.9	SO_2	70 %
				HCl	90 %
SCR	154–219	0.5–2.3	1.1	NO_x	90 %
				Hg	Depends on configuration
ACI alone	5–27	0.0	2.4	Hg	90 %
ACI plus FF	144–228	0.5–0.9	0.5	Hg	90 %

[a]All costs presented in 2004$

coal, enough for compliance burning most bituminous coals, while just over 100 achieve 90 % when burning subbituminous coal, largely through existing ACI.

The remaining plants must install some combination of retrofits, or in some cases, switch to a lower mercury coal type, in order to continue operation. Depending on their existing configuration, their HCl compliance needs, and the value of SO_2 and NO_x reductions in their region, this may be as simple and inexpensive as adding ACI, at a relatively low capital cost, or it may be necessary or optimal to upgrade their SO_2, NO_x, or PM control equipment as well or instead, at costs up to nearly two orders of magnitude higher.

Finally, enhanced filterable PM controls are required at many units to control emissions of other toxins under MATS. US EPA (2011b) evaluated existing coal units and found that 393 units would be required to upgrade their existing ESP or install a new FF. These upgrades were exogenously imposed on each unit in the modeling described below, with capital costs imposed as an increment to annual fixed O&M charges of $5.5–20.4 $/KW, depending on the upgrade required.

Because of this great diversity in compliance costs and the unit-level nature of the MATS requirements, analysis of the regulation's impact based on average or typical plant characteristics, as would be required in a model with coarse geography, would fail to represent the very detailed supply curve for the survival of existing plants. And importantly, it would also fail to capture the regional diversity of retrofit costs and the need to build replacement capacity for those plants that retire. This geographic information is essential for the analysis of carbon regulations because the costs of implementing low carbon technologies depend on geographical relationships between low carbon resources, electricity generation and transmission infrastructure, and loads. The distribution of low carbon resources, including wind, solar, geothermal, and access to CO_2 sequestration sites, is highly heterogeneous, leading to significant regional differences in the costs of emission reduction (Wright and Kanudia 2014).

3 Modeling the Power Sector in FACETS

The Framework for Analysis of Climate-Energy-Technology Systems (FACETS) multi-region US TIMES model has been designed to enable such geographically rich analysis of the US energy system. Specifically, FACETS has been designed with unit-level detail in the power sector, including a rich set of emissions control retrofit options for coal-fired units, and a regional structure that emphasizes existing infrastructure and key geographical relationships. This section describes the FACETS power sector and associated fuel supplies, with a focus on the techniques used to handle the challenges described in the previous section. The rule-based VEDA-TIMES system was essential to handle the enormous level of detail required, and was enhanced on both the input and output sides. In particular, we describe three things: the use of VEDA rules to describe the existing control equipment at each unit and its retrofit options and resulting emissions; the use of a topology insert table to create coal input options specific to each unit, and the VedaViz system to support analyzing the correspondingly large volume of results data.

The data source for the power sector is the US EPA National Electric Energy Data System database (US EPA 2010), which provides capacity, cost, efficiency, availability, emissions, and emissions control equipment data for just over 15,000 units in the lower 48 states. Plants are grouped into 32 regions that represent regional transmission organizations (RTOs), independent system operators (ISOs) and key transmission bottlenecks. A matrix of transmission capacities and costs describes the potential flows between these regions, and data from the US Department of Energy (DOE) National Energy Modeling System (NEMS, US EIA 2009) provides capital costs for additions to this capacity.

In order to preserve this infrastructure information, the 32 power sector regions were implemented as regions within FACETS, with the transmission capacities serving as a trade matrix. Electricity demand[5] takes place in a different set of regions: the nine Census divisions that US DOE uses to track sectoral consumption data. A matrix of user constraints prescribes the share of each consumption region's electricity that must be provided by each of its corresponding electricity regions.

[5]Although FACETS contains a full representation of end use sectors, for this study, which focuses on power sector policies, only the power sector and its fuel supplies were used. The demand for electricity consumption was driven by Annual Energy Outlook projections (US DOE 2011a).

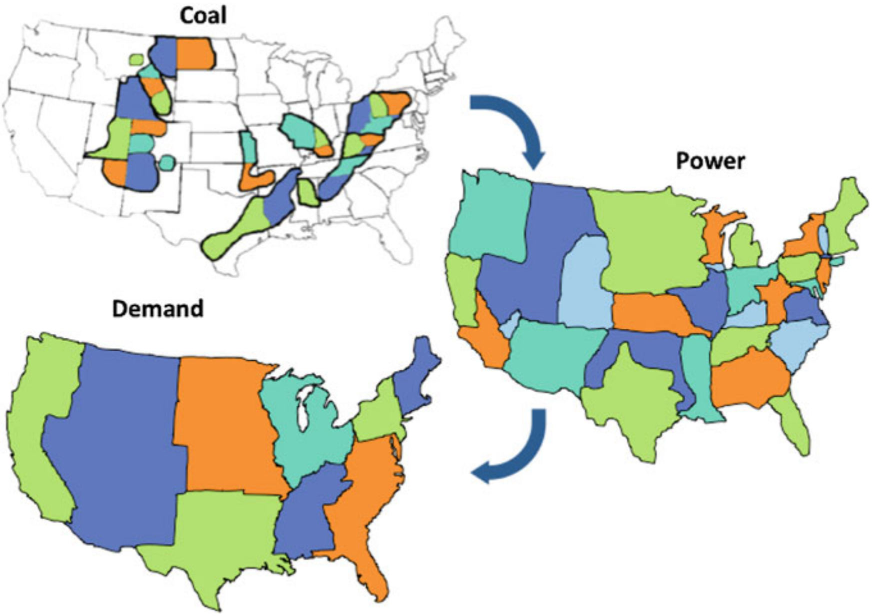

Fig. 1 FACETS coal, power, and demand regions

This matrix is based on historical data and represents the physical location of homes, businesses, and facilities within each power region's territory.

On the input side, coal and biomass are sourced from their own sets of regions and traded to the power sector regions using trade matrices, as illustrated in Fig. 1. (Because of high cost of transport, biomass may only be traded to geographically overlapping regions.) Finally, when the model implements carbon capture and storage, the CO_2 flows are traded to a set of sequestration regions, each with their own "supply" cost curves for accepting CO_2, and again governed by a trade cost matrix from the power regions.

Within the power sector, the nearly 3800 hydroelectric units, whose production is governed by seasonal capacity factors, are aggregated by power region and state. The remaining 11,200 units are modeled individually. While much of the data for these units can be read in a single Excel table built directly around the source data, a major data handling challenge is presented by the need to describe the input fuel choice, emissions, and emissions retrofit options for the 1100 coal units.

A TIMES model is based on network topology. The inputs and output of each process must be specified in order to provide the links that "hook" the network together. FACETS includes 85 bituminous, subbituminous, and lignite coals, distinguished by rank, source region (and hence transportation cost to each unit) and sulfur level, each with its own sulfur, mercury, and chlorine content. Each unit may burn some subset of these fuels, depending on its configuration, location, equipment, and permitted sulfur emissions level. Some units are restricted to only one rank, while others are flexible. And beginning in 2017, each is subject to its individual MATS constraints. Enumerating the input fuel options for each of these 1100 units line by line in an Excel file would be a prohibitively labor intensive, error-prone process, not only to create and check, but also to update when updated data sources are available.

A second challenge arises from representing unit configurations, emissions, and retrofit options. The existing units have more than 100 different combinations of boiler type and existing emissions control equipment. As described in the previous section, each combination removes a different fraction of the content of each pollutant in the source coal, and each combination is also eligible for a different set of retrofit options, ranging from zero choices, if it already has a fully compliant combination, to eleven, if it has no pre-existing equipment, and can fully select from the options in Table 1. To minimize the model size implications of duplicating each of these processes, we wish to make only potentially improving options available.

VEDA's rule-based approach and Excel lookup tables have been heavily relied upon to build the specifications. To drive these specifications, heavy use has been made of information embedded within each process's short and long names. Unit short names consist of the federal unit ID number, followed by a seven character code that describers its boiler configuration and NO_x, acid, PM, and mercury emissions control equipment specifications and indicates whether it is the original (mother) unit or one of its retrofitted replacements. Unit descriptions are packed with information as follows:

> EPLT -<Plant name>.<Fuels>.<Coal transport cost category>.<County>-<State>.<Plant type>.<Plant size category>.<Optional code for retrofit equipment>

For example, *EPLT—E C Gaston.CoaB.ALR3.Shelby-Alabama.CST.SC3.EmRf C* describes a coal steam (CST) unit at E C Gaston plant in Shelby County, Alabama, that burns bituminous coal only, is approximately 300 MW in size, has been retrofitted with SCR, and receives coal according to transport cost category ALR3. The unit size categories are used to specify costs for emissions control retrofits. This information allows emissions, retrofit, and fuel choice data to be input by rules based on process name and description, rather than manual data entry.

The code in each unit's short name is used in the input template to look up from a source data table of emission modification factors the amount of each pollutant "scrubbed" from the input coal. All emissions constraints are then written in terms of the net of raw minus scrubbed emissions. Another lookup table specifies which retrofits are available to plants with each code. For example, plants with existing wet scrubbers but no post-combustion NO_x or mercury controls are eligible for retrofits with SCR, ACI, or SCR + ACI. A set of process declaration tables references this table using each unit's code to declare or not declare each possible option. A set of simple update tables then references the codes in the process description to add the corresponding capital cost and modify the unit's operating costs and efficiency.

Table 2 Topology insert table for coals to coal-fired units

~TFM_TOPINS			
PSET_SET	PSET_PD	CSET_CN	All regions
ELE	*.CoaB.*	ECoal-__-B*	IN
ELE	*.CoaB/CoaS.*	ECoal-__-B*,ECoal-__-S*	IN
ELE	*.CoaL.*	ECoal-__-L*	IN
ELE	*.CoaL/CoaS.*	ECoal-__-L*,ECoal-__-S*	IN
ELE	*.CoaS.*	ECoal-__-S*	IN

User constraints limit the total capacity of each group of mother plus retrofit units to the capacity of the original unit. In principle, lumpy investment in each retrofit choice would be a more precise way to model the retrofit choice, as the current approach could lead to partial retrofits. However, with this many units, lumpy investment would be prohibitive in terms of solve time, and because of the unit-level nature of the constraints, in practice this behavior has been minor.

To manage the fuel inputs, all units that take a single input energy carrier—for example, dedicated natural gas units, and renewable units with dummy inputs—have that specification directly entered in the base year (2012) input template, reading from the source data. All other inputs have been created by means of a Topology Insert table using rules based on the process description. Table 2 shows the portion of the table for coal-fired units. The first row assigns *all* bituminous coal types as inputs to every bituminous unit. Two restrictions are then applied to limit the coals actually available to the unit. First, the coal transport cost matrix specifies the actual list of some 1200 allowable links and their costs, which range from very small costs and single links for mine-mouth plants, to high costs for cross-country rail transport. One single-line table bounds out all possible transport links, and another reads the transport matrix, releases the bounds on allowed links, and assigns them the correct cost. Finally each unit has a permitted sulfur emissions rate, which in conjunction with its scrubber efficiency (if any) will further restrict its allowable fuels. This limit is imposed via user constraint on each unit restricting the net sulfur emissions per electricity generated.

The rich detail of the model creates data handling challenges on the output side as well. In particular, the regional information and trade flows between regions are crucial to understanding the model behavior and extracting meaning from the results. But trade flows in particular are difficult to interpret in a table of numbers. The regions themselves are many and do not correspond to political, social, or cultural boundaries. Because regions are of different geographic size, viewing, for example, capacities of retrofits or retirements by model region may not give and accurate sense of how these changes are distributed in the country.

To help interpret these results, a geographic information systems (GIS) results mapping system has been developed within the VedaViz[6] online results processing

[6]http://vedaviz.com.

and visualization tool. VedaViz was developed to facilitate collaborative interpretation of model results by analysts who are not themselves TIMES modelers or VEDA users. Originally developed as part of the Energy Modeling Forum EMF-27 study (Weyant and Kriegler 2014), it begins with a set of standard high-level summary variables, including primary energy, electricity generation and capacity, final energy consumption, emissions, and cost data, which are then made available online for quickly generating summary graphs and tables using a set of flexible forms based on Google Chart tools[7] and the D3 JavaScript visualization library.[8] Dimensions including scenarios, regions, variables, years, and (for multi-model comparisons) models may be pivoted, and small multiples may be created for side-by-side comparisons.

This system makes high-level results available online to any domain-aware analyst without them needing to be experts in the model Reference Energy System (RES). The tool is designed facilitate collaborative analysis and results dissemination. One can create and save views for others to view, post and respond to comments on views, and generate links from any view to publish online. We now use VedaViz as a primary tool for a first, high-level graphical view of the patterns in the results, combined with VEDA-BE for drilling down into RES details as needed.

The GIS system is based on Google Maps components. Each region in the model is represented by a map coordinate, allowing values to be "graphed" on the map using pie or bar charts. Trade flows may be visualized using arrows, whose width corresponds to the size of the flow (example in Fig. 5). In the FACETS power sector, each unit is coded in the input data with its latitude and longitude, so that unit-level data may also be visualized to see how retirements, retrofits, and emissions "clump" geographically (Fig. 6).

To create a VedaViz online project for a set of results, the VD files[9] are read into an SQL server database, which creates the variable names, processes the raw VD results into the variable values. It can then can do further operations on them, including scenario differences, period averages, shares, capacity utilization, and so on. These variables and calculations are data driven, and customized for each application. In addition to standard charts and maps, a host of other graphical features are available, including animated bubble charts, and Sankey diagrams.

4 Analysis

This section describes the scenarios modeled and the national, regional, and unit level results.

[7] https://developers.google.com/chart/.

[8] http://d3js.org/.

[9] Standard results files from TIMES runs.

4.1 Scenarios Modeled

In addition to the MATS regulations described above, which are assumed to be fully in effect in 2017, the Reference scenario includes regional cap and trade standards for SO_2 and NO_x under the Clean Air Interstate Rule (CAIR), and the proposed New Source Performance Standard (NSPS) for CO_2. The NSPS is implemented as a ban on new coal units without CCS.

The new CO_2 policy analyzed here is a power sector clean energy standard (CES), similar to that analyzed by US EIA (2011b). Like a renewable portfolio standard (RPS), a CES requires a minimum fraction of generation to be obtained from specified sources, in this case a range of zero and low carbon technologies. One full CES credit is awarded to generators per MWh of zero-carbon generation, and partial credit is awarded for some other types in rough proportion to their degree of carbon emissions reduction from coal steam generation (Table 3).

The percentage of CES credits as a share of total national generation ramps up from 2010 levels of roughly 42.5–90 % in 2050, the last model year, with the constraint first binding in model year 2023, after MATS compliance decisions are final. Three different CES trajectories were tested, representing a range of aggressive to delayed action, as illustrated in Fig. 2. The scenarios are named 85, 65, and

Table 3 CES credits by generation type

Generation type	CES credits per MWh
Biomass, geothermal, hydro, nuclear, solar, wind	1.0
Gas combined cycle	0.5
Coal or gas with CCS	0.9

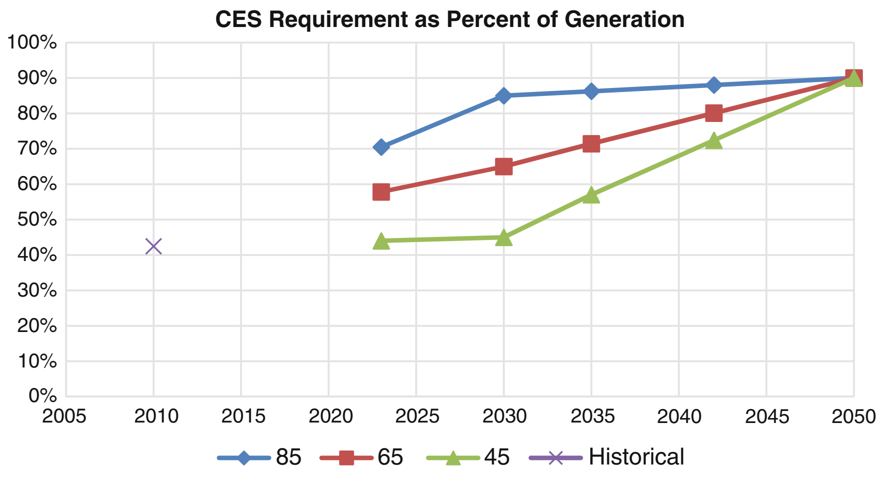

Fig. 2 CES trajectories

Table 4 Build rate constraints

Plant type	Annual build limit before cost penalty incurred (GW/year)			
	2010	2020	2035	2050
Coal/Gas with CCS	1.3	2.6	3.9	5
Photovoltaic	5	15	45	450
Offshore wind	0.5	1.5	10	100
Onshore wind	10	30	90	900

45, for the share required in 2030. The 65 trajectory increases linearly to 2050, while the 85 trajectory ramps up much more aggressively, reaching nearly the full level by 2030, and the 45 trajectory postpones most action until after 2030. Banking and borrowing are not permitted.

New power plant cost and performance characteristics are derived from AEO 2013 (US EIA 2013). All plant options face the same cost of capital. However, plants also face capital cost supply step adders that vary by plant type, representing short-term increases in costs for labor and materials when the model seeks to build new capacity faster than the rates shown in Table 4. These steps are based on a review of similar build rate adders in IPM (US EPA 2010) and NEMS (US EIA 2011c), as well as recent historical maximum annual builds (US EIA 2012) for these capacity types. Plant types with complex engineering requirements and limited recent builds (coal/gas with CCS and offshore wind) have more stringent limits that increase more slowly over time than types with simpler engineering and more rapid recent capacity additions. All supply steps relax over time to represent the potential for development of increased national construction capacity for in-demand plants.

New nuclear builds are prohibited. The cost and social acceptance of new nuclear builds in the US is highly uncertain, as no new plants have been completed for several decades. Previous analysis (Wright and Kanudia 2014) found that CES compliance strategies and cost are highly sensitive to these assumptions. At AEO 2013 costs, new nuclear was the dominant strategy in many regions. Prohibiting nuclear leads to a richer regional mix. For these runs, electricity demand was kept fixed at AEO levels, rather than responding to price changes using elastic demand, in order to keep the focus on generation technology changes.

To assess the impact of the timing of knowledge about the CES when making MATS compliance decisions, each CES scenario was analyzed in two variations. The "foresight" version is a standard TIMES run, in which the CES requirement is "seen" at the time of MATS compliance. In the "myopic" version, the Reference case solution is frozen up to the end of the compliance window (model year 2018), after which the model is free to make new decisions about CES compliance.

5 Results

5.1 National Results

As shown in Table 5, the cost of the CES policy is very sensitive to policy ramping speed. The slow-ramping 45 scenario increases total system cost—which can be interpreted in this instance as the total net present value cost of delivering electricity to all US end users—by about eight percent. The 65 scenario roughly doubles this impact to around 15–16 %, and the fast-ramping 85 scenario increases it further. The cost impacts of myopia depend even more dramatically on CES stringency. In the 45 scenario, lack of foreknowledge about the carbon policy increases the policy's cost by only one percent, or approximately 4 billion dollars. In the 65 and 85 scenarios, these increases are far more significant, at 9 and 23 %.

Figure 3 shows how the CES compliance strategies vary with policy ramping speed and foresight versus myopia. The difference between the foresight and myopic cases derive from two factors: the relative build rates of different low carbon generation types, and the extra retrofitted coal stock in the myopic cases.

In 2018, the 65 and 85 foresight scenarios have begun to deviate significantly from the Reference case. They undertake significantly less coal retrofitting, and make up the difference with new gas combined cycle builds and, in the 85 case, small amounts of gas and coal with CCS. By scenario design, the three myopic scenarios are frozen to the reference case in this period, and the 45 foresight case requires CES compliance so far down the road that it deviates from Reference hardly at all.

By 2023, the 85 foresight scenario is generating more than 10 % of its electricity from CCS plants, and the lead over the myopic scenario in building these plants persists over the model horizon. The myopic scenario relies on quicker-to-build wind and combined cycle to meet the suddenly tightening CES. In the two 65 cases, total generation from existing coal units is similar, at around 19 % of total generation, but the myopic case is more heavily relying on the retrofits it has invested in, whereas the foresight case is splitting generation roughly evenly between retrofits and retained original equipment. The early compliance strategy for both of these scenarios is an investment in new combined cycle capacity.

Table 5 Scenario system cost impacts

Scenario	Increase over reference (%)	Increase due to Myopia (%)
85-MY	35.6	23
65-MY	16.5	9
45-MY	8.1	1
85-FS	28.9	
65-FS	15.1	
45-FS	8.0	

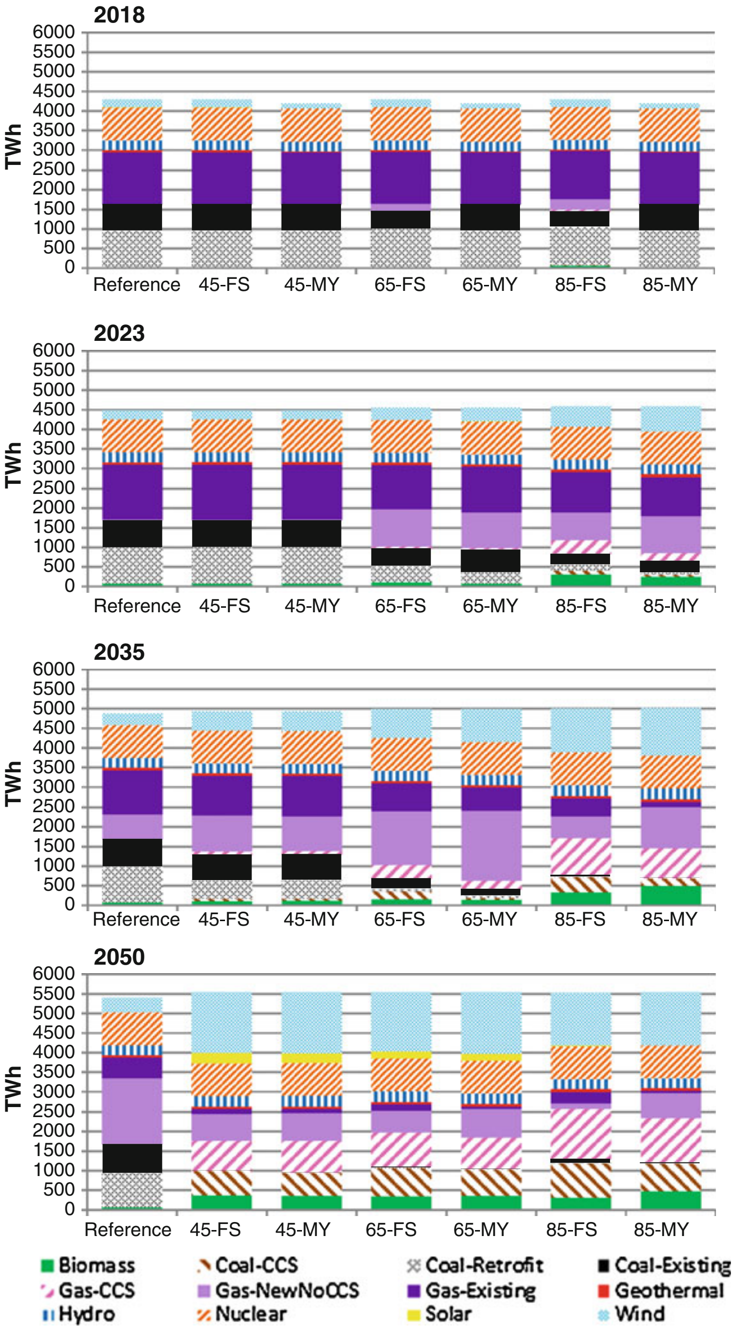

Fig. 3 National generation mix across scenarios

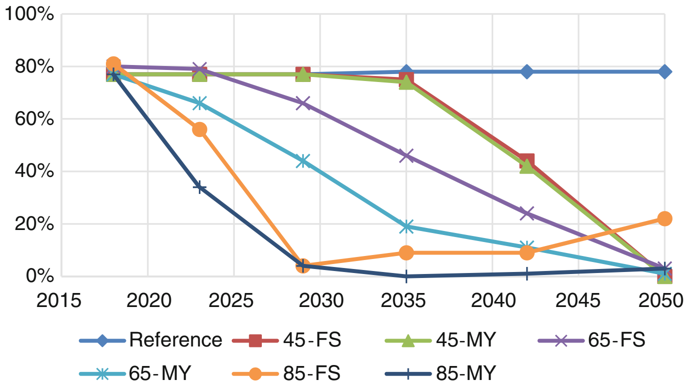

Fig. 4 Utilization of retrofitted coal units

By 2035, the 65 foresight case is still operating nearly half of the coal capacity it retrofitted, covering this non-compliant generation with more CCS than the myopic case, which has abandoned most of its retrofits (Fig. 4). The 45 cases have begun investing in wind and combined cycle, but are still operating most of their retrofit capacity. The differences between the foresight and myopic cases are minimal.

2050 brings a convergence of all the CES policies to the same 90 % requirement, but the compliance strategies differ significantly depending on the route taken over the previous periods. The 85 foresight case relies most heavily on the CCS it has been building steadily over the entire horizon, followed closely by the 85 myopic case. The foresight case is still operating around a quarter of its retrofit capacity. The other cases include more wind and solar, whose cost has come down, and the differences between the myopic and foresight cases have largely evaporated.

Table 6 summarizes retrofits and retirements by scenario. 76 GW of capacity retires rather than retrofit in the Reference and myopic cases, with an additional 30 GW in the 65 foresight case and a further 9 GW in the 85 foresight. Most of the foregone retrofits are additions of ACI to control mercury, along with some decrease in SCR and FGD. Perhaps surprisingly, DSI retrofits, which have lower

Table 6 Coal unit retirements and retrofits by scenario (GW)

	85-MY	65-MY	45-MY	85-FS	65-FS	45-FS	Reference
Retirements	76	76	76	115	106	76	76
Retrofits—ACI	71	71	71	44	49	71	71
Retrofits—SCR	4	4	4	0	0	4	4
Retrofits—DSI	11	11	11	13	4	11	11
Retrofits—FGD	41	41	41	8	23	41	41
Retrofits—All[1]	100	100	100	55	65	100	100

[1]Retrofits do not sum to totals because some units receive more than one retrofit

capital but higher operating costs, are not stimulated in the foresight cases. Overall, there are 35 GW fewer units that receive retrofits in the 65 foresight case and 45 GW in the 85 foresight. The 45 cases show no difference between myopic and foresight choices.

Figure 4 shows that, in both the 65 and 85 myopic cases, the model must precipitously abandon much of its retrofitted capacity, once the unanticipated CES kicks in, while the foresight cases are able to continue using their more modest retrofitted stock for longer. The difference is most significant and prolonged in the 65 cases, in which the moderately ramping CES allows continued utilization of retrofitted units at greater than 50 % through model year 2035.

5.2 Regional and Unit-Level Results

Figure 5 shows the generation mix and inter-regional trade flows in 2035 for the 85 foresight and myopic scenarios. (Pie and wedge sizes in the figure are proportional to generation, and arrow widths are proportional to interregional flows.) A mix of compliance strategies are visible, with heavy investment in wind and biomass in the resource-rich Plains and Upper Midwest. Coal and gas with CCS are concentrated in Southeast and Gulf Coast regions with good access to sequestration sites, and other regions rely on new gas combined cycle and existing nuclear and hydro.

Table 7 shows the net present value change of the costs to each region of supplying its own consumers' electricity demand, including capital, operating, and fuel costs, along with net costs/earnings for inter-regional electricity and CES permit trades. The values are then scaled by 2012 generation in order to allow impacts on regions of different sizes to be compared.

The CES hits the small, gas-dependent regions of New York City and Long Island hardest, with both higher gas prices and the need to import CES credits. Other high cost regions are those that have fewer (Kentucky) and/or more expensive (Southwest Power Pool—South) compliance options, or that have significant existing coal fleets that must be abandoned and replaced (PJM). Those regions that already have (Upstate and Downstate New York, Commonwealth Edison, and Pacific Northwest) or can relatively cheaply build (Northwest Power Pool—East, and Midwest Regional Organization) significant supplies of compliant generation experience a net benefit from the CES.

Myopia imposes costs on most regions, especially under the high-cost 85 CES. But some regions benefit under myopia from being able to export higher cost credits to regions with more constrained options. For example, regions in the Upper Midwest (Midwest Regional Organization) and Plains (Southwest Power Pool—North) with strong wind and biomass resources are able to become large exporters of power and CES credits in the myopic scenarios, and experience a net cost gain from myopia as a result (Fig. 5).

Those who are impacted most by not knowing about the CES before retrofit decisions must be made are, of course, the owners of the coal plants affected.

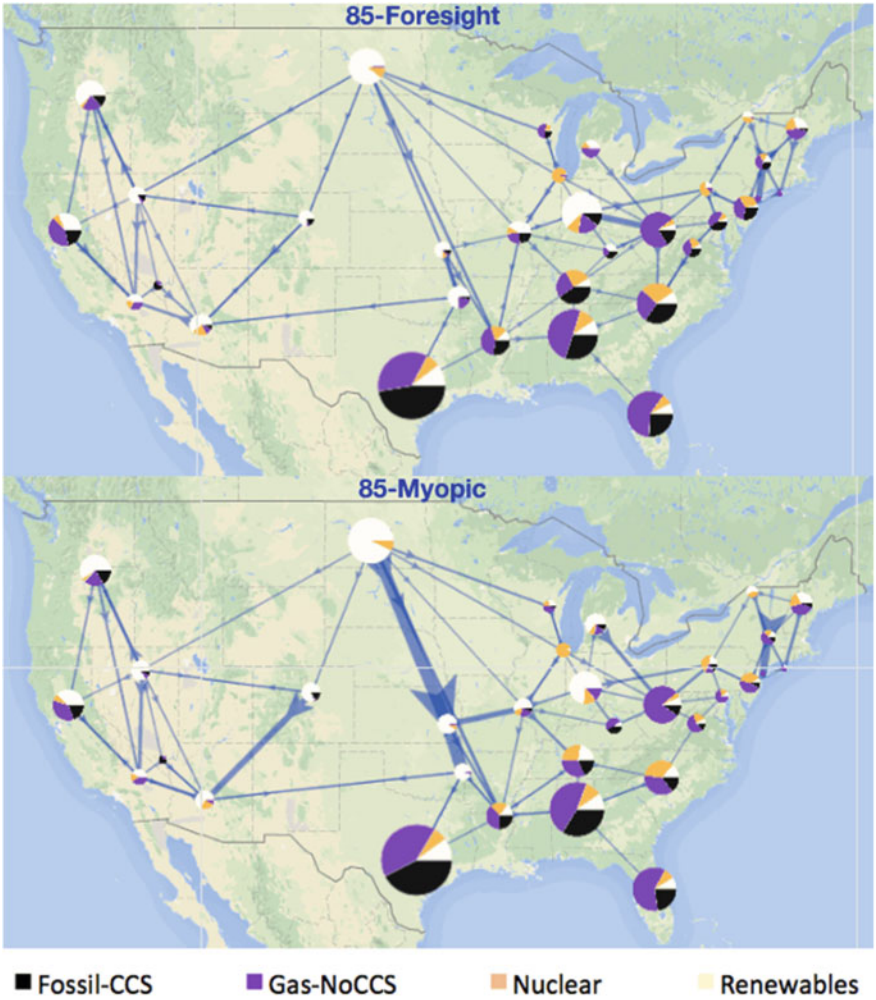

Fig. 5 2035 generation mix and inter-regional trade in the 85 foresight and myopic scenarios

Table 8 shows the cost of stranded retrofitted capacity, measured by regional annualized investments in retrofits multiplied by the difference in utilization between the Reference case (taken to be normal utilization rates) and each scenario's regional utilization. These costs range several orders of magnitude across regions, up to more than $1 billion in some regions. Regions with the lowest costs have little or no retrofitted capacity even in the Reference scenario, whereas the highest cost regions tend to be those with the largest retrofit capacities (Southwest Power Pool—South, Texas Regional Entity, and Midwest Regional Organization), along with those that must abandon retrofit capacity most precipitously (Southern Company and MISO).

Table 7 Net present value regional cost of electricity supply (M2004$/MMBTU)

Region	Cost increase over reference (scaled)						Cost of Myopia		
	85-MY	65-MY	45-MY	85-FS	65-FS	45-FS	85	65	45
Arizona—New Mexico	72	6	42	58	25	36	13	−19	6
California North	60	6	20	121	12	13	−61	−6	7
California South	351	100	37	308	126	41	43	−26	−4
Commonwealth Edison	−242	−177	−34	−143	−209	−21	−98	32	−13
Downstate New York	−1190	−681	−200	−948	−645	−190	−241	−35	−9
Kentucky	403	202	147	240	203	104	162	−1	43
MISO	105	65	−9	63	91	−5	41	−26	−4
PJM	501	254	89	313	242	89	187	13	0
Entergy	263	87	32	123	59	41	140	28	−9
Texas Regional Entity	183	89	35	114	108	34	68	−19	1
Florida Reliability Coordinating Council	321	134	45	227	125	45	94	9	0
Long Island Lighting Company	959	433	149	711	456	152	248	−24	−3
Mid-Atlantic Area Council—East	102	25	16	84	32	20	18	−7	−4
Mid-Atlantic Area Council—South	351	124	44	95	174	42	256	−50	2
Mid-Atlantic Area Council—West	178	39	17	151	26	21	28	12	−4
Gateway (Illinois-Missouri)	327	178	43	170	198	43	156	−20	0
Michigan Electric Coordination System	110	78	18	116	29	26	−5	49	−8
Midwest Regional Organization	−116	34	0	−40	61	−6	−77	−27	6
New England Power Pool	76	−59	−12	24	−56	−12	52	−3	0
Northwest Power Pool East	−271	−58	−35	−190	−48	−50	−81	−11	15
New York City	960	440	132	719	463	128	241	−23	4
Pacific Northwest	−180	−140	−29	−92	−149	−19	−87	9	−10
Rocky Mountain Power Area	−67	89	10	26	99	11	−92	−9	−2

(continued)

Table 7 (continued)

Region	Cost increase over reference (scaled)						Cost of Myopia		
	85-MY	65-MY	45-MY	85-FS	65-FS	45-FS	85	65	45
Southern Nevada	95	−25	−158	−81	−59	−141	176	34	−17
Southern Company	210	129	46	144	97	44	66	32	2
Southwest Power Pool—North	−445	−13	−28	−123	−14	−39	−321	1	11
Southwest Power Pool—South	571	221	68	283	229	68	289	−8	0
Tennessee Valley Authority	192	66	27	82	67	28	109	−1	−2
Upstate New York	−447	−282	−66	−283	−304	−66	−163	22	0
Virginia-Carolinas	151	46	29	43	47	31	108	−1	−2
Dominion Virginia Power	219	65	39	177	24	29	42	41	10
Wisconsin-Upper Michigan	265	101	39	312	103	42	−47	−2	−3

Table 8 Net present value cost of abandoned retrofit capacity (M2004$)

Region	Cost of lost retrofit utilization						Cost of Myopia		
	85-MY	65-MY	45-MY	85-FS	65-FS	45-FS	85	65	45
Arizona—New Mexico	209	99	42	107	53	40	102	46	2
California North	0	0	0	0	0	0	0	0	0
California South	3	2	1	3	1	1	0	1	0
Commonwealth Edison	1	1	0	1	0	0	0	0	0
Downstate New York	0	0	0	0	0	0	0	0	0
Kentucky	85	40	17	0	0	16	84	40	0
MISO	878	563	174	330	152	156	548	411	18
PJM	756	469	170	37	92	163	719	376	7
Entergy	459	314	100	0	40	97	459	275	3
Texas Regional Entity	470	359	109	227	215	116	243	144	−7
Florida Reliability Coordinating Council	254	165	57	3	38	57	251	127	0
Long Island Lighting Company	0	0	0	0	0	0	0	0	0
Mid-Atlantic Area Council—East	0	0	0	0	0	0	0	0	0
Mid-Atlantic Area Council—South	0	0	0	0	0	0	0	0	0
Mid-Atlantic Area Council—West	224	57	52	60	31	53	164	26	−1
Gateway (Illinois-Missouri)	265	176	51	145	72	51	120	105	−1
Michigan Electric Coordination System	95	68	23	15	25	21	80	44	2
Midwest Regional Organization	770	531	250	338	215	239	432	316	11
New England Power Pool	2	1	1	0	1	0	2	0	0
Northwest Power Pool East	205	128	57	146	53	59	58	74	−1
New York City	0	0	0	0	0	0	0	0	0
Pacific Northwest	1	1	0	0	0	0	1	1	0
Rocky Mountain Power Area	145	77	39	48	38	38	97	39	1

(continued)

Table 8 (continued)

Region	Cost of lost retrofit utilization						Cost of Myopia		
	85-MY	65-MY	45-MY	85-FS	65-FS	45-FS	85	65	45
Southern Nevada	0	0	0	0	0	0	0	0	0
Southern Company	1053	675	231	22	11	217	1031	664	14
Southwest Power Pool—North	372	217	104	122	101	102	249	115	2
Southwest Power Pool—South	1311	768	331	395	371	310	916	396	21
Tennessee Valley Authority	724	479	165	240	139	148	484	340	17
Upstate New York	0	0	0	0	0	0	0	0	0
Virginia-Carolinas	158	82	32	12	6	30	146	76	2
Dominion Virginia Power	128	65	23	0	0	23	128	65	0
Wisconsin-Upper Michigan	106	93	30	0	0	32	106	93	−3
Total	8673	5430	2057	2254	1656	1971	6335	3709	41

The additional costs imposed by myopia also vary greatly, even among the high cost regions, with some regions able to eliminate most or all of these costs with foresight, even in the 85 case, through reduced retrofit investments and longer utilization of the retrofitted stock. For example, the PJM region foregoes more than 5 GW of capital-intensive FGD retrofits, retaining only 0.3 GW of FGD and 1.4 GW of ACI, substantially reducing its lost investments when these units must be shut down under the increasing CES. Overall, foresight saves more than $6 billion in stranded asset costs in the 85 case and nearly $4 billion in the 65 case.

Figure 6 compares the distribution of the retrofitted units in the 85 foresight and myopic scenarios. The concentration of additional myopic retrofits—and hence the costs of myopia—in the Ohio Valley and Southeast is clearly visible.

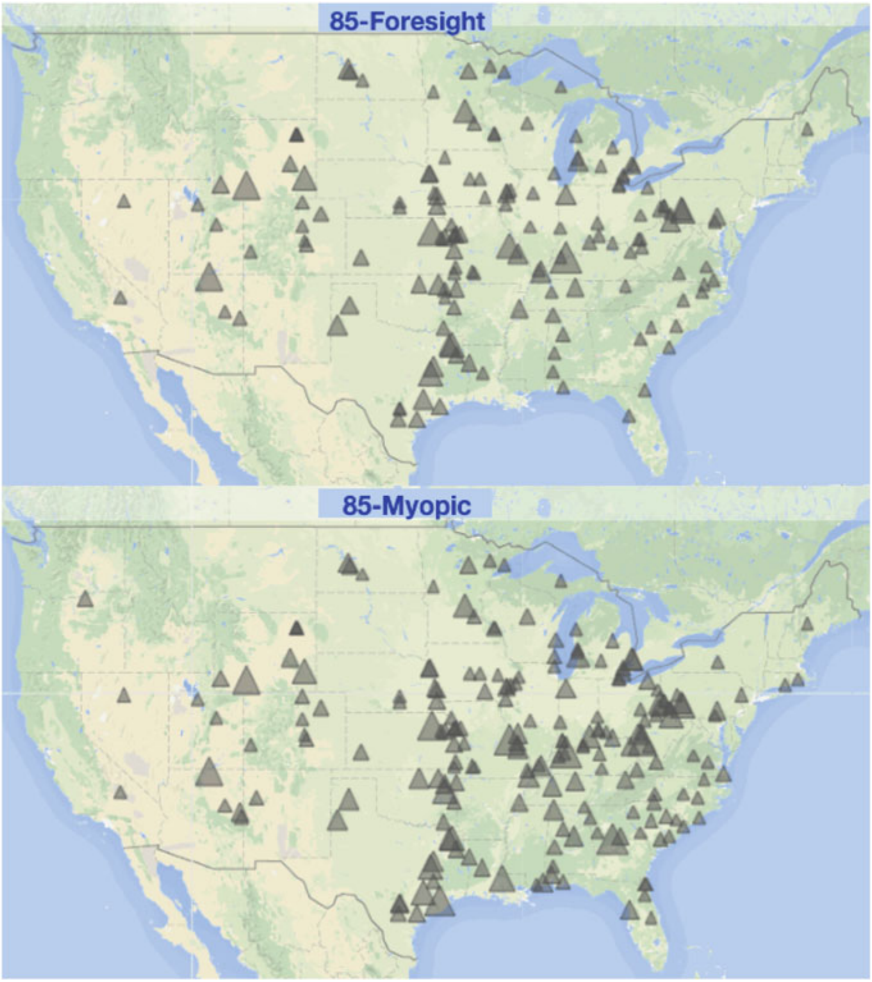

Fig. 6 Retrofitted units in 85 foresight and myopic scenarios

6 Conclusions

This chapter has described and illustrated the techniques used to conduct highly detailed modeling of existing coal-fired units in the US power sector. Such detailed modeling is called for in situations where the existing stock plays a key role in determining policy cost and incidence, and will be increasingly necessary for analyzing real climate policies. It also permits the application of TIMES modeling to policies that are far nearer-term than has been commonly practiced.

In the analysis presented here, the FACETS model was used to analyze the interactions between air quality and carbon policies, when the timing and stringency of the carbon policy is uncertain. The overall national costs of myopia were found to be small (1–10 % of overall carbon policy cost), except when the carbon policy ramps up very quickly after air quality compliance decisions are made. However, these national results obscure significant regional heterogeneity. Some regions experience substantial cost increases from myopia, while others that can export valuable credits actually experience a net benefit. The cost of retrofitted units that must be underutilized or abandoned later range from $2 billion in the slow-ramping 45 cases to more than $8 billion in the 85 myopic case. Substantially fewer retrofits are undertaken in the foresight cases, reducing stranded asset costs in some regions by up to 100 %. Because elastic demand was not used for these runs, we would expect the real world cost and generation mix impacts to be somewhat muted as electricity demand responded to price changes.

Recently US EPA (2014) has released draft regulations for carbon emissions from existing power plants under section 111d of the Clean Air Act, known as the Clean Power Plan (CPP). The CPP is similar to the CES modeled here, imposing a maximum carbon emissions rate for covered generation in each state, where covered units include existing fossil plus non-hydro renewables. Existing hydro and most existing nuclear are excluded, reducing or eliminating the windfall gains found herein for regions with substantial shares of hydro and nuclear capacity in their existing mix. The CPP requirements ramp in over the period 2020–2030, reaching approximately midway in stringency between our 45 and 65 cases, and require no further reductions beyond 2030.

The analysis conducted here suggests that the overall costs of the CPP are likely to be modest, although some regions may experience substantially greater cost impacts than others. Assuming any new, additional carbon policy would not take effect until after the CPP's compliance period ends in 2030, additional costs from having taken MATS decisions more than a decade earlier without foreknowledge of the future carbon policy will be small. If, however, the need for additional carbon emissions reductions from the power sector comes to be seen as more urgent, the potential for significant costs from stranded assets rises.

Because the CPP will be implemented at the state level, each state will need to conduct its own analysis of compliance strategies, based on its own existing stock and resource base. An analysis of the CPP using FACETS is underway.

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An Analysis of the Impacts of New Oil Pipeline Projects on the Canadian Energy Sector with a TIMES Model for Canada

Kathleen Vaillancourt, Yuri Alcocer and Olivier Bahn

Abstract The oil industry currently plays a major role in the Canadian economy. In the future, further developments of the oil sector will be affected by the ability to transport crude oil (mainly from Western Canada) to consuming regions in Canada and abroad. This chapter analyzes different crude oil exportation scenarios based on existing pipeline expansions and the development of new pipelines. We use for this a multi-regional TIMES energy model for Canada. Our results indicate that: (i) the exporting capacity will be an important driver for oil production levels in Canada, and (ii) impacts on the other Canadian energy sectors are rather limited.

1 Introduction

It is an understatement to allege that the oil industry plays a major role in Canada's economy and development. Considering crude oil alone, with over $69 billion of private investment in 2013, it represents nearly a fifth of Toronto's Stock Exchange value and pays over $18 billion to the provincial and federal governments in taxes and revenues each year (CAPP 2014a). Providing over 550,000 direct and indirect jobs in the country, the oil industry is the backbone of Canada's actual economy and financial stability.

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_14

In 2013, Canada's crude oil production reached an approximate total of 3.5 million barrel/day (bbl/d), of which 1.9 were produced from oil sands. It is expected that by 2030, Canada will produce a total of 6.4 million bbl/d, with crude oil from bitumen representing over 90 % of this augmentation (CAPP 2014b). Even if new techniques and technologies improve the actual life expectancy of conventional oil reserves, oil sands, with a fast expending capital investment and the recent confirmation of new reserves, is where the growth is expected. Of the 339 billion barrels of crude oil that represent Canada's estimated resources by the end of 2012, oil sands bitumen and conventional crude are in a respective proportion of 90 and 10 % (NEB 2013). All of Canada's bitumen resources can be found in Alberta and Saskatchewan. Canada owns the third largest reserves of oil in the world, just after Saudi Arabia and Venezuela.

However, every actor in the industry agrees that in order to achieve such a progression in production, Western Canada's oil must find a demand for its offer. As Alberta and Saskatchewan are inland provinces, without access to tidewater ports, they are in need to develop their capacity to export this expected production. It is now becoming a political, economic and national security matter that this oil finds access to tidewater and export opportunities (McKenna 2013). As for their actual markets, maintenance on existing pipelines and the necessity of upgrading refineries receiving the crude oil from Western Canada, create bottleneck in the distribution system that furthermore puts pressure on expected growth. Already, the impact of this surplus in crude, and the inability to reach external markets, produces negative effects for the industry. Furthermost, is the price discount that Canadian oil producers must pay for their inability to reach markets, putting negative pressure on their profits. From 2011 and 2012, the Western Canadian Select (WCS), the price reference for Canadian heavy crude, traded up to US$19/bbl below West Texas Intermediate (WTI). This price reflects also the difference in quality of the two products (CAPP 2014b).

Seeing how, in the short term, production is straining pipeline capacity and will soon exceed transportation capacity, implementing only long term solutions may jeopardize this intended growth. On the order hand, short term solutions may prove useful in the interim, as such, the transport by rail cars may prove an interesting temporary solution. Rail cars shipping is expected to increase in Canada from about 200,000 bbl/d in late 2013 to 700,000 bbl/d by the end of 2016 (CAPP 2014c), about the transport capacity of a major pipeline. Even with this rapid development, Western Canada must increase dramatically its capacity to export.

The objective of this chapter is to analyze different crude oil exportation scenarios based on existing capacity expansion and new pipeline projects taking off from the *Western Canadian Sedimentary Basin* (WCSB) to reach North American, Asian or domestic markets. For the maximum levels of oil exports corresponding to the available pipeline capacity in each scenario, we compare both the impacts on the final energy demand and on the crude oil production profiles.

This chapter is organized as follows. Section 2 gives an overview of the different markets opportunities for supplying Canadian oil while Sect. 3 presents the database structure for the oil sector. Section 4 details our scenario definition. Section 5 provides contains the analysis of all scenarios, namely the impacts on the Canadian oil sector in particular and on the energy system in general. In Sect. 6, we compare some of our results with results from existing outlooks before concluding in Sect. 7.

2 Canadian Oil Exportation Options

It falls to the industry and governments to find and open new markets in order to achieve a significant increase in oil production. Three markets are therefore considered: (1) Central and South USA markets, (2) Canadian and USA West coasts and Asia, and finally (3) East Canada and Eastern USA.

2.1 Central and South USA Markets

The Midwest or PADD II district (Petroleum Administration for Defense District), is currently the largest market for Canada's oil, for an approximate amount of 1.7 million bbl/d. These markets are connected to Canada by two major pipelines, Enbridge Mainline and TransCanada Keystone. Both of these networks are suffering from overload capacity and are in need of major improvements. Secondly, PADD II's refineries are already receiving most of their foreign oil (98 % in Eastern district) from Canada, allowing less space for new market shares. Finally, recent years have seen an increase in tight and crude oil, as well as in natural gas in the USA. This new production is mainly directed in this district, competing directly with Canada's oil (EIA 2014). With these constraints, demand is anticipated to reach only 2.2 million bbl/d in 2020.

The main hope for future exportation resides in PADD III, Gulf district. It is home to half the refining capacity of the USA, with over 9.4 million bbl/d (EIA 2014). From this amount, 3.7 million bbl/d of crude were imported, mainly from Saudi Arabia, Mexico and Venezuela. But this share is diminishing rapidly with the surge in local oil, 17 % in 2012 alone. Mexico is producing slightly less each year and Venezuela is constantly threatening to diminish its offer to USA markets as a political lever. These trends, and the fact that the refineries in the Gulf are the most sophisticated in North America, already able to receive and transform Canada heavy crude, makes it an excellent option for exportation. Since this is a remote region from Western Canada, to reach this market, the authorities have been pushing its project of TransCanada Keystone XL for over 5 years now. If completed, it would provide an additional 830,000 bbl/d of capacity.

2.2 Canadian and USA West Coasts and Asia

By improving the pipeline network of Kinder Morgan Trans-Mountain (+590,000 bbl/d) and by developing the Enbridge Northern Gateway (525,000 bbl/d) between Edmonton and Kitimat, Western producers wish to accede to tidewater and therefore to Asian and Western USA markets. However, most of the extra capacity of the Kinder Morgan Trans-Mountain is already locked by firm 15–20 years' contract to Washington's refineries. It is primarily the Northern Gateway project, with its tidewater port at Kitimat, that could open the new and avid markets of India and China for Canada's crude oil. Singapore and Japan could also become interesting markets for light crude since they already have an extended refining industry for this product. Furthermore, the cost of transportation by tankers is also on par with the pipeline tariffs to USA refining markets (Wood-Mackenzie 2011). A tidewater access could also mean reaching PADD III and its attractive refining industry.

2.3 Eastern Canada and Eastern USA

Moreover, Western producers are also considering new markets on the other side of the country. Refineries in Québec and Atlantic Provinces import more than 80 % of their crude oil (642,000 bbl/d) from international markets, which makes them perfect targets for the expanding production. It is an argument in favor of the country's energy security. These regions' four refineries can handle heavier crude without much modification to their installation and their products could therefore be exported to Eastern USA. There is also the advantage of an existing, but incomplete network of pipelines that could be used to transport large amount of crude to these regions. In Ontario, in 2013, the refineries processed 380,300 bbl/d of crude oil from Canadian producers (94 % of capacity) with the first phase of the re-reversal of Enbridge line 9 of the same facilitating transportation. PADD I district is also a potential market that, if reached, may want to change its international imports to a more local and secure supply. Two pipeline projects are key to open these new markets, the re-reversal of Enbridge line 9 A and B, and the TransCanada Energy East Pipeline. If they were to be accepted in their actual form, they would add respectively 300,000 bbl/d and 1 million bbl/d to Québec's and Atlantic refineries.

3 Modeling the Canadian Oil Sector

The multi-regional energy model used for this study is an application of the TIMES model generator (Loulou et al. 2005) supported by the Energy Technology Systems Analysis Program (ETSAP 2014) of the International Energy Agency. More precisely, this TIMES model for Canada is part of a larger modeling framework: The North American TIMES energy model (ESMIA 2014).

The model covers the energy system of the 13 Canadian provinces and territories. The model spans 90 years (2011–2100) and this study will cover 2011–2050 through nine time periods and 16 annual time slices: four seasons (spring, summer, fall and winter) and four intraday periods (day, night, morning peak, evening peak). All costs are in 2011 Canadian dollars (CAD$). The global annual discount rate has been set to 5 % for this study. The model is driven by a set of 70 end-use demands for energy services and the database includes more than 4500 technologies and 800 commodities in each jurisdiction, logically interrelated in a reference energy system. As a result of our calibration process, the TIMES model for Canada yields for 2011 energy balances and greenhouse (GHG) emissions consistent with official statistics (Statistics Canada 2011, 2012; OEE 2011; NEB 2013; Environment Canada 2013) for the different province and territories.

In particular, Fig. 1 gives a simplified representation of the oil sector in the model. Supply curves have been built from the latest data available from NEB (2013) and CAPP (2013) for the different types of oil (conventional and non-conventional), reserves (located reserves, enhanced recoveries and new discoveries) and extraction techniques (mined and in situ). Most of the Canadian oil reserves (93 %) are located in the WCSB spread in four main provinces (Alberta, Saskatchewan, British Columbia, Manitoba). Extraction technologies are modeled for each type of oil and reserves, including several new methods for in situ extraction. Most of the mined bitumen (95 %) is currently upgraded into synthetic oil, while

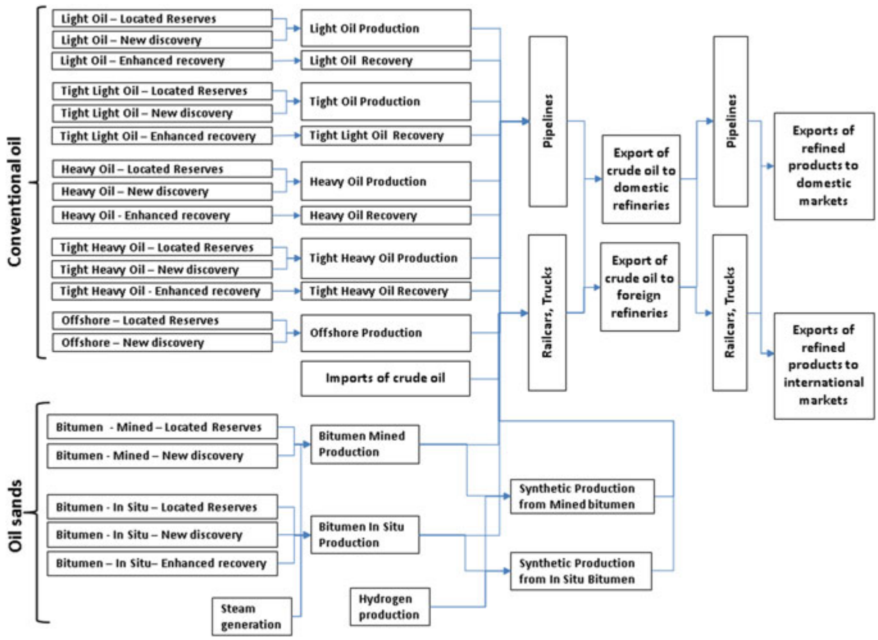

Fig. 1 Simplified representation of the oil supply sector

the in situ bitumen is mixed with condensates to produce a diluted bitumen appropriate for transport by pipeline.

Downstream activities includes six upgraders with a total capacity of 1.2 million barrels per day and 19 refineries with a total capacity of 2.06 million barrels per day and producing a full range of refined products (CAPP 2014b). Only a small number of refineries in Ontario and Alberta are currently configured to upgrade bitumen directly. All technologies are characterized by different costs and energy requirements. An important quantity of natural gas is use for steam generation (bitumen recovery) and hydrogen production (bitumen upgrading). Corresponding GHG emissions from fuel combustion and fugitive emissions are accounted at each step of the supply chain as well as flaring and venting emissions.

The model database includes the current existing transportation capacity as well as already planned projects for existing capacity expansion or new infrastructure. Due to the location of the main production centers in the WCSB and of the major markets in the USA Midwest and Gulf Coast regions, the pipeline network in North America has a strong North-South linkage. There are actually four main pipelines exiting the WCSB with a total capacity of 3.67 million barrels per day. The existing pipelines as well as planned projects are listed in Table 1 for exports from the WCSB to international destinations; they can all be visualized on maps in CAPP (2014b). In addition, rail transportation capacity has evolved quickly from 46 thousand barrels per day in 2012 to 300 thousand barrels per day in 2014 (CAPP 2014b). The growth in available rail capacity is expected to slow down and reach a maximum of 945 thousand barrels per day in 2050.

As for domestic trade, two major new projects are proposed and they are considered as future investment options in the model (Table 2) (CAPP 2014b). These projects would allow synthetic oil from the WCSB to be exported to Eastern refineries (not equipped to process bitumen) and consequently for Quebec and New Brunswick to reduce their imports from foreign countries.

Table 1 Existing and proposed pipelines for international exports

Pipeline	Target in-service	Capacity (k bbl/day)	Capacity (PJ)
Enbridge mainline	1950	2500	5651
Kinder Morgan trans mountain	1953	300	678
Spectra express	1997	280	633
TransCanada keystone	2010	591	1336
Total existing capacity		3671	8298
Enbridge Alberta clipper expansion	2014	120	271
Enbridge Alberta clipper expansion	2016	230	520
TransCanada keystone XL	2020	830	1876
Trans mountain expansion	2017	590	1334
Enbridge northern gateway	2017	525	1187
Total proposed capacity		2295	5188
Total capacity		5966	13,486

Table 2 New pipelines for domestic exports

Pipeline	Target in-service	Capacity (k bbl/day)	Capacity (PJ)
Enbridge line 9 reverse	2015	300	678
TransCanada energy east	2018	850	1921
Total proposed capacity		1150	2599

The model captures six types of oil commodities that can be transported by pipelines and/or other means (trucks, trains and tankers) from primary production wells to different types of destinations: domestic refineries, USA refineries and export terminals (e.g. Kitimat in BC) reaching two aggregated international regions (Rest of the World—East and Rest of the World—West). While international trade movements are modeled using fix prices and limits on quantities by origins and destinations, domestic trade movements within Canada are determined endogenously.

4 Description of Scenarios

For this study, end-use demand have been projected using a coherent sets of socio-economic drivers (NEB 2013), together with coefficients capturing demand sensitivity to these drivers. This approach builds on Vaillancourt et al. (2014) where five different baselines were developed and characterized by different assumptions on oil prices or economic growth covering a large range of uncertainties related to possible future trends. We have used here the central baseline scenario consistent with an oil price reaching US$123/barrel in 2050.

4.1 Pipeline Capacities in the Baseline Scenario

Baseline (BAU): This scenario illustrates the situation where all new projects would take place. The following assumptions are used to define the real availability of pipelines for exportation from the WCSB (CAPP 2014b):

- Enbridge Mainline: The pipeline is used at 70 % of its existing capacity for international exports (USA) and at 5 % for domestic exports (Ontario), while the remaining portion (25 %) is not available due to the competition with the oil entering the pipeline on the other side of the USA border.
- Enbridge Alberta Clipper Expansion: About 90 % of the total capacity will be used for international exports and 10 % for domestic exports (Ontario).
- Kinder Morgan Trans Mountain and Expansion: Most of the capacity is currently used to export oil to the USA (70 %), and to the rest of the world through

terminals in British Columbia (26 %). A small portion (4 %) is already used for carrying oil to domestic refineries in British Columbia.

- Spectra Express and TransCanada Keystone: These pipelines are available at 100 % to export oil to USA.
- TransCanada Keystone XL: This pipeline would be available at 100 % to export oil to USA.
- Enbridge Northern Gateway: This pipeline would be available at 100 % to export oil to ROW.
- Enbridge Line 9 reverse & TransCanada Energy East: These pipelines would be available at 100 % to export oil to Central and Eastern Canada.

Given these assumptions, the remaining available capacity is 4858 PJ and is expected to be doubled by 2020 with an additional 4986 PJ of capacity (Table 3).

A breakdown by type of destinations gives a better illustration of the saturation levels and potential for increases. Most of the existing capacity is used to export oil to Southern markets (capacity used at 97 %), while only a marginal portion is sent to Western markets (used only at 15 %). The addition of new capacity will allow increasing current exportation levels to the Southern markets by 1.79 times and to the Western markets by 65 times.

4.2 Pipeline Capacities in Three Alternate Scenarios

We have defined three alternate scenarios which differ in terms of the pipeline capacity available to supply the WCSB oil on various markets.

- **Southern markets (No South)**: This scenario represents a situation where there would be less additional options for WCSB oil to reach South and Central USA markets. The following project would never occur: TransCanada Keystone XL (1876 PJ of additional capacity for international trade).

Table 3 Available pipeline capacity for oil exports by destination

	Existing capacity (PJ)	New capacity (PJ)	Total capacity (PJ)	Exports in 2011 (PJ)	% of capacity in 2011
Southern markets	4679	3448	8127	4546	97
Western markets	179	1538	1717	27	15
Total international	4858	4987	9844	4573	90
Eastern: up to Quebec		678	678		
Eastern: up to new Brunswick		1921	1921		
Total domestic		2600	2600		

- **Western markets (No West)**: This scenario builds on the previous one and represents a situation where there would be also less additional options for WCSB oil to reach Canadian and USA West Coast and consequently Asian markets. The following projects would never occur: TransCanada Keystone XL (1876 PJ of additional capacity for international trade) as well as the Enbridge Northern Gateway (1187 PJ of additional capacity for international trade).
- **Eastern markets (No East)**: This scenario represents a situation where there would be no additional options allowing WCSB oil to reach refineries in Central and Eastern Canada (more precisely Quebec and New Brunswick). The following projects would never occur: Enbridge Line 9 reverse and TransCanada Energy East (2600 PJ of additional capacity for domestic trade).

5 Analysis of Scenarios

In this section, we present the impacts on the Canadian oil production levels and trade movements both within and outside Canada in all four scenarios: on the oil sector specifically (Sect. 5.1) and on the overall energy system in general (Sect. 5.2).

5.1 Impacts on the Canadian Oil Sector

These results show the evolution of the total oil production to 2050 to meet both the domestic demands and international exports. Figure 2 illustrates the breakdown of crude oil production by type in all scenarios. In the BAU scenario, oil production increases by 1.72 times between 2011 and 2030 level and peaks at 12,045 PJ in

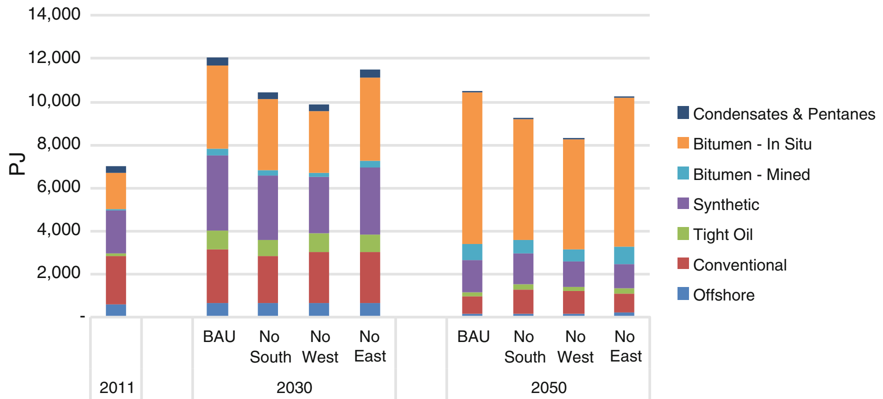

Fig. 2 Oil production by type in all scenarios

2030 before starting its decline to reach 10,492 PJ in 2050. The highest growth occurs between 2020 and 2030 after all pipeline projects have been built and the available capacity for exports has reached its maximum. The stability in the share of conventional oil between 2011 and 2030 is due to the availability of enhanced oil recovery options extending the life of some wells and the extraction of tight oil. However, conventional and tight oil *production* declines by significant faster rates between 2030 and 2050, representing only 10 % of the total oil production in 2050. While oil sands represented already half of the total oil production in 2011, it is expected to represent 88 % of the production in 2050. The proportion of oil sands extracted via in situ techniques alone is expected to represent 67 % of the overall production in 2050. A significant portion of this oil sands production via mined or in situ techniques is converted to synthetic oil.

Oil production levels in the three alternate scenarios show the significant impacts of available pipeline capacity for international exports: total oil production is 18 % lower in the No West scenario than in the BAU scenario in 2030 and 21 % lower in 2050. Conversely, the impacts of available pipeline capacity for domestic exports are non-significant, with only a 2 % decrease in 2050. As most of the production is exported, the international demand for Canadian crude is the main driver of oil production levels. A very large proportion of all the oil produced in the WCSB is exported to international destinations: 64 % in 2011 to 82 % in 2050 (Fig. 3). Consequently, the availability of the pipeline capacity for international exports has direct impacts on oil production levels while the effect of domestic exports is minor. In terms of international destinations, oil exports are almost exclusively oriented to USA markets by pipeline in 2011 but diversify on the long term both in terms of transportation means and other destinations due to (the assumed) higher oil prices.

5.2 Impacts on the Canadian Energy System

The availability of pipeline capacities do not significantly affect final energy consumption in Canada, even if fossil fuels continue to represent a large part of the fuel mix in the long term. Looking at the primary energy consumption (Fig. 4), energy

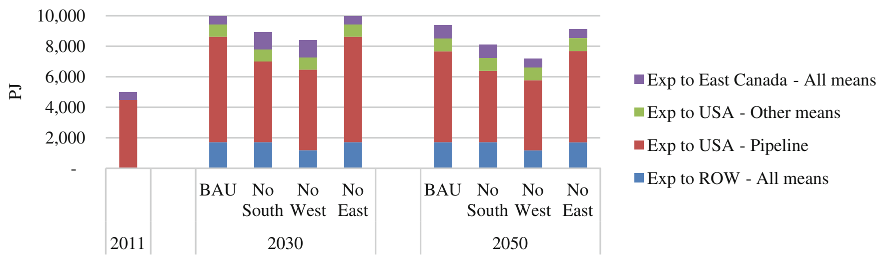

Fig. 3 Oil exports by destination in all scenarios

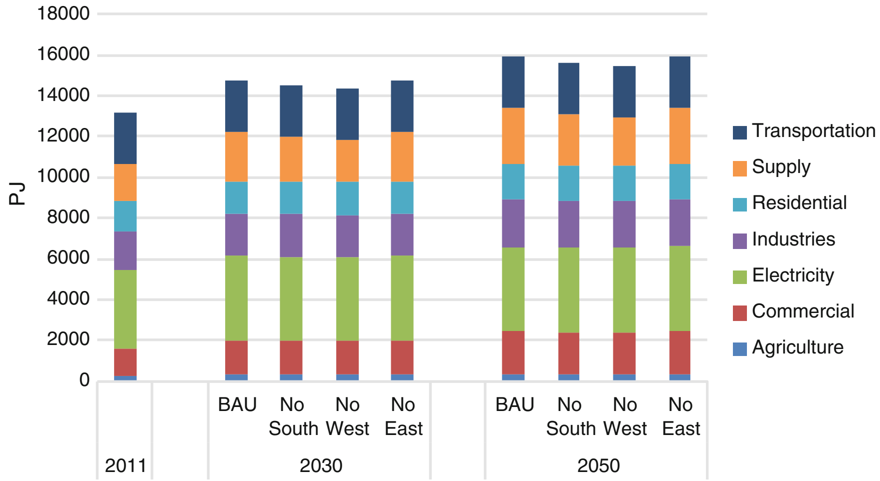

Fig. 4 Primary energy consumption by sector in all scenarios

uses in the supply sector is reduced along with the decline in oil production and exports: energy uses in the supply sector reach 2729 PJ in the BAU scenario, but only 2302 PJ in the No West scenario. However, the impacts on the primary energy consumption are minor. Less energy is required for oil extraction, upgrading and transportation of crude oil, but a portion of this decline is offset by an increase of energy uses for natural gas production, another resource largely available in Canada especially with the tight and shale gas.

The origin of crude oil used in the Central and Eastern regions of Canada (Fig. 5) indicates a strong trend toward the replacement of international light crude oil with domestic synthetic crude through the reversed Enbridge Line 9 and the TransCanada Energy East pipeline. The No East scenario shows that the high dependence Central and Eastern provinces would have to maintain imports from global markets, a situation with many energy security concerns. Only domestic supply is limited to the imports of WCSB bitumen and synthetic crude in Ontario through the existing pipeline network. In all scenarios, the need for crude oil is decreasing significantly toward 2050 due to two main factors: (1) a larger diversification of fuel used in transportation as well as important energy efficiency improvements for the various types of vehicles, and (2) an important decline in the exports of offshore oil from Newfoundland & Labrador to the USA.

In the BAU scenario, the level of GHG emissions reaches 704 Mt CO_2-eq in 2050. Due to changes in the primary energy consumption patterns, GHG emissions are lower in the scenarios where the exporting capacity is limited: 686 Mt CO_2-eq in the No South scenario (a 2.5 % reduction from the BAU level) and 673 Mt CO_2-eq in the No West (a 4.4 % reduction from BAU). The variations in GHG emissions are more significant than the variations in primary energy due to the fact that oil sands production is more energy intensive than natural gas production.

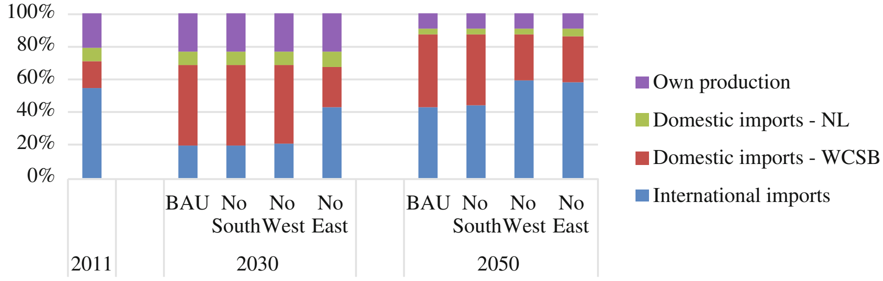

Fig. 5 Crude oil supply by origin in Central and Eastern Canada in all scenarios

6 Discussion

It is interesting to see how these oil projections compare with official Canadian outlooks. Figure 6 displays the oil production in all scenarios until 2035: oil production stabilizes at 9691 PJ in 2035 in the most conservative scenario (No West) and to 12,014 PJ in the most optimistic scenario with all pipeline projects (BAU). In all cases, these production levels are conservative compared with the central and high scenarios of the NEB (2013), where oil production reaches up to 13,201 PJ (NEB–Med) and 14,806 PJ (NEB-High) in 2035 respectively and with the scenario of the Canadian Association of Petroleum Producers (CAPP) (CAPP 2014b). These outlooks build on an optimistic view about the global demand for Canadian unconventional oil and the corresponding infrastructure capacity necessary to supply global markets: not only the available options (pipelines and/or other means) should include all projects already proposed but additional ones equivalent to the Enbridge Northern Gateway project for the NEB-Med scenario and to both Enbridge Northern Gateway and TransCanada Keystone XL projects in the NEB-High scenario.

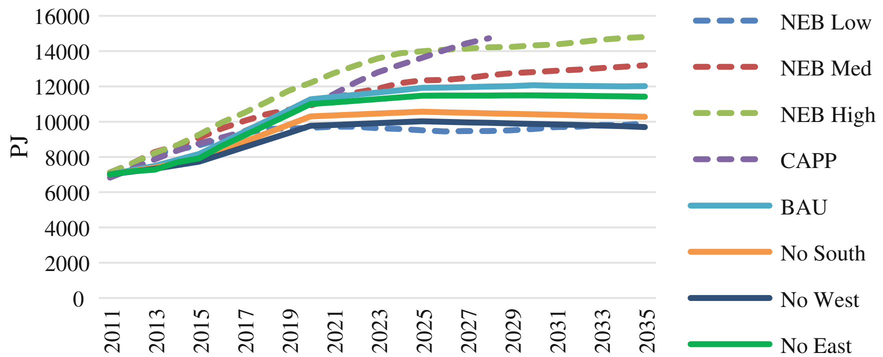

Fig. 6 Oil production levels compared with Canadian outlooks

These projections could appear as rather optimistic in the face of the many uncertainties surrounding the development of some pipeline projects that have the highest potential for increasing the exporting capacity. For instance, the TransCanada Keystone XL is currently facing vivid political opposition in the USA, augmenting the project's uncertainty.

7 Conclusion

We have presented the oil sector of a multi-regional TIMES energy model for Canada, a bottom-up optimization model that represents, in details, the whole integrated energy system from primary to useful energy in all provinces. We have also defined different exportation scenarios based on existing pipeline capacity expansion proposals and new projects taking off from the WCSB to reach North American and Asian markets. For corresponding maximum levels of conventional and unconventional oil exports, we have compared both the impacts on the crude oil production profiles and on final energy consumption mix. Results show that the exporting capacity will be an important driver for oil production level in Canada. Outside the oil sector, impacts on the energy system are limited. In particular, final energy consumption patterns are similar across scenarios since fossil fuels remain the basis for the economy whatever the origin of crude oil.

If Western oil producers are experiencing uncertainty as per which market they will be able to occupy, and by when, what is certain is that, default by them and the interested governments to find new avenue to a fast growing production will result in lower price for Canadian oil and postpone major investments and expected financial development. Variation of oil prices on international markets have indeed major impacts on the Canadian oil sectors in addition to pipeline capacities. Future works will study the impacts of different oil price forecasts on the Canadian energy system.

Acknowledgments The authors wish to acknowledge financial support from the Natural Sciences and Engineering Research Council of Canada (individual grant of Olivier Bahn) as well as research assistance from Cedric Gagnon-Ducharme.

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Multi-cluster Technology Learning in TIMES: A Transport Sector Case Study with TIAM-UCL

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Abstract The costs of technologies often fall over time due to a range of processes including learning-by-doing. This is a well-characterized concept in the economics of innovation, in which learning about a particular technology, and hence cost reduction, is related to cumulative investments in that technology. This chapter provides a case study applying technology learning endogenously in a TIMES model. It describes many of the key challenges in modelling technology learning endogenously, both in terms of the interpretation and policy relevance of the results, and in terms of methodological challenges. The chapter then presents a case study, exploring a multi-cluster learning approach where many key technologies (fuel cells, automotive batteries, and electric drivetrains) are shared across a set of transport modes (cars, buses and LGVs) and technologies (hybrid and plug-in hybrid fuel cell vehicles, battery electric vehicles, hybrid and plug-in hybrid petrol and diesel vehicles). The multi-region TIAM-UCL Global energy system model has been used to model the multi-cluster approach. The analysis is used to explore the competitive and/or complementary relationship between hydrogen and electricity as low-carbon transport fuels.

1 Introduction

Energy system models inform policymakers about the potential importance of particular technologies by examining whether their presence or absence (at a given cost/performance) influences the overall costs of decarbonisation. In examining the potential of new technologies, technology-rich models like TIMES and MARKAL

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_15

take one of three approaches, which can be varied with different model runs or scenarios, for the capital cost of a technology:

1. Assume no technological change to examine whether, with stock turnovers, current technologies are sufficient to meet energy system goals.
2. Use exogenous forecasts of technological development, drawn from a range of sources. This is the approach that is typically taken with MARKAL and TIMES model.
3. Endogenise technological change into the model structure (by implementing "Endogenous Technology Learning" or ETL).

Most bottom-up energy system models adopt the second approach, using exogenous forecasts of technological development to represent technology improvements. These forecasts come from diverse sources, for which underlying assumptions are not always clear. Typically, it is recognized that while significant cost reduction is possible as a result of research and development (R&D) before a technology enters markets, there is further cost reduction after market introduction, as a result of learning-by-doing, economies of scale, continued R&D and other factors such as maturing supply chains. Some technological forecasts are produced on the basis of learning curve studies that posit a particular level of deployment of the technology. This can lead to several problems:

- First, the models' technology choice is resting on inputs that already assume the success of particular technologies. If the analyst is interested in optimal technology portfolios, this is clearly problematic: the input data already incorporates assumptions about which technologies will be most widely deployed.
- Second, exogenous technology learning allows the energy system to get the benefits of learning for free. There is no need to deploy expensive first-of-a-kind technologies, because in later years the costs will have fallen. It is possible that this appears to implicitly advocate a wait-and-see mode of technology deployment (it is not cost effective yet, so it should not be deployed yet); and it understates the total investment requirements and costs of decarbonisation, since learning costs are ignored. This has been described as 'learning without doing' (Seebregts et al. 1999).

Endogenous technology learning thus improves the internal consistency of the models (Grubb et al. 2002), and can be more appropriate for analysis attempting to gauge the relative importance of different technologies. Multi-cluster ETL-enabled models also allow insights into technology dynamics, which may suggest that technologies are worth supporting even if they are not in themselves the least-cost option, because they support learning that enables other lower cost solutions.[1]

[1]For example, fuel cell buses may not themselves be the least-cost bus technology in a carbon constrained future; but they may 'earn' their position in a least-cost solution if their deployment results in learning that can be applied to cars.

This chapter provides a case study applying technology learning endogenously in TIMES model. It applies a multi-cluster approach where many key technologies (fuel cells, automotive batteries, and electric drivetrains) are shared across a set of transport modes (cars, buses and LGVs) and technologies (hybrid and plug-in hybrid fuel cell vehicles, battery electric vehicles, hybrid and plug-in hybrid petrol and diesel vehicles). The analysis is used to explore the synergies and interactions between key component technologies, and the competitive and/or complementary relationship between hydrogen and electricity as low-carbon transport fuels.

2 Background: Modelling Technology Learning and the Experience Curve

The relationship between cumulative deployment and capital cost—described as the "learning curve"—is a well-characterized concept in the economics of innovation. Learning curves have been determined empirically for a wide range of energy technologies (McDonald and Schrattenholzer 2001). The most common formulation of the learning curve is described by Eq. 1 below:

$$C_t = C_0 * (Q_t/Q_0)^{-b} \tag{1}$$

where C_0 and Q_0 are the initial capital cost and initial installed capacity respectively, while C_t and Q_t are the capital cost and cumulative installed capacity respectively at time t. The parameter b is not intuitively easy to grasp, so is usually expressed as the progress ratio ($PR = 2^{-b}$) or the learning rate ($LR = 1 - PR$). The learning rate is the cost reduction achieved for a doubling of cumulative capacity, and is typically around 15–20 % for new energy technologies (Gritsevskyi and Nakićenovic 2000; Seebregts et al. 1998).

The learning curve equation, based on cumulative capacity, is an intuitive and analytically tractable account of how deployment relates to technological change. As a result, it has become the most widespread approach to implementing technology learning endogenously within energy-economy models. However, a growing literature—from both quantitative analysts and more qualitative 'innovation studies' scholars (Winskel et al. 2013) highlights the complexities that such a basic formulation overlooks. Perhaps unsurprisingly, representing technology dynamics effectively in energy systems and integrated assessment models is recognised as one of the great challenges for the field (Grubb et al. 2002). Here, we highlight three key methodological challenges and issues in modelling ETL, and the ways in which previous analysis has addressed them.

First, empirically derived learning curves capture changes that are both time dependent (typically thought to reflect learning 'by research'), and scale dependent (including returns to scale, and maturation of supply chains). For this reason, some scholars prefer the term 'experience curve'. Disentangling those different factors is not always straightforward, and the estimation of true 'learning by doing' can thus be challenging. Other factors come into play too—commodity costs, supply-chain bottlenecks, and the processes of 'forgetting' (described by economists as depreciation of knowledge stocks) that can occur when an industry experiences pauses or set-backs, as has occurred with the nuclear industry in many countries. The wider innovation literature highlights the existence of regulatory and wider socio-technical processes (such as socially conferred 'legitimacy' and the establishment of political lobbying power) that also go hand in hand with successful deployment, and help to reinforce allocation of R&D budgets and reduction in regulatory and transaction costs (Bergek et al. 2008). Some authors have suggested that the specification of future learning rates in models should therefore be dependent on the policy scenario (Winskel et al. 2014).

Some authors have attempted to disaggregate these diverse learning and other effects. For example, the separate processes of learning-by-doing and learning-by-research have been modelled by adopting a 'two-factor' learning curve, in which both cumulative capacity, and some measure of the R&D knowledge stock, influence rates of learning (e.g. Totschnig and Keppo 2007; Criqui et al. 2014). Others have developed three-factor or multi-factor models (Yeh and Rubin 2012). However, such approaches add analytic complexity, and may not be appropriate for a large, technology rich model. In any case, an innovation system perspective suggests that it is rare that technologies are fostered solely through R&D or solely through deployment with no accompanying R&D. It seems possible that a single learning curve, though undoubtedly a simplification, may be well placed to represent aggregate capacity-cost relationships that emerge from a wide range of processes, including both true 'learning' and other correlated processes. A similar point is made by Watanabe et al. (2000) and Kahouli-Brahmi (2008), and a good discussion of the issues is provided by Yeh and Rubin (2012). An alternative to two-factor or multi-factor learning is to model exogenous learning as a function of time in addition to learning-by-doing.

Second, technologies are often closely related, and cost reductions in one application often leads to cost reductions for a related technology in a different application, even where slightly different characteristics are required. In modelling ETL, it is possible to create 'clusters' of closely-related technologies, which share learning, to account for this effect. Examples of cluster-based learning include Totschnig and Keppo (2007), who assessed clusters around several key technologies for cars (fuel cells, hydrogen tanks, hybrid systems, and onboard fuel reformers); and Gritsevskyi and Nakićenovic (2000), who modelled ETL for fuel cells, with full spill-overs between different types of fuel cell for cars (e.g. running on hydrogen vs. on methanol), and partial spill-overs between automotive and stationary fuel cells. Krzyzanowski et al. (2004) explored clusters in which learning in hybrid drive trains is shared between light trucks and cars, and it appears that Krzyzanowski et al. (2008) explored cluster learning in which fuel cell learning was shared between buses and cars, but this is not made explicitly clear in the paper. Gül et al. (2009) applied learning to clusters of hydrogen and electricity production technologies, but the representation of transport technologies does not use a cluster approach, and so does not enable spill-overs between e.g. fuel cell cars and battery electric light goods vehicles.

The degree of spill-over between particular technologies is an important assumption in such analysis, but it is not clear that such relationships can be forecasted with any accuracy. Past practice has tended to make assumptions about the degree of relatedness and spill-over, largely on the basis of modeller judgement rather than empirical evidence. Furthermore, it is not necessarily straightforward to define the level of aggregation at which to study (and model) the experience curve. Components (such as wind turbine blades or nacelles) may develop at different rates from the aggregate wind turbine.

A third methodological challenge relates to the perfect foresight nature of bottom-up energy system models such as MARKAL/TIMES. Many earlier studies applying ETL in MARKAL/TIMES or other bottom-up optimization models (e.g. Mattsson and Wene 1997; Seebregts et al. 1998; de Feber et al. 2003) found that the model tends to deploy the 'learning technology' very rapidly and to the greatest extent possible—or not at all. In terms of interpretation, this raises questions about the feasibility of very rapid transitions from one technology to another, as well as questions about the relationship between deployment speed and learning rate. An observation from the rapid roll-out of flue-gas desulphurisation in Germany during the 1980s was that simultaneous deployment across a large number of power stations inhibited effective learning because the same mistakes were being made at the same time (Eames 2000). There was no time to learn from one installation and apply those lessons to the next, since they were not occurring sequentially. The implications of this observation for system models is that the relationship between learning rates and deployment rates (and rate constraints) should be considered, at least in the interpretation of results if not endogenously within the model.

The immediately-or-never pattern of deployment of a learning technology within an ETL model has led some authors to advocate caution in modelling ETL: if the resulting model dynamics are simply the result of exogenous rate constraints and upper bounds, then there may be few additional insights derived from the considerable effort required to endogenise learning in the model (Loulou et al. 2005). However, the approach presented in the case study in this chapter appears to reduce the problem of immediately-or-never deployment in an ETL model. This case study applies multiple clusters in which key vehicle components (automotive batteries, fuel cells, and electric drivetrains) undergo learning that is then combined within and shared across vehicle modes (buses, HGVs, cars). As the analysis shows, the model does not show the immediately-or-never behavior typical to previous work with ETL in energy system models.

3 Endogenous Technology Learning in TIMES

To represent learning-by-doing in TIMES, the investment cost (INVCOST) of the learning technology will decrease with the cumulative investment of the learning technology. The investment cost of the learning technology becomes a variable investment cost. This is represented by Eq. 2.

$$INVCOST = aC_t^{-b} \quad (2)$$

where, a is initial investment cost, C is cumulative investment and b represents learning. Since the relationship between the investment cost and learning rate is non-linear (Eq. 1), the TIMES model's objective function will yield a non-linear expression, which as a linear programming model it is unable to solve. To avoid a non-linear relationship, the investment cost in the objective function will be represented by piecewise linear approximation of total investment cost (TCt) as shown in Fig. 1. The cumulative learning curve is approximated by linear segments and binary variables are used—leading to mixed integer programming, which increases computing time.

Learning in one technology often enables cost reductions in closely related technologies. To account for this effect, a cluster approach can be used in TIMES, in which a group of technologies sharing a common component—the 'key technology'—learn together. The technologies constituting a cluster are related by multiple links that contribute to magnify their economic, social and environmental impacts (Grübler et al. 1999). These multiple relations ensure that progress in one technology contributes, directly or indirectly, to progress for other members of the cluster, as it helps to reinforce their own position in the marketplace.

In TIMES, it is possible to apply learning for a single technology at a regional level or global level. When learning is global, deployment yields cost reductions for users of the technology worldwide regardless of which region has deployed the technology—learning is said to spill over globally.

For each learning technology, the user provides:

The progress ratio pr [$pr = 2^{-b}$; $1 - pr$ (learning rate) is the cost reduction incurred when cumulative investment is doubled];
One initial point on the learning curve, denoted (C_0, TC_0) and floor cost;
The maximum allowed cumulative investment $C_{\max}$ (from which the maximum total investment cost $TC_{\max}$ may be inferred);

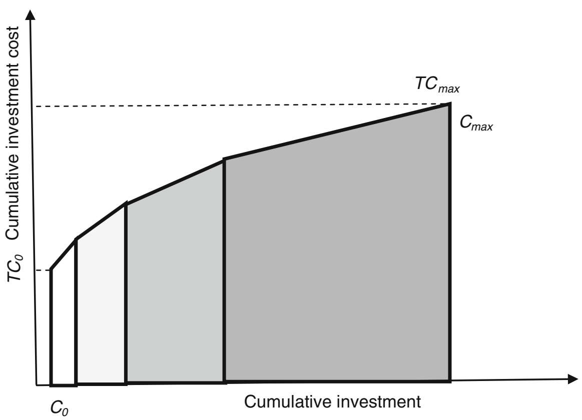


Fig. 1 Segment approximation of the cumulative cost curve

The number N of segments for approximating the cumulative learning curve over the (C_0, $C_{\max}$) interval (note that N may be different for different technologies).

As noted above, many previous applications of ETL within MARKAL/TIMES models have observed that the model tends to select learning technologies, and invest massively in early periods in these technologies in order to lower future cost. The resulting unrealistically rapid deployment can be prevented by additional constraints (build rate). Results are then conditioned by the exogenous upper bound. The discount rate provides an incentive for postponing investments. Investing early allows the unit investment cost to drop immediately, and thus allows much cheaper investments in the learning technologies in the current and all future periods. The resulting dynamics depend on the learning rate and the discount rate.

4 Case Study

4.1 Introduction

Both hydrogen and electricity have been widely discussed as possible fuels for decarbonising road transport, as long as hydrogen and/or electricity is produced in a sustainable manner. Yet deployment of such vehicles is currently limited, as battery electric and fuel cell technologies are too expensive to compete techno-economically with internal combustion vehicles using fossil fuels. This case study, which draws on Anandarajah et al. (2013), analyses the long-term role of hydrogen and electricity in facilitating decarbonisation of the global transport sector by implementing global learning endogenously in the TIAM-UCL multi-regional global energy system model. The 16-region TIAM-UCL model has been developed at UCL through the UK Energy Research Centre (UKERC) by breaking out the UK from the Western Europe Region in the 15-Region ETSAP-TIAM model, which is the global multiregional incarnation of the TIMES model generator (Loulou et al. 2005; Loulou and Labriet 2008).

4.2 Technology Learning

The cluster approach adopted in this paper uses single factor learning, where a group of technologies sharing a common component—the ‘key technology’—learn together. For example, fuel cells are an example of a key component technology, and members of the corresponding cluster of ‘shell’ technologies in which the component is used are hybrid- and plug-in hybrid-fuel cell vehicles both in cars and light goods vehicles (LGVs) as well as in buses. Three key component technologies undergo learning in the model, and are thus explicitly represented in the model as technologies in their own right, in addition to the vehicle ‘shell’ systems in which they are deployed (Fig. 2):

Fuel cell systems ($/kW)
Electric drivetrains ($/kW)
Automotive battery systems ($/kWh)

Only investment costs undergo learning. As a result, the component technologies in the model only carry investment costs. Efficiency and O&M costs are attributes of the vehicles (shell) themselves. Each of these component technologies is embedded in vehicles that use them. For example, a hybrid hydrogen fuel cell vehicle uses electric drivetrain, battery, and a fuel cell system. A plug-in hybrid petrol car, in contrast, uses an electric drivetrain and battery but no fuel cell. Table 1 shows the vehicle types, the acronyms used to describe them in this paper, the fuels they use, and which of the component ‘key technologies’ they use. Data are not shown in the table, for brevity, since the capacity of each key technology differs depending on whether the vehicle type is deployed as a car, bus or LGV. Data can be found in McDowall (2012).

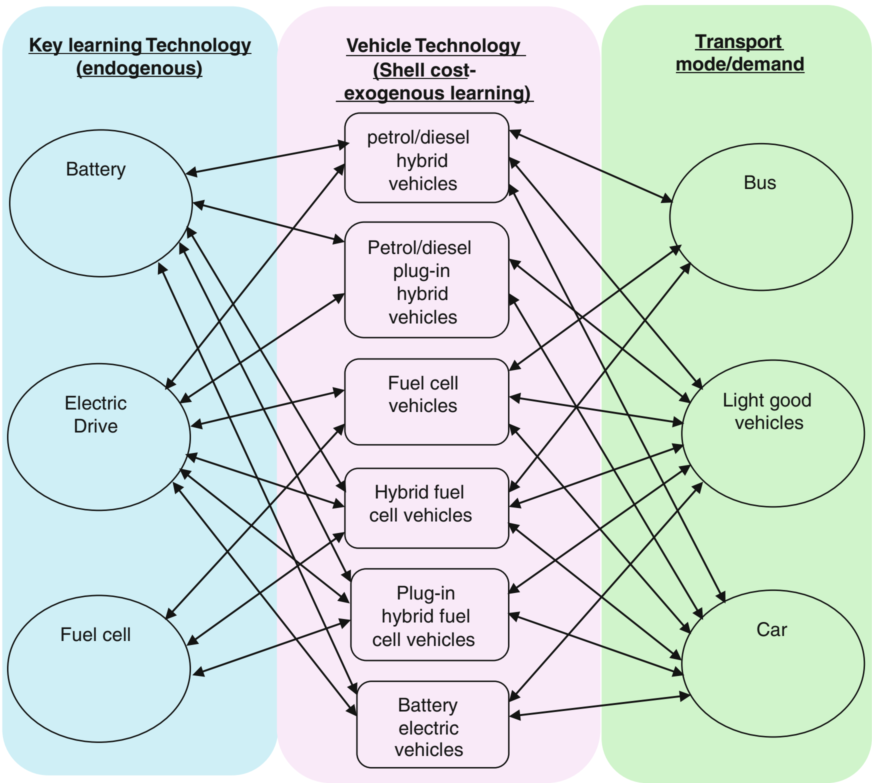


Fig. 2 Multi-cluster learning approach modelled in TIAM-UCL

Table 1 Vehicle types in the model. All vehicle types are available as cars and light goods vehicles (LGVs), only those marked with an asterisk are available as buses

Vehicle type	Acronym	Fuels used	Key technologies		
			Battery	Electric drive	Fuel cell
Petrol vehicle	Petrol ICE	Petrol or ethanol	✗	✗	✗
Diesel vehicle*	Diesel ICE	Diesel or biodiesel	✗	✗	✗
Petrol hybrid vehicle	Petrol HEV	Petrol or ethanol	✓	✓	✗
Diesel hybrid vehicle*	Diesel HEV	Diesel or biodiesel	✓	✓	✗
Petrol plug-in hybrid vehicle	Petrol PHEV	Petrol or ethanol and electricity	✓	✓	✗
Diesel plug-in hybrid vehicle	Diesel PHEV	Diesel or biodiesel and electricity	✓	✓	✗
Fuel cell vehicle	FCV	Hydrogen	✗	✓	✓
Fuel cell hybrid vehicle*	FCHV	Hydrogen	✓	✓	✓
Fuel cell plug-in hybrid vehicle	FCPHEV	Hydrogen and electricity	✓	✓	✓
Battery electric vehicle	BEV	Electricity	✓	✓	✗
Natural gas vehicle*	CNG	Natural gas	✗	✗	✗
LPG vehicle	LPG	Liquefied petroleum gas	✗	✗	✗

Learning for a component takes place regardless of the vehicle type in which it is deployed. i.e. cost reductions that arise from deployment of fuel cells in buses also apply to fuel cells for use in cars. Shared learning of this kind is thought realistic by the automotive industry, which sees opportunities for hybrid vehicles to provide a stepping stone into electric vehicles, whether battery powered or fuel cell powered (Lipman and Hwang 2003). Similarly, Zaetta and Madden (2011) suggest that a plausible route for bus fuel cell system development is through shared learning with car fuel cells.

4.3 *Data*

Documentation for TIAM-UCL is available in the website of the UK Energy Research Centre, and data and assumptions for vehicle characteristics and learning technologies are fully documented in McDowall (2012) and McDowall and Dodds (2012). For brevity, only the key technology learning parameters (learning rate, initial cost, initial capacity and floor cost) are presented in Table 2. It is assumed that learning can start from 2015. All costs are in year 2005 US$.

Table 2 Data on key learning technologies. Detailed assumptions found in McDowall (2012)

	Fuel cell system	Electric powertrain	Automotive batteries
	$/kW	$/kW	$/kWh
Initial cost	883	244	756
Floor cost	27	24	151
Learning rate	18 %	10 %	7 %
	GW	GW	GWh
Initial installed capacity	1.1	250	6.5
Number of doublings of capacity to reach floor cost	18	23	23

5 Scenarios

Five groups of scenarios have been run in order to examine the role of learning in determining the optimality of electricity and hydrogen in the global road transport sector. All scenarios are greenhouse gas (GHG) reduction scenarios, in which cumulative carbon-equivalent (CO_2e) emissions are constrained to a total of 1980 GtCO_2e during 2010–2100 (consistent with a 50 % likelihood of global mean temperatures rising no more than 2 °C above pre-industrial levels). This scenario does not force the model to meet commitments made by particular countries to reduce emissions. Instead, the model is free to determine the least-cost global abatement.

1. ***Static technological development***. Transport technologies undergo no learning; transport technology costs are constant across the model time horizon.
2. ***ETL base case scenario***. Transport technologies undergo ETL; roll-out of hydrogen and electric vehicles occurs only when they become cost effective.
3. ***ETL Early hydrogen deployment scenarios***. Cases in which countries deploy hydrogen vehicles before they are part of a cost-optimal carbon abatement solution. There are several scenario variants:

   Three scenarios examine differing levels of non-optimal early deployment of fuel cell cars, representing efforts made by countries to launch fuel cell vehicles domestically in order to capture first-mover advantages in this technology. The first of these scenarios envisages Germany and Japan each deploying 15,000 vehicles in 2020. The importance of early deployment is further tested by running scenarios with twice and four times this early deployment level.

   An additional early deployment scenario examines early deployment of fuel cell buses. This scenario supposes that some cities force uptake of fuel cell buses for air quality reasons.

4. ***ETL No CCS scenario***. Deployment of carbon capture and storage (CCS) technologies is prevented; otherwise same as ETL base case scenario
5. ***ETL Late action scenario***. Global mitigation is delayed; no emissions reductions against the base case are possible before 2020 in this scenario; otherwise same as ETL base case scenario.

The global availability of bioenergy is uncertain, and it may have an important effect on the cost-effectiveness of low-carbon vehicle technologies, since biofuels derived from biomass might be expected to compete with hydrogen and electricity in a low carbon scenario. The base case scenarios assume that global availability of biomass is broadly in line with the more optimistic scenarios of Erb et al. (2009). However, Slade et al. (2011) note that the literature encompasses estimates of significantly greater global biomass availability. Each of the above scenarios has therefore also been tested under more optimistic assumptions about the global availability of biomass, in which the availability of biomass is twice that in the base case.

6 Results

6.1 Roles for Hydrogen and Electricity in the Transport Sector

Static Technology Scenario: Without significant learning, hydrogen and electric vehicles remain too expensive, and hence play a minimal role, appearing only in 2095, in the transport sector even under a stringent carbon constraint.

Endogenous Technology Learning base scenario (*ETL*): When the model is allowed to benefit from learning-by-doing, hydrogen and electricity both play a substantial role. Learning brings down the cost of fuel cells and electric vehicle components, enabling hydrogen and electricity to become cost-effective transport fuels.

Early Hydrogen Deployment Scenarios: The forced early deployment in these scenarios does not change long-term transport sector hydrogen or electricity consumption patterns as compared to the ETL scenario. While early deployment reduces vehicle costs, these technologies and their associated infrastructure remain too expensive to justify deployment until marginal abatement costs have risen further.

Later Action Scenario: Combined consumption of electricity and hydrogen in the transport sector substantially exceeds that in the ETL base case scenario. This is because the model is unable to reduce emissions before 2020, and must therefore ‘work harder’ to reduce emissions after this date to remain within the cumulative carbon emissions budget.

No CCS scenario: This scenario shows a similar pattern to the late action scenario. In the absence of CCS technologies, the model must reduce emissions more quickly in end-use sectors including transport, and so deploys both battery electric vehicles and fuel cells more rapidly than in the ETL base case.

Sensitivity scenarios on Biomass Availability: In the base case runs, the model deploys bioenergy in the power sector and in industry, often in combination with CCS, rather than in the transport sector. One might imagine that in scenarios with greater availability of bionenergy, the model might select biofuels rather than electricity or hydrogen.

However, the results of the biomass resource sensitivity scenarios do not support this view. Instead, increasing biomass resource availability increases the ability of the model to deploy bio-CCS (which is assumed to be net carbon negative). As a result, the model delays the entry of hydrogen and electricity into the transport sector, with little early deployment of either, as end-use sectors need less decarbonisation thanks to the greater contribution from bio-CCS to emissions reductions.

6.2 Transport Technology Deployment Pathways

Within each of the vehicle classes, the results suggest a sequence of vehicle technology transitions. In all vehicle types, the sequence begins with hybridisation of the vehicle fleet, reducing the fuel consumption and deploying a significant number of electric drive-trains and automotive battery systems. Later, these hybrids are replaced, sometimes followed by plug-in hybrid technology as an intermediate stage, and ultimately followed by hydrogen fuel cell technologies, and for cars some battery electric vehicles. An example of this pattern is shown in Fig. 3.

Many studies applying endogenous technology learning find that the model seeks to deploy in early periods a very large amount of the ultimate technology (in this case usually fuel cell vehicles), since early deployment drives down costs and

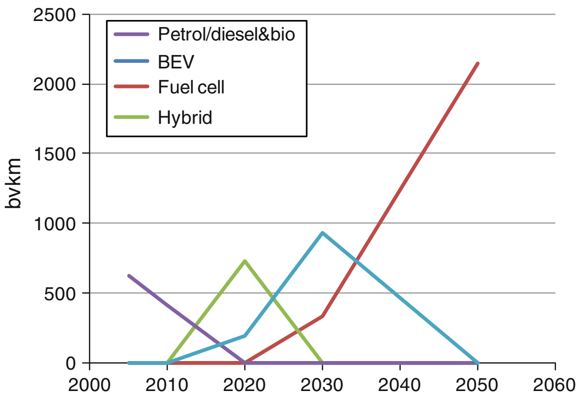


Fig. 3 Sequential deployment of different vehicle technologies (2005–2050) in light goods vehicles (ETL-base case scenario)

those lower costs can be enjoyed for the rest of the modelling period. However, with components sharing learning, and recombined across different vehicle modes and platforms (and across different global markets in the 16 regions of the model), the model can reduce the costs associated with moving down the learning curve by sequential deployment of technologies that contribute to learning without incurring the high costs associated with an early massive deployment of not-yet cost-effective technologies.

There is also a sequence in terms of the timing of deployment of low-carbon technologies across vehicle types. Fuel cells are deployed first in buses and LGVs, which have higher average annual mileage than cars, and which therefore prioritise lower running costs (and hence higher efficiency) more highly than cars. In LGVs, the model first deploys hydrogen, and ultimately transitions to electric vehicles after 2075 in many scenarios. This is likely to be because the efficiency of electric vehicles is higher than that of hydrogen, but so is the capital cost. It is only later in the period, when carbon abatement costs have become very high, that the model prefers the greater efficiency of battery electric vehicles.

The deployment of vehicles results in the deployment of the key technologies that undergo learning. Fuel cell technology becomes cost effective first in buses and LGVs, and then in cars following the cost reductions associated with deployment. Electric drive trains and batteries are cost effective starting in hybrid vehicles, and are subsequently deployed in all other low-carbon vehicle types.

6.3 Implications of ETL for Vehicle Cost

Cumulative investment brings down the costs of key technologies (fuel cell, electric battery and electric drive) in all scenarios in which ETL is applied (ETL base case scenario is shown in Fig. 4). Since the learning rate for fuel cells (18 %) is relatively high compared to that of batteries (7 %) and electric drive-trains (10 %), the cost of fuel cells decreases more rapidly. Battery costs fall quickly to just over $300/kWh,

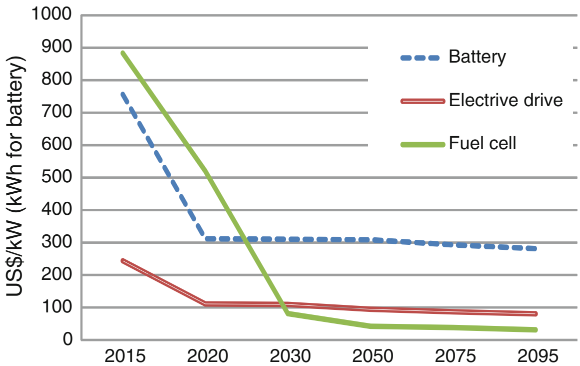


Fig. 4 Unit cost of key technologies in the base case ETL scenario

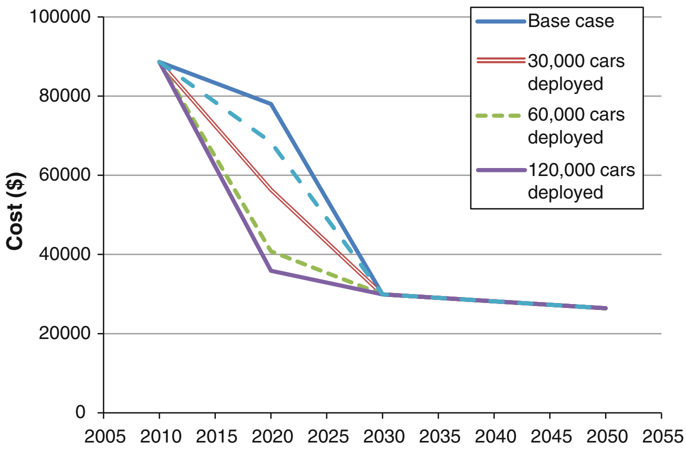


Fig. 5 Capital cost of a hybrid fuel cell vehicle under different early deployment scenarios

but are not deployed in sufficiently large quantities to reach their potential floor cost of $150/kWh. The cost of fuel cells in 2050 is reduced to less than a twentieth of the 2015 cost. To achieve these cost reductions, the transport sector requires a cumulative installed capacity of around 131,000 GW of fuel cells by 2050 worldwide; corresponding to a cumulative total of around 1.6 billion vehicles, with around 53 million new fuel cell vehicles added each year by 2050.

The investment (discounted to base year 2005) over the 35 years from 2015 to 2050 that achieves these cost reductions in fuel cells is a cumulative global total of $1200 bn (i.e. the cumulative total investment in fuel cell technologies globally). The figure for the 15 years from 2015 to 2030 is $64 billion (required to have a cumulative installed capacity of around 1860 GW of fuel cell by 2030). However, this cost is offset by the avoided investments in the conventional technology: petrol and diesel engines. As a result, the additional 'learning investments' required to bring down fuel cell cost are rather small, around $33 bn (discounted to base year 2005) for the 15 years.

As noted above, it is larger vehicles with higher annual mileage[2] that are deployed first, rather than cars. Nevertheless, the costs of fuel cell cars is reduced significantly in 2030 (Fig. 5), despite having had no deployment of fuel cells in cars by that date. Instead, roll-out of fuel cell buses and light-goods vehicles has driven down the costs of fuel cells and other EV components, reducing the capital costs of fuel cell vehicles. Even so, fuel cell vehicles remain too expensive in the near term

[2]Average annual mileages for buses and light goods vehicles are much higher than for cars. In the model, this is reflected in assumed average annual mileages specific to each vehicle mode.

to compete with conventional hybrids, which are deployed globally resulting in a significant reduction in global transport CO_2 emissions. Only from 2050 onwards, as emissions constraints bite further, does the transition to hydrogen passenger mobility begin.

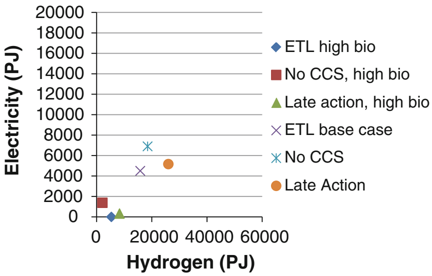
The early deployment scenarios demonstrate a clear effect on near term costs, with early deployment of fuel cell technologies in cars or buses driving down costs of key components. This is shown in Fig. 5. However, despite these accelerated cost reductions in the near term, the early deployment scenarios do not have a sufficiently large impact on costs to accelerate adoption. Given the presence of other, cheaper abatement opportunities throughout the energy system, the model prefers to deploy hydrogen vehicles later, as carbon abatement costs rise.

6.4 Hydrogen Versus Electric Vehicles?

There is an on-going debate about the complementarity or competitiveness of hydrogen and electric vehicles (Bento 2010). In the results presented here, both hydrogen fuel cell vehicles and battery electric vehicles are deployed in all scenarios. At a global level then, the model does not support an absolute trade-off between hydrogen and electricity as transport fuels, since different markets in different regions may prefer one or the other,[3] and both are required to achieve global decarbonisation at least cost. There is also significant deployment of fuel cell plug-in hybrid electric vehicles (FCPHEVs) in all scenarios, representing a complementarity between fuel cell and battery electric technology at the level of the individual vehicle.

In the medium term, therefore, there appears to be synergy between vehicles using hydrogen and electricity as fuels, as scenarios with more hydrogen vehicles (FCVs and FCHVs) tend also to deploy more electric vehicles (BEVs, Petrol and diesel PHEVs), in part because of the shared cost reductions. By the end of the century, most passenger cars and light goods vehicles are fuelled with either hydrogen or electricity or both (FCPHEVs). In this heavily decarbonised transport sector, hydrogen and electricity become competitors in the sense that scenarios with more of one have less of the other (see Fig. 6). It should be noted from the axes of the diagram that in the long term (by 2095), more hydrogen than electricity is consumed by the transport sector in all scenarios.

[3] Technology costs are global, but fuel production costs and carbon intensities vary, reflecting different resource endowments, and this can result in different fuels being preferred in different regions.



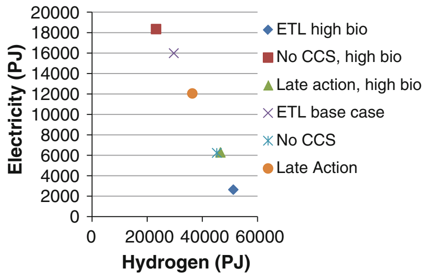


Fig. 6 Transport sector consumption of hydrogen and electricity under different scenarios, in 2050 (*left panel*) and 2095 (*right panel*)

7 Conclusions, Limitations and Policy Implications

The study concludes that electricity and hydrogen emerge as complementary fuels, rather than as strict competitors, with both deployed in all scenarios. This reflects the fact that hydrogen and battery electric vehicles share components: in the near term, deployment of hybrid cars reduces the costs of components that are used in fuel cell vehicles; and later deployments of fuel cell vehicles further reduce the costs of battery electric vehicle components, resulting in synergy rather than competition between hydrogen and electricity technologies. However, in the long term when the transport sector has been largely decarbonised, technology competition between hydrogen and electricity does arise, in the sense that scenarios using more electricity in the transport sector use less hydrogen and vice versa.

Methodologically, a key observation is that a multi-cluster approach appears to overcome a shortcoming found by many previous authors. Specifically, while many previous applications of ETL within MARKAL/TIMES models have observed either immediate and rapid or zero deployment of the learning technology, with a resulting need for transition rate constraints, the multi-cluster approach presented here results in a gradual and phased deployment of the learning technology. The multi-cluster approach thus appears to be a promising approach to improving the modelling of endogenous technological change.

However, there are limitations that should be borne in mind in considering the conclusions from a policy perspective. In particular, there is deep uncertainty relating to the learning curve specifications, including the value of the learning rate and potential changes to the learning rate over time. Moreover, real world multiple and divergent scale-dependent drivers of cost reduction have been modelled with a single factor. Similarly, a single global learning process has been modelled here, whereas in reality some components of learning tend to be location specific (e.g. related to local practices and institutions). These uncertainties and limitations are in addition to those inherent in all long-term energy system optimization, and the results are not intended to be predictive, but rather are intended to yield insights into possible dynamics and patterns in the energy system.

The messages for policymakers must therefore be drawn with caution. The current analysis suggests that, in the long-term, both hydrogen and electricity remain important options for long-term decarbonisation. The results also suggest that policymakers seeking to accelerate the deployment of hydrogen or electric vehicles through early deployments may be disappointed if the rest-of-the-world follows a least-cost abatement trajectory.

Acknowledgments TIAM-UCL was developed through the UK Energy Research Centre, while the analysis reported in this chapter was part of the UK Sustainable Hydrogen Energy Consortium. The RCUK Energy Programme funded both these initiatives.

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Modal Shift of Passenger Transport in a TIMES Model: Application to Ireland and California

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Abstract Climate change mitigation clearly requires a focus on transport that should include improved representation of travel behaviour change in addition to increased vehicle efficiency and low-carbon fuels. Energy system models focus however on technology and fuel switching and tend to poorly incorporate travel behaviour. Conversely, transport demand modelling generally fails to address energy and climate policy trade-offs. This chapter seeks to make energy systems analysis more holistic by introducing modal choice within passenger transport in a TIMES model, to allow trade-offs between behaviour and technology choices explicit. Travel demand in TIMES models is typically exogenous—no competition exists between alternative modes. A simple illustrative TIMES model is described, where competition between modes is enabled by imposing a constraint on overall travel time in the system. This constraint represents the empirically observed travel time budget of individuals, constraining the model choosing between faster and more expensive modes (e.g. cars) and slower but cheaper mode (e.g. buses or rail).

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_16

Further, a new variable is introduced, called travel time investment, which acts as a proxy for infrastructure investments to reduce the time associated with travel, to enable investment in alternative modes of transport as a means of CO_2 mitigation.

1 Introduction

Transportation contributes to 23 % of energy-related CO_2 emissions globally. With increasing demands especially for light-duty vehicles, freight, and aviation, global transport CO_2 emissions are expected to double by 2050 (IEA 2010). Reducing greenhouse gas emissions from the transport sector will require complementary policies in improving the efficiency of vehicles, introducing low-carbon fuels and advanced vehicles technologies, and better travel demand management (Schafer and Heywood 2009). Most of the growth in demand for cars will come from developing countries, as car travel in developed countries essentially saturated, and is projected to remain flat in the next few decades. On the other hand, public transport and aviation already play an important role in many developed (especially Europe) and developing countries. The importance of their role is expected to continue to increase given the need to drastically reduce on-road transportation emissions in order to meet stringent climate targets (Fulton et al. 2009; IEA 2012).

However, while most of the integrated assessment models (IAMs) that governments rely on for developing climate mitigation policies have been able to project portfolios of advanced fuels and vehicle technologies given climate goals, bottom-up models are currently ill suited to examine potential travel demand changes and travel mode shifts given climate policies and changes in fuel prices, and most importantly the necessary investments needed to reduce vehicle travel, increase public transport shares, and non-vehicle infrastructure given climate goals (Schafer 2012). Most IA models use scenarios describing future travel modal shifts without explicitly linking demand changes to drivers (e.g. fuel price changes) or infrastructure and technology investment decisions. This is despite the many studies which show that technological change is not sufficient for the transportation sector to develop in a way that is consistent with long-term climate targets (Hickman and Banister 2007; Bristow et al. 2008; Johansson 2009; Åkerman and Höjer 2006).

The aim of this chapter is to describe a methodology of modelling transport mode shift behaviour in TIMES models, which allows the model to more realistically represent the dynamics of mode choice behaviour and allows investment into public transport infrastructure as a mitigation option. A paper by Schafer (2012) provides a critical review of the (lack of) modelling of behavioural changes in transportation in energy, economy, environment, engineering (E4) models, compares common methodologies employed in IA models, their shortcomings and gives recommendations for future improvement. This paper argues that introducing behaviour change in transportation in these models is indispensible for exploring holistic approaches to mitigation, while being feasible and intellectually rewarding.

This chapter explores some of the recommended methodologies and applies them for the first time in the bottom-up optimization modelling framework using the TIMES model and implements this in two case studies based on the Californian TIMES model and the Irish TIMES model.

This chapter reviews the role of transport in energy models and key underlying concepts of travel behaviours and travel time budgets in Sect. 2, introduces a new methodology for energy system models in Sect. 3, introduces and compares the case studies in Sect. 4, presents results in Sect. 5 and discusses results and concludes in Sect. 6.

2 Transport Modeling and Energy Systems Models

Transport modelling is a very well established discipline used widely by decision-makers for planning infrastructure such as airports, roads and railways, for cost-benefit analyses, and environmental impact assessments. Transport planning models typically simulate travel trips by origin and destination, trip purpose, mode of travel and household demographics. Multinomial logit (MNL) modelling is often used to compute mode choice for trips between each origin and destination (de Dios Ortúzar and Willumsen 2001). This methodology expresses the utility associated with alternative modes and includes the variables that describe the attributes of alternatives, which influence the utility of all members of the population, and variables that influence people's preferences, or choices, among alternatives. Infrastructure and land use play a critical role in the patterns of travel demand, and accessibility to transport infrastructure is a strong determinant of mode choice and travel demand (Kockelman 1997). Therefore behaviour is a strong element of transport models, as is detail of the transport network. There is generally very little or no treatment of energy demand in transport planning models: They can be suitable for projecting travel (and hence energy) demand, but not for analysing trade-offs in climate mitigation policymaking.

On the other hand, E4 models such as TIMES explicitly look at the energy system to examine issues ranging from macroeconomic interactions to looking at pathways to meeting climate mitigation scenarios, with very rich technological detail of the entire energy system, from fuel production and imports to energy conversion and demand technologies. A common use of TIMES/MARKAL models is developing least-cost pathways for meeting long-term climate targets, but the nature of the model restricts these pathways to showing only fuel and technology options. Travel demand for each mode is individually inputted into the model over the time horizon, and technologies within that model compete to meet the demand at least cost, subject to system-wide constraints. This deficiency in representing travel behaviour is common in technology-rich linear optimisation models.

Several energy models have included a mode choice module using different modal choice methodologies: For example, the Global Change Assessment Model (GCAM), developed at the Pacific Northwest National Laboratory, is a general equilibrium model that solves for prices, supply and demand for all markets (Kyle and Kim 2011). Mode choice in this model is endogenous, using a MNL approach, and responds to fuel price, wage rate and the cost of transport services. The Canadian Integrated Modelling System (CIMS) also includes a logit sub-model for mode and fuel choice (Horne et al. 2005). A third hybrid model with transport behaviour is IMpact Assessment of CLIMate policies-Recursive version (IMAC-LIM-R), developed at CIRED, which maximises a utility function subject to travel budget constraints. Infrastructure is endogenous: a decrease in supply leads to congestion and lower speeds, which feeds back into the model (Waisman et al. 2013). From the reviewed transport models, this is the only study that includes transport infrastructure endogenously as a determinant of travel demand.

Pietzcker et al. (2014) compares transport decarbonisation from five energy-economic models, and finds that for the linear optimisation models based on TIMES have less flexibility than other models for mitigation, because mode choice is not endogenous. One model from the study (GCAM) includes the value of time in determining travel patterns. This study also points out that targeting behaviour through infrastructure can have a major impact on travel demand patterns, and should be considered in developing mitigation policies.

2.1 Travel Time Budget (TTB)

An important attribute of the passenger transport sectors of the hybrid energy models such as GCAM, where modal choice is simulated, is that travel time is modelled. Representing travel time explicitly is at the core of our approach. We use the conception of a fixed travel time budget to constrain overall travel time in the model: Empirical research has shown that averaged over a country or region, people spend a fixed amount of time travelling per day. Studies suggest that region-wide average personal travel time is constant and is estimated as 1.1 h per person per day (Zahavi and Ryan 1980). This "travel time budget" as such is a stable characteristic and is considered a constant in our model.

Other studies have used the notion of a travel time budget to simulate travel demand and modal split: Schafer and Victor (2000) uses a fixed travel time and money budget to forecast future global mobility, assuming a constant shift towards faster travel modes. Metz (2010) comes to a different conclusion, observing that daily travel demand is saturating in Britain, while the daily travel time budget has been constant, because of the diminishing marginal utility of the value of the extra choice associated with more mobility. Girod et al. (2012) also uses fixed travel time and money budgets to simulate travel demand and modal share. The fixed travel time has implications for travel demand and speed: Studies have shown evidence that reducing travel time of journeys through increasing capacity and improving infrastructure induces increased travel demand (Noland and Lem 2002).

3 Methodology

This section describes the basic model structure of the methodology and its implementation in a simple illustrative TIMES model. In this model, different transport modes compete on the basis of fuel and capital costs to deliver overall travel demand, while a constraint on overall travel time in the system, representing the travel time budget (TTB) of individuals, ensures that faster and more expensive modes can also compete. We introduce a new variable, travel time investment (TTI), a proxy for investments to reduce the time associated with travel. This model is then tested under a reference scenario (to 2030), an investment scenario and a CO_2 emissions reduction scenario. To the authors' knowledge, while TTB has been used in other energy models, this is the first time this parameter has been used to represent modal choice in a linear optimisation model, which has the advantage of being technologically rich and comprehensively covering the whole energy system.

3.1 Model

Motorised travel demand is represented by passenger kilometres travelled (PKT), which is the sum of demands of car (CKT), bus (BKT) and train (TKT). PKT for a technology is given by the vehicle kilometres travelled (VKT) multiplied by the load factor (LF, or occupancy of the vehicle). PKT is divided into long and short distance demand (PKT_{L} and PKT_{S}) in order to capture the characteristics of the different technologies servicing the different demands: High-speed train and buses can service long distance travel, while city buses and electric trams can service short distance; cars serve both. Furthermore, the speed of technologies serving long and short distance differs significantly: For example, for longer distance a rail trips, the required waiting time is absorbed by the speed of the overall journey and is more significant in shorter trips.

The model is based on a least-cost linear programming approach. It determines $PKT_{\mathrm{t,d}}$, the travel demand d for long and short distance of each of the technologies t such that the overall system cost is minimised. The cost of technology activity, $c_{t,d}$ is the cost in €/PKT of travel in each technology producing long or short distance travel demand d, given by the sum of the fuel, investment and operation and maintenance (OM) costs in €/PKT.

The concept of a travel time budget (TTB in million hours, mhs) is introduced to the model to represent the empirically observed fixed travel time per-capita in the real world, as described in Sect. 2.1. This enables competition between different transport modes based on travel time in addition to cost. Without this the model will be likely to switch modes immediately to the cheaper but slower and more time–costly public transit modes, which does not reflect travel behaviour.

Ideally, speed and infrastructure would be endogenous to the model, so that the model could invest into decreasing travel time. We introduce a variable travel time investment (TTI) which is a proxy to endogenise this relationship.

The model determines $PKT_{\mathrm{t,d}}$ and $tti_{\mathrm{t,d}}$ subject to Eq. 1:

Minimize total cost:

$$C = \sum_{t,d} PKT_{t,d} \cdot c_{t,d} \tag{1}$$

where $PKT_{\mathrm{t,d}}$ is the travel demand of technology t for long or short distance travel demand d, and $c_{t,d}$ is the sum of fuel, investment, OM and TTI cost in €/PKT:

$$c_{t,d} = f_{t,d} + i_{t,d} + om_{t,d} + tc_{t,d}$$

Fuel cost $f_{t,d}$ is a product of the price per unit of energy of fuel and the energy intensity of the technology, divided by the load factor, and the cost of travel time investment $tc_{t,d}$ depends on vehicle speed (Eq. 2):

$$tc_{t,d} = \frac{tti_{t,d} \times \tau}{s_{t,d}} \tag{2}$$

τ is the TTI cost in €/h and $s_{t,d}$ is the speed in kilometres per hour of technology t.

The model is subject to two main constraints, firstly, that technologies meet the exogenously defined travel demand for long and short distance demand d, and secondly, that the total yearly travel time of the system minus the travel time investment (a proxy for a reduction in the travel time of modes) does not exceed the yearly travel time budget (TTB) (Eq. 3 and 4):

$$\sum_{t,d} PKT_{t,d} = D \tag{3}$$

$$\sum_{m} s_m \times PKT_m + TTI \leq TTB \tag{4}$$

3.2 Implementation in TIMES

Within the new Reference Energy System, as shown in Fig. 1, we introduce just two travel demand commodities: long distance demand (TLDD) and short distance demand (TSDD) expressed in PKT/year. In order to produce energy service demands all technologies such cars, trains and buses have two inputs: the fuel input and the time input. Here the TIME input describes the travel time from origin to destination, which is dependent on the modal speed, waiting and transfer time. This depends on technology, infrastructure, reliability, congestion, accessibility, etc.

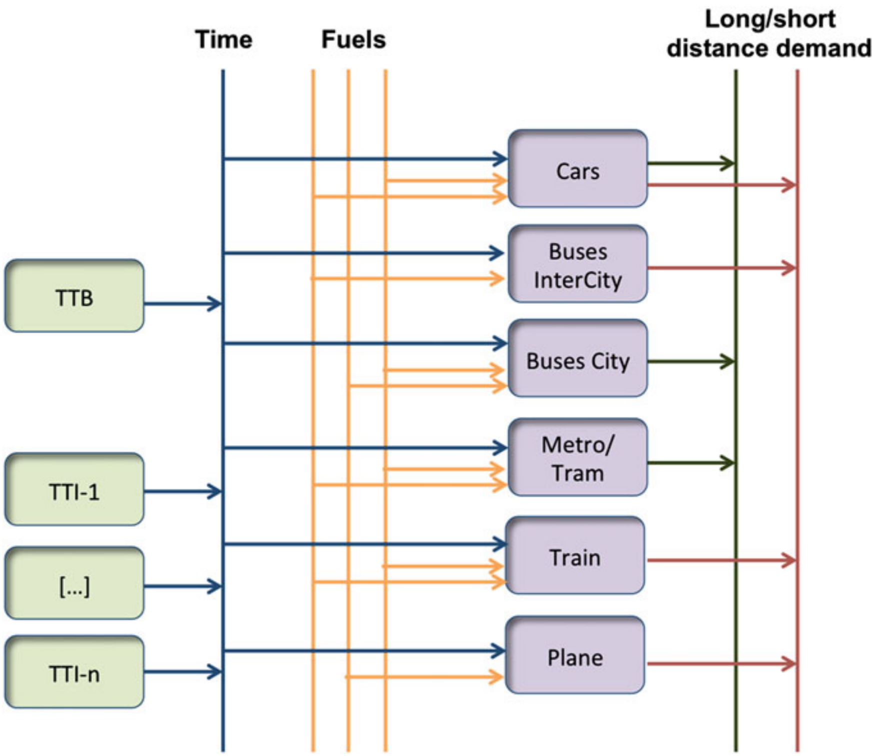

Fig. 1 New reference energy system

4 Case Studies: Ireland and California

The above methodology is applied to two case studies, Ireland and California, two regions for which TIMES models already exist.

Passenger cars are predominantly used as the preferred mode of transport in California. Public transit, that includes all the commuter trains and buses in the state, comprises about 4.4 % of the total trips (California Department of Transportation 2013). In this study we define short distance PKT demands as those trips within the metropolitan areas in the state, with population greater than 1 million.

For the Irish model, short distance travel demand is defined to be trips of 30 km or less. Total annual travel demand and the base-year modal split of demand by car, bus and train for short and long demand were derived from microdata from Ireland's Central Statistics Office Pilot National Travel Survey (Central Statistics Office 2011) conducted in 2009. This used a travel diary methodology to survey travel characteristics, including distance, mode, time and trip purpose, for a cross section of the population. Total annual travel demand in PKT for this modelling exercise was calculated using the average daily distance (by car, bus or train) per

Table 1 Important input parameters

	Source	California	Ireland
Travel time budget (h/person/day)	Zahavi and Ryan (1980)	1.1	1.1
Motorized TTB (2009)	Irish *National Travel Survey* and US *Nationwide Household Travel Survey*	1.02	0.91
Motorized TTB (2030)	Based on Schafer-Victor model (Schafer and Victor 2000; Daly et al. 2014)	1.07	1.03
Per-capita PKT (annual, 2009)	Irish and CA TIMES models	18,803 km	12,305 km
Per-capita PKT (annual, 2030)	Calculation in Daly et al. (2014)	26,209 km	19,829 km
Travel demand elasticity	Girod et al. (2012)	1	1
2009 motorized mode share (bus/car/train, %)	Irish and CA TIMES models	1.9/97.9/0.2	5.2/1.2/3.6
Car speed (miles/h) (long/short distance)	Irish *National Travel Survey* and US *Nationwide Household Travel Survey*	37/32	59/28.8
Bus speed (miles/h) (long/short distance)		15.3/14.6	47.1/13.9
Train speed (miles/h) (long/short distance)		NA/24.7	55.7/20.2
2030 population (million)	CA/Irish TIMES model	44.57	

person for this survey. The speed of each mode for long and short distance demand was calculated as the weighted average quotient of trip distance and trip time.

In order to calculate load factors for cars and buses, vehicle kilometres travelled (VKT) were used: Total private car VKT for 2008 was derived from national car test odometer readings (Daly and Gallachóir 2011); bus VKT were sourced from the Central Statistics Office, and VKT for Dublin's light rail system (Dart and Luas) was used for short distance demand (CSO 2008).

The physical characteristics of transport technologies—costs and efficiencies of different modes—for each region is derived from the TIMES models that exist for California, CA-TIMES (McCollum et al. 2012), and Ireland, Irish TIMES (Chiodi et al. 2013). A detailed description of the data inputs and derivation of baseline travel demand is described in Daly et al. (2014), and Table 1 summarises the main input parameters used.

5 Results

The modal-share model is run for four scenarios for each case study. The first scenario is a reference case which represents the previous state of modelling in TIMES, including no TTB. The following three scenarios describe the mode share (in total PKT) when introducing TTB, TTI and a constraint on CO_2 emissions. A detailed description of each scenario follows.

S0: *Reference*. This reference scenario represents the outcome of standard TIMES model structure. The model is first run without the limit on travel time budget, which implies the passenger has no bound on travel time. The model chooses freely between modes on the basis of technology and fuel costs. As shown in Fig. 2 once the existing car capacity retires, the model chooses bus technology for both regions, which is the slower and cheaper mode of transport according to our assumptions.

S1: *No TTI*. A constant travel time budget is introduced into the model based on projected annual passenger kilometres travelled (PKT) and assumed modal speeds. In both regions, PKT grows faster than TTB, therefore pushing the model to choose faster modes of travel within the given time budget. The models quickly become unfeasible as cars, the fastest mode, are already saturating travel demand and the model has no faster mode to switch to. Results for this scenario are shown in Fig. 3.

S2: *Including TTI*. Travel Time Investment (TTI) is introduced in this scenario, allowing the model to invest in increasing the overall travel time budget.

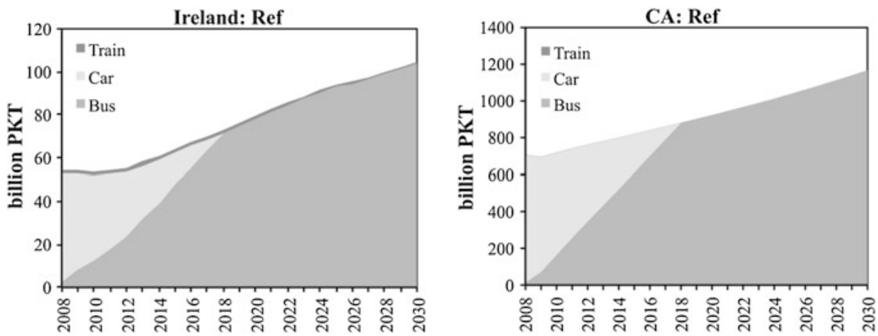

Fig. 2 Modal share results for S0 (bPKT), illustrative of approach without TTB

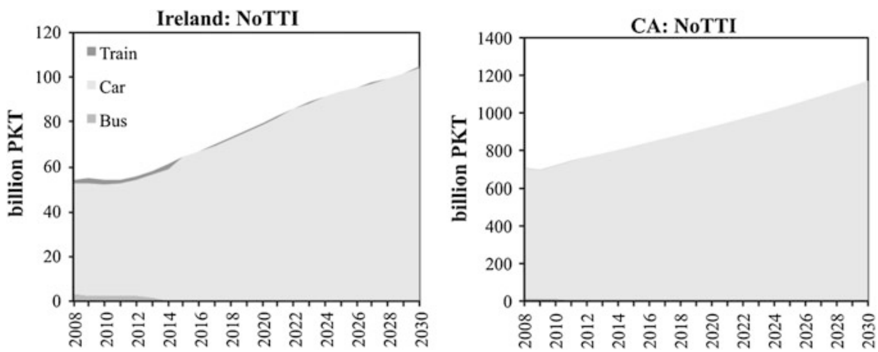

Fig. 3 Modal share results for S1 (bPKT), illustrating the impact of including TTB and not TTI

This variable acts as a proxy for the investment required to encourage modal shifting, for example through improving public transport speeds. The cost of TTI impacts significantly on results: For low TTI costs (e.g., €2/h), the model for both regions invests heavily in slower public transport, because the modes' investment, fuel and OM costs are sufficiently low that investment in TTI is cost effective. At low TTI cost, the model for both regions also chooses a level of rail transport, which has a higher cost but greater speed than bus transport. When TTI cost is sufficiently high (e.g., €7/h), shown in the results here, the model invests in new private cars exclusively in Ireland, while using the installed capacity of buses and trains, and invests in some new bus technology in California as well as mainly private cars. At very high TTI costs, the model chooses exclusively private cars in meeting travel demands, and the current capacity of bus and rail is not used. Figure 4 shows results for TTI cost at €7/h.

S3: *TTI + CO_2 constraint*. This scenario introduces a 20 % CO_2 emissions reduction constraint, relative to S2 emissions. The constraint is applied to 2030 emissions from S2 and linearly interpolated from 2010. In this scenario, there is a tradeoff between speed and emissions: the slower public transport modes are invested in both regions so that the emissions constraint is met, but a minimal amount of TTI is invested in. New rail is invested in this scenario for both regions for short distance travel, with new capacity for long distance buses also featuring. At a very high TTI cost, rail is chosen exclusively over busses, as the slower speeds consumes more TTI and makes buses more costly than trains. Thus, the modal share in a CO_2 constraint scenario is sensitive to the price of TTI. Figure 5 shows results for a TTI cost of €7/h.

The results of the four scenarios are intuitive: In an optimising energy system framework with no constraint on travel time (S0), the cheapest mode is bus travel, which for both regions is invested in fully once the current stock of cars is retired. When a travel time budget is introduced, cars, being the fastest mode, dominate (S1). Mode shift under emissions constraint without TTI is infeasible in the model because no mode exists which is sufficiently time- and carbon-efficient to meet both

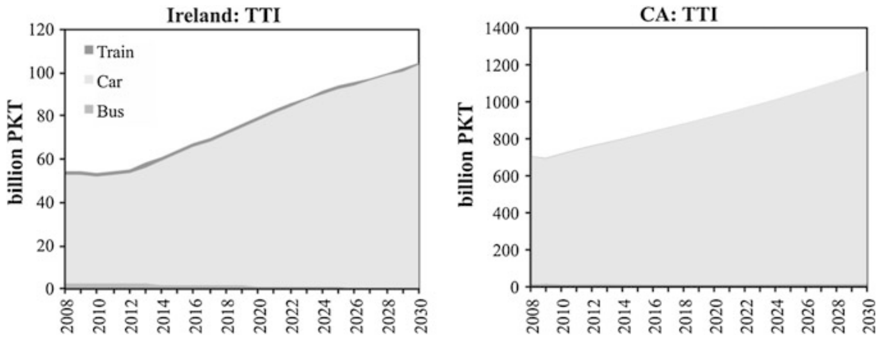

Fig. 4 Modal share results for S2 with TTI cost €7/h (bPKT), illustrating the model's investment in infrastructure to enable further travel demand growth

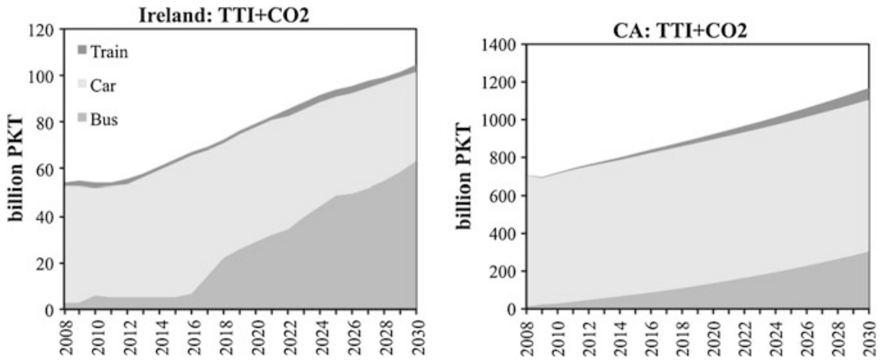

Fig. 5 Modal share results for S3 with TTI cost €7/h (bPKT), illustrating the case of modal shift, enabled by an investment into infrastructure

demands. S2 illustrates a realistic baseline scenario with no emission constraint: private cars dominate both cases, with no significant shift to public transport, because incomes increase, causing a greater per cavity travel demand with no per capita increase in travel time. S3 illustrates the potential for mode shifting when investments into public transport infrastructure is allowed to lower the time associated with these modes and increase the attractiveness to users. Both rail and bus travel are selected in this scenario, along with additional passenger cars.

6 Discussion and Conclusion

The results presented in the previous section show how this methodology portrays the competition between transport modes in a least-cost linear framework. In particular, results show a higher penetration of efficient, public transport modes when a CO_2 constraint is imposed. In this case, there is a trade-off in the model between the cost of investing in higher TTI, and so reducing the travel time associated with these modes to make them more attractive to passengers, and an emissions constraint. The reference scenario shows why a TTB constraint and a TTI cost is necessary to the model: Without imposing a restriction on travel time, the model would choose the most efficient and cheapest mode, which are buses in both Ireland and California. This reflects the real-world drawback of public transport, namely, the associated additional time and inconvenience, and the cost required of government to make efficient transport modes more acceptable to the public. These results are not intended to project realistic travel behaviour, but rather act as an illustration for how the mitigation potential of public transport infrastructure can feasibly be introduced to E4 models.

Many parameters influence modal choice. Some, such as the cost of fuel for a car or price of public transport or the travel time of different modes are objective and easily modelled. Other parameters—social status and comfort, for example—are not so easily quantifiable, and so are more difficult to incorporate into a model. Price alone is not the main consideration for passengers, making modal choice particularly complicated for cost-optimisation models such as TIMES. Developers of these models often overcome this difficulty by imposing constraints: In the case of passenger transport, this is manifested in exogenous projections of passenger kilometre demand for each mode individually. The overlooks that energy demand in passenger transport is a derived demand for mobility, and not private car travel, and consequently, investment into public transport and influencing travel behaviour as a strategy for decarbonisation is overlooked by energy systems models, whose outputs typically focus on technological solutions. Policy makers rely on outputs from energy systems models to formulate least-cost strategies for meeting CO_2 targets, and influencing behaviour has an important role in meeting these goals.

This model makes a first step towards incorporating competition between modes in linear optimisation energy models. Novelly, it uses a methodology based on the empirically observed, stable and global daily travel time budget to realistically represent the modal choice in a reference case, and introduces a new parameter, travel time investment, which is a proxy cost for investment into public transport, representing the cost to decision-makers of reducing the barrier to more public transport use. While TTB has been used in other energy models, this is the first time known to the authors this parameter has been used to represent modal choice in a linear optimisation model, which has the advantage of being technologically rich and comprehensively covering the whole energy system.

This prototype model requires further work to be fully useful, in particular, an extension of the TTI parameter to distinguish investment costs for each mode, and the inclusion of the methodology into a full energy systems model. However, the approach presented here is a significant step towards incorporating behaviour into energy systems models. In particular, it represents the feedback from transport infrastructure investment to travel time and quality, and therefore modal choice.

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The Role of Energy Service Demand in Carbon Mitigation: Combining Sector Analysis and China TIMES-ED Modelling

Wenying Chen, Xiang Yin, Hongjun Zhang, Ding Ma, Jincheng Shi, Weilong Huang and Nan Li

Abstract China's primary energy consumption increased from 1.46 btce (billion tons of coal equivalent) in 2000 to 3.25 btce in 2010, greatly influenced by energy service demand growth. For example, crude steel production rose from 152 to 637 million tons, urban per capita floor space from 10 to 21.5 square meters, passenger transport turnover from 1226 to 2789 billion passenger km (pkm), and freight transport turnover from 443 to 14,184 billion tons km (tkm). This trend in energy service demand will be a critical factor in the level of energy consumption and carbon emissions in the future. In this chapter, multiple approaches, including the stock-based model, the saturation model, the discrete choices model, and so on, are used to project energy service demands from different demand sectors. The projections of energy service demand are used as inputs in the China TIMES-ED model to generate a reference scenario. Several carbon constraint scenarios have been designed to analyze the role of energy service demand reductions in industry, building and transport in the mitigation of carbon emissions in China.

1 Introduction

Over the past three decades China's economy has experienced rapid development, with annual growth rates of around 10 %. GDP per capita reached 4400 US$ in 2010, with an annual growth rate of around 7 % (NBS 2011a). The value-added contribution of the tertiary industry to total GDP increased by 21.6 % points between 1980 and 2010, but the value-added contribution of secondary industry still accounted for 46.67 % of total GDP in 2010. Finally, the urbanization rate reached 51.3 % in 2010, on the back of an average annual increase of around 1 percentage point since 1980.

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_17

These changes, as expressed in industrialization and urbanization, led to the rapid expansion of industrial production, transportation and building throughout the country. For example, the production of crude steel and cement was 637 and 1882 million tons respectively in 2010, 17.2 and 23.4 times the level of 1980 (NBS 2011a). Freight and passenger transport turnover increased to 14,184 billion ton km and 2789 billion passenger km respectively, and car ownership rose to 57 vehicles per thousand people in 2010 (NBS 2011a). Urban residential, rural residential, and commercial floor space increased to 24.4, 14.4, and 7.9 billion square meters respectively by 2010. The result is that final energy consumption increased to 2.28 btce (billion tons of coal equivalent) in 2010, with the industrial sector consuming around 70 % of this. Primary energy consumption increased to 3.25 btce in 2010, having recorded an average annual growth rate of 5.78 % in the past 30 years (NBS 2011b). However, with coal dominating energy supply (70 % of the total), the downside of this growth is that carbon dioxide emissions reached 7.2 billion tons in 2010.

With economic growth and living standard improvements, China's energy consumption and carbon emissions are expected to continue to grow without strong climate mitigation efforts. Critical to China's efforts to achieve low carbon development are structural adjustments in the economy towards producing more higher value-added and less energy intensive products and services, energy saving and energy efficiency improvements, the development of new renewable energy, and improvements in consumer behavior. This chapter contributes to the debate on these changes by using multiple approaches including the stock-based model, the saturation model, the discrete choices model and so on, to project energy service demands from different demand sectors. The chapter also presents the China TIMES-ED model, which is used to generate a reference scenario and several carbon mitigation scenarios. Finally, the role of energy service demand reduction in industry, transport and building sectors in carbon emission mitigation is analyzed.

2 Methodology

2.1 China TIMES Modelling

TIMES (The Integrated MARKAL and EFOM Model) is a combination of the MARKAL (Market allocation) and Energy Flow Optimization Model (EFOM) models developed by the Energy Technology Systems Analysis Program (ETSAP) of the International Energy Agency (Loulou et al. 2005). China MARKAL, a dynamic linear programming energy system optimization model, was developed to study China's future energy development and carbon mitigation strategies beginning in 2000 (Chen 2005; Chen et al. 2007, 2010). On the basis of China MARKAL, the China TIMES model was developed for 5-year intervals extending from 2010 to 2050. This development is based on a reference energy system (RES), which incorporates the full range of energy processes, i.e. exploitation, conversion, transmission, distribution and end-use (Chen et al. 2013). The five demand sectors of agriculture, industry, commercial, residential (divided into urban and rural), and transportation are considered and further divided into over 40 sub-sectors (Fig. 1). More than 400 technologies, including existing and advanced technologies such as poly-generation with carbon capture and storage (CCS), which may be deployed in the future, are included in the model.

Modeling using China TIMES first determines the least-cost mix of technologies and fuels to meet projected energy service demands for sectors and sub-sectors generated by the Energy Service Demand Projection Model (ESDPM) for a given social economic development scenario. This leads to the detailed fuel and technology mixes for both the demand and supply sides, as well as for the carbon emissions pathway from 2010 to 2050 for the reference scenario. Carbon constraints are then introduced into the model with elastic demand, and the supply/demand equilibrium where both the supply side and the demand side adjust to change in prices to maximize net total surplus, is computed (Eq. 1):

$$\begin{aligned} &\text{Max} \quad \sum_i \sum_t \left(p_i^0(t) \cdot \left[DM_i^0(t) \right]^{-1/\mathrm{E}_i} \cdot DM_i(t)^{1+1/\mathrm{E}_i} / (1 + 1/\mathrm{E}_i) \right) - \mathrm{c} \cdot \mathrm{X} \\ &\text{s.t.} \quad \sum_k CAP_{k,i}(t) \geq DM_i(t) \qquad i = 1, 2, \ldots, I; \quad t = 1, \ldots, T \\ &B \cdot X \geq b \end{aligned} \tag{1}$$

where

DM is a vector of variable demands;

p_i is the marginal cost of procuring demand DM_i;

E_i is price elasticity of demand DM_i;

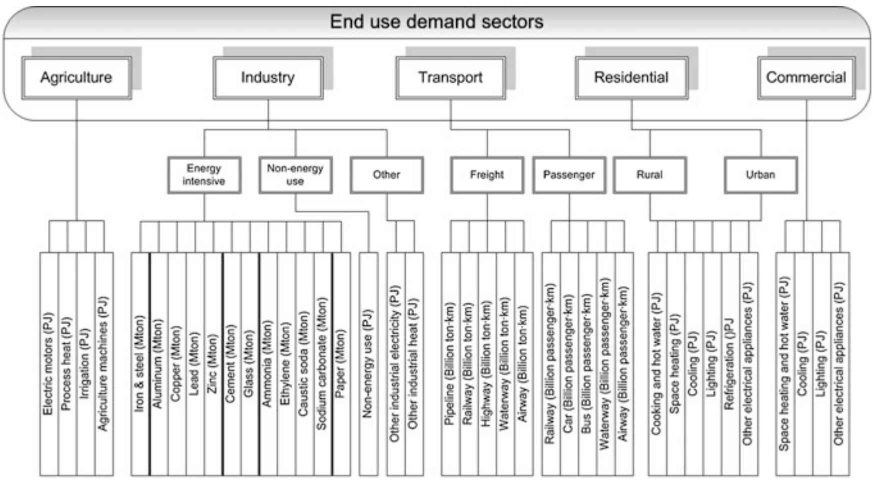

Fig. 1 End-use demand sectors and subsectors in the China TIMES model

$CAP_{k,i}$ is the capacity of end-use technology k to meet demand DM_i;
X is the vector of all TIMES variables with associated cost vector c;
DM_i^0 is the energy service demands from the ESDPM model as in the reference scenario; and
p_i^0 is the marginal cost of demand DM_i generated from the reference scenario.

In the carbon constraint scenarios, DM_i will be obtained based on the endogenous p_i, which is affected by the choices of technology, fuel, and so on. Therefore, in the China TIMES model with elastic demand, carbon mitigation can be achieved not only by technology and fuel substitution, but also by energy service demand reductions. Different price elasticities of energy service demand for each end-use sector are assumed (Kesicki and Anandarajah 2011). For example, −0.37 to −0.49 is assumed for different energy intensive industrial products, −0.32 to −0.41 for different energy service demands in building, and −0.18 to −0.4 for different transport modes.

2.2 Energy Service Demand Projection

2.2.1 Industry

The energy service demand projection for the industry sector is calculated to project production amounts of energy-intensive products such as steel, cement, ammonia, aluminum, paper, and so on, and a bottom-up stock-based approach is applied. This chapter takes steel as an example, to describe how to build the projection model for industry. Nine main steel consumers, including construction, machinery, automobile, shipbuilding, railway, petroleum, household appliances, containers and other industries, are considered and analyzed individually as shown in Fig. 2. Steel consumption in the petrochemical and other industries is calculated by share in total steel consumption, while that of the other seven industries is analyzed using a stock based model (Yin and Chen 2013).

For most of these industries, we first analyze future product stocks, such as the total floor space in the building sector, and the stock of vehicles and household appliances, and then study future new additions as well as discarded products with the consideration of lifetime distribution; in this way, future steel demand in each industry is analyzed. The construction industry for example, is divided into two sub-sectors: the infrastructure sector and the building construction sector, which is further divided into three distinct building types: urban residential, rural residential, and commercial buildings. Also, steel consumption in the machinery industry is assumed to change synchronously with that of the construction industry. In turn, the automobile manufacturing industry is divided into private passenger vehicles, business vehicles, buses and trucks. Considering the variance in household

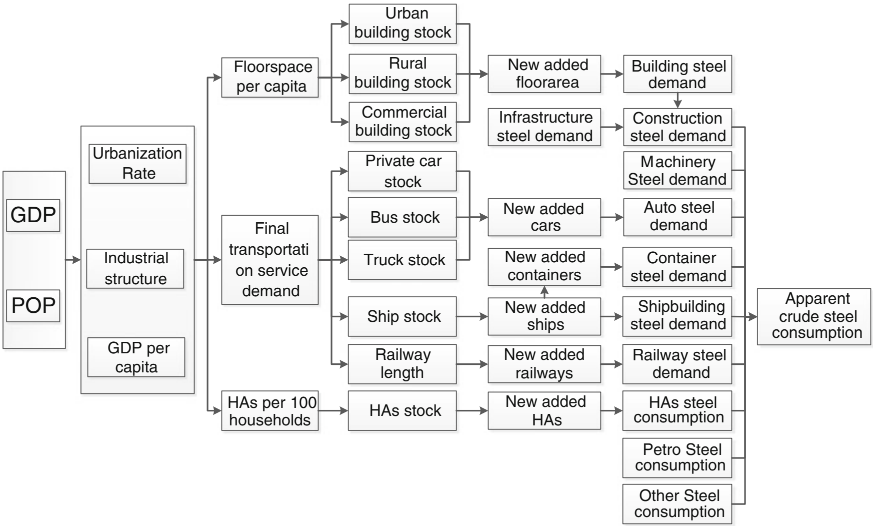

Fig. 2 A bottom-up analysis model of steel demand

appliance (HAs) possession, usage and discard between urban and rural areas, these are analyzed separately.

The stock based model was developed by employing the Material Flow Analysis (MFA) method. The stock based model can be described mathematically with four equations as follows. Equation 2 describes the driving forces of the model; here the stock of products is driven by population and lifestyle representing the engine of the system. Equation 3 describes the interaction between the inflows/outflows and stocks; stocks increase when the inflows exceed the outflows. Equation 4 indicates the obsolete outflow at time t and can be expressed as the function of the inflows and obsolete rates. Equation 5 is used to calculate steel consumption in each industry.

$$S_{i,t} = SP_{i,t} \times P_t \quad (2)$$

$$F_{i,t}^{in} = (S_{i,t} - S_{i,t-1}) + F_{i,t}^{out} \quad (3)$$

$$F_{i,t}^{out} = \sum_{k=1}^{L_i} F_{i,t-k}^{in} \times d_{i,k} \quad (4)$$

$$ST_{i,t} = F_{i,t}^{in} \times M_{i,t} \quad (5)$$

where

i	represents the product category, such as household appliances, house floor area and vehicles;
$S_{i,t}$ and $S_{i,t-1}$	are the in use stocks of product i in year t and year $t-1$;
$SP_{i,t}$	is the per capita ownership of product i in year t and year $t-1$;
P_t	is the population in year t;
$F_{i,t}^{in}$ and $F_{i,t-k}^{in}$	are the product i inputs in year t and year $t-k$, respectively;
$F_{i,t}^{out}$	is the outflow of discarded or obsolete product i in year t;
L_i	is the maximum lifetime of product i and $d_{i,k}$ is the obsolete rate in the kth year of product i;
$ST_{i,t}$	is steel consumption in year t for product i; and
$M_{i,t}$	is the steel intensity of product i in year t.

The supply of steel scrap is made up of three parts: home scrap generated in steel-making (SM), society scrap from steel-processing (SP) and depreciation scrap from end-of-life steel produces (SD), and imported steel scrap. SM, SD and SP can be calculated using Eqs. 6–9:

$$SC = SM + SP + SD \tag{6}$$

$$SM_t = ST_t \times \alpha_t \tag{7}$$

$$SP_t = RS_t \times \beta_t \tag{8}$$

$$SD_{i,t} = \gamma_t \times \sum_{k=1}^{L_i} ST_{i,t-k} \times d_{i,t-k,k} \tag{9}$$

where

ST_t	is crude steel production in year t;
RS_t	is the rolled steel production in year t;
α_t	is the scrap production rate in steel making;
β_t	is the scrap production rate in steel processing; and
γ_t	is the collection rate in year t.

The values of α_t, β_t, γ_t were about 5.5, 5.6 and 40 % in 2010 respectively, and α_t, β_t were assumed to be constant during 2010–2050; γ_t was assumed to increase to 50 % in 2050 (Yin and Chen 2013).

A normal distribution is applied with respect to the lifetime of floor space and household appliances, and the standard deviations are 20 % of the mean values. The real observed life of urban and rural buildings is only about 30 years and 25 years respectively, as a result of both the low quality of construction in the past and the rapid urbanization of recent years. They are both assumed to reach their design lifetime of 50 years by 2030. The average product lifetime of refrigerators, washing machines, air conditioners and microwave appliances is assumed to be 10, 12, 12 and 10 years respectively. In the analysis of the lifetime of vehicles, a Weibull distribution was applied. The average lifetimes of private LDVs, buses, heavy duty, medium duty and light duty trucks were assumed to be 14.46, 13.11, 12.8, 10.09 and 8.02 years respectively (Yin and Chen 2013).

The intensity of the use of steel in buildings depends upon a range of factors such as the structure and height of the buildings. The average steel intensity was assumed to be 95 kg/m^2 for both urban residential and commercial buildings in 2010. It will increase to 97.1 kg/m^2 in 2020. Thereafter it decreases by 10 % per decade from 2025 to 2050, while steel intensity in rural buildings will be 13.7 % of that in urban buildings during the modeling time horizon. Current steel intensity for private LDVs is assumed to be 842 kg/vehicle; 7566, 2552, 1033 and 727 kg/vehicle for large, medium, small and mini passenger vehicles respectively; and 9164, 3624, 1606, and 766 kg/vehicle for large, medium, small and mini trucks respectively. This is projected to decrease by 20 % from 2010 to 2020, and 10% per decade from 2020 to 2050. The steel intensity for refrigerators, washing machines, air conditioners, and microwave ovens was assumed to be 30, 18, 26 and 8 kg/unit respectively in 2010, and to decrease by 10 % per decade in the future.

2.2.2 Transportation

Passenger transport is divided into five services, and freight into four as displayed in Fig. 3. Passenger services based on business LDVs owned by government bodies and companies is treated separately from private passenger services, as these do not generally compete with each other. Private passenger transport was disaggregated into four distinct inland passenger transport service indicators, based on geographic coverage and travel purposes (intercity (pass_intercity), urban (pass_urban), rural (pass_rural), and business (pass_business—refers to government and company owned LDVs) and one international passenger service, i.e. international aviation (pass_intl_aviation). Freight transport encompasses two inland freight transportation services—domestic freight (freight_domestic) and rural freight (freight_rural)—and two international freight transportation services—international ship (freight_intl_ship) and international aviation (freight_intl_aviation). Within each type of transportation service multiple subsectors representing available modal choices are created. Passenger transport employs motorcycles, walking, cycles, LDV, buses, rail, high-speed rail, and air, whereas freight transport modes are truck, rail, ship, air and rural vehicles (3 and 4 W).

The discrete choices model is applied to project energy service demand for every transport mode (Mishra et al. 2013). The demand for transportation services is determined by income, population, and the weighted average service cost of various transportation modes and technologies. Passenger transportation services (passenger kilometers) in period t is given by:

Fig. 3 Representation of transportation services and modes. *Top* passenger. *Bottom* freight

$$Passenger_{r,t} = A \times Income.p_{r,t}^{E\_income_{r,t}} \times C_{r,t}^{E\_TSC_{r,t}} \times Pop \tag{10}$$

where

A	represents a calibration coefficient;
$Income.p_{r,t}$	is per capita income or regional income (for urban and rural transportation);
$C_{r,t}$	is weighted-average service price;
Pop	is total population or regional populations (for urban and rural transportation); and
$E\_income_{r,t}$ and $E\_TSC_{r,t}$	are income and price elasticity, respectively.

Freight transportation service demands, which rely on the aggregate level of economic activity, are similarly formulated but are scaled by total income rather than per capita income and population. Freight transportation service in period t is given by Eq. 11:

$$Freight_{r,t} = A \times Income_t^{E\_GDP_{r,t}} \times C_t^{E\_TSC_{r,t}} \tag{11}$$

The transportation service price is expressed by the cost per unit of service demand. This is the weighted average of technology-specific service prices, which includes a technology's capital and fuel costs, and the time value of its use; it is given by Eq. 12:

$$C_t = \sum_m \sum_j share_{m,j,t} \times P_{m,j,t} \tag{12}$$

where

$P_{m,j,t}$ represents the general transport service price of technology j in mode m in period t; and

$Share_{m,j,t}$ is the share of technology j in mode m in period t.

The service price of using a transportation mode in period t is given by Eq. 13:

$$P_{m,j,t} = \frac{\sum_i (FuelPrice_{m,j,i,t} \times FuelEconomy_{m,j,i,t}) + Non\_FuelCost_{m,j,t}}{LF_{m,j,t}} + \frac{GDP_{r,t}}{Speed_{r,m,t}} \tag{13}$$

where

$FuelPrice_{m,j,i,t}$ is the fuel price (\$/MJ);

$FuelEconomy_{m,j,i,t}$ is the vehicle fuel intensity (MJ/VKM)

$Non\_FuelCost_{m,j,t}$ is the non-fuel price (\$/VKM);

$LF_{m,j,t}$ is the load factor (in persons or tons per vehicle);

$GDP_{r,t}$ is the wage rate (\$/(person-hour)), which is related to economic behavior; and

$Speed_{r,m,t}$ is the vehicle speed (km/h).

Fuel prices, including carbon prices are endogenous, and all the other variables are exogenous for different technologies. For freight transportation modes, where hauling time may not incur direct opportunity costs, time value is excluded.

In turn, $Share_{m,j,t}$ is given by Eq. 14:

$$Share_{m,j,t} = \frac{(SW_m)(P_{m,t})^{-\lambda_r}}{\sum_j (SW_m)(P_{m,t})^{-\lambda_r}} \tag{14}$$

where: λ_r is the price sensitivity constant in region r, which determines the degree to which future price changes will be reflected in modal shifts and varies from different service demand sensitivity; and SW_m is share weight, a calibration parameter.

In this discrete choices model, higher general transport service prices will lead to lower market share, but those modes with high prices will not totally disappear, and the share of modes with low prices will not increase sharply to dominate the market. While competition among modes does exist, all modes will have some market share.

2.2.3 Building

Buildings are divided into urban residential, rural residential, and commercial categories, and energy demand is further divided into space heating, cooling, water heating and cooking, lighting and electric appliances. With respect to different climate conditions and building design standards: four regions, Severe Cold (SC), Cold (C), Hot Summer Cold Winter (HSCW) and Hot Summer Warm Winter (HSWW), are considered separately, based on the Standard of Climatic Regionalization for Architecture (GB 50178-1993) (MOHURD 1993). Per capita floor space is the basis for the projection of space heating, cooling, lighting and similar types of energy demand sources. This is expected to increase with the improvement of living standards, but a saturation level is recognized with the application of the Gompertz model as follows (Eq. 15):

$$PFS = ae^{-be^{-cPGDP}} \tag{15}$$

where

PFS	represents per capita floor space;
$PGDP$	is per capita GDP;
a	represents the ultimate saturation level of per capita floor space; and
b and c	are two parameters that determine the shape of the curve.

The following approach from the literature Eom et al. (2012) is used to project energy service demand for space heating and cooling. The service demand per floor space is given by Eq. 16:

$$d_j = k_j \cdot \overline{q_j} \cdot \phi_j(P_j, i) \tag{16}$$

where

j	is a given service, such as space heating, cooling, lighting, etc.;
k_j	is a calibration parameter;
$\bar{q}_j$	is the saturation demand level;
$\varphi_j(P_j,i)$	represents the effect of income and price for the demand;
P_j	gives the price of service j; and
i	is per capita income.

The price and income effects are represented by Eq. 17:

$$\phi_{P,j} = 1 - \exp(-\frac{\ln 2}{\mu_j}\frac{i}{P_j}) \tag{17}$$

where

μ_j is referred to as the saturation impedance.

Demand saturation level for space heating and cooling is given by Eqs. 18 and 19:

$$\overline{q_H} = HDD \cdot \eta \cdot r - \lambda_H \cdot IG \tag{18}$$

$$\overline{q_C} = CDD \cdot \eta \cdot r + \lambda_C \cdot IG \tag{19}$$

where

HDD and CDD	are heating and cooling degree days, which represent the annual requirement of space heating and cooling to achieve comfortable indoor temperature which, in China is summer 26 °C for all four regions, and in winter 16 °C for the HSWW region, and 18 °C for other regions;
η	is the thermal conductance of buildings [GJ/(m^2 day °C)];
r	is the building's floor to surface ratio;
IG	represents the amount of building internal gains (GJ/m^2); and
λ_H and λ_C	are both calibration parameters.

2.3 The Decomposition Approach

To assess the contribution of energy service demand reduction to carbon mitigation, the following approach is applied (Eq. 20):

$$CO_2 = \sum_i Demand_i \times \frac{CO_{2i}}{Demand_i} \tag{20}$$

where

CO_2	is total carbon emission;
$Demand_i$	is energy service demand i; and
CO_{2i}	is carbon emissions for energy service i.

Using the Laspeyres decomposition approach (Ang 2004), change of carbon emission is given by Eq. 21:

$$\Delta CO_2 = \Delta Demand_{effect} + \Delta(\frac{CO_2}{Demand})_{effect} \tag{21}$$

where

ΔCO_2 is the change in carbon emissions;

$\Delta Demand_{effect}$ is the change of total carbon emissions from energy service demand; and

$\Delta(\frac{CO_2}{Demand})_{effect}$ is the change in total carbon emissions from carbon intensity.

$\Delta Demand_{effect}$ is given by Eq. 22:

$$\Delta Demand_{effect} = \sum_i \Delta Demand_i \times (\frac{CO_2}{Demand}) + \sum_i \Delta Demand_i \times \Delta(\frac{CO_2}{Demand})/2 \tag{22}$$

where

$\Delta Demand_i$ represents the change of $Demand_i$ compared to the reference scenario.

3 Scenario Design

3.1 Main Assumptions for Future Social Economic Growth

Economic and population growth, industrial structure adjustment and the urbanization rate are the four most important factors to impact on future energy consumption and carbon emissions. In this study, annual GDP growth rate is assumed to be 7.9, 7.0, 6.0, 4.5 and 3.0 during 2010–2015, 2015–2020, 2020–2030, 2030–2040 and 2040–2050 respectively. With the Chinese government's continued efforts at structural adjustment of the economy, the share of secondary industry value-added in GDP is projected to decrease from 45.75 % in 2010, to 36 % in 2050, while the share of the tertiary industry will increase from 43.14 to 62 %. Also, China's population is expected to peak at around 1.47 billion in 2035, and then decrease to 1.44 billion in 2050. There is strong empirical evidence that the urbanization rate is correlated to GDP, so the urbanization rate in China will increase as per capita GDP increases. Hence, we assume the urbanization rate to be a function of per capita GDP, and is therefore projected to increase from 49.9 % in 2010 to 74.0 % in 2050.

3.2 Scenario Design

Besides a reference scenario, four carbon constrained scenarios were considered; that is, M10, M20, M30 and M40. The cumulative carbon emissions from China during 2010–2050 are assumed to reduce 10, 20, 30 and 40 % relative to the reference scenario for M10, M20, M30 and M40, respectively.

4 Modeling Results

4.1 Emission Pathways in Different Scenarios

In the reference scenario, policies and measures related to carbon mitigation planned and implemented in China, such as energy savings and the development of new renewable energy technologies have been considered. Carbon emissions in 2050 are expected to increase to around 14.5 $GtCO_2$, and the accumulative carbon emissions between 2010 and 2050 would be around 480 $GtCO_2$ in the reference scenario. Carbon emissions from industry are expected to peak around 2025, mainly as a result of peak of energy-intensive products and greater energy efficiency improvements. Carbon emissions for the power sector are expected to almost stabilize after 2040 due to large-scale use of new and renewable energy. However, carbon emissions in buildings and transportation are expected to grow steadily, since emissions reduction from technology improvement and fuel substitution cannot offset emission growth from the expected increase in building floor space and transport turnover.

Each sector behaves differently in the mitigation scenarios as displayed in Fig. 4. Compared with the reference scenario, carbon emissions will reduce by 14–55 % or 0.5–1.8 billion tons for industry by the year 2050, and 2–54 % or no more than 0.7 billion tons for buildings, in carbon constrained scenarios. CO_2 emissions in

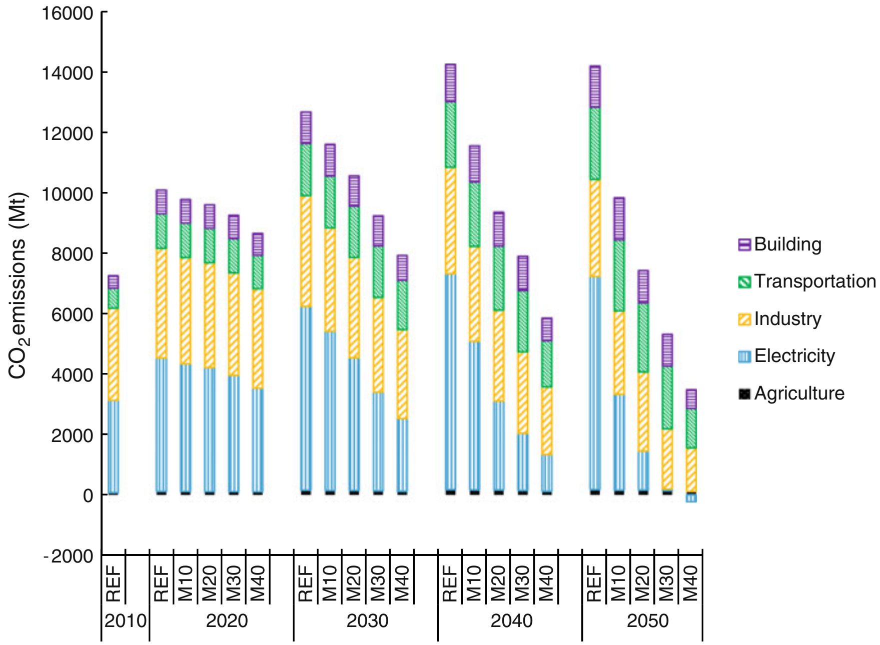

Fig. 4 Carbon emission mitigation for different sectors

transport will only reduce by 2–13 %, or about 0.1–0.3 billion tons in the M10, M20, and M30 scenarios due to heavy dependence on oil, while it will increase to 46 % in M4 (to nearly 1.1 billion tons). Reductions will be a result of large decreases in transport turnover, and rapid expansion in fuel cell, electric and biofuel vehicles, and so on. Overall, the end-use sectors can only reduce emissions by 0.6–3.7 billion tons of CO_2 in 2050, far below the 3.9–7.3 billion tons of reduction that will take place in the power sector.

Direct emissions account for the carbon emissions from coal, oil and gas for final energy consumption for each end-use sector. While for consumption of electricity and heat indirect carbon emissions are used to account for the carbon emissions from power and heat production. When indirect CO_2 emissions are considered, the total carbon reduction rate in the building sector will be 37, 63, 78, and 88% in M10, M20, M30, and M40 respectively, similar to those in the industry sector (36–81 %), as shown in Fig. 5. For the transport sector, this reduction will only be 6–19 % in M10, M20 and M30, and 50 % in M40, closer to direct emission reduction rates as a result of lower electricity consumption than in the two other sectors.

With improvements in the country's final energy mix, carbon intensity is expected to decrease from 2.01, 1.92 and 1.27 tCO_2/tce in 2010, to 1.96, 1.41 and 0.92 tCO_2/tce in 2050, for the transport, industry and buildings respectively (Fig. 6). The carbon intensity in the industry and buildings sectors will begin to decrease visibly after 2025. However, in the transport sector, significant decreases in carbon intensity will happen only after 2035, and its carbon intensity will still be

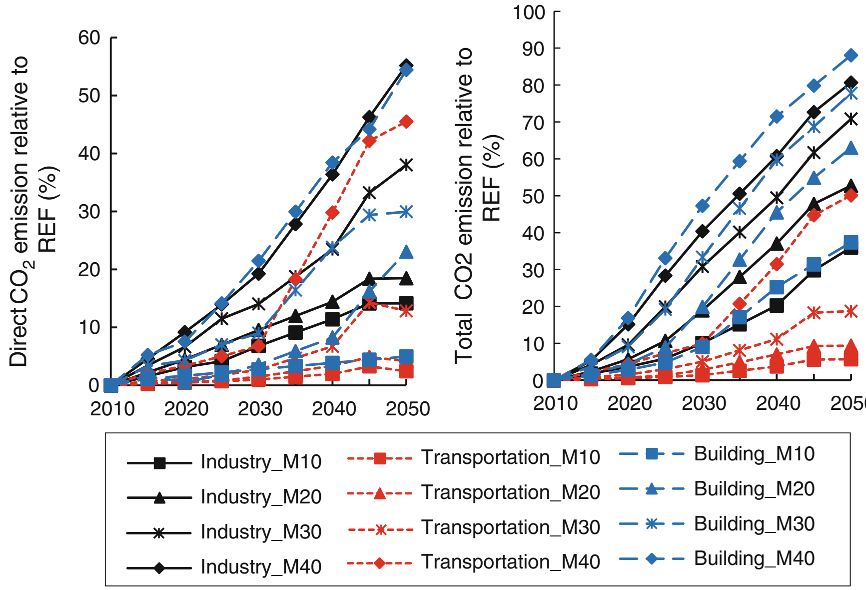

Fig. 5 Direct and indirect carbon emission reduction rates for different end-use sectors

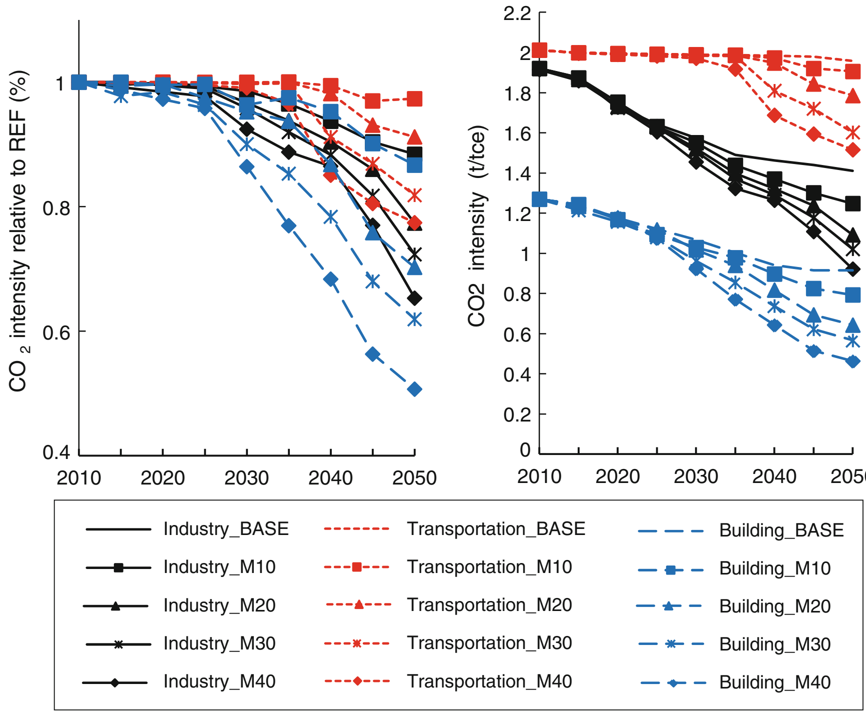

Fig. 6 Changes of carbon intensity in different end-use sectors

much higher than that of industry and building in 2050. Compared with the reference scenario, the carbon intensity of the industry, buildings and transport sectors will decline by 12–35 %, 13–49 % and 1–23 % in 2050, respectively.

4.2 Demand Reductions

In the ED version of the China TIMES model, carbon mitigation is achieved by both energy service demand reduction and the deployment of low and non-carbon technologies. Figure 7 compares the change of energy service demand in the industry, buildings, passenger transport and freight transport sectors under different carbon constrained scenarios, where the different symbols denote the deviation of energy service demand from the reference scenario for different energy services. The energy service demands of industry, especially the energy-intensive industries, record the greatest decrease. In 2050, the energy service demand in industry decreases by 12, 15, 23 and 30 % under M10, M20, M30 and M40 respectively, while the energy service demand in buildings, passenger transport, and freight transport decreases by only 7–25 %, 2–9 % and 3–17 % respectively. The finding of

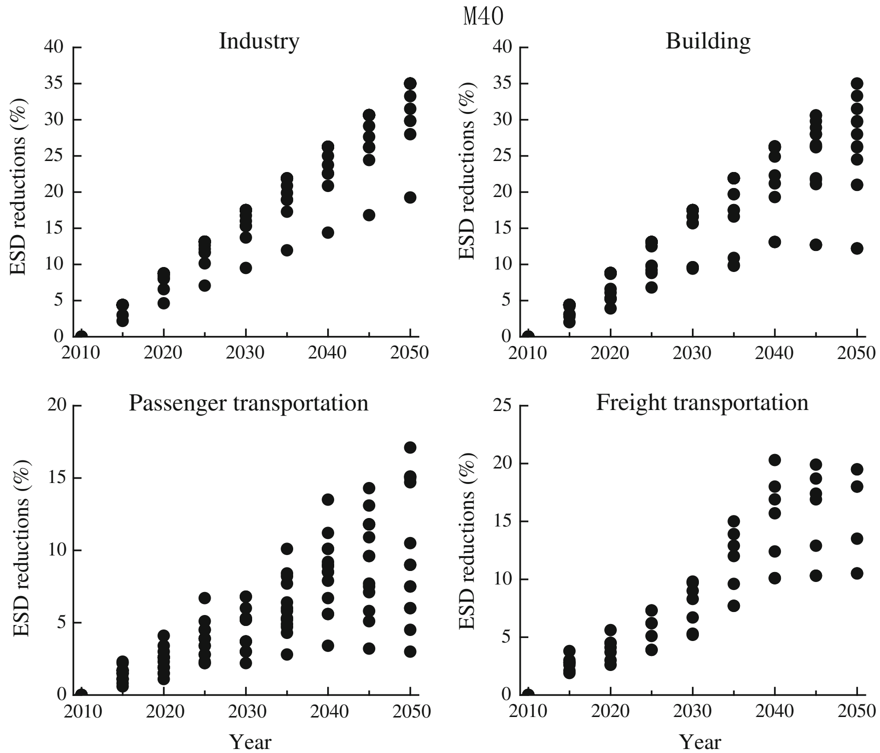

Fig. 7 Energy service demand reductions in M40

less energy service demand reduction in transport than the other two end-use sectors is consistent with the literature.

In the industry sector, taking the steel sector as an example, per capita steel consumption in 2050 decreases from 277 kg in the reference scenario, to 224 kg in M10, and 209 kg in M20, similar to the world average level in 2010 (207 kg), and lower than the current level of the developed countries (USA 277 kg, Japan 842 kg, Germany 541 kg and France 241 kg). In the M30 and M40 scenarios, per capita steel consumption decreases sharply after its peak in around 2015, to only 190 kg and 175 kg in 2050 respectively.

In the buildings sector in 2050, taking space heating as an example, demand for rural residential, urban residential and public buildings decreases by 12–25 %, 11–28 %, and 12–33 % respectively in the carbon constrained scenarios compared with the reference case. Considering that the current heating ratio of urban residential and public buildings is about 42 and 49 % of the total floor space respectively, the sharp decrease in the stringent carbon constraint scenarios will be difficult to achieve without significant breakthroughs in building thermal insulation technology. The total building floor space decreases from 90.3 billion square meters in the reference scenario, to 62.5–81.5 billion square meters in different mitigation scenarios, without considering the change of energy service demand per unit floor area. Per capita living space decreases from 42.6 m^2 in the reference scenario, to 35.1–36.5 square meters in M10 and M20 respectively, close to the current level in Japan (35.8 square meters in 2010). Under the M30 and M40 scenarios, however, per capita living space further decreases to 28.1–33.0 square meters. Assuming there are no actual reductions in floor space, the energy service demand per square meter needs to drop from 11.8 kgce/m^2 in the reference scenario to 8.0–11.2 kgce/m^2 in the constrained scenarios by 2050.

In the transportation sector, passenger and freight transport turnover in the mitigation scenarios decreases by 2–10 % and 2–12 % respectively in 2050. Within this pattern, turnover in those transport modes with higher energy intensities like airplanes and cars, decreases much faster than that of trains. Car turnover, for example, decreases by 3–16 % in 2050. If the load rate (persons per car) and the use intensity (kilometers per year) are consistent with the assumptions in the reference scenario, vehicle ownership per 1000 people in 2050 decreases from 415 to 350–400 (440 for Japan, 450–600 for the European Union, and 800 for the USA in 2010).

4.3 Contribution of Demand Reductions in CO_2 Mitigation

Figures 8 and 9 show the direct and total (including direct and indirect emissions) CO_2 emissions of end-use sectors in the four mitigation scenarios. With the increase in emission reductions, energy service demand reductions in end-use sectors will also contribute more to CO_2 emission reductions. In 2050, the decline of energy service demand contributes 420, 670, 1020 and 1460 million tons of direct CO_2 reductions in the M10, M20, M30 and M40 scenarios, respectively; accounting for

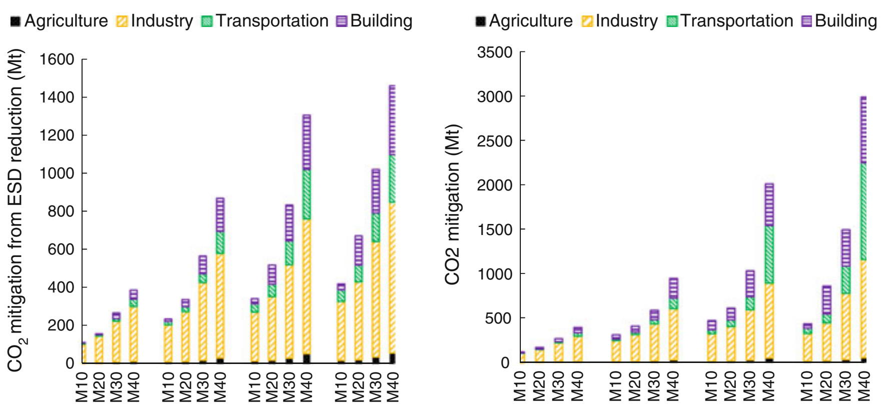

Fig. 8 Direct carbon mitigation from energy service demand reduction

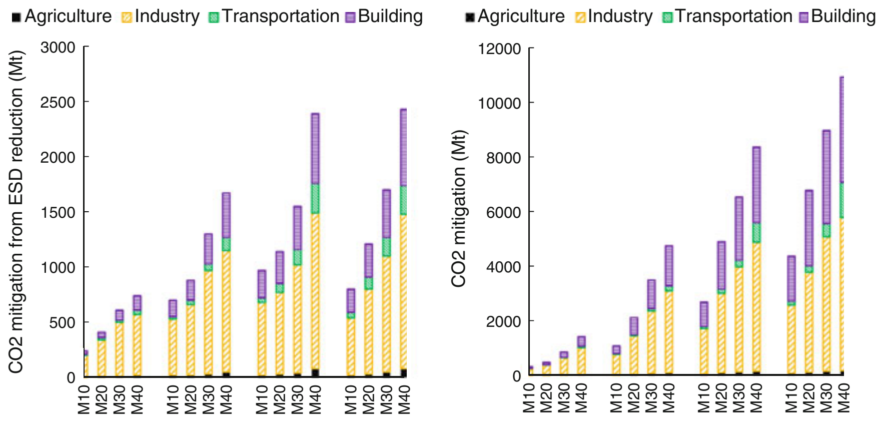

Fig. 9 Total carbon mitigation from energy service demand reduction

90, 75, 70 and 50 % of total direct CO_2 emission reductions. The total (direct and indirect) emissions reduction due to energy service demand reduction could be up to 800, 1200, 1700 and 2400 million tons in 2050. This contributes to 18, 18, 19 and 22 % of total CO_2 emission reductions in the four mitigation scenarios.

Among the end-use sectors, energy service demand reduction in industry makes up the largest proportion of total CO_2 mitigation, contributing 520, 770, 1050 and 1400 million tons of CO_2 reduction in the 4 different scenarios in 2050 (Fig. 9). However, with the increase in CO_2 mitigation, this proportion decreases from 64 to 58 % across these scenarios. Compared with the industry and buildings sectors, energy service demand reduction in transport have a relatively small effect on CO_2 emission reductions, with only 50, 170 and 260 million tons of emission reductions in M10, M20 and M30 in 2050, contributing between 6 and 11 % of total CO_2 mitigation. Energy service demand reductions in the buildings sector contribute 210–690 million tons of carbon reductions across all four scenarios in 2050, around 26 % of total reductions. However, although it is apparent that energy service demand reductions can make a large contribution to carbon mitigation, the model results also show that welfare loss from energy service demand reduction in M40 will be 6.5 times, 4.3 times, and 2.2 times that of M10, M20 and M30 respectively.

Due to the relatively high cost of advanced energy efficient and low carbon technologies, and lower mitigation requirements before 2020, energy service demand reductions contribute more than 50 % of the total CO_2 reductions in 2020. But this figure decreases to less than 25 % in 2050. The energy service demand reductions in industry contribute more than 55 % to sectoral emission reductions before 2025. However, because of the difficulty in effectively decarbonizing transport, energy service demand reductions continue to have a significant impact on sectoral CO_2 reduction before 2035. What is more, the proportion of CO_2 mitigation from energy service demand reduction in the buildings sector is far less than that in other end-use sectors.

5 Conclusion

China's energy service demand, total energy consumption and carbon emissions have experienced fast growth in the past three decades. However, due to its relatively low per capita income and per capita energy use, energy consumption as well as carbon emissions are projected to continue to increase in the future without strong carbon mitigation efforts. Carbon emissions in 2050 are expected to increase to around 14.5 $GtCO_2$, and cumulative carbon emissions between 2010 and 2050 will be around 480 $GtCO_2$. The 10–40 % reductions in cumulative emissions discussed in this chapter will require great efforts in both the low and non-technology deployment scenario, as well as transformation in both production and consumption modes to decrease energy service demand. Compared with the results derived from using the China TIMES without elastic demand (Chen et al. 2013), the marginal carbon abatement costs for similar levels of reduction will however be around 50 % lower.

Greater levels of carbon mitigation will require more reduction of energy service demand, but this would result in higher community welfare loss. It is therefore more important to control the current fast increases in energy service demand in the short term through transformation of both production and consumption modes to avoid lock-in. In the longer term, development of low and non-carbon energy will be more critical with respect to the achievement of significant carbon mitigation, as a result of the limited room for energy service demand reduction and the consequent higher community welfare loss. Apart from significant breakthroughs in both energy supply and end-use technologies, stronger policies and actions on the limitation of the export of energy intensive products, reasonable city layout planning, public transportation system improvement, building energy saving, housing property taxes, and so on, are necessary for the promotion of low carbon society development.

Acknowledgments We would like to thank Ministry of Science and Technology of China (2012BAC20B01), Ministry of Education of China (12JJD630002), and National Development and Reform Commission of China (2012011) for the support on model development and simulation.

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Part III
Gaining Additional Insights Through Model Coupling

Soft-Linking Exercises Between TIMES, Power System Models and Housing Stock Models

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Abstract Soft-linking TIMES models with carefully selected complementary models can provide useful additional insights into the results from the TIMES model and can usefully scrutinize specific TIMES results in greater detail with another model. This multi-model approach can take advantage of the individual strengths of different modelling approaches. This chapter collates methodologies and results from a number of soft-linking exercises with TIMES. Two specific examples are given; firstly the soft-linking of TIMES to a power system model to investigate the TIMES results and provide additional insights into power system flexibility, reliability and market issues. The second example comprises the soft-linking of a TIMES model to a power system and a housing stock model to explore the impacts of increased electrification of residential heating on the power system and associated emissions from the residential sector. These examples show how a

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_18

multi-model approach and soft-linking can provide a strong complementary analysis to TIMES modelling exercises and generate insights into results that otherwise would be difficult to achieve with a single model approach.

1 Introduction

Soft-linking with TIMES is undertaken when the outputs from TIMES are scrutinized in greater detail with another model such as a dedicated power systems model, a macro-economic model, or a detailed sectoral models. The motivation for soft-linking is to provide a two-way transfer of information between the TIMES model and the linked model, in a manner that takes advantages of the strengths of each model. This exchange of information can provide additional insights and can improve and develop a deeper understanding of TIMES models' results. Part of this motivation is derived from a view that one specific energy modelling tool cannot address all aspects of the full energy system in great detail and greater insights and progress can be gained by drawing on the strengths of multiple modelling tools rather than trying to incorporate them all into one comprehensive model. A further motivation for soft-linking with sectoral models arises from the additional insights that may be gained regarding the timing for individual policy measures, thus facilitating a transition from technology roadmaps to policy roadmaps.

In the case of the electrical power system, both TIMES and power systems models address the modelling of complex systems, even though they are fundamentally different in their focus and application. Power systems models focus solely on the electrical power system and sometimes the gas network but do not consider the rest of the energy system. The primary inputs are generally exogenous in nature, including electricity load, fuel prices and power plant technical limits. Energy systems models examine the full energy system and in this case the electrical power system is by contrast completely endogenous and driven by the combined behaviour of supply sectors that provide primary fuels and end-use sectors driven by exogenous energy service demands. The focus is typically to provide a technology rich basis for estimating energy dynamics over a medium and long-term, multiple period time horizon. Because of the exclusive focus on electricity generation within power systems models, the problem description can be at a higher resolution, i.e. higher temporal resolution and with increased technical power plant operational detail (including ramp rates, minimum stable level, cold starts etc.) when compared to full energy systems model, which have to handle a much broader range of problems and sub-systems. Typically a power systems model can model from hourly to 5 min or higher resolution while energy systems models may have a limited number of temporally-independent "timeslices", which can be a limitation when looking at power systems with levels of fluctuating renewable energy.

The same applies in soft-linking with other model types. Regarding sectoral models, for example a dedicated housing stock model tends to have a focussed and detailed representation of housing stock in the residential sector while TIMES captures the housing stock in a more simplified manner. Soft-linking results from TIMES to a housing stock model can allow for results (in terms of energy) to be further scrutinised and translated into more meaningful units such as number of particular houses effected by a technology or policy.

This chapter collates methodologies and results from a number of soft-linking exercises including:

- The soft-linking of the Irish TIMES model to the power system model PLEXOS to scrutinise results in terms of power system flexibility and reliability.
- The soft-linking of TIMES Italy with a power system model to provide a complimentary dimension to TIMES analysis surrounding market issues.
- The soft-linking of the Irish TIMES model to a power system and housing stock model to examine the impact of increased electrification on the power system and associated emissions from the housing stock.

2 Why Soft-Linking to a Power System Model

The following sections highlights key areas of technical importance that benefit from soft-linking to a power system model.

2.1 Flexibility and Reliability

Power systems models can more readily take account of power system operation and be used to assess issues relating to flexibility and reliability. The benefit of higher resolution within power systems and energy systems modelling has been recognized where it was shown that optimal investment decisions derived from models can vary significantly depending on the timeslice selection used (Ludig et al. 2011). In Kannan (2011) the author has developed a temporal UK MARKAL model to investigate the role of electricity storage. The UK temporal MARKAL model has 20 annual timeslices compared to six in most standard MARKAL databases. In Pina et al. (2011) the authors have developed a high resolution temporal TIMES model by dividing each year into 4 seasons, with 3 days per season and 24 h per day. The results show that the increase in temporal resolution allows for more constraints to be taken into account, such as renewable resource availability, operational constraints, electricity demand dynamics and others.

Fluctuating renewable power such as wind, solar and ocean energy bring more variability and uncertainty to power system planning and operations and this can have an impact on power system reliability. Power system reliability is fundamentally composed of security and adequacy. A power system can be considered secure if it can withstand a loss (or potentially multiple losses) of key power supply components such as generators or transmission links. A power system is adequate if there is a sufficient installed capacity to meet demand. In general a number of key metrics are used to assess reliability. An overview of these can be found in Holttinen (2012). Briefly these are Loss of Load Probability (LOLP) which is a measure of the probability that demand will exceed the capacity of the system in a given period and the Loss of Load Expectation (LOLE) which is number of times in a given period that the load will be greater than the demand. LOLE can be used to set a security standard, generally given as a number of hours per year. If this is exceeded in, it indicates the system has a higher than acceptable level of risk. Expected Unserved Energy (EUE) is also a useful metric as it takes account of the extent of the shortages.

2.2 Unit Commitment and Dispatch

The security-constrained unit commitment and dispatch problem involves deciding the correct combination and power output of units for the economic and reliable operation of the power system, taking into account fuel and carbon costs, and reserve requirements required in case of forced outages of power plants or transmission lines and against demand uncertainty. Unit commitment being the decision of which units to turn on or off and dispatch being the decision of what level to run units at once they are on. The value of detailed unit commitment and dispatch modelling is that it captures many of the technical constraints and limitations of thermal power plant and quantifies the implications for variable renewable generation in terms of its impact on the probability of the system running short of generation and/or reserve requirements. This feeds back into the determination of the technical suitability and flexibility of the power system. While power systems models can model the unit commitment and dispatch problem at high resolutions (1 min–1 h), energy systems model generally assume a lower timely resolution for which the problem is solved. This is done so as to keep the problem computationally manageable. The unit commitment and dispatch problem can be relatively complicated to solve because the physical delivery of electricity is subject to the technical and economic constraints on generation. Some of these technical constraints may introduce integer variables into the linear programming formulation in order to track the on/off state of generation plant in time and to enforce important technical constraints minimum stable generation, minimum up and down times and start costs as a function of unit temperature.

2.3 Market Issues

Soft-linking can provide a complimentary dimension to TIMES analysis by allowing greater examination of the electricity market and impact of different portfolios on market prices and support mechanisms. A challenge for power systems is that the investments in flexibility required by a low carbon power system can be difficult to achieve if the market does not properly value the benefits of flexible resources. The problem here is if the market design benefits technologies that would help realize a system in line with political goals. A key characteristic of a market with large shares of renewables is its new market rationale, where the merit order is replaced by net demand (and the profile of the price curve is different from the demand curve) and the role of thermal plants changes substantially. There are many more periods of (temporarily) very low market prices, when there is a surplus of renewables and nuclear output, so that renewable electricity shifts the supply curve of conventional electricity virtually out of the market. Moreover, thermal plants have on average much lower load factors. Historically, in power market the ability to earn money on investments in new production facilities depends on whether the more expensive units can sell their electricity and recover more than their short run marginal cost. So, for conventional plants it was generally possible to recover the fixed costs when more expensive plants, usually gas-fired peaking units, set the price. But as the share of fix costs is considerably higher when full-load hours are low, in a high renewable market where renewables with virtually zero marginal costs set market clearing prices, this may no longer be the case. Power systems model generally can provide greater insight and analysis of these issues as they can simulate market configurations and allow for an understanding of market challenges to be developed.

3 Soft-Linking Methodology

The software used in these softlinking examples is PLEXOS Integrated Energy Model.[1] PLEXOS, developed by Energy Exemplar, is an electricity and gas systems modelling tool that uses mixed integer optimisation techniques to determine the least cost unit commitment and dispatch solution to meet demand while respecting generator technical-economic constraints. The software co-optimises hydro, thermal, renewable, and reserve classes; and no heuristic or sequential approach is taken. Modelling is carried out using mixed integer linear programming that aims to minimize an objective function subject to the expected cost of electricity dispatch and a number of constraints. The objective function of the model includes operational costs, consisting of fuel costs and carbon costs; start-up costs, consisting of a fuel off-take and a start cost; penalty costs for unserved energy and for failing to meet reserve requirements. System level constraints consist of an energy balance equation ensuring supply (net pumping demand) meets regional demand at each period. Water balance equations ensure water flow within the pumped storage units is conserved and tracked. Constraints on unit operation

[1] See http://energyexemplar.com/.

include minimum and maximum generation, maximum and minimum up and down time and ramp up and down rates. In chronological mode, the software solves for each period and maintains consistency across the full problem horizon.

The soft-linking methodology is described in detail in Deane et al. (2012). The initial step in the soft-linking methodology is to extract the power system from the energy system results. The power systems model is populated with an electrical portfolio, fuel prices and demand from the energy systems model while the energy systems model is enhanced with output from the power systems model. The goal of the methodology is ultimately to have an improved understanding of the energy systems model's results in relation to the electrical power sector and to understand what elements of the power system are important.

The steps in the soft-linking methodology are as follows:

1. Select the model, the scenario and the target year of the analysis for the energy systems model and execute the model.
2. Extract results from the energy systems model for the target year of interest for the electricity generation portfolio and populate the power systems model with this generation portfolio. Additional technical detail and data such as minimum stable generation, ramp rates and start costs, failure and maintenance rates are included in the power systems model. Fuel prices and carbon prices from the energy systems model are also provided to the power systems model.
3. Convert the annual electricity demand profile for the target year from the energy systems model into a half hourly chronological profile.
4. Initially run the power systems model for the target year using this data at half-hourly resolution without any additional technical constraints such as minimum stable generation, ramp rates and start costs. This is done to investigate the impact of increasing the chronological resolution of model.
5. Subsequently run the power system model with increasing level of technical constraints in order to determine the impact these technical parameters on model results.
6. Compare results between the two models, determine the differences and examine the reliability and flexibility of the power system.
7. Determine the implications of low wind production years on the reliability of the derived portfolio from the energy system model by running the power systems model with a number of different years of wind production profiles.
8. Use the insights gained from the results comparison to introduce constraints into the TIMES model to take account of the power system operation characteristics that are not readily captured within TIMES.

Figure 1 details a graphical representation of the methodology. Depending on differences that arise and insights that are gained, the energy systems model inputs or technical parameters can be adjusted to aim for improvement of results.

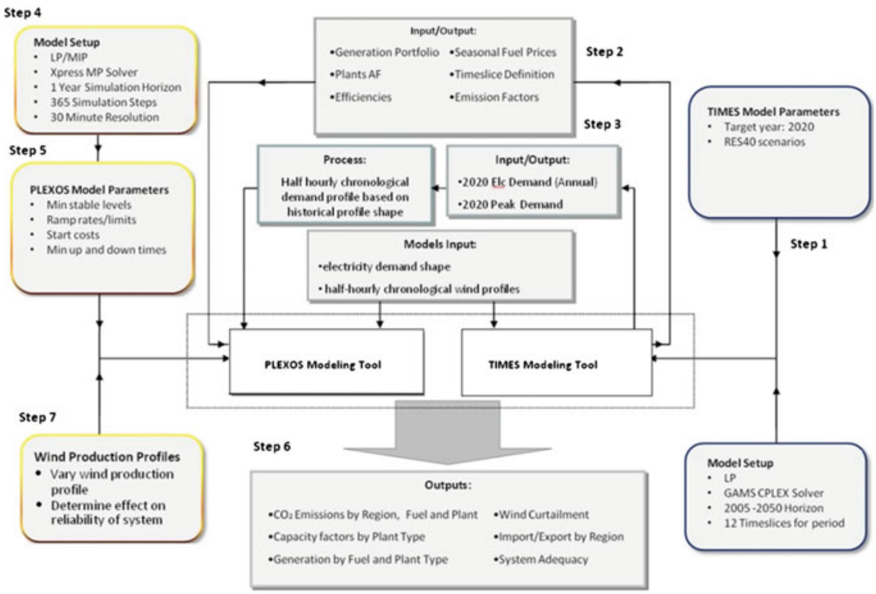

Fig. 1 Flow chart of soft-linking methodology

4 Power System Results

4.1 Flexibility

To demonstrate the soft-linking methodology as outlined above, we applied soft-linking to an energy systems model, Irish TIMES and a single year (2020) power systems model that was built using the results from a specific Irish TIMES scenario. This section describes summary results from the analysis.

Results of the detailed unit commitment and dispatch for a target year show that the power systems model commits more of the less efficient Combined Cycle gas Turbines (CCGT) units (*CC*-00) than the energy systems model across all technical scenarios examined. This is because these units come online when the newer CCGT units (*CC*-01) are out for maintenance or forced outages and are an important source of flexibility for the system. The energy model exploits the coal powered plant to its full capacity whereas in the power systems model these units are used less particularly with the inclusion of more technical parameters as the start cost gets incorporated into the objective function and coal generation is a ‘pulled back’ to allow gas and other generation to come online and run above their minimum stable level. As shown in Fig. 2, the distillate fuelled plants, while having a low capacity factor in the energy systems model run are shown to provide an import peaking ability and this value is only seen when higher levels of technical detail are modelled in the power systems model. Also pumped storage is an important

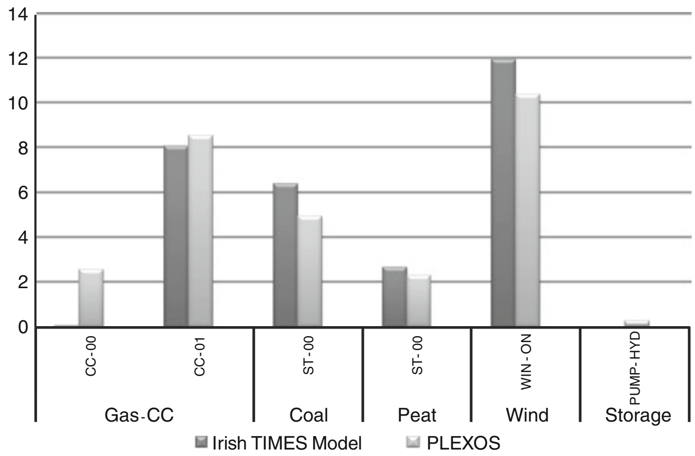

Fig. 2 Annual generation (TWh) for target year (2020) for both models

contributor to spinning reserve and is brought online more often to provide this service. Likewise the value of the pumped storage plant only becomes apparent in the power systems model. In relation to wind energy it can be seen that wind production is lower in the power systems model than the energy system model simulations indicating that wind curtailment is occurring. Results from the power systems model show annual wind curtailment of 8 % whereas The Irish TIMES model shows no wind curtailment. This stresses the importance of the correct modelling of flexible resources such as storage in the determination of system flexibility and suitability for renewable energy integration. These insights were fed back into the TIMES model by enforcing a constraint that limited the maximum annual production of wind generation on the power system and rerunning the system. Results for the low wind year simulations were broadly similar however as annual wind generation was lower an increase in thermal generation was seen. Equally results for the low wind year showed that system reliability was not compromised. This suggests that the power system portfolio in this analysis from TIMES is robust and resilient to changes in annual wind resource.

Table 1 shows the annual CO_2 emissions for both model runs. Looking at the power system scenario it is seen that the Irish-TIMES model has a greater

Table 1 Annual CO_2 emissions (Mt) for target year for both models

Fuel type	Irish TIMES model	Power systems model (PLEXOS)
Gas-CC-00	0.01	1.10
Gas-CC-01	2.95	3.12
Coal	5.77	4.35
Peat	2.48	2.20
Total	11.21	10.77

estimation of total annual emissions. This is because it has a higher level of coal and peat generation compared to the power systems model. The power systems model has higher emissions from gas plant but is offset by higher reduction in emissions from the coal and peat plant. In the absence of technical constraints the power systems model produces higher emissions as the baseload peat and coal plants are allowed to run longer.

In conclusion, the soft-linking of TIMES to a power systems model allows for greater technical scrutiny of the initial results from TIMES. Results in this analysis point to an overestimation of installed wind capacity in the original TIMES results. This insight was fed back into TIMES through a constraint on annual generation for this resource. This analysis also points to an underestimation of flexible resources such as pumped hydro storage.

4.2 Market Issues

This section applies the soft-linking methodology as described previously, to a case study in Italy. The objective of this particular exercise is to gain insights into the electricity market prices which can provide a complimentary dimension to analysis from TIMES. In this analysis we build a model of the Italian power system (PLEXOS-IT), using an energy system model (MONET). MONET is a six-region TIMES model of the Italian energy system developed by RSE (De Miglo et al. 2012) which is populated with detailed information on all main existing power plants and those under construction in Italy. In addition to detailed power plant technical characteristics, PLEXOS-IT also includes a representation of the 6 Italian market zones linked by transmission lines. The power system model contains data on transmission, in term of maximum/minimum flow, overloading ratings, resistance and reactance. PLEXOS-IT also includes linearised DC optimal power flow, which simply refers to the generator dispatch and resulting AC power flow that is minimum cost and feasible with respect to thermal limits on the AC transmission lines.

The MONET model is run with seasonal time slices and three diurnal time slices (day, night and peak), whereas PLEXOS_IT is run at half hourly time resolution and thus requires information in addition to that provided by MONET. The following characteristics apply to both models:

- The demand data for the 6 regions data has been scaled up to 2030, using the hourly demand profile data from 2010 (assumed the same one for all the regions).
- The half hourly renewable profiles are assumed the same in all the regions (in the absence of regional data).
- The model includes 6 nodes with transmission lines associated between relevant node and generators categorised by zone (and assuming current import and export transfer capacities).

The PLEXOS-IT model has also been populated with the data on the key technical characteristics of the functioning of power systems, i.e.:

- detailed characterization of power system operation, in terms of its key generation constraints;
- detailed characterization of the load, in terms of time granularity;
- detailed characterization of hydro resources (pumped storage as well as long- and short-term storages are optimized);
- a set of parameters/modules which are key for a proper representation of power system flexibility, in order to get insights into the flexibility requirement (e.g. impacts on the operation of the thermal system) of energy system scenarios characterized by a high share of variable renewables.

Key flexibility instruments have been added to the model, e.g. ancillary services (spinning, regulation and non-spinning reserves), demand response, pumped storage and hydro modelling. The models can also now be run at higher resolution time, up to 5 min, as previous research has shown the benefits provided by increasing the model temporal resolution (Deane et al. 2014).

Figures 3 and 4 show the hourly system marginal electricity price over the course of the year in the North region, in PLEXOS-IT–reference scenario and PLEXOS-IT–High renewables scenario. It is notable that (1) clearly the high VER

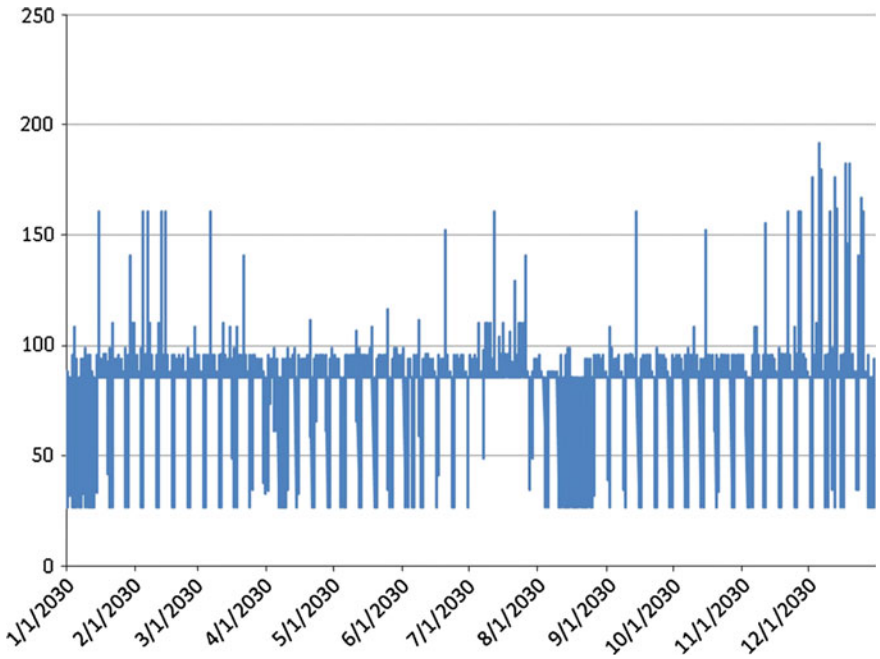

Fig. 3 Hourly electricity price over the course of the year, PLEXOS-IT—reference scenario, North region (€/MWh)

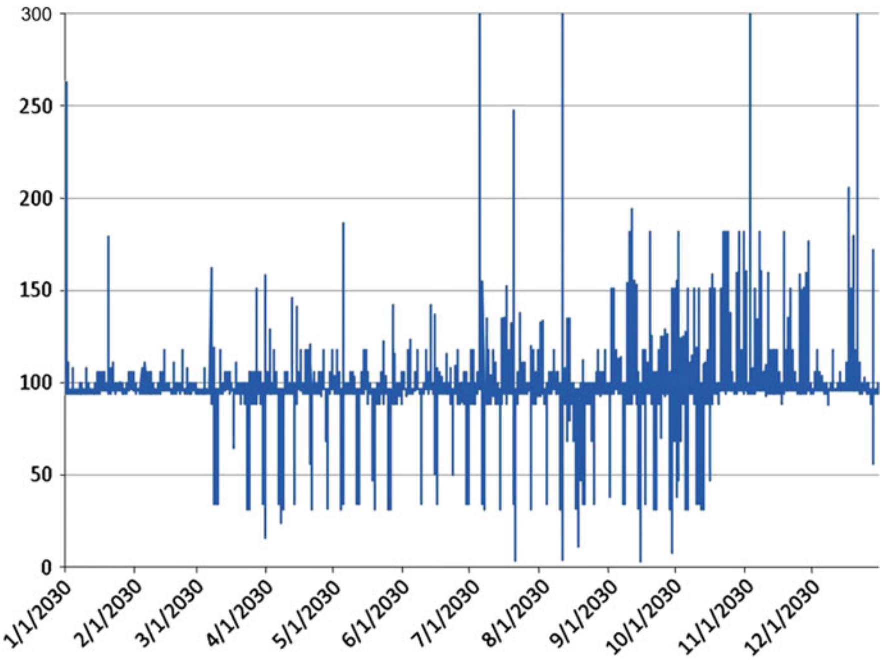

Fig. 4 Hourly electricity price over the course of the year, PLEXOS-IT—high renewables scenario, North region (€/MWh)

scenario presents a much higher volatility; (2) the volatility is higher during summer, when prices can even get close to zero.

This is further confirmed by Fig. 5, which shows the electricity prices in PLEXOS-IT High Renewables for Sardinia compared to the reference scenario, which is the region with the higher penetration of variable renewables. In this case the volatility becomes impressive, as well as the frequency of negative prices. This exposes an additional challenge for power systems with high levels of variable renewable generation. Results of simulations show that annual capacity factors from thermal fired gas plant drop from 58 to 28 % when moving from the reference scenario to the high renewables scenario. This poses great challenges in terms of financial remuneration for this type of plant and highlights the need for greater examination of this issue in terms of integrated energy system modelling.

The objective of this exercise is to demonstrate how soft-linking methodologies can be used to gain insight into market issues surrounding the integration of high levels of low marginal costs generation into current electricity market structures. It provides an extra dimension to a TIMES analysis by allowing an understanding of the market prices and market volatility to be developed. The above analysis does not answer the question on what market structure is best suited to power system with high level of variable renewables, however it provides a starting point in understanding this important issue.

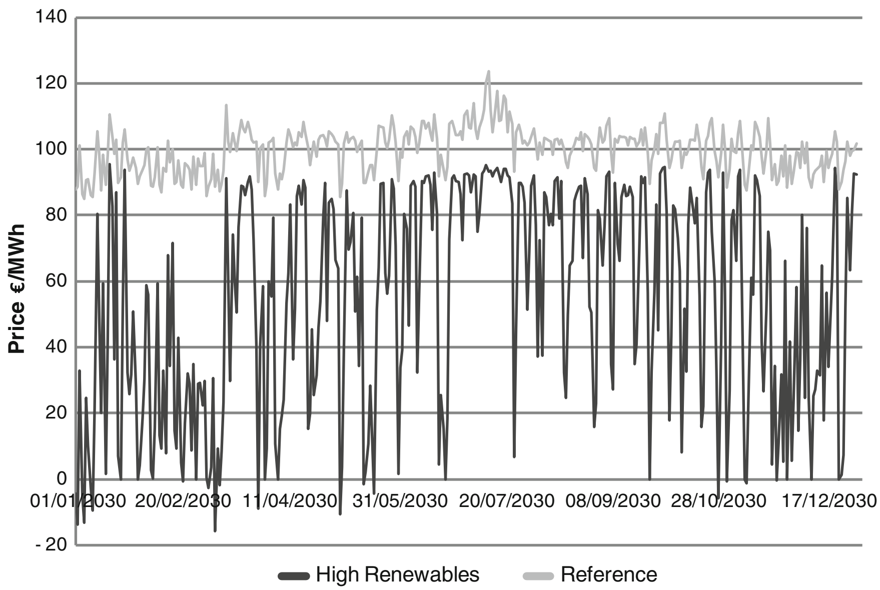

Fig. 5 Daily electricity prices over the course of the year, PLEXOS-IT high renewables Sardinia (€/MWh)

5 Soft-Linking TIMES to a Housing Stock Model

In this section we present a multi-model and soft-linking approach to assess the technical appropriateness of results for electrification of residential heating from TIMES.

5.1 Methodology

A number of models are used in this analysis to determine the impact of increased electric residential heating. In essence in this analysis each modelling tool, depending on its strength, asks and answers a different question. The questions can be summed up as follows:

1. What levels of electrification of residential heating form part of a least cost energy system in 2020 for Ireland to meet its national targets for emissions reductions in the Non-ETS sectors?
2. Can the power system operate with this extra level of electrification (provided by the answer to question 1) and what are the associated impacts, including the increase in power system CO_2 emissions? and

3. How many dwellings (and which type) should have heat pumps installed and how much oil based CO_2 emissions are offset as a result?

The methodology proceeds as follows (Fig. 6). The Irish-TIMES energy system model is used to assess the full energy system of Ireland under an emission mitigation scenario. The model assesses the cost optimal pathway for Ireland to achieve national emissions reduction targets in 2020. PLEXOS is then used to examine the impact and technical appropriateness of the half hourly heating requirement on the operation of the power system for the target year 2020 (Irish TIMES has a lower temporal resolution and more simplified representation of power system operation than the half hourly PLEXOS electricity dispatch model of the Irish power system). The ArDEM archetype dwelling model [previously used in Dineen and Gallachóir (2011)] is then used to determine the number of dwellings that could be served for a given amount of heat energy supplied.

Results for the Irish TIMES model suggest that electrification of residential heating will rise by the year 2020 in order for Ireland to meet its non-ETS emission reduction target in a cost optimal fashion. This is shown in Fig. 7, which presents the energy systems modelling results for the residential sector to the year 2020. The figure also compares results from a reference scenario (REF), which provides a least cost solution in the absence of a mitigation target, with those from a mitigation scenario, which seeks to deliver a 20 % emissions reduction relative to 2005 levels on non-ETS sectors and a 21 % on ETS CO_2 emissions by 2020 (in accordance

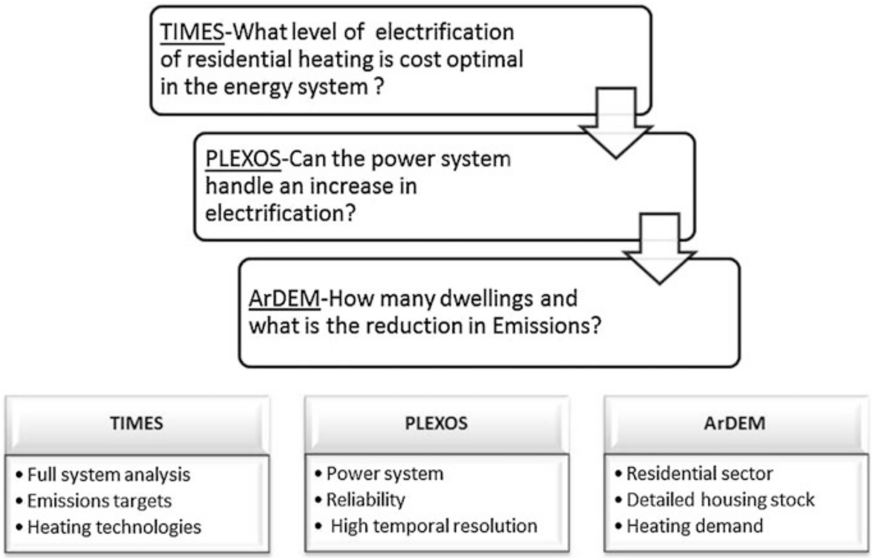

Fig. 6 How different models answer different questions

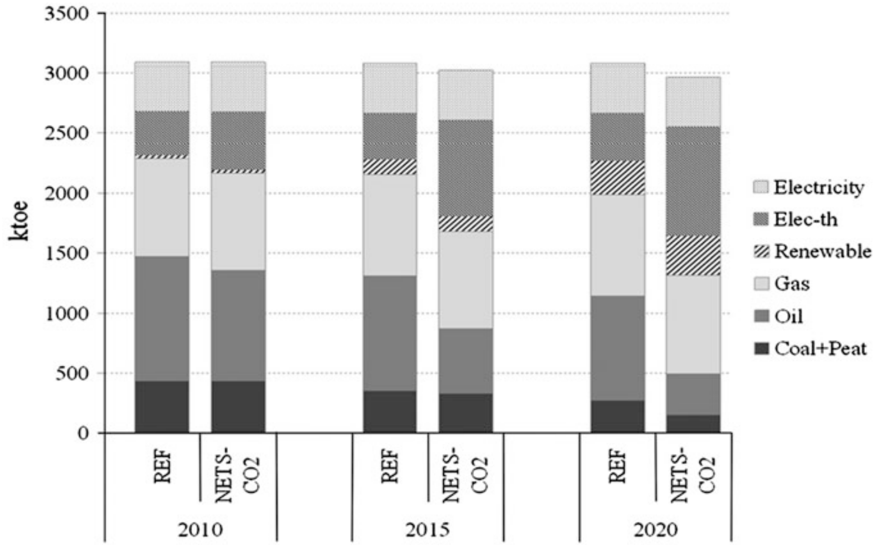

Fig. 7 Results from Irish TIMES for REF and emissions reduction scenario (NETS) to 2020

with current EU GHG policy frameworks through Directive 2009/29/EC[2] and Decision 2009/406/EC).

The REF scenario indicates that, in absence of emissions constraints, electrification of heating will almost remain stable in the next decade, while imposing the legally binding non-ETS emissions reduction target results in high levels of electrification. Electrification reaches a level of approximately 914 ktoe (10.6 TWh) by the year 2020. This represents the heating requirements of approximately 817,000 dwellings and the results suggest it is met mainly through the use of technologies such as direct electric heating and heat pumps mostly displacing oil and coal based systems. By 2020 electric heat accounts for 44 % of total residential heating demand in NETS-CO_2, and constitutes an almost four-fold increase on base year levels.

5.2 Power System Implications

A number of scenarios of installed heating capacity were examined in the 2020 power system using a half hourly heating profile derived from actual data. The power system portfolio was extracted from TIMES for that year. Each scenario

[2] The authors are cognisant that we have simplified how the ETS target is applied in this chapter, i.e. at Member State level rather than EU wide, while the Directive applies the target reduction across the entire EU.

represents installed electrical capacities ranged from 0 to 2000 MW and were examined in increments of 500 M. Results from the detailed power system analysis showed that the power system reliability (as derived by TIMES) was breached just above 1000 MW of installed Air Source Heat Pumps ASHP capacity. At levels above this, the reliability of the power system was compromised and extra capacity would be required. The use of a high resolution heating profile is important as it allows for the relationship between high heating demand (cold weather) and possible low renewable output (low wind speeds) to be captured.

5.3 How Many Homes?

To determine the CO_2 emissions, the ArDEM model was used to estimate the number of dwellings that could be heated with 1000 MW of installed ASHP electrical capacity. It is assumed for this analysis that the ASHP are replacing existing oil fired boilers that are at least 20 years old as it is unlikely that newer boilers would be replaced before the end of their useful life. Two retrofit scenarios are considered, the first where the ASHP would replace oil boilers and no other retrofit works would be carried out to the dwelling. As many of the dwellings considered are old and of poorer construction quality this would lead to situations where the ASHP would operate in poorly insulated inefficient dwellings. In the second scenario the ASHP is assumed to be installed and at the same time the roof and wall insulation of the dwelling are retrofitted to modern standard. Equally in this scenario it is assumed that appropriate heat emitters are installed for the dwelling. This would reduce the heating energy requirement for a 'typical' house from 18,709 to 14,904 kWh/year. This will allow greater efficiency and a greater number of dwellings to be converted from oil to electricity for the same load on the electricity generation system. The results of this analysis for 1000 MW of installed capacity are presented in Table 2. Note that the emissions associated with the '*Unaltered dwelling*' and '*Improved roof and wall insulation*' dwelling are different for the same energy delivered. This is due to the heterogeneous nature of dwellings in the ArDEM model and varying oil fired boiler efficiencies.

Table 2 Results from dwelling energy assessment model (ArDEM)

	Unaltered dwellings	Improved roof and wall insulation
Energy required for main space and water heating (GWh)	5087	5087
Energy requirement per dwelling (kWh/year)	18,706	14,904
Numbers of dwellings converted	271,951	341,315
Total CO_2 for oil existing oil boiler (kt/annum)	1841	1832
Total CO_2 with new ASHP (t/annum)	953	953
Net reduction in CO_2 (kt/annum)	888	879

The results in Table 2 shows that 1000 MW of ASHP's could provide the annual space and water heating requirements to meet the demand of 271,951 unaltered dwellings, but if these dwellings had shallow retrofits (such as wall and ceiling insulation) then this heat load can meet the requirements of approximately 341,315 dwellings. The associated reduction in emissions for the full system is approximately 879 kt of CO_2. This is in strong contrast to 817,000 dwellings converting to air source heat pumps using a single model approach with TIMES. In our analysis the TIMES model primarily underestimates the impact of ASHP on power system reliability particularly at times of high heating demand and low renewable energy output. To improve results from TIMES we fed the insights gained from this analysis back into the model by placing a constraint on the amount of electric heating that can be absorbed in the power system. When the analysis was rerun for this scenario, an increase in the use of bioenergy for heating and transport was observed. It was also noted that the power system portfolio did not significantly change.

In conclusion, this analysis provides a useful framework for providing complimentary analysis of results from TIMES by leveraging the strength of other models. The exercise shows that relying solely on an integrated energy systems model may lead to an overestimation of the extent of electrification of residential heating. Our multi-model approach suggests that between 270,000 and 340,000 existing oil fired residential dwellings could be with converted to air source heat pump technology (ASHP) without compromising the operation of the electrical power system. This is in contrast to 817,000 dwellings converting to air source heat pumps using a single model approach.

6 Conclusion

The examples presented here provide an indication of the benefits that a multi-model approach can bring in terms of both the additional insights it provides and how it can inform improvements in TIMES. There are many other examples of soft-linking TIMES with other models; chapters by Glynn et al. of this book provide some examples of soft-linking TIMES models with CGE models. This approach draws on the strengths of different models and develops innovative soft-linking methodologies in order to ensure robust data and communication flows between the models and is a useful alternative to trying to develop a model that tries to answer all questions.

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Economic Impacts of Future Changes in the Energy System—Global Perspectives

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Abstract In a climate constrained future, hybrid energy-economy model coupling gives additional insight into interregional competition, trade, industrial delocalisation and overall macroeconomic consequences of decarbonising the energy system. Decarbonising the energy system is critical in mitigating climate change. This chapter summarises modelling methodologies developed in the ETSAP community

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_19

to assess economic impacts of decarbonising energy systems at a global level. The next chapter of this book focuses on a national perspective. The range of economic impacts is regionally dependent upon the stage of economic development, the level of industrialisation, energy intensity of exports, and competition effects due to rates of relative decarbonisation. Developed nation's decarbonisation targets are estimated to result in a manageable GDP loss in the region of 2 % by 2050. Energy intensive export driven developing countries such as China and India, and fossil fuel exporting nations can expect significantly higher GDP loss of up to 5 % GDP per year by mid-century.

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1 Introduction

1.1 Why Link Energy-Economy Models?

In these two chapters the current state of the art of methods within the ETSAP community to couple energy systems models to macroeconomic models are presented. This chapter covers perspectives on the environmental rationale, model coupling development, outlines model coupling policy and research applications at the global and regional level. Next chapter of this book continues with national case studies, showing the UK's legislative use the coupled hybrid MARKAL[1]-MACRO (MM) model, and updates to the mathematical formulations of its successors TIMES[2]-MACRO (TM) and most recently TIMES MACRO-Stand-Alone (TMSA). The energy systems models discussed are bottom-up (BU) techno-economic linear optimisation engineering TIMES models, while coupled to top-down (TD) macroeconomic models. These range from single producer-consumer agent production function models, to multi-region structural computable general equilibrium (CGE) models. Both chapters collate the collective work that was presented at an IEA-ETSAP funded workshop in University College Cork in February 2014. They conclude synthesising common critical messages from the range of studies. The applied theory of what constitutes a consistent, pragmatic and heuristic model linkage is discussed. Soft-linking and hard-linking multi-model methods are introduced with attention paid to model structures, consequent data harmonisation and data transfer frameworks. Multi-regional models add insight into trade and competition effects upon delocalisation. Overall, maintaining a consistent paradigm throughout model coupling is critical in understanding the economic impacts of future changes to the energy system.

Affordable access to an acceptable energy supply is critical for a prosperous stable economy. Functional markets are theorised to price primary energy supply commodities, their refined products and final consumer energy products. Non market externalities such as green-house-gas (GHG) emissions or long term strategic policy decisions are difficult to fully include in near term commodity futures pricing, as a result of changing trends and resultant uncertainty. Half of all cumulative anthropogenic CO_2 emissions have occurred in the past 40 years. Increasing energy system carbon intensity between 2000–2010 has contributed to GHG growth increasing to 2.2 %/year when compared with 1.3 %/year over the previous three decades (IPCC 2014). Two thirds of global GHG emissions are produced by the energy system. The energy system analysis of International Energy Agency's (IEA) New Policy Scenario leaves the world on track for a long term average temperature increase of 3.6 °C, dangerously beyond the 2 °C limit (IPCC 2013; OECD/IEA 2013). A restructured low-carbon world economy is thus imperative (Capros et al. 2014; Krey et al. 2014).

[1] MARKAL—**MARK**et **AL**ocation model.

[2] TIMES—**T**he **I**ntegrated **M**ARKAL-**E**fom **S**ystem.

Internalising the energy system GHG environmental externality by appropriate pricing mechanisms via emissions permits trading markets and carbon taxation is seen as the primary means to drive decarbonisation in the energy system. In energy systems modelling, the marginal abatement cost of carbon is typically used as the scenario comparison yard-stick. Carbon pricing is critical to stabilise investor expectation to promote investment in marginal mitigation technologies. The European emissions trading scheme (EU-ETS) has made efforts to account for the environmental externality, but thus far has failed to be the causal force in reducing carbon emissions. It must be fixed, and other regions must similarly collaborate (Edenhofer 2014). Otherwise, climate change—essentially a commons problem—could become the modern era "tragedy of the commons" (Hardin 1968; Nordhaus 1994). Recently the UK has made efforts to correct this market failure with amending policy to introduce a carbon price floor (HM Revenue and Customs 2013). Revenue recycling schemes from carbon taxation can bring long term decarbonisation benefits to near term social good, tacking climate inequality, or achieve revenue neutrality. Policy-makers need tools to understand the effectiveness and the economic impact of policies whose purpose is to shift energy systems toward more environmentally desirable development pathways (Hourcade et al. 2006). Understanding energy-economy coupling is crucial in analysing regional effects of carbon tax, trade, competitiveness, and energy policy at large.

Accounting the cost of investment required to achieve least cost energy systems is achievable with technology rich BU energy systems models. The rationale behind linking engineering energy systems models with macroeconomic models is to include the feedback effect between energy cost and energy service demands. Coupling energy-economy models enables analysis of heterogeneous sectoral dynamics while providing a more suitable microeconomic framework (Bataille et al. 2006), that energy systems models on their own can only approximate with elastic demand. The objective is to estimate the changes in welfare and growth, where deviation from business-as-usual (BAU) in investment requirements induces productivity and consumption pattern changes through substitution effects. The potential magnitude of these effects vary considerably across differing economic schools of thought; from neoclassical to ecological economics; from growth opportunities to deep sustainability (Warr and Ayres 2006; Strachan and Kannan 2008; Jackson 2009; Ayres et al. 2013; Krey et al. 2014; The Global Commission on the Economy and Climate 2014). GHG emissions are typically the constraint driving redistribution of investment capital causing macroeconomic feedback, but of course this is not the only model scenario that could be considered. The macroeconomic cost of energy supply insecurity is an alternate use of model coupling, as is energy export and trade dynamics. The benefit of soft-linking energy system and macroeconomic models is in utilising the complementary strengths of both models to overcome the other's weaknesses. This allows additional insights of technological and economic detail to be gleaned that otherwise would not be quantified.

1.2 BU and TD Models

BU engineering models and TD macroeconomic models have evolved as the economically consistent means of assessing long term energy system dynamics and costs (Wene 1996; Hourcade et al. 2006). BU models include *optimisation, simulation, accounting and multi agent techniques* (Fleiter et al. 2011). Some TD methods include *input–output, econometric, computable general equilibrium* (CGE) and *system dynamic models*. This chapter is primarily focused on coupling TIMES optimisation and CGE models.

BU model methods are explicit in their data richness and outline detailed technology development pathways, interdependencies and costs. TIMES and it's forebear MARKAL form the primary constituent parts of a family of linear programming models supported by ETSAP under an implementing agreement of the IEA. TIMES is a techno-economic model generator for local, national or multi-regional energy systems, which provides a technology rich basis for estimating energy dynamics over a long-term (20–50 years), multi-period time horizon. TIMES computes a time varying inter-temporal partial equilibrium on inter-regional markets. The objective function maximises total surplus. This is equivalent to minimising the discounted total energy system cost while respecting environmental, technical and scenario constraints. This system cost includes investment, operation and maintenance and fuel import costs, less export income, terminal technology values and salvage values. This approach does not consider the same microeconomic theoretical underpinnings as a TD model and can be viewed as the optimisation by a clairvoyant energy planner with perfect information and perfect foresight over the total system, rather than maximising consumer choice preferences at a microeconomic level. Thus, TIMES models reference scenario pathways are driven by energy service demands exogenously defined by macroeconomic conditions and resource supply curves; while, subsequent dynamics are driven by environmental constraints under user consideration. The technical foundations of MARKAL is outlined by Fishbone and Abilock, while the full technical TIMES documentation is hosted online by ETSAP (Fishbone and Abilock 1981; Loulou et al. 2005).

TD CGE methods describe the whole economy, mapping and subdividing sectoral structures where substitution between factors of production is allowed. CGE models are built upon microeconomic theory to calculate prices and activities in all sectors of an economy to reach a general equilibrium. Consumers maximise their utility through demanding goods met by producers who maximise profits (Arrow and Debreu 1954; Johansen 1960). Historical national or global accounts data is required for calibration, where the Global Trade Analysis Project (GTAP) database is the most commonly used example. TD models in general, namely CGE models, do not include many technical aspects of the energy system. The energy system combined with the other factors of production, forms of capital and labour, are described in inter-related production functions to optimise consumer utility and economic growth. Capital value shares, elasticities of substitution, and autonomous energy efficiency improvement coefficients—estimating technological learning—and marginal technology cost curves (Kiuila and Rutherford 2013) enable estimation of technology choice and fuel switching dynamics.

The Lucas critique argues econometric models based on historic trends cannot model policy changes nor remain valid in future technology paradigm shifts (Lucas Jr 1976; Grubb et al. 2002). CGE models usually have smooth rates substitution, whereas poorly constructed optimisation models can display a "flip-flop" binary characteristic related to the capacity size of the marginal technology choices and level of model constraints (Grubler et al. 1999). The different approaches can provide differing solutions and result in differing policy conclusions. However, CGE models can give long term macroeconomic outlooks to drive TIMES energy systems models which can in-turn feedback energy costs adjustments to the CGE model, which upon iteration provides new energy demands (Hoffman and Jorgenson 1977). In a consistent framework the coupled hybrid model can build a more accurate representation of the system under scrutiny.

1.3 Hybrid Model Evolution

The linking of the Brookhaven Energy System Optimisation model (BESOM) with a CGE model is the first hybrid energy-economy model reported (Hoffman and Jorgenson 1977). The outputs of each of the individual models were transferred between each other manually by the user, in what has become known in the proceeding decades as *soft-linking*. Soft-linking is typically the simplest starting point by its transparency, flexibility, learning (Martinsen 2011), and practicality in establishing consistent common measuring points (CMP) in the overlap of model structures.

The alternative of programmatically linking of models to automate data transfer between models is known as *hard-linking*. MARKAL-MACRO is the first such reported hard-linked energy-economy model (Manne and Wene 1992), and is the basis for the subsequent TIMES-MACRO, TIMES-MSA and others (Manne et al. 1995; Wene 1996; Messner and Schrattenholzer 2000). Hard-linked models tend to establish optimum data transfer methods, enabling greater productivity, control, convergence and solution uniqueness. Historically hard-linking has come at a computational cost, requiring the model to be a reduced form single sector model (Manne and Wene 1992; Manne et al. 1995; Böhringer 1998; Messner and Schrattenholzer 2000; Bosetti et al. 2006; Strachan and Kannan 2008). This results in aggregated energy economy interactions, giving overall trends but limits its usefulness when applied to sector specific enquiries.

Combining BU and TD models in a mixed complementarity problem introduces a limited set of technological sectoral detail into a CGE framework (Frei et al. 2003; Sue Wing 2008; Proença and St. Aubyn 2013). The whole energy system cost optimisation problem could be integrated into a CGE model, with decomposition to improve solution algorithm performance and reduce computation time (Böhringer 1998; Böhringer and Rutherford 2008, 2009). However, the authors are not aware of such a model. Aside, the International Monetary Fund have made attempts to integrate oil supply dynamics into their global dynamic stochastic general equilibrium model GIMF (Benes et al. 2012; Kumhof and Muir 2014).

2 Linkage of the Global Energy Models TIAM-WORLD and GEMINI-E3

In order to assess climate mitigation agreements, an iterative procedure linking TIAM-WORLD and GEMINI-E3 is the first method proposed. TIAM-WORLD (TIMES Integrated Assessment Model) is a BU global multi-regional technology-rich optimisation model. GEMINI-E3 is a TD global multi-regional general equilibrium model (Loulou and Labriet 2008; Bernard and Vielle 2008). Recent work soft-linking the two models explores global and partial climate agreements (Labriet et al. 2015). An accurate representation of the energy and technology choices, and the macro-economic impacts, especially in terms of trade effects of climate polices, is critical in understanding future pathways to a climate constrained world.

TIAM-WORLD is part of the TIMES family of energy models and calculates a dynamic inter-temporal partial equilibrium on worldwide energy and emissions markets based on maximisation of total surplus (Loulou 2008). The version of the model uses in this application divides the world in 15 regions, driven by 42 energy service demands across all sectors. It covers the procurement, transformation, trade and end use of all energy forms, represented by over 1500 energy technologies and one hundred commodities in each region. Energy demands are calibrated by the user for the reference scenario, and each has its own price elasticity. Environmental emissions are endogenously modelled at the technology level. TIAM-WORLD integrates a climate module for the modelling of greenhouse gas concentrations, radiative forcing and temperature increase.

GEMINI-E3 is a multi-country, multi-sector, recursive computable general equilibrium model. It represents the world economy in 28 regions and 18 sectors. The standard model is based on the assumption of total flexibility on both macroeconomic markets, such as the capital and the exchange markets (the associated price are the real rate of interest and the real exchange rate, which are then endogenous), and microeconomic or sector markets (goods, factors of production). GEMINI-E3 is calibrated with the GTAP database which includes physical energy market data, social accounting matrices and bilateral trade flows.

2.1 Data Harmonisation

The initial harmonisation of the two very different model structures represents a critical challenge for hybrid model's theoretical consistency. Each of the model regions and commodities need to be paired. Furthermore, reference scenarios require harmonisation of the basic drivers of the energy system, being population growth, GDP trends, energy prices and energy policy constraints. Once harmonized, the reference cases of TIAM-WORLD and GEMINI-E3 propose similar CO_2 emission trajectory until 2030. Differing technological assumptions lead to longer term divergence of CO_2 trajectories. This effect has also been seen in similar modelling exercises (Labriet et al. 2012; Kanudia et al. 2014; Krey et al. 2014).

2.2 The Coupling Method

The purpose of the linkage of the models is to allow the strengths of each model (technological richness of TIAM-WORLD and macro-economic details of GEMINI-E3) to augment the overall analysis of energy and climate policies. The coupling approach optimises the data flow of common market points, from the model of relative more accuracy, to the other model. GEMINI-E3 receives data from TIAM-WORLD on energy and CO_2 prices, technical progress on energy use and capital consumption. TIAM-WORLD receives sector economic production data to recalculate energy service demands.

TIAM-WORLD only goes through one major modification: the removal of price elasticities of the energy service demands. This microeconomic behaviour is modelled by GEMINI-E3. GEMINI-E3 requires more numerous modifications to consistently utilise the data linkages: energy technologies that are not present in the standard version of GEMINI-E3, such as biomass, hydrogen, nuclear and other renewable energy sources are added to the model structure and the nested structure of the CES functions are rewritten; the CES functions relating to all energy consumption are replaced by Leontief function, whose coefficients representing the energy shares are computed on the basis of TIAM-WORLD results; technical progress is modified with energy efficiency improvements from TIAM-WORLD; finally, energy and carbon prices are computed by TIAM-WORLD.

The coupling procedure is carried out in a Gauss-Seidel method (Hageman and Young 2012) which seeks a fixed point for the useful demand vector through an iterative process. TIAM-WORLD is first run with useful demands from the harmonisation phase of the two models. TIAM-WORLD passes its results to GEMINI-E3, which is re-run. This is the first iteration. New macroeconomic output and industrial value added obtained from GEMINI-E3 are used to re-estimate the energy service demands. This process is repeated until model convergence is reached, defined as the Euclidean distance between the two last demand vectors over the norm of the last demand. Convergence is typically achieved in 6 iterations for climate constrained scenarios.

2.3 Results

Both global and partial climate agreements are studied with the proposed coupling methodology.

The comparison of the Iron and Steel production results obtained with TIAM-WORLD in a standalone manner with elastic demand and with the coupled models illustrates one of the added-value of the coupling: in a global climate agreement, while the iron-and-steel production decreases in all countries in TIAM-WORLD used in a standalone manner, several countries increase their production in the coupled models to compensate the production decrease in China and India. The combined analysis of trade, provided by GEMINI-E3, and energy dynamics, provided by TIAM-WORLD, helps understand these decisions: India and China prefer importing Iron and Steel from some other countries rather than producing it locally with clean energy and processes because of the lack of clean production opportunities in these countries compared with the others, more particularly biomass-fired power plants opportunities with carbon capture and sequestration.

However, the differences in sectoral emissions between TIAM-WORLD used in a standalone manner and the coupled models are smaller than 5 % over the model time horizon. This is an interesting result, showing that the inter-sectoral effects of climate policies have little effect on overall aggregated sectoral emissions.

In partial agreements, the coupled models help the assessment of the delocalisation of not only primary energy extraction (to Former Soviet Union and Africa), represented in TIAM-WORLD but also industrial production (to Asia), provided by GEMINI-E3. However, emission leakage remains small, mainly due to global lower oil demand.

The macroeconomic analysis from the coupled models also shows fossil fuel exporting countries, represented by the Middle East, Former Soviet Union and to a lesser degree Africa, are all extremely penalized by climate constraints. This simply occurs as a result of trade imbalances consequent to energy export revenue reductions while fossil fuel production declines.

2.4 Discussion

The two global models are coupled through an iterative exchange of data until convergence of energy demands. It builds upon the technology richness of TIAM-WORLD and the macro-economic details of GEMINI-E3. Technology changes, macroeconomic and inter-sectoral effects are assessed with the coupled models.

Although such an approach minimizes the number of structural changes of the original models compared to the full integration of models within a same optimization framework (Labriet et al. 2015), a meticulous examination and understanding of both models is crucial in order to define the correspondence between energy commodities, regions, economy sectors, to build the data exchanges between both models, and to avoid any methodological inconsistencies (Böhringer and Rutherford 2009).

An added value of the proposed coupling framework at a global scale is the understanding of the energy system transition interdependences upon trade and competition effects.

3 Global Energy Policies Analysed with TIAM-FR and IMACLIM-R

The hybrid linking of TIAM-FR and IMACLIM-R, while conceptually similar to linking TIAM-WORLD and GEMINI-E3 (summarised in Sect. 2), is fundamentally different in a specific assumption of perfect foresight. The CGE model IMACLIM-R allows the exploration of the differences in myopic technology pathways due to recursive time dynamics, i.e., the model is solved in sequential (yearly) time steps, linked through time by capital accumulation based on exogenous savings rates, while TIAM has perfect foresight of technology availability and development. This first section focuses on the reconciliation of these theoretical differences.

TIAM-FR, a version of the TIMES Integrate Assessment Model (TIAM) developed in France, is a typical BU TIMES model that has been widely used to assess sectoral and global energy and climate policy from both developed and developing countries perspective (Bouckaert et al. 2011; Assoumou and Maïzi 2011; Ricci and Selosse 2013). IMACLIM-R, is the recursive version of IMACLIM, a multi-regional multi-sector TD model that has been developed by CIRED to assess the long-term global economic impacts of climate policy (Guivarch et al. 2009; Sassi et al. 2010; Mathy and Guivarch 2010; Rozenberg et al. 2010; HAMDI-CHERIF et al. 2011).

The divergent viewpoints of models developed by energy engineers, or BU models, and those developed by economists, or TD models, can hinder effective dialogue and mutual understanding between researchers from different academic backgrounds. The purpose of this work is to promote a constructive dialogue between modellers from each side of the modelling paradigms, based on a comparative critique of the BU TIAM-FR model and the TD IMACLIM-R model.

3.1 Method

First and foremost, the conceptual frameworks (optimisation *vs.* recursive) of the two models must somehow be reconciled, and is done so with approaches to harmonise the theoretical structure, data and nomenclature of each model.

TIAM-FR is geographically aggregated in 15 world regions. It covers the time horizon from 2005 to 2100 to properly reflect the long-term nature of the climate constraint. Indeed, a climate module computes the change in CO_2 concentrations in atmospheric radiative forcing from anthropogenic activities and the temperature change relative to the pre-industrial period. The climate module does not induce retroactive energy services demands, which remain unchanged. More generally, TIAM-FR is driven by 42 exogenous end-use energy demands grouped into six sectors. Each energy demand is calibrated for the base year, and then follows a trend induced by some exogenous driver, *i.e.* regional economic and demographic projections and region-specific elasticities.

IMACLIM-R provides a more aggregated view of global economic activity, which it divides into 12 regions and 12 sectors. The base year of the model (2001) builds on the GTAP-6 database, a balanced Social Accounting Matrix (SAM) of the world economy although the original GTAP-6 dataset was modified to (i) aggregate regions and sectors according to the IMACLIM-R mapping, and (ii) accommodate the 2001 IEA energy balances (Sassi et al. 2010; Rozenberg et al. 2010).

IMACLIM-R's rationale stems from the necessity to understand better, amongst the drivers of energy-economy prospective trajectories, the relative role of (i) technical parameters, (ii) structural changes in the final demand for goods and services (dematerialisation of growth patterns) and, (iii) micro and macroeconomic behavioural parameters in open economies. This is indeed critical to capturing the mechanisms in the transformation of a given environmental alteration into an economic cost and in the widening or narrowing margins of freedom for climate mitigation or adaptation.

To fully exploit the potential of this dual representation requires abandoning the use of conventional aggregate production functions, which roughly represents the technological constraints impinging on an economy (Berndt and Wood 1975) and (Jorgenson 1982). It is indeed arguably impossible to find mathematical functions flexible enough to encompass all the contrasted scenarios resulting from the interplay between consumption styles, technologies and localisation patterns (Hourcade 1993), for small as well as for large departures from the reference equilibrium. This accounts for the already reported absence of formal production functions in IMACLIM-R.

IMACLIM-R and TIAM-FR use the same data and scenario with regards to the growth of population, from the United Nations. The global geographical division in TIAM-FR have been reprocessed from the simulation outcome of IMACLIM-R and re-aggregated in accordance with its 15 regions. The macroeconomic indicators were integrated into the TIAM-FR model to drive the energy service demand and, from it, determine the energy system in an optimisation framework. TIAM-FR model is then re-run with the macroeconomic output indices coming from IMACLIM-R to calculate the optimal outcome of the energy supply system and carbon emissions trajectories at the world level

Three Scenarios are considered, a business as usual scenario (BAU), and two climate scenarios (CLIM), one with BAU drivers, Clim_dBAU and the third scenario with drivers from a climate run of IMACLIM-R, Clim_dClim. More precisely, BAU scenario from TIAM-FR is based on macroeconomic indicators extracted from the BAU scenario of IMACLIM-R. Concerning the climate scenario, CLIM_dBAU and CLIM_dCLIM refers to two different trajectories consistent with the 450 ppm target in 2100 for CO_2 emissions. CLIM_dBAU is derived from simulation based on the BAU growth indices in IMACLIM-R, whereas CLIM_dCLIM is driven by growth indices from the 450 ppm scenario in IMACLIM-R. The price elastic energy demand functions are not used in running TIAM-FR as the prices have not been harmonized between the two models.

3.2 Results

The results specifics are not in focus here but more so the relative impact between scenarios are of interest in investigating the demand reduction as a result of climate scenario in IMACLIM-R. CO_2 emissions paths induced by climate constraints are reported in Fig. 1.

The comparison of CLIM_dBAU and CLIM_dCLIM pathway shapes illustrates again the divergence between TIAM-FR and IMACLIM-R in terms of modelling philosophy. Under an inter-temporal optimized abatement trajectory (CLIM-dBAU), emissions may keep growing by 2040 then slightly drop until 2060 before declining sharply. By contrast, the agent cannot see this *optimal* abatement pathway in the IMACLIM-r. Therefore, the pricing signal must be very strong, to reflect the 450 ppm constraint to curtail the fossil-fuel dependent goods and services demand. The growth indices would be much lower than in the case of the *optimal* growth in the short and mid-term. However, in the long run, there would be more flexibility for emission growth in CLIM-dCLIM than CLIM_dBAU as the economy will be largely decarbonized and thus offers more room for an emissions increase. TIAM-FR and IMACLIM-R suggest different timing and arbitrage for sectoral emission abatement for a given climate target (Fig. 2).

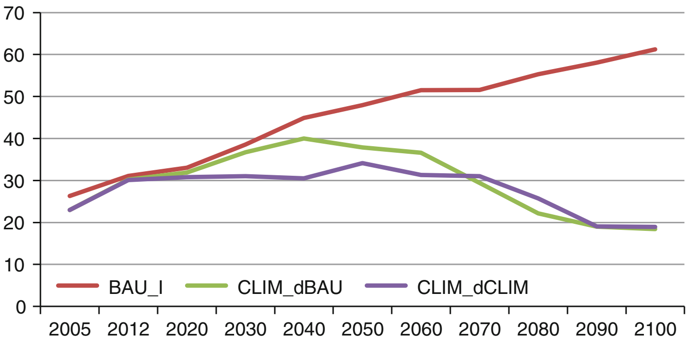

Fig. 1 World CO_2 emission trajectories under the three example scenarios (Gt)

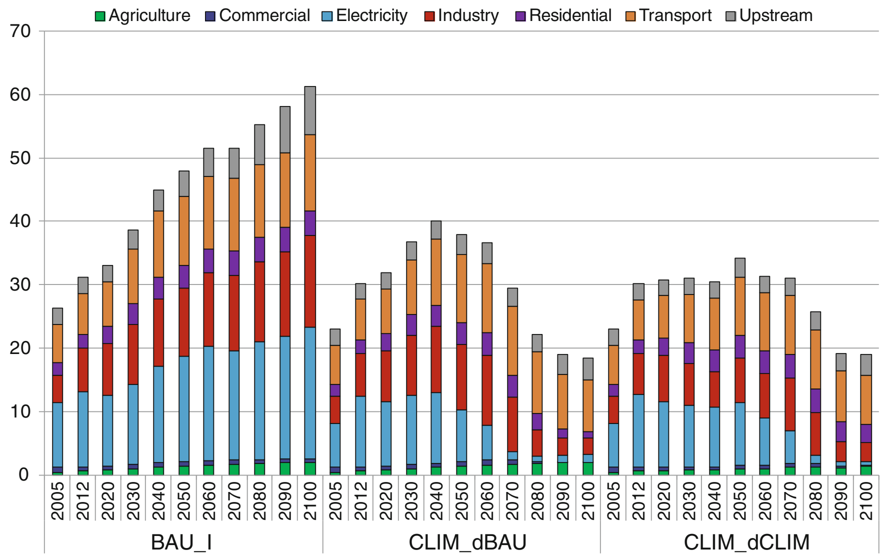

Fig. 2 World CO_2 emissions by sector (Gt)

In the CLIM_dBAU scenario, the CO_2 emitted by the electricity sector decreases from around 7 Gt in 2005 to 1.2 Gt in 2100. CO_2 emissions reach 0.6 Gt in 2100 in the CLIM_dCLIM scenario. CO_2 emissions represent nearly 21 Gt in 2100 in the BAU. The electricity sector share of total CO_2 emissions moves from 30 % in 2005 to 7 and 3 % respectively in CLIM_dBAU and CLIM_dCLIM. While CLIM_dCLIM appears more stringent in terms of decarbonisation for the electricity sector, it is interesting to note that the CO_2 emissions mitigation in the industry is more important in CLIM_dBAU than in CLIM_dCLIM with 2.6 Gt of CO_2 emitted in 2100 in the former against 3 Gt of CO_2 emitted in the latter scenario. CO_2 emissions in industry in 2100 represent 14 % in CLIM_dBAU and 16 % in CLIM_dCLIM of the total CO_2 emissions (24 % in BAU) against 19 % in 2005.

Other sectors impacted by the climate policies implemented in scenario are commercial and residential. In the BAU, these sectors account for 1 and 6 % respectively of the CO_2 emissions in 2100 (3 and 7 % in 2005). In CLIM_dBAU, they represent near to zero and 5 % respectively for commercial and residential sectors in 2100 and 1 and 16 % respectively in CLIM_dCLIM at the same period. The CO_2 emissions in commercial sector move from 0.8 Gt in 2005 to 0.007 Gt in 2100 (0.1 Gt in CLIM_dCLIM and 0.5 Gt in BAU) in 2100. Note that in the BAU, the CO_2 emissions from the commercial sector are less in 2100 than in 2005. As regard the CO_2 emissions in residential sector, they reduce from 1.9 Gt in 2005 to 0.9 Gt in 2100 (2.8 Gt in CLIM_dCLIM and 3.9 Gt in BAU in 2100).

3.3 Discussion

This coupling tentatively shows that modellers can benefit from information on the whole economy with the representation of factor markets (capital, labour) from a Macro model on the one hand, combined with technology richness of the BU models, which represent better the technologies available in a specific bounded economy for a given time. Nevertheless, the models do not necessarily converge due to the difference in structural design and modelling paradigm. Some technical and mathematical challenges need to be addressed to provide insights into policy recommendations. The applied methodology presents some limitations in terms of indicators harmonization and prices consistency and results should be interpreted with care. From microeconomic point of view, a major difference residing in TD and BU models is that the behaviours of both energy suppliers and end-users may affect significantly the general equilibrium and underlying prices on the different markets; which in turn will have repercussions on the investment and savings decisions across regions. Also, the government's fiscal policies play a central role in boosting or slowing the economic growth and influence all the institutions of the market.

4 From Global Modelling to Country Analysis: Focus on China with ETSAP-TIAM and AIM

China's economy and energy system developed rapidly since the 1980s, followed by an increase in CO_2 emissions. Analysing pathways for China's future development and associated global issues relies on complex global modelling tools that incorporate sufficient sub-regional details of China. Recent modelling exercises that account for such global and sub-regional economy and energy system features are however rarely described in the peer-reviewed academic literature (Mischke and Karlsson 2014).

This China soft-linking case study aims to bridge this knowledge gap between existing global and China-specific scenario studies, which are currently carried out by different academic institutions with multiple modelling tools (Mischke and Karlsson 2014). One example of such a modelling exercise for China was carried out by Chen (2005). Using a hybrid MARKAL MACRO model for China, (Chen 2005) concluded that the economic costs of a carbon emission reduction pathway in China towards 2050 are rather high, estimated at up to 2.54 % of GDP loss.

The soft-linking of a global TD economic model, the Asian-Pacific Integrated assessment Model (AIM/CGE) developed in the National Institute of Environmental Studies of Japan (NIES), with a global BU energy system model, the ET-SAP-TIAM model with sub-regional China features developed in the Technical University of Denmark (DTU), is carried out here to establish a common global and China-specific reference scenario. On this basis, global, China national and China sub-regional economic, energy and emission pathways can be documented, analysed, and replicated simultaneously.

4.1 Methods

The two global optimization models are expanded with a sub-regional level of detail for China as per the country's regional geographic definitions of the 7th Five Year Plan (National People's Congress 1985). Both models represent the economy and energy system of 16 world regions plus China. China-specific base year data are calibrated against official Chinese government statistics, including provincial energy balances and input-output tables. The global AIM/CGE model represents moreover up to 30 provinces of China, with 22 economic sectors and three final demand sectors (Dai and Mischke 2014). A triangulation method to integrate provincial energy statistics for China into ETSAP-TIAM (Loulou and Labriet 2008) was established (Mischke 2013).

The soft-linking approach used in this study comprises the following three major steps, which are similar to other country case studies presented here:

Step 1: **TD to BU**
The AIM/CGE model provides initial inputs for the ETSAP-TIAM model for a direct or indirect linking of the sectors in both models. The outputs of the economic sectors from the AIM/CGE model are used as drivers for energy service demand in ETSAP-TIAM model. If required, alternative projections from other sources are used, such as population statistics.

Step 2: **BU to TD**
After ETSAP-TIAM calculates the optimal technology mix and final energy demand in different sectors, the energy efficiency parameters of the AIM/CGE model are adjusted so that the energy consumption matches the ETSAP-TIAM results.

Step 3: **Model iterations**
After these two steps, equivalent to the first iteration, the results of energy service demand in the AIM/CGE model might change. If the change in parameters is significant, new iterations are carried out until an acceptable convergence is found. The hybrid model developed in this study is named CGESL.

4.2 Common Reference Scenario

A common reference scenario is constructed and tested in various iterations. It follows the GDP and demographic trends of a newly developed, moderate Shared Socio-economic Pathways (SSP2) scenario (O'Neill et al. 2014). The SSP2

Table 1 Future economic growth increase for sub-regions of China under SSP2 (2005 = 1)

Region	2005	2010	2020	2030	2040	2050
East-China	1.0	1.5	3.5	6.5	9.8	12.3
Central-China	1.0	1.5	3.9	7.5	12.1	15.8
West-China	1.0	1.5	3.7	7.0	11.1	14.4

pathway is downscaled for China, following the principle that the existing socio-economic disparities within China will be narrowed towards 2050. Future GDP growth projections for China and other model regions are thus a main driver in both models. GDP pathways of East-, Central- and West-China are summarised in Table 1.

4.3 Reference Scenario Results

At a **global level**, the hybrid model (Fig. 1, marked in green) shows a 2–2.5 times increase in global power production, primary and final energy use and CO_2 emissions towards 2050. The pathway for final energy is thereby highly harmonised between the different modelling tools. The AIM/CGE model and the ETSAP-TIAM model (Fig. 3, marked in red and blue), if used stand-alone, diverge increasingly in their pathways for global power production, primary energy use and global CO_2 emissions.

At a **China national level**, the hybrid model (Fig. 4, marked in green) shows a 5 times increase in China's power production, primary and final energy use and CO_2 emissions towards 2050. A peak in these pathways is suggested around 2040 in the TD AIM/CGE and the hybrid CGESL model, however not in the BU ETSAP-TIAM model. As described above, the models stand-alone diverge increasingly towards 2050. While the TD AIM/CGE model calculates an almost 6 times increase

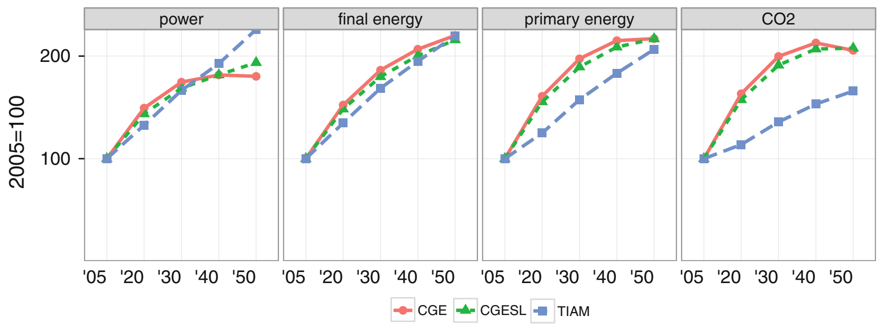

Fig. 3 World reference scenario in TD AIM/CGE, BU TIAM and hybrid CGESL models—pathways for power generation, primary and final energy use, and CO_2 emissions towards 2050

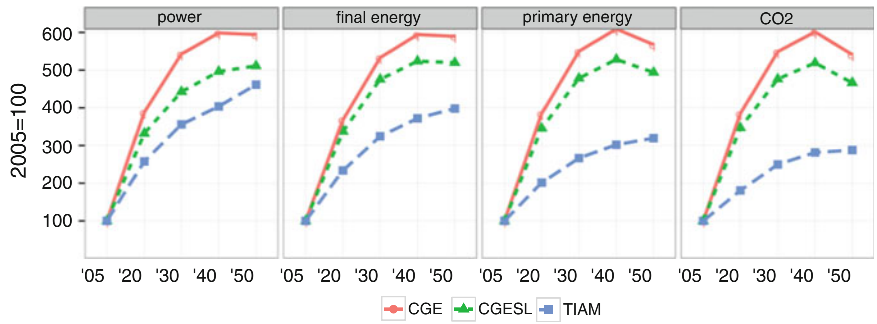

Fig. 4 China reference scenario in TD AIM/CGE, BU TIAM and hybrid CGESL models—pathways for power generation, primary and final energy use, and CO_2 emissions towards 2050

in all pathways towards 2050, the BU ETSAP-TIAM model calculates a much lower rate of increase of about 3–5 times.

Analyzing the modelling results for the **East-China sub-region**, which summarizes the highly developed coastal provinces of China, provides the further insights. The hybrid CGESL model (Fig. 5, marked in green) shows a 3.5–4 times increase in East-China's power production, primary and final energy use and CO_2 emissions towards 2050. A peak around 2040 is suggested in most pathways studied here, similar to the national-level results for China. As discussed before, the models stand-alone diverge increasingly.

The pathways for the **Central-China sub-region**, which comprises many resource-rich provinces of China, are provided in Fig. 6. The hybrid CGESL model (Fig. 6, marked in green) indicates a 6–6.5 times increase in Central-China's power production, primary and final energy use and CO_2 emissions towards 2050. The divergence in the pathways of the TD and BU models is highest for CO_2 emissions: the maximum increase in CO_2 emissions between 2005 and 2050 is about 7 times in the TD AIM/CGE model and only about 3 times in the BU ETSAP-TIAM model.

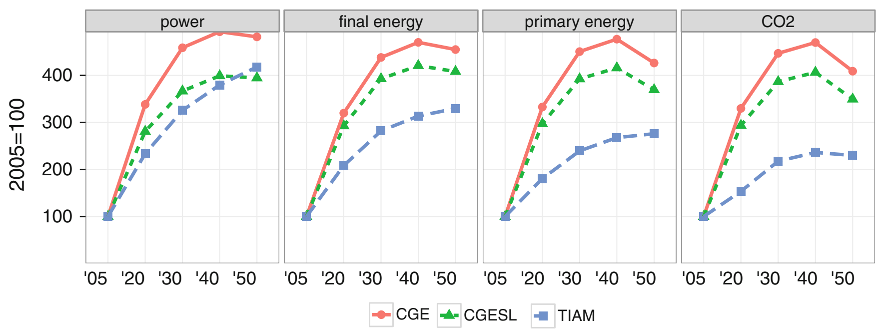

Fig. 5 East-China reference scenario in TD AIM/CGE, BU TIAM and hybrid CGESL models—pathways for power generation, primary and final energy use, and CO_2 emissions (2005–2050)

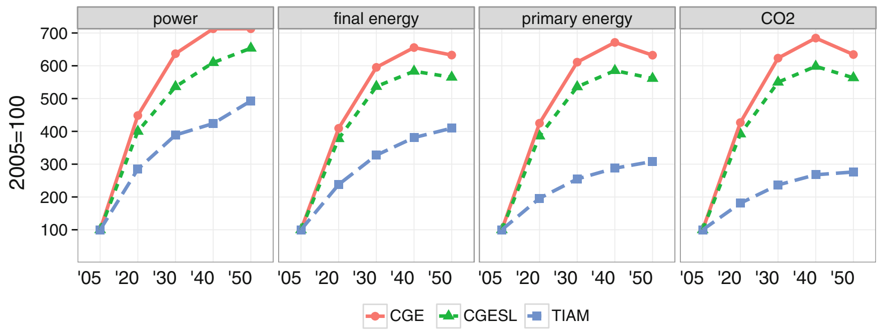

Fig. 6 Central-China reference scenario in TD AIM/CGE, BU TIAM and hybrid CGESL models—pathways for power generation, primary and final energy use, and CO_2 emissions towards 2050

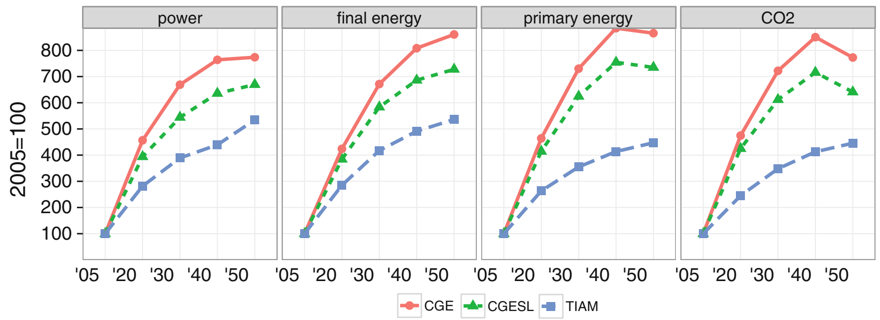

Fig. 7 West-China reference scenario in TD AIM/CGE, BU TIAM and hybrid CGESL models—pathways for power generation, primary and final energy use, and CO_2 emissions towards 2050

The **West-China sub-region** comprises many sparsely populated and economically less developed provinces of China. The corresponding future pathways are provided in Fig. 7. The results are similar to the other sub-regions of China, indicating major differences if models are not soft-linked and used stand-alone under a common reference scenario.

4.4 Discussion

Soft-linking global models with regional China features allows for new, sub-regional insights into China's future economic and energy system development. The common reference scenario established and tested in this study could provide a basis for future scenario studies about the potential global impacts of China-specific sub-regional and national energy and climate policies. These results, if replicable, reliable and transparent, could feed into an ongoing energy and climate policy debate in China, which is striving to balance global and China-specific regional development issues.

As previous scenario studies for China showed, the divergence in China-specific scenario results calculated by different modelling tools with different underlying assumptions is rather high (Mischke and Karlsson 2014). Our preliminary results confirm that China-specific modelling exercises should be sufficiently harmonised and documented first, before applying any modelling framework to study policy scenarios for China in a global context.

To cope with the range of uncertainty in China's future energy and emission projections, future work should focus on benchmarking such a global and China-specific modelling exercise with more leading global and China-specific scenario studies. More research is also needed to understand and explore uncertainty in underlying statistical differences that serve as inputs for this and other modelling frameworks.

5 From Global Modelling to Country Analysis: Focus on South America with TIAM-ECN and E3ME

Within the framework of the European research project CLIMACAP[3] the global energy system model TIAM-ECN and the global macro-economic model E3ME are linked in order to enhance the energy and economic analysis capabilities focusing on Latin American energy topics.

TIAM-ECN is the TIMES Integrated Assessment Model (TIAM) of the Energy research Centre of the Netherlands (ECN), used for long-term energy systems and climate policy analysis. It has a global scope with a world energy system disaggregated in 20 distinct regions. TIAM-ECN is a linear optimisation model, based on energy system cost minimisation with perfect foresight until 2100. It simulates the development of the global energy economy over time from resource extraction to final energy use.

E3ME is an econometric input-output model of the global economy, energy system and environment. It is maintained and developed by Cambridge Econometrics (CE), and is frequently applied to assess the macroeconomic impact of energy policies and technologies, as well as other energy-environment-economy (E3) interactions. In the CLIMACAP project is applied as a tool to assess the impact of whole energy system scenarios on the wider economy of selected Latin American countries. The model uses a combination of accounting identities and

[3] www.climacap.org.

empirically estimated econometric equations to assess the impact of these different energy system pathways on consumers, industries and the economy as a whole. Importantly, E3ME includes a technology defined approach to modelling the power sector, and therefore the scenarios can be made compatible with TIAM-ECN.

5.1 Methods

The two models are aligned in the sense that, firstly, they apply consistent assumptions for global parameters, including fossil fuel prices, carbon prices, technology efficiency and technology costs. Secondly, that the results from the TIAM-ECN model, including capacity and generation figures, energy demand and required investment costs, define model input data that is fed into E3ME. Energy sector results from TIAM-ECN are processed and input to E3ME including:

- Electricity capacity and generation development, by power sector technology;
- Hydrogen capacity and generation development, by hydrogen sector technology;
- Industrial energy consuming technology (production method) CCS capacity;
- Energy demand, by final user and fuel type;
- Energy system investment costs, by technology type;

These inputs are processed before being used in E3ME to convert to the required units of measurement and classifications. As the TIAM-ECN model is solved every 10 year interval to 2050 (focus in CLIMACAP project on horizon until 2050) and E3ME requires annual inputs, the figures for the intermediate years are interpolated from the TIAM-ECN results.

As explained above, a change in electricity prices is modelled in order to account for changes in the cost of power sector investment, transmission costs and CO_2 capture and storage. In all other cases it is also assumed that there is an increase in prices to finance the energy technology investment. There is an increase in prices in the industries that invest in carbon capture and storage (CCS) technology to fund investment in industry CCS. It is assumed that there is an increase in the price of vehicles that is sufficient to cover the investment cost to finance additional investment in vehicles.

Electricity prices, energy system investment, prices of energy-using capital, and fuel demand determine the overall economic impact. There are three channels through which the TIAM-ECN results impact on the economy:

- through the level of investment in energy technologies, and the upstream impact of that investment,
- through the electricity prices and industry costs, and the consequential impact on demand,
- through the mix of energy demand by fuel in the economy and the associated trade balance.

5.2 Results

The results in Fig. 8 show on the left side energy technology expenditures for Latin America and representative selected countries, and on the right side the corresponding macro-economic impact in term of GDP change decomposed by their main effects. The results refer to a scenario with a carbon tax on GHG starting at US$50 in 2020 and increasing by 4 % per year in real terms. The change of GDP is given versus the baseline development which does not impose any climate policy measures for the future.

For the macro-economic modelling with E3ME a dominating investment effect can be observed for Latin America. The investment is paid for, ultimately, by consumers who see an increase in real household consumption.[4] In net terms, GDP increases by 1.6 % in 2030, 2.0 % in 2040 and 1.3 % in 2050. The main driver for this dynamic is the shift in the structure of the economy, from fossil fuel supply chains to capital supply chains, which leads to stronger dynamic multiplier effects. A closer look at investments shows for Latin America as whole, and in particular for Brazil and Mexico, that additional investment in the power sector does not crowd out investment in the rest of the economy, since investment in productive assets is not constrained, because it can be withdrawn from investment in non-productive assets. As a result, the impact on GDP in E3ME is a net effect of the increase in investment. In principle, the positive investment impact could outweigh the negative price effects reducing real consumer spending since E3ME allows for spare capacity in the labour market and so demand-side (investment) stimulus can yield positive GDP results. Since many consumer goods are imported, the reduction in consumption leads to a reduction in imports which also impacts on GDP. For Mexico the net impact on GDP mostly reflects two competing factors in the longer term driven by the changing structure of the energy system. As more capital and less fuel intensive technologies come into the energy system a demand for these capital goods (investment) is offset by the extra price of these technologies. The technology outcome matters considerably in the determination of the results, in particular the overall cost and the relative weighting of the capital and operating cost components and the characteristics of those supply chains in the domestic economy. In the early period, the investment effects dominate substantially, but by 2050 the differences are much smaller and the net impact on GDP is only around 1 % at a CO_2 price of $165/t$CO_2$ and emissions reductions of over 50 % compared to the baseline. Consumer spending in 2050 is 0.4 % higher than in the baseline due to the recycling of the carbon tax. Colombia's total production could be positive with an increase of up to 2.7 % by 2050, with negative GDP impacts from increasing imports (to meet increasing demand) and reducing exports (as a result of the price effects). The developments of employment under the carbon tax scenario show an increase of employment compared to the baseline by almost 5 million (net additional) jobs (+1.4 %) across Latin America by 2050. New jobs are created in particular in Brazil and in Argentina with a growth of more than 2 % each.

[4] In the modelling approach applied in this study the carbon tax revenues has been recycled to households.

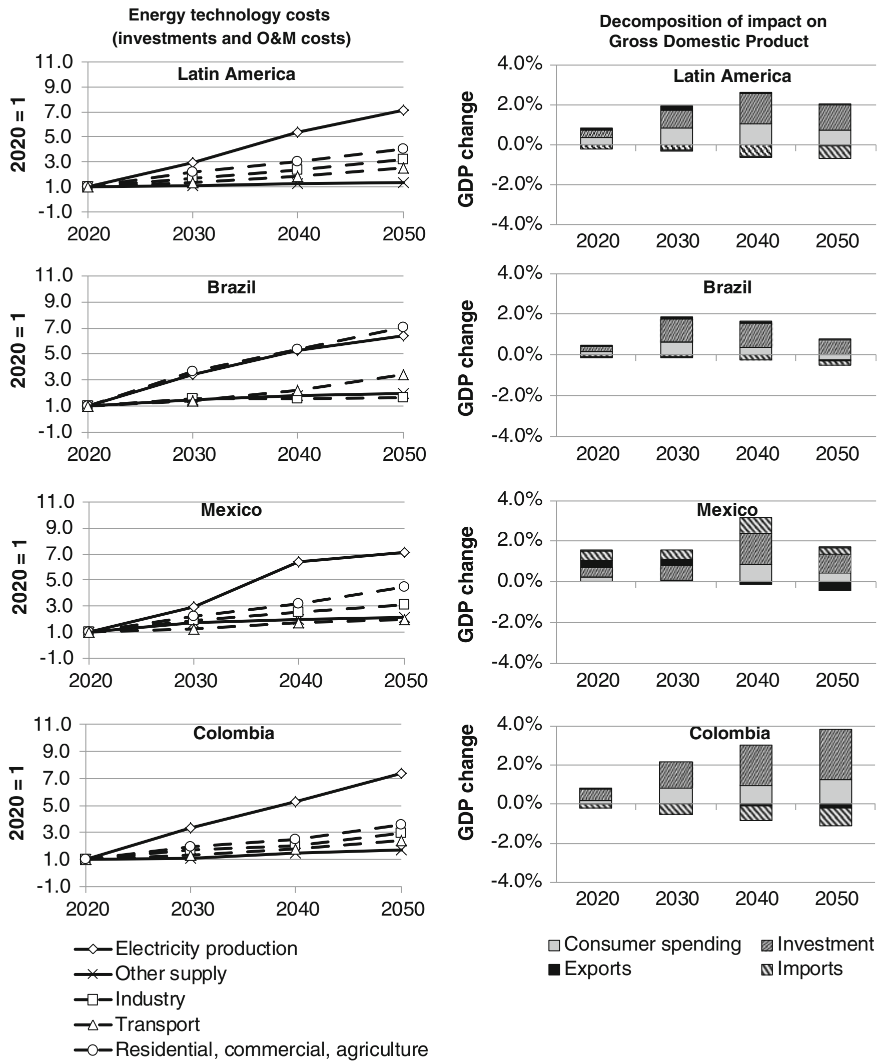

Fig. 8 Energy investments and GDP impact on Latin America under a high carbon tax scenario

5.3 Discussion

Comparing the results from the linkage of TIAM-ECN and E3ME with results from the CGE model, the consequences of increasingly higher carbon prices in terms of reduced consumer spending and GDP are linear in the CGE models and increase as the carbon price increases; but divergent and non-linear in the soft-linked modelling approach reflecting the explicit definition of physical characteristics of technology in TIAM-ECN and the economic impact of the technologies different economic characteristics as represented in E3ME

The model linkage approach captures detailed technology switching and this is reflected in the non-linearity of the economic results, but the model also yields different results because of fundamental differences in economic structure and approach that allows policy impacts that stimulate the demand side to lead to positive impacts on GDP even in the long term. The outcome of the combined model approach shows that both investments and consumer spending will increase under climate policy, which suggests that the price impacts of more expensive energy due to structural changes to the energy system can be compensated by the impact of the related changes to the structure of the energy system and economy.

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Economic Impacts of Future Changes in the Energy System—National Perspectives

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Abstract In a climate constrained future, hybrid energy-economy model coupling gives additional insight into interregional competition, trade, industrial delocalisation and overall macroeconomic consequences of decarbonising the energy system. Decarbonising the energy system is critical in mitigating climate change. This chapter summarises modelling methodologies developed in the ETSAP community

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_20

to assess economic impacts of decarbonising energy systems at a national level. The preceding chapter focuses on a global perspective. The modelling studies outlined here show that burden sharing rules and national revenue recycling schemes for carbon tax are critical for the long-term viability of economic growth and equitable engagement on combating climate change. Traditional computable general equilibrium models and energy systems models solved in isolation can misrepresent the long run carbon cost and underestimate the demand response caused by technological paradigm shifts in a decarbonised energy system. The approaches outlined within have guided the first evidence based decarbonisation legislation and continue to provide additional insights as increased sectoral disaggregation in hybrid modelling approaches is achieved.

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1 Introduction—Regional Applied Hybrid Models

Global economic and environmental scenarios consistently show a trend of continuous decline in natural resource reserves, degradation of environmental quality, increasing vulnerability of economic growth as a result of environmental stresses, competition for natural resources, soaring energy prices and climate change. These scenarios partly rest on significant efforts by the scientific community over the past three decades to improve knowledge of the interactions between economic growth and the environment; particularly modelling methods have developed to become increasingly applied to the assessment of the environmental and economic consequences of various energy and greenhouse gas (GHG) policies. Policy makers need clear and consistent information concerning the real impact of energy and climate policies on the economy and the most cost-effective technology portfolio to achieve their goals. Separate use of top-down (TD) and bottom-up (BU) models do not adequately address all these aspects, which might lead to ineffective policies.

Hybrid models, that combine the technological detail of BU models with the economic framework of a TD, e.g. General Equilibrium (CGE) models, have been developed as an alternate method. Despite the extensive literature on hybrid models, there are few quantitative examples employing a 'full-link' (i.e. not focusing on only one sector) and 'full-form' BU and TD models. This chapter outlines several hybrid models considering both full-link, full form, and sectoral model developments as well as hard-linking MARKAL and TIMES MACRO models. All models presented are applied nationally within the Energy Technology Systems Analysis Programme (ETSAP) Community. The general rationale, motivation for regional and global model development are summarised in preceding chapter. This chapter focuses on the first national decarbonisation legislation, theoretical model updates, improvements and lastly learning outcomes from applied methods to national models.

2 Evidence Based UK Climate Legislation Using Hybrid Models

The energy modelling research community has long underpinned energy policy (Jebaraj and Iniyan 2006), in providing insight and numerate policy guidance (Huntington et al. 1982). The United Kingdom (UK) was the first government to legislate for mandatory GHG reduction targets, first aiming at a 60 % CO_2 reduction by 2050 relative to 1990 (BERR 2007). The ETSAP hybrid UK MARKAL-MACRO (UK MM) model was used extensively to provide the evidence base to guide discussion in the first iteration of analyses and represented a significant addition to UK energy-economy modelling capacity (FES 2003; DEFRA 2007; Strachan and Kannan 2008). UK-MM is a BU optimisation method that maintains sectoral technological detail, but endogenises aggregated price dependent energy service demand dynamics via the single sector neoclassical growth model. It is the first step in assessing the competing elements of hybrid energy modelling: technological explicitness, microeconomic-realism and macroeconomic completeness (Bataille et al. 2006). It gave insights while public debate was still ongoing as to the costs, benefits, opportunities and energy security concerns of climate change under long term uncertainty (Pearce 2003; Nordhaus 2007). UK climate policy had been primarily driven by scientific and political competition (RCEP 2000; Stern 2006), while macroeconomic impact was not a significant concern in the short term. The UKERC UK-MM studies showed that the short term impacts were manageable (Strachan and Kannan 2008). This enabled public and policy discussion to focus on sector specific impacts, social impacts and industrial effects. Further, it moved the policy discussion from whether the UK should decarbonise or not, to how to decarbonise. Four subsequent studies combined modelling effort of the AMOS, E3MG, MDME3 and MARKAL-MACRO models to continue to assess the technical feasibility of the 60 % CO_2 reduction target, finding critical technologies and reducing uncertainty (Allan et al. 2007, 2012; Strachan et al. 2009). These modelling activities highlighted the critical nature of developments in the power sector, marginal technologies, resource availability, the cost of carbon and behaviour in relation to the potential impact upon economic activity (GDP). As a result of the 2008 climate change act, the climate change committee was founded, providing legally binding carbon budgets for the UK, and is investigating stronger measures of 80 % CO_2 reductions, beyond the power sector, by 2050.

In the wake of the 2008 economic crisis, with the resultant austerity measures, risk aversion, and reduced investment capital, implementing the carbon budgets have been more difficult that initially expected. In previous studies, ex-post analysis has shown errors in model forecasting in the EU (Pilavachi et al. 2008), and US (Winebrake and Sakva 2006), and notes particular care should be taken to avoid model bias entering energy policy when energy models are directly applied by policy makers (Laitner et al. 2003).

2.1 Modelling Method Summary

Like TIMES, MARKAL is a dynamic, technology rich linear programming (LP) energy systems optimisation model. It's objective function minimises total discounted costs, including capital, fuel and operating costs for resource, process, infrastructure, conversion and end use technologies. It is a partial equilibrium model with perfect foresight. MARKAL was extended with a hard-link to MACRO. The objective function of the hybrid model is the maximisation of discounted log of utility summed over all periods (t) with an end of horizon terminal investment term. Utility is derived as the log of consumption. National production is from energy, capital and labour, substitutable in a nested constant elasticity of substitution (CES) production function. Capital and labour substitute directly for each other based on optimal capital value shares in their aggregate. Aggregated capital and labour is substitutable with a separate energy aggregate. Investment is recycled to build up a depreciating capital stock, while labour growth rates are defined exogenously.

The marginal change in production output is equivalent to the cost of changing its energy demand. This allows heterogeneous energy demand adjustment across sectors dependent upon marginal demand costs. However, shadow price responses need to be smooth to ensure marginal demand responses are realistic and allow model convergence. Autonomous energy service demand adjustment enables useful climate scenario analysis of demand responses that are decoupled from economic growth. A technical summary of the TIMES-MACRO model formulation follows in Sect. 3, while further technical detail of the UK-MM is available in Strachan and Kannan (2008).

2.2 Evidence Base for Policy

54 low-carbon "what if" scenarios were modelled with UK-MM to advise the UK energy white paper of potential costs of differing technology development pathways in a future with a 60 % reduction in CO_2 emissions (BERR 2007). The summary results are clustered into 4 representative scenarios, focusing on insights from the hybrid linkage, the timing of emissions constraints trajectories, fossil fuel costs and technology abilities (Strachan and Kannan 2008). The macroeconomic impact of the future changes to the UK energy system are summarised as percentage loss of projected GDP in Table 1. There is significant technical change across all sectors in all base case scenarios—before carbon constraints are applied—with car stock switch to hybrid vehicles and implementation of energy efficiency measures in building energy conservation. In the medium to long term (2030–2050) energy efficiency opportunities are exhausted and final energy demand grows, even with MACRO feedback. Higher or lower fossil fuel prices lead to lower (8 %) or higher (3 %) energy consumption respectively in 2050.

In carbon constrained scenarios, decarbonising the electricity sector is seen as the best technology pathway without behavioural change and demand adjustments, while allowing greater electricity consumption. The additional flexibility of demand endogeneity through MM is critical in accurately assessing the marginal cost of carbon. In MM 60 % CO_2 reduction scenarios, energy efficiency and conservation is maximised, with 10–15 % reductions in individual energy demand (compared to

Table 1 UK MARKAL-MACRO scenario analysis summary results

MARKAL-MACRO scenario run	% GDP loss			
	2020	2030	2040	2050
Central scenario	0.46	1.7	2.43	2.81
With accelerated technological change	0.45	1.6	2.35	2.58
With higher fossil fuel prices	0.45	1.54	2.27	2.64
With accelerated energy efficiency	−0.07	0.63	1.63	2.04

standard MARKAL runs) contributing considerably to lowering marginal CO_2 prices. In the short term it is noted that all carbon constrained scenarios have relatively benign impact upon GDP, while accelerated energy efficiency policies can have positive economic benefits via energy cost savings increasing alternative consumption. It is also noted that while there is a significant loss of GDP in the range of 2–2.8 % GDP in the long term to 2050, this impact is not seen as insurmountable. The marginal CO_2 price of the central scenario rises to €147/tCO_2 ($189/t$CO_2$), while this price is estimated at €189/tCO_2 ($243/t$CO_2$) without endogenous demand reductions from MM.

2.3 Discussion

UK energy policy makers have recognised the insights generated by hybrid energy-economy giving GDP and demand responses to energy system decarbonisation. Relevant policy makers were educated in formal energy-economic analysis and how to interpret decarbonisation scenario analysis results. Key staff members of the Committee for Climate Change were on the original UK-MARKAL project steering group. The additional flexibility of the MM demand endogeneity is seen as critical in estimating the marginal cost of carbon. There are notable trade-offs between optimum technological decarbonisation pathways and the impact that behaviour has on the marginal technology choices.

While seen as manageable, the cost impacts from the UK MM model are likely to underestimate the cost of CO_2 mitigation as a result of the lack of regional trade competitiveness or transitional effects. This is observed when comparing results from the studies in Sect. 3, and Sect. 2 in Chap. 19. Decarbonising faster than other nations creates a competitiveness disadvantage that UK MM does not account for. Resultantly inter-regional hybrid models are critical to account for global trade and competitiveness effects. Further experience from policy engagement sees the requirement for more detailed disaggregation of hybrid models to investigate spatial and socio-demographic effects. An extended treatment of natural capital stocks within nested CGE models is required to investigate realistic substitutability between natural and conventional capital as factors of production. A final lesson learned from the UK policy experience is the need for greater modelling transparency to enable replication of results. Next however, the theory behind the MACRO and MSA models—the work of Socrates Kypreos and Antti Lehtilla—are outlined in Sect. 3.

3 TIMES-Macro Stand Alone

Computer based models representing energy, economy and environmental interactions are specified, among others as non-linear (NL) optimization problems or as computable general equilibrium (CGE) simulation models (Arrow and

Debreu 1954). Optimization models when satisfying some maximization conditions give the same solution as CGE models (Capros et al. 1997). The multiregional bottom-up energy system model TIMES (Loulou et al. 2005), linked with the top-down macroeconomic module MACRO called TIMES-MACRO (TM) (Remme and Blesl 2006), is solved by maximizing an inter-temporal utility function for a single representative producer-consumer agent in each region. TM has been developed as part of the Implementing Agreement of the Energy Technology Systems Analysis Project (ETSAP) of the International Energy Agency to assess, among others, the whole energy system and climate change mitigation options and policies on the national, multiregional or global level. The multiregional TM models are large in size not solvable with direct NL optimization methods even when the most powerful commercial solvers and state of the art computers are used. On the other hand, a similar in size and structure model, the well-known MESSAGE-MACRO of IIASA (Messner and Schrattenholzer 2000), is successfully and efficiently solved by decomposition methods. The mathematics to decompose and solve TM with an iterative algorithm is outlined below. The decomposition method converts TM to an energy part (TIMES) and a small size NL macroeconomic model, called TIMES-MACRO Stand-Alone (TMSA), where the energy model TIMES is substituted by appropriate quadratic cost supply functions (QSF). This outline continues describing the demand projections for TIMES and explain the multiregional TMSA, the Negishi (1972) welfare function and the iterative procedure applied to solve the problem based on the sequential equilibrium algorithm of Rutherford (1992) (Negishi 1972; Rutherford 1992). Finally the performance of the algorithm is explained and some resultant conclusions discussed.

3.1 Energy Service Demand Projections

The ETSAP family of models defines demands that reflect past trends and exogenous assumptions on population, GDP, energy intensity and technology penetration based on demand drivers and their elasticities. As most of the efficiency improvement options are included in the engineering model explicitly, and are selected if they make economic sense, the specific selection of autonomous efficiency improvement factors (*aeeif*) applied below could be introduced to reflect mainly life style changes. A simple but useful relation for demand projections is Eq. 1:

$$\frac{D_{kt}}{D_{k0}} = \left[\frac{dr_{kt}}{dr_{ko}}\right]^{\alpha_i} \cdot \left[\frac{P_{kt}}{P_{k0}}\right]^{-\sigma_i} \cdot \prod_{\tau=1,t} (1 - aeeif_{k\tau})^{ypp_\tau} \tag{1}$$

where

D_{kt}	the demand projection for sector k and period t;
D_{k0}	the same demand for the starting year calibrated to energy statistics in line with the socio-economic assumptions and the efficiencies of the end-use devices valid in the starting year of analysis;
dr_{kt}	the demand driver;
α_k	the driver elasticity;
σ_k	the price elasticity;
$aeeif_{kt}$	the autonomous efficiency improvement factor per demand category;
ypp_τ	the years per period;
P_{kt}/P_{k0}	the index of relative price of demand in sector k.

TIAM (the global multiregional integrated assessment version of TIMES) assumes different growth rates and elasticities of demand drivers for each individual demand category. Usually some consistency checks of economic assumptions and the projections generated based on the equation above must be completed. IIASA for example adjusts projections to the results of MERGE (Manne et al. 1995), while ETSAP uses GEM-E3 (Capros et al. 1997).

3.2 The Multi-regional TIMES-SA Model

In the following section the global and multi-regional macroeconomic growth model is decomposed into a multi-regional partial equilibrium energy problem, e.g., TIMES and a multi-regional macroeconomic model maximizing the global welfare function.

3.2.1 The Macro Stand-Alone Formulation (MSA)

For the new stand-alone Macro formulation, the original Macro model had to be generalized to support multiple regions. In the multi-regional case the model is solved by maximizing the Negishi-weighted sum of regional utilities based on iterations between the stand-alone TM model (TMSA) and the standard TIMES model. The TMSA model explicitly considers only the trade of the numéraire good, as the trade in all energy products is defined in the TIMES model. The basic formulation of the original TM implementation can be rewritten by Eqs. 2–11:

$$\text{Max} \quad U = \sum_{t=1}^{T} \sum_{r} nwt_r \cdot pwt_t \cdot dfact_{r,t} \cdot \ln(C_{r,t}) \tag{2}$$

$$Y_{r,t} = C_{r,t} + INV_{r,t} + EC_{r,t} + NTX(nmr)_{r,t} \tag{3}$$

$$Y_{r,t} = \left(akl_r \cdot K_{r,t}^{kpvs_r \cdot \rho_r} \cdot l_{r,t}^{(1-kpvs_r)\rho_r} + \sum_k b_{r,k} \cdot DEM_{r,t,k}^{\rho_r} \right)^{\frac{1}{\rho_r}} \tag{4}$$

$$K_{r,t+1} = tsrv_{r,t} \cdot K_{r,t} + \frac{1}{2}(d_t \cdot tsrv_{r,t} \cdot INV_{r,t} + d_{t+1} \cdot INV_{r,t+1}) \tag{5}$$

$$K_{r,T} \cdot (growv_{r,T} + depr_r) \leq INV_{r,T} \tag{6}$$

$$DET_{r,t,k} = aeeifac_{r,t,k} \cdot DEM_{r,t,k} \tag{7}$$

$$EC_{r,t} = qa_{r,t} + \sum_k qb_{r,t,k} \cdot (DET_{r,t,k})^2 + amp_{r,t} \tag{8}$$

$$\sum_r NTX(trd)_{r,t} = 0 \quad \forall \{ t, trd\} \tag{9}$$

$$aeeifac_{r,t,k} = \prod_{\tau=1}^{t} (1 - ddf_{r,\tau,k})^{\frac{d_t + d_{t+1}}{2}} \tag{10}$$

$$l_{r,1} = 1 \quad \text{and} \quad l_{r,t+1} = l_{r,t} \cdot (1 + growv_{r,t})^{\frac{d_t + d_{t+1}}{2}} \tag{11}$$

where

$C_{r,t}$	annual consumption in period t (variable)
$Y_{r,t}$	annual production in period t (variable)
$K_{r,t}$	total capital in period t (variable)
$INV_{r,t}$	annual investments in period t (variable)
$DEM_{r,t,k}$	annual demand in Macro for commodity k in period t (variable)
$DET_{r,t,k}$	annual demand in TIMES for commodity k in period t (variable)
$EC_{r,t}$	annual energy system costs in Macro in period t (variable)
akl_r	production function constant
amp_t	constant term to account for the full annualized investment cost of existing capacities in the starting period
$b_{r,k}$	demand coefficient for demand commodity k
$aeeifac_{r,t,k}$	autonomous energy efficiency improvement
dt	duration of period t in years
$ddf_{r,t,k}$	demand decoupling factor (calibration parameter)
$depr_r$	depreciation rate
$dfact_{r,t}$	utility discount factor for period t
$dfactcurr_{r,t}$	annual discount rate for period t
$growv_{r,t}$	growth rate in period t (calibration parameter)
$kpvs_r$	capital value share
$l_{r,t}$	annual labor growth index in period t
nwt_r	Negishi weight for region r

pwt_t period-length-dependent weights in the utility function (to be introduced to in cases where the period lengths are not equal)
$qa_{r,t}$ constant term of the quadratic supply cost function
$qb_{r,t,k}$ coefficient for demand k in the quadratic supply cost function
$tsrv_{r,t}$ capital survival factor between periods t and t + 1
ρ_r substitution constant
T number of periods in the model horizon

The primary differences in relation to the standard Macro formulation are; (a) The use of Negishi weights in the objective function when the model is multi-regional; (b) The inclusion of the trade in the numéraire good NTX(nmr) in the production function; (c) The introduction of the trade balances on the global level (Eq. 9); (d) The Negishi iterations balance for inter-temporal discounted trade deficits of a region over the full time horizon of the analysis; (e) The replacement of the full TIAM LP cost accounting by quadratic supply-cost functions for each demand commodity (Eq. 8).

3.2.2 The Standard TIMES LP Formulation

The second part of the decomposed model, the TIMES LP model, uses the standard TIMES formulation, which can be written in short as:

$$\text{Min}\ \ NPV = \sum_{r=1}^{R} \sum_{y \in YEARS} (1 + d_{r,y})^{REFYR-y} \cdot ANNCOST(r, y) \tag{12}$$

$$A \cdot x = b \quad \text{and} \quad x \geq 0 \tag{13}$$

where
NPV net present value of all energy system costs
YEARS the set of years within the model horizon
REFYR reference year for discounting
$d_{r,y}$ capital discount factor for region r in year y
ANNCOST(r,y) annual energy system cost in region r and year y
A coefficient matrix for all other model equations
x vector of all model variables
b RHS constant vector for all other model equations
R number of internal regions in the model

For a comprehensive treatment of the standard TIMES LP formulation, see Loulou et al. (2005). In order to make the LP formulation more analogous with the Macro objective function, the objective function of the standard TIAM code can be rewritten in terms of period-wise average annual costs and period-specific discount factors, as follows:

$$\text{Min } NPV = \sum_{r=1}^{R} \sum_{t=1}^{T} pvf_{r,t} \cdot AESC(r,t) \tag{14}$$

where

$pvf_{r,t}$	present value factor for period t in region r
AESC(r,t)	annual energy system costs in region r and period t
T	number of periods t in the model horizon

The general specifications of the decomposition algorithm are described by Kypreos and Lehtila (2013).

3.2.3 The Algorithm and It's Performance

In both MACRO formulations, the use of the MACRO model for evaluating policy scenarios requires that the demand decoupling factors (*ddf*) and labour growth rates (*growv*) have first been calibrated with the baseline scenario and the corresponding GDP growth projections. The core part of the calibration procedure is the updating of the demand decoupling factors and labour growth rates between successive iterations of the calibration algorithm.

In the TMSA implementation, all the basic mathematical formulas for the initial specification and updating the demand decoupling factors and labour growth rates are fully equivalent to those in the standard TM formulation introduced first by Kypreos (1996). The TIMES-MACRO documentation (Remme and Blesl 2006) contains the details on the calibration algorithm and follow the description of Kypreos and Lehtila (2013) in the ETSAP documentation (Kypreos 1996; Kypreos and Lehtila 2013).

The initial Negishi weights are proportional to the regional output share while the updated ones balance for inter-temporal trade deficits following the sequential optimization algorithm of Rutherford (1992). The weights are adjusted using the normalized price of the traded products, the trade excess and the inverse of the marginal regional utility and in that case, according to Rutherford the solution obtained is Pareto optimal.

$$\begin{aligned} NW_r &= \sum_{t,trd} \pi_{trd,t} \cdot NTX_{r,t,trd} + \sum_{t} \pi_{nmr,t} \cdot C_{r,t} \text{ with} \\ nwt_r &= NW_r / \sum_{r} NW_r \end{aligned} \tag{15}$$

One significant test run for the algorithm was the solution of TM for a single region as the problem could be solved with a direct optimization and the decomposition method and results are directly comparable. The USA TMSA model validated well against the direct solution of the TM of USA as solutions are identical. However, the decomposed problem needs 2 min to be solved while the direct optimization takes more than 100 times longer. It is interesting to report the computer time needed to solve the calibration and the policy analysis case as function of the number of regions. The model starts in 2005 and covers up to 2060 in 7 time steps. A 6-region model takes about 32 min to be solved; a 10-region model needs 66 min and finally a 15-region model takes 100 min.

3.3 Conclusions

The large scale general equilibrium growth model TIMES-MACRO is solvable only when decomposed to the linear energy model TIAM and a non-linear macroeconomic stand-alone model (TMSA) where quadratic supply functions substitute for the energy system represented in TIMES.

The methodology is presented herein that allows projecting demands for energy services for a set of socio-economic assumptions, life style changes and energy intensities based on sectoral drivers, and its income and price elasticities. The regional demand decoupling factors (*ddf*) are introduced to calibrate the baseline case reproducing the same demands, although the MACRO model uses unitary income elasticity and the same elasticity of substitution across all sectors. The TMSA model then including these decoupling factors simulates the postulated GDP growth and the demands for energy. This is done with a minimum investment in respect of computation time. The execution times needed for low tolerance errors (less than 10^{-4}), is significantly reduced during both the calibration itself and when applying the model for a policy case. This can be done for either a single country model or for the multiregional and global TM model.

Although the quadratic supply cost function is a simple and approximate metamodel that substitutes for the full-scale energy model and the marginal prices are sensitive to small demand changes, the algorithm is able to give an exact calibration for the baseline case followed by good results for the carbon constrained case as the tolerance error in demand evaluation is below 10^{-4}. The prerequisite for a successful application of the QSF in representing energy and economy interactions is to have all the important system constraints determining the changes of the energy system linearized and included in TIMES. This is because the quadratic cost formulation allows for small changes around the demand variables when searching for optimal solutions and converges in small steps. For the first time the decomposition method proposed is able to solve the global TIAM-MACRO model with 15 regions in 1.5 h based on TMSA (in Windows 7, 64-bit workstation, solution in a single thread).

3.4 Ireland—Application of TIMES-Macro Stand Alone

The hybrid linking of the Irish Energy system model, Irish-TIMES is taking a two pronged approach. Firstly the linkage and calibration of the newly developed Macro Stand Alone model to form Irish-TIMES-MSA. Secondly a softlinking process is underway linking the National macroeconomic HERMES model to enable model comparison between the two approaches—aggregated production function and disaggregated sectoral production.

HERMES is a complete structural model of the Irish economy. The specification of the HERMES model is built on the assumption that firms are attempting to minimise their cost of production or maximise their profits and that households are attempting to maximise their utility. The energy system is no longer specifically modelled in the HERMES model. Energy is taken as an exogenously determined cost to firms and households through the international oil price taken from NIESR's NiGEM model. Carbon taxation is incorporated in the government's financial accounts as a revenue source paid by firms and households. It is through oil and carbon pricing, both of which are exogenously determined within HERMES, that energy system costs feedback into the economy.

The initial Irish-TIMES-MSA results outline energy system pathways for a reference scenario (REF), a carbon constrained scenario with CO_2 reductions of 80 % relative to 1990 levels (CO_2-80), and an equivalent scenario with the macroeconomic impacts integrated into the analysis. The MSA scenarios cause a 10 % reduction in final energy consumption by 2040 due to reduced demand as a result of increased energy system cost and a reduction of consumption in the economy. Interestingly this alters the fuel mix most notably in the transport and residential heating sectors as carbon constraints become less binding and so fuel switching is delayed. The loss of GDP in the CO_2-80 scenario rises to −1.5 %/year by 2050, with the CO_2-95 scenario at −2.5 %.

4 Portugal—HYBTEP

The lack of "full link", "full form" models integration in other modelling studies has been overcome by the development of an integrated methodology to soft-link the extensively applied BU TIMES model (Loulou and Labriet 2008), with the CGE GEM-E3 model (Capros et al. 1997, 2014), used by several Directorates General of the European Commission. The hybrid platform, named HYBTEP (Hybrid Technological Economic Platform), applied to the Portuguese case, is defined by the soft-link between single country versions of the two models: TIMES_PT and GEM-E3_PT (Fortes et al. 2013). HYBTEP overcomes the main limitation of CGE models—failure in represent technology choices—considering the energy profile and prices from TIMES, and minimizes the drawback of BU modelling—failure to represent adequately the link between energy and economy—as the changes in the sectors economic behaviour are set by GEM-E3 according to the BU technological choices.

4.1 Methods

HYBTEP was built by the following tasks, taking an approach close to Labriet et al. (2010).

(i) Defining coherence between the two models. Correspondence and harmonization between the models sets and variables were set up, namely the economic sectors and energy commodities. Additional energy carriers were also added to GEM-E3_PT, namely biomass. This process resulted in thirteen economic sectors in HYBTEP from the aggregation of eighteen sectors from GEM-E3_PT and more than sixty demand categories of TIMES_PT. Moreover, a crucial step to achieve consistency among the models is the definition of common scenario assumptions, namely fossil fuel import prices, interest rates, energy constraints and policy conditions.

(ii) A new energy module in GEM-E3_PT was programmed allowing the model to receive exogenously the energy consumption by energy carrier and sector. This was done by assuming fixed shares of total energy demand per sector with a Leontief technology (i.e. elasticities of substitution of the Constant Elasticities Substitution (CES) production function equal to zero) (Fig. 1). These changes further implied alterations to the definition of the price of the energy aggregate, which are also set exogenously according to the BU model energy system costs evolution per energy aggregate (ELFU).

(iii) The interaction algorithm (Fig. 1) and the conditions for convergence between the models require careful planning and definition. TIMES_PT physical energy consumption and system costs evolution per sector are 'translated' in GEM-E3_PT monetary units through an energy link module and inputted in the CGE model as energy demand and energy prices. In addition, GEM-E3_PT technological change, as measured as increased efficiency in the energy system was defined by the output of the BU model. When a market policy instrument is being considered in TIMES_PT, e.g. an energy tax or a feed-in tariff, the respective economic value is also included in GEM-E3_PT, associated with the respective payer and payee sectors. GEM-E3_PT than compute economic drivers, such as sector domestic production, which are converted in energy services demand through a demand generator. Energy services are inputted into TIMES_PT and the model sets the least cost technological profile of the energy system. This cycle establishes a single iteration of the linked models. It continues until convergence is achieved between the models results, which are reached by assuming a stopping threshold, reflecting minimal energy service demand differences from iteration n and the previous (n − 1) (Fig. 2).

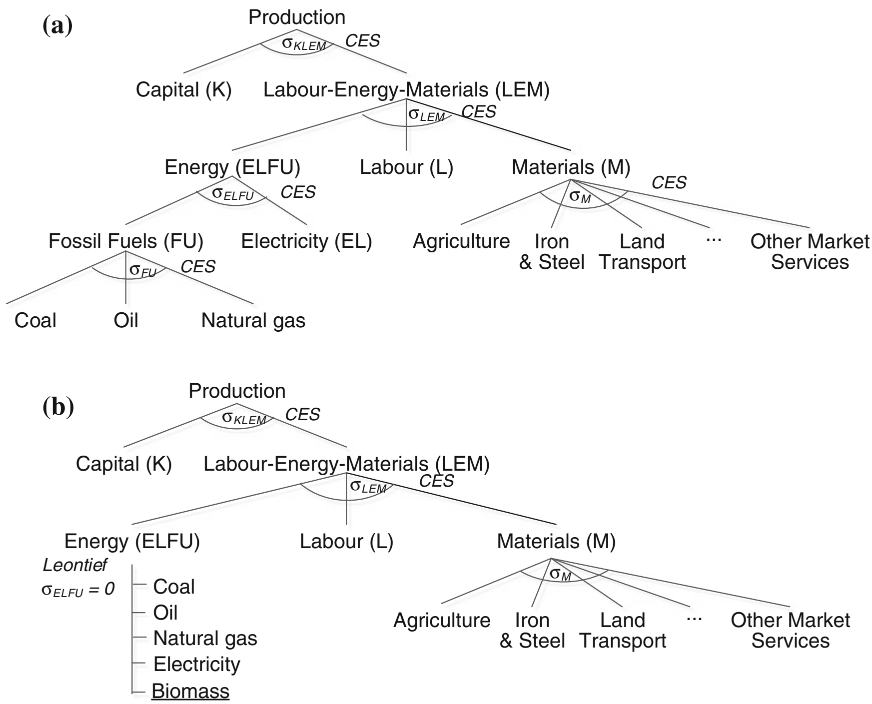

Fig. 1 GEM-E3_PT computable general equilibrium nested tree structure (*upper*—**a**) Original GEM-E3_PT structure (*lower*—**b**) adapted Leontief structure in HYBTEP

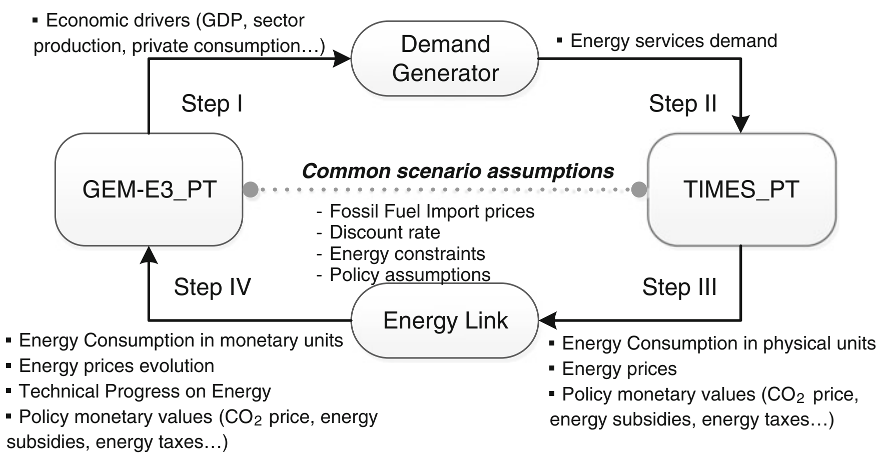

Fig. 2 HYBTEP soft-linking methodology (Fortes et al. 2014)

The additional advantages of HYBTEP in assessing the impact of climate and energy policies when compared with conventional BU model, were analysed under the following scenarios modelled to 2050:

- Current Policy Regulation (CPR) extends beyond 2020, the current Portuguese energy-climate policy within the EU climate-energy package, including a reduction in GHG emissions, and an increase in renewable energy.
- CO_2 price scenario (TAX) comprises in addition to CPR assumptions, a domestic carbon tax on GHG energy emissions from 25 €/t in 2020 up to 370 €/t in 2050.
- RES support scenario (RES) involves, in addition to CPR assumptions, a monetary incentive to renewable energy, from 50 $€_{08}$/MWh in 2020 to 191 $€_{08}$/MWh in 2050.

For all the scenarios it was assumed in GEM-E_PT a fixed government's deficit/surplus and additional revenues are recycled to economy to reduce endogenously social security tax. In addition to HYBTEP platform runs, the policy scenarios were run by the standard TIMES_PT and by TIMES_ED, assuming an energy service-price elasticity of −0.3 for almost all demand categories, and a sensitivity analysis considering higher (−0.5) and lower (−0.1) values.

4.2 Results

The HYBTEP results show, that under TAX and RES scenarios, the modelling tools present differences regarding energy consumption and GHG emissions. It is not possible to define a linear relationship between HYBTEP results and TIMES elasticities, as these vary across scenarios and in some cases years. Under the TAX scenario, HYBTEP outcomes are close to TIMES_ED(−0.1) values, with differences below 1 %. However, in the RES scenario the hybrid model reveals a lower endogenous elasticity, closer to TIMES_PT results.

In HYBTEP, the carbon tax induces an increase in production costs, but also represents a source of additional revenue to government. In this modelling exercise the income is recycled to the economy leading to a reduction in labour costs, which can partially offset the increase in energy costs in production. This economic framework that result in a GDP loss of −2.4 % in 2050 (versus a non-policy scenario), can justify the fact that HYBTEP is less responsive to energy prices than TIMES_ED(−0.3). In contrast, additional RES funding from the government means less available revenues to reduce social security contributions. The latter makes labour more expensive outweighing the decrease in energy system costs due to energy subsidies. The fact that HYBTEP results are close to the inelastic TIMES_PT, suggest that, the reduction of energy prices are offset by an increase in labour costs, leading to a small impact on demand for energy services. In 2050, RES scenario results in GDP gains of 2.8 %, mostly driven by exports increase. Besides ignoring this comprehensive economic context, and with exception of the energy sector (e.g. power or refinery), TIMES neglects the linkages between the sector, i.e., the intermediate consumption. Variations in the production price of one sector, also affect domestic demand in other sectors production, which are not considered by the BU model.

Moreover, the sensitivity analysis of TIMES energy services elasticities highlights the impact of this parameter on the energy system profile. The BU model final energy consumption presented differences [TIMES_PT vis-à-vis TIMES_ED (−0.5)] of up to 14 and −12 % in TAX and RES scenarios, respectively. The uncertainty of elasticity parameters, due to the lack of national studies, increases the uncertainty of the model results when comparing with a more transparent approach from HYBTEP.

4.3 Discussion

HYBTEP represents an evolution in the methodological complexity describing a method of soft-linking 'full-form', multi-sector BU and TD CGE models, resulting in an integrated modelling platform. Since the main structures of the models are maintained, HYBTEP can accommodate an extensive group of technologies and contains a sector detailed economic matrix, considering sectors own characteristics and specificities. The major conclusion concerns the increase of transparency and accuracy of modelling outcomes achieved with HYBTEP, since, by assuming the economic framework of each sector, it enables understanding of the mechanisms behind energy demand evolution while taking into account the cost-effective energy profile from a technological model.

5 Sweden—TIMES-Sweden and EMEC

The Swedish study describes development of full-form soft linkages between the models EMEC (Environmental Medium Term Economic Model—a TD CGE model) and TIMES-Sweden (a BU energy system model). A robust and transparent method to translate simulation results between the two models is developed, resulting in intermediate 'translation models' between EMEC and TIMES-Sweden. EMEC provides demand input to TIMES, while TIMES provides feedback on the energy efficiency parameters, the energy mix, and the prices of electricity and heat. These 'translations' can also be used stand-alone to feed into other energy system models. The presented soft-linking process demonstrates the importance of linking an energy system model with a macroeconomic model when studying energy and climate policy. With the same exogenous parameters, the soft-linking between the models results in a new picture of the economy and the energy system in 2035 compared with the corresponding model results in the absence of soft-linking.

EMEC is a static computable general equilibrium model of the Swedish economy developed and maintained by the National Institute of Economic Research (NIER) for analysis of the interaction between the economy and the environment (Östblom and Berg 2006). The EMEC model includes 26 industries and 33 composite commodities including seven energy commodities. There is also a public sector producing a single commodity. Produced goods and services are exported and used together with imports to create composite commodities for domestic use. Composite commodities are used as inputs by industries and for capital formation. In addition, households consume composite commodities and there are 26 consumer commodities. Production requires primary factors (i.e. two kinds of labour and capital) as well as inputs of materials, transports and energy. Households maximise utility subject to an income restriction, firms maximise profit subject to resource restrictions, the provision of public services is subject to a budget constraint and the foreign sector's import and export activities are governed by an exogenously given trade balance. The model differs from many other CGE models by having a detailed description of the energy use, environmental economic instruments as well as emissions.

The main structure of TIMES-Sweden was designed within the NEEDS and RES2020 projects, and has since been further developed (Krook Riekkola et al. 2011). TIMES-Sweden covers the Swedish energy system divided into six main sectors (Electricity and heat, industry, agriculture, commercial, residential and transport), based on the structure of EUROSTAT database. Each sector includes 60 different demand segments that drive the model. The structure and many of the assumptions are similar to the JRC-EU-TIMES model, documented in Simoes et al. (2013).

Even though the two models have different scientific bases, they both assume cost-minimising behaviour by producers and household demands based on optimising behaviour.

5.1 Methods

The recognition that difference sets of connection points are needed depending on which direction the information is being transferred during the iteration process resulted in two different approaches in mapping of the connection points—one when transferring information from EMEC to TIMES-Sweden and another when transferring information in the opposite direction.

Energy system models are not well suited to address changes in demand due to economic growth. Thus the EMEC model will be the provider of demand drivers from which the demand for goods and services to TIMES-Sweden is estimated. This approach will not differ from running TIMES-Sweden stand-alone, when the demand drivers always are based on results from CGE models like EMEC, the difference will be that they are re-estimated for each iteration-run. All demand segments cannot be treated in the same way and there are cases where no relationship exists between change in demand of a certain commodity and economic growth. Different approaches for translating the output from EMEC into usable input into TIMES-Sweden include; a direct approach based on economic development in a corresponding sector, an indirect approach based on an alternative activity economic development in one or several corresponding sectors, or an assumption of no connections.

Due to their broader focus, CGE models such as EMEC, are unable to explicitly address aspects of the energy system related to (i) changes in energy intensity due to introduction of new technologies, (ii) changes in the energy mix following changes in energy demand and, (iii) changes in electricity and heating prices due to competition of limited energy commodities between and within sectors. These aspects are the focus of the energy system output. To facilitate the transformation of results between TIMES and EMEC, the production function in the soft linked version of EMEC has been changed so that the elasticity between the different energy products in each sector is set to zero, i.e. the energy branch is assumed to be represented by a so-called Leontief structure with fixed input coefficients (Fig. 3).

5.2 Results

In EMEC, the reference scenario describes a possible outcome for the Swedish economy and energy demand in the long run. The reference scenario is based on the official macroeconomic forecast of NIER with the exception of energy efficiency

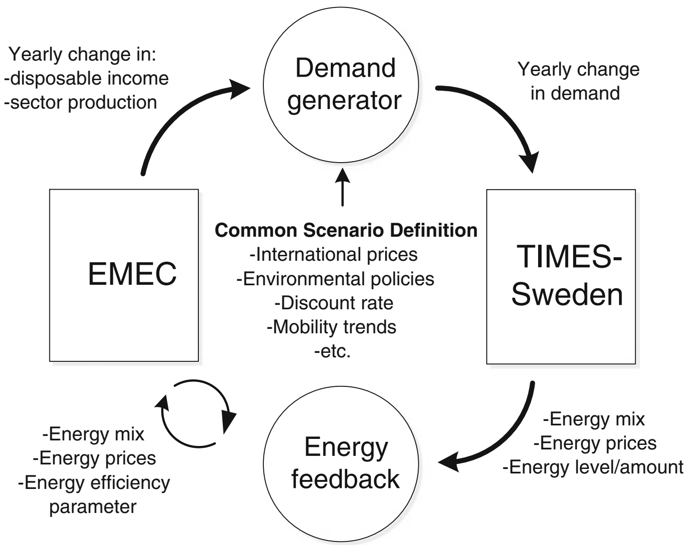

Fig. 3 Soft-linking between EMEC and TIMES-Sweden

parameters, which are determined by soft-linking the two models. In the climate scenario, the CO_2 tax is assumed to increase by 50 % and the CO_2 prices within the EU-ETS is increased from 16 to 30 €/tonne in 2020 and stays at this level to the end of the modelling period in 2035.

The iteration process (Fig. 4) starts with EMEC, whereby its macroeconomic outputs are fed into the translation model, providing a set of energy service demands for TIMES-Sweden. The models adapt to each other primarily in the first reference iteration R-2, and there-after only minor changes are made, while the models are considered converged within tolerance.

The lower demand in energy-intensive industries, after the reference iteration process, can be explained by a higher electricity price from TIMES-Sweden when compared to EMEC in isolation. TIMES-Sweden assumes fewer technology options in energy intensive industries to reduce their demand compared with EMEC, which assumes changes in energy demand based on substitution elasticities. Higher electricity prices and lower substitution possibilities imply increased production costs and a decreased demand for energy-intensive goods as their relative price increases. Soft-linking reinforces the trend towards higher increased demand for transport and services.

The climate scenario is analysed based on three different starting points: a non-linked reference scenario (Climate NL-ref), a non-linked climate scenario (Climate NL-Climate) and a soft-linked scenario (C-x Iteration). In the latter case, when the

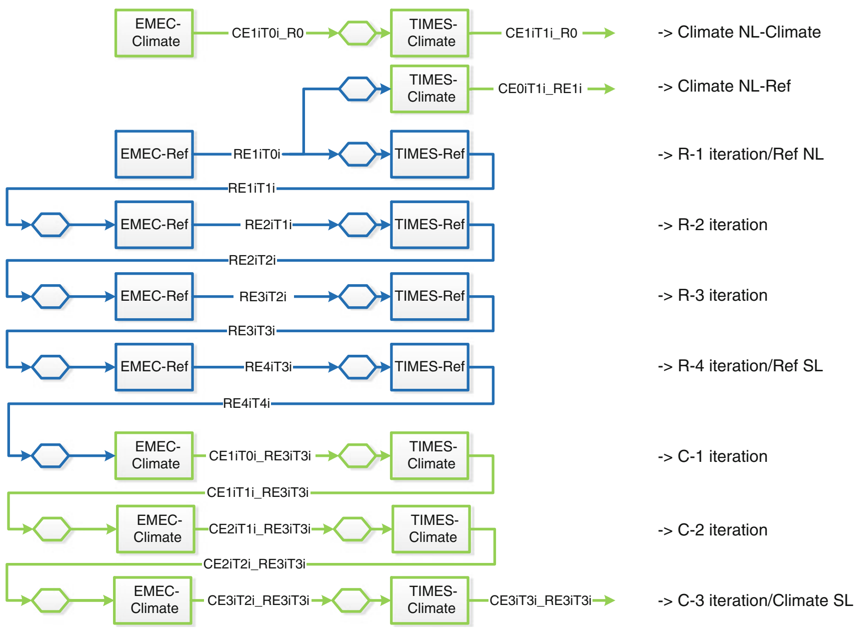

Fig. 4 The iteration scheme between EMEC and TIMES-Sweden

soft linked reference scenario is the starting point of the climate scenario iterations, the number of iterations does not affect the production level from EMEC to any greater extent. Hence, the differences between C-1 and C-3 are small compared with the differences between R-1 and R-2. The results of the EMEC model have already adjusted to mimic TIMES-Sweden's behaviour in the reference scenario. One reason is that the Swedish power system is almost carbon free, which in combination with the green electricity certificate scheme only gives marginal changes in the electricity price when the EU-ETS price is increased.

In order to test of the changes in the results from introducing the soft-linking process had a policy impact the resulting CO_2 trajectories from TIMES-Sweden were scrutinized. The results show the CO_2 emissions are significantly reduced with soft-linking. This is mainly a result of lower demand for energy services.

5.3 Discussion

Both EMEC and TIMES are based on national statistics which has permitted the build-up of detailed models. However the two models are based on two different statistical databases (national accounts versus energy statistics). The national account are structured to capture the main economic activities and thereby facilitate an robust analysis of the economy, while the energy statistics are structured in order capture the energy flows and thereby facilitate a robust energy analysis. When identifying connections points, several overlaps and mismatch were identified. Thus, instead of using common measuring points, we identify direction-specific 'connection points' to describe the interaction of model results from one model to the assumptions used in the other model.

The biggest challenge and uncertainty in soft-linking iteration is the price information from TIMES-Sweden to EMEC. The prices change between the base year in 2008 and the horizon end year 2035 were found to be exaggerated. The main explanation for this is that the calculated prices in the first modelling years do not include all costs. The optimization solves for the lowers total cost, but when the base years are fixed there is no need to include those cost figures when TIMES-Sweden is use stand-alone and comparing the results from different scenarios in a specific year. In contrast, the soft-linking process compares the price difference between two years with one scenario. This particular issue need to be solved in future studies.

Changes in investment flows, due to large structural changes in the energy system were aspects that could not be captured in a satisfactory way in this soft-linking methodology. The presence of a major restructuring of the economy, for example caused by the radical reduction of fossil fuel use, investment flows would most likely change substantially and affect the overall investment requirements and in turn give rise to significant general (dis)equilibrium effects.

6 South-African Electricity Sector—SATIM-el and SAGE

South Africa has a carbon-intensive economy. The energy sector is responsible for most of the country's emissions, with 78.9 % of total emissions from energy. These emissions have resulted from the extensive use of coal in the generation of electricity, the conversion of coal into liquid fuels, and coal for thermal uses in industry.

The Long Term Mitigation Scenarios (LTMS) study found carbon taxes to have the biggest emissions reduction potential compared to various other mitigation options (Winkler 2007). In a developing country like South Africa, it is important that policies and measures aimed at achieving the country's emissions reduction targets are not applied to the detriment of other national development objectives. The hybrid model linking the South African TIMES model (SATIM) to the extended South African General equilibrium model of the economy (e-SAGE) addresses this issue.

SATIM is an inter-temporal bottom-up optimisation energy model of South Africa built around the MARKAL-TIMES platform. SATIM uses linear or mixed integer programming to solve the least-cost planning problem of meeting projected future energy demand, given assumptions about the retirement schedule of existing infrastructure, future fuel costs, future technology costs, and constraints such as the availability of resources.

The e-SAGE model simulates the functioning of the economy and uses South Africa's 2007 Social Accounting Matrix (SAM) as data input, accounting for industries and commodities in South Africa, as well as factor markets, enterprises, households and the 'rest of the world'. The 2007 SAM has 61 industries and 49 commodities. It also has 9 factors of production, namely, land, 4 education based labour groups, and capital which is divided into 1 energy and 3 non-energy capital groups.

6.1 Methods

Alternate runs of SATIM and e-SAGE are performed from 2006 to 2040, each time exchanging information about fuel prices, demand, investment (capital growth), electricity production by technology group and electricity price. Given an initial demand, TIMES computes an investment plan, and a resulting electricity price projection, which is passed onto e-SAGE to see the impact, if any, that this new price projection has on the demand, which then go back to TIMES in the next iteration. The problem is that if both the price and capital growth are imposed onto e-SAGE for the entire model horizon, there is little room for demand to react. Demand tracks the investment (capital growth), which defeats one of the main points of using a CGE.

To circumvent this, only the price projection is imposed onto e-SAGE for the entire model horizon, and the production schedule and capital growth is only gradually imposed. The result of this is that by the end of the planning horizon, we have used a demand projection that is consistent with price, and can react to price changes. Based on this consistency, we can analyse the economic impacts of the investment decisions that were made in the power sector subject to constraints defined in that sector, such as a nuclear programme or a renewables programme, or how the energy and economy would respond to CO_2 mitigation policies.

The following scenarios are run as a demonstration of the linked models for the purpose of evaluating mitigation actions:

1. A set of TIMES runs without the CGE model, but assuming the same demand as the Reference linked model run for all scenarios:
   (a) A Reference case of the power sector without any mitigations actions (Reference).
   (b) A CO_2 tax runs starting at \$5 (R48)/ton CO_2 in 2016, increasing to \$12 (R120)/ton CO_2 in 2025, approximating Treasury's proposed carbon tax.
   (c) Two renewable energy scenarios:
      - 20 % share of centralised generation by 2030 and 30 % in 2040 (RE Prog 1); and
      - 30 % share of centralised generation by 2030 and 40 % in 2040[1] (RE Prog 2).
2. The same set of runs as above but this time with the linked CGE and TIMES models.

6.2 Results

Total capacity of the TIMES reference case reaches 103 GW in 2040, still dominated by coal with 55 GW (54 %). Coal also dominates production, maintaining the current share of around 81 % through to 2040. Gas (open cycle gas turbines and combined cycle gas turbines) capacity reaches 23 GW (23 %) for peaking and mid-merit loads. The remainder is made up of solar PV (13 %), hydro and pump storage (4 %) and nuclear and imports (6 %).

The currently proposed CO_2 tax level has a small impact on the system in this scenario. Total capacity is slightly higher at 106 GW in 2040, due to increased share of gas and solar PV that run at a lower capacity factor than coal. The coal share of capacity drops to 51 % and production to 79 %, whereas gas remains at around 23 % of total capacity. The coal production is mainly replaced by solar PV, increasing its share of production from 6 to 7 %.

[1] RE includes: centralised solar PV, solar thermal, wind, domestic and imported hydro, and biomass.

To reach a share of production of 30 % in 2040 in program 1 and 40 % in program 2, the RE share of capacity reaches 43 and 50 % by 2040. The high share of low-capacity technologies means that total capacity goes up to 120 and 126 GW, respectively. The RE program pushes the coal share of capacity further down to 30 and 19 % for the two programs, respectively. The gas share of capacity reaches 18 and 23 %.

The CO_2 emissions from the power sector of the reference scenario grow to almost double the 2010 levels reaching 430 Mton/annum in 2040. In the CO_2 tax scenario, the annual CO_2 drops by only 3 % relative to reference case. However, when using the more optimistic RE costs, a 20 % reduction is observed. When the penetration of low emission technologies is imposed directly with the RE programs, the CO_2 emissions drop more radically by 33 and 50 %, respectively by 2040.

Comparing the TIMES runs and the CGE-linked runs for the reference case and the CO_2 tax case, the reference cases are identical, given that they have the same demand, and fuel prices. In the CO_2 tax scenario though, there is a drop of the peak demand in the CGE-linked run, showing some demand response from the CGE to the higher electricity price.

All the policy scenarios result in slight GDP loss in 2040 relative to the reference case. In all the policy scenarios, the mining and metals sectors are the most negatively affected, mainly because of the electricity price increase, and the switch away from coal for some of the electricity production. The electricity sector grows quite significantly relative to the base with more investment taking place in this sector, however, not enough to avoid a net negative impact on GDP.

6.3 Discussion

The results so far indicate that the linked SATIM e-SAGE model is able to contribute to the goal of analysing the trade-off between mitigation and development objectives for South Africa. However, to gain further confidence in the results, more work is still needed in aligning both models, by ensuring consistency between other energy consuming sectors, not only in terms of their energy consumption, but also in terms of how the capital and labour costs computed in e-SAGE affect energy sector decisions in SATIM.

7 Danish—IntERACT

As a part of the Energy Agreement from 2012 all parties in the Danish Parliament except one agreed on an ambitious plan for phasing out fossil fuels for energy in Denmark. In 2035 the power and heating sector has to be without fossil fuels and all of the Danish energy system has to be independent of fossil fuels by 2050. As a part of the agreement and to support future planning, a new energy policy analysis model has to be developed.

The model outlined here is decided to be a combination of a CGE model for the Danish economy (CGE-IntERACT) linked with a TIMES model of the Danish energy system (IntERACT-TIMES-DK). The CGE and the TIMES model are being developed simultaneously to secure optimal structural fit and data harmonisation in the linking between the models. A soft-linking approach is chosen and energy demand in form of services are sent from the CGE to TIMES and fuel mix, energy use, energy cost and energy service prices are returned to the CGE.

The IntERACT project is developing a novel CGE approach modelling the energy service demand within its economic CGE model, rather than the typical approach of modelling specific energy goods such as oil, gas, coal or electricity. As has already been indicated in Sect. 5.3 the traditional approach is not well suited when analysing large scale technological changes such as in the case of a complete green transition and phase out of fossil fuels. The demands for comfortable room temperature, lighting, transport services and process energy are the basic needs of the economy, and it is the impact of the relative costs of these services that have significant influence on the economic behaviour.

The premise in the IntERACT model is that agents make economic decisions based on the relative prices of energy services, while the specific fuel use and the specific technology applied in order to obtain the energy service is secondary; i.e. economic utility or revenue is not derived from the amount of energy (PJ) of fuel consumed, but rather from the energy services the fuel actually delivers. This leads on from the concept of exergy and useful work as a productive element in the economy, as opposed to gross energy consumption. Agents maximise profit and utility using the costs of the energy service, using relative prices as usual. By using energy services in this method, the economic TD model creates an abstraction of energy and in a sense reduces the role of exact technologies. Indeed the TD model does not make any technological decisions to obtain a given amount of energy services. From the consumers perspective it does not matter how the room is heated (with an explicit technology choice), but rather how much the costs relative to inputs in the production or goods in the utility bundle vary.

8 Norway—Regional Effects of Energy Policy (RegPol)

The goal of the RegPol[2] project is to develop a hybrid energy-economy framework for Norway with special attention to the regional level, combining the technology rich bottom-up TIMES model with a top-down multi-sector economic computable general equilibrium (CGE) model. CGE-models focus on the interaction between different supply and demand sectors, and are developed to study effects of different policy proposals that apply different instruments within and across the sectors of an

[2] The RegPol project is financed by the Norwegian Research Council. Collaborative research partners are SINTEF Technology and society, NTNU and IFE.

economy. CGE-models usually do not include much technical detail, and have little information on the underlying infrastructure.

The majority of research has addressed the national and international level. The RegPol project focuses on the need to better understand how energy policies affect local decisions and how local advantages can be used actively in regional policy addressing implications for the energy sector. Both models will have a subnational geographical level with multiple regions. The TIMES model will have a geographical representation of the energy system, while the CGE model will describe the regional multi-sector economies plus trade and transport between regions. These models are called spatial CGE models (SCGE) and include modelling elements from new economic geography.

A regional model framework is needed to assess the effect of technology drivers on the deployment of technologies, localisation of new large scale production and changes in end use. Parameters, such as energy demand, population density, local electricity production, untapped resources, available energy infrastructure and geographical conditions influence the future regional development.

The model structures will be general, but a relevant geographical division for analysing energy policies consists of the Norwegian electricity price areas. Some areas have significant power surpluses while others have significant power deficits. Together with transmission constraints, this is relevant for location of both new production and new consumption. Some relevant analysis cases are:

- In Norway there is a political objective to build a substantial amount of renewable energy supported by green electricity certificates. Norway has excellent wind resources, and the RegPol project will analyse which project locations are advantageous, and how projects will affect regional development.
- The electrification of offshore oil and gas fields in order to avoid greenhouse gas emissions would constitute major electricity consumers. Such projects have created strained power situations, and should be analysed within a regional hybrid modelling framework such as RegPol.
- There has been increased focus on Norway's potential to store water in reservoirs. Norwegian hydropower could play a balancing role as a green battery within a European power system with a high share of power production from intermittent sources as wind and sun. This will require new production capacity and new interconnections to be built, both internally to access export links, and to the export markets.
- Development of the grid infrastructure is in itself an important question to analyse. Low transmission capacities may induce different price-levels between price areas, with corresponding consequences for regional industries and other demand.

The hybrid framework with TIMES and the SCGE model will be designed for efficient successive exchanges of adjusted solutions. Different designs for linking the models are investigated, both soft-linking, hard-linking and full integration. The higher data granularity, the more important it becomes to handle data exchange with automatic routines. RegPol starts with a soft-linking approach, but seeks to automate the linking and embed it in the hybrid framework.

Since production and consumption takes place in different locations, the spatial characteristics are important in order to find optimal solutions and effective policies. Various policies (like energy taxes and subsidies) also have regional rates and different regional impacts. The combination of technological and economical models with regional resolution is well suited to improve current analyses and provide the best guidance for future sustainable solutions.

9 Critical Messages from Applied Hybrid Methods

There are many useful points to note in this state of the art review of IEA-ETSAP hybrid energy-economy modelling. A final synthesis of the critical messages from all of the model applications and discussions are summarised below.

A restructured low carbon world economy is imperative to mitigate climate change. Modelling results repeatedly show global CO_2 emissions are significantly lower in hybrid model decarbonisation scenarios as a result of demand adjustments. The range of the differences between isolated energy system CO_2 emissions and their comparable hybrid model is between −5 and −13 % by 2050 depending on the carbon intensity of the region in question's economy.

Economic impacts vary regionally again dependent upon the energy intensity of a nation's economy, the trade partnerships, competitiveness and level of development. Loss of GDP can be as high as 5 %/year by 2050 in developing countries, while up to 3 %/year by 2050 in developed countries depending on the implemented mitigation mechanisms and revenue recycling schemes. Short term economic gains are to be made in energy efficiency measures.

Both energy system models and CGE models play an important role in the existing energy and climate policy analyses. Even when running the two kinds of models in isolation, the models use assumptions which are based on results from the other model (directly and indirectly). Thus, by soft-linking energy system models and CGE models the energy and climate policy analysis becomes more transparent.

Hybrid Models have already played a critical role in carbon mitigation policy and should continue to play a key role in policy advice in upcoming COP talks. Hybrid energy-economy modelling has an increasingly key role to play in accurately modelling the economic impact of climate mitigation, while addressing the most cost-effective technological solutions.

Furthermore, hybrid linking displays non-linear, sectoral non-uniform demand responses that cannot be captured with demand price elasticities, increasing the understanding and transparency of the model results. Model methodological and documentation transparency is a critical moving beyond publishing and presenting papers. Replicability is near impossible and makes difficult the traditional scientific process. A move to more open models is required for more rigorous validation of models and model results.

A challenge and source of uncertainty in soft-linking hybrid models is the price information from bottom up optimisation models to top down models. The price change between the base year and the end of horizon year are found to be exaggerated. The main explanation for this is that the calculated prices in the first modelling years do not include all costs. The optimization solves for the lowers total cost, but when the base years are fixed there is no need to include those cost figures. In contrast, the soft-linking process compares the price difference between two years with one scenario. This particular issue need to be solved in future studies.

Changes in investment flows, due to large structural changes in the energy system are difficult to satisfactorily capture in typical soft-linking methodologies. A major restructuring of the economy as a result of a radical reduction of fossil fuel use would most likely change investment flows substantially and affect the overall investment requirements. In turn this would give rise to significant general (dis) equilibrium effects resulting in model uncertainty.

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Assessing Climate Impacts on the Energy Sector with TIAM-WORLD: Focus on Heating and Cooling and Hydropower Potential

Maryse Labriet, Markus Biberacher, Philip B. Holden, Neil R. Edwards, Amit Kanudia and Richard Loulou

Abstract Much research is still needed to understand the climate vulnerability of the energy sector and to identify cost-effective adaptation options. This chapter explores the coupling of the World TIMES Integrated Assessment Model (TIAM-WORLD) with an emulated version of the climate model PLASIM-ENTS to assess the impacts of future temperature and precipitation changes on the heating and cooling subsector and available hydropower. An absence of climate feedback induced by the adaptation of the energy system to future heating and cooling needs was found for a 1.6–5.7 °C range of long-term global mean temperature increase: when aggregated at the global level, some changes compensate others, and heating and cooling represent a relatively small contributor to total energy consumption. However, significant changes are observed at the regional level in terms of additional power capacity, mostly coal power plants, to satisfy the additional cooling needs. Reduced needs for heating affect gas and coal heating systems more than

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_21

biomass and electric heaters, reflecting higher costs of these heating options in the longer term. Available hydropower is estimated to increase on a seasonal basis in most regions under future climate change. It could therefore contribute to supply the additional electricity needed for cooling in regions where both future cooling needs and hydropower potential are expected to increase. Hydropower results are however characterized by high uncertainty due to uncertainties in projected precipitation changes as well as the relatively coarse resolution of PLASIM-ENTS.

1 Introduction

Until recently, decision-makers within the energy sector have focused their interest on emission mitigation, given the contribution of energy to greenhouse gas emissions. However, the interest in climate risk management in the energy sector is growing, acknowledging that changes in weather patterns due to climate change can have severe implications for both the demand and supply sides of the energy sector (Mideksa and Kallbekken 2010; Ebinger and Vergara 2011; Schaeffer et al. 2012). The most recent Assessment Report of the Intergovernmental Panel on Climate Change concludes that "*the energy sector will be transformed by climate policy* (…) *but impacts of climate changes too will be important for secure and reliable energy supply*" (Arent et al. 2014).

Climate change may result in the following impacts on energy demand and production.

- Space heating and cooling requirements vary according to air temperature. Several studies assess these impacts often using engineering approaches, such as Wilbanks et al. (2007b) for the USA, Aebischer et al. (2007) for Switzerland and Europe, Akpinar-Ferrand and Singh (2010) for India, Isaac and van Vuuren (2009) and Mima and Criqui (2009) at global level. Impacts are expected to vary between different fuel sectors: on the one hand climate change may result in an increase in net annual electricity and electricity-peaking demand, driven, for instance, by additional cooling requirements and stressing the installed capacity and grids; on the other hand, demands for heating energy sources, possibly not electricity, may decline (Wilbanks et al. 2007a). The overall balance will depend on geographic, demographic, economic, building and technological conditions (Arent et al. 2014).
- Changes in water and air temperature modify the cooling efficiency of thermal and nuclear power generation, resulting in modified availability and efficiency of plants. Except in the case of extreme events, the average impact of future climate change is expected to remain small at the level of each plant (Durmayaz and Oguz Salim 2006; Linnerud et al. 2011; Rubbelke and Vogele 2011); however, the need for adaptation of the overall energy sector might be non-negligible

given the high share of fossil and nuclear power plants in some regions of the globe. Van Vliet et al. (2012) estimate a summer average decrease in the capacity of power plants of 6.3–19 % in Europe and 4.4–16 % in the United States, depending on cooling system type and climate scenario for 2031–2060.

- Changes in seasonal river flows and their variability, resulting from changes in precipitation patterns and surface water discharges, may affect hydropower potential and generation. Hydropower represents a large share of the electricity mix of several countries and of the renewable energy sources at the global level. Moreover, hydropower plants usually have a long lifetime. Given these different factors, the assessment of climate change impacts is likely to be crucial for this source of energy. Lehner et al. (2005) estimates that the hydropower potential for the whole of Europe could decline by 6 % by 2070 (20–50 % decrease around the Mediterranean, 15–30 % increase in Northern and Eastern Europe, stable hydropower pattern for western and central Europe). Hamududu and Killingtveit (2012) estimate that most of the high hydropower-producing countries in Northern regions (Canada, United States and parts of Europe and Russia) will have increased generation, while for most of the other regions, hydropower generation will decrease. Mima and Criqui (2009) estimate an average increase of the world hydro electricity generation of up to 7 % in 2100 resulting from climate change (+12 % in North America, +13 % in Commonwealth of Independent States, +7 and 6 % in Japan and Australasia, −2 % in Western Europe). Reduction in available capacity may reach 7 % in some regions of Brazil by the end of the century (Lucena et al. 2009).
- Changes in wind and solar conditions remain uncertain and will be highly dependent on regional characteristics (IPCC 2011). The relatively short lifespan of solar and wind technologies implies that the facilities would be replaced over time and therefore could spontaneously adapt to new local climate conditions or room would remain for relocation (Ebinger and Vergara 2011).
- The impact of altered soil conditions and precipitation on future available crops and bioenergy is expected to be relatively small on a global basis, but with large and uncertain regional differences (IPCC 2011). CO_2 fertilization as well as diet are considered as crucial factors of uncertainties on future bioenergy (Haberl et al. 2011).
- Finally, energy-related infrastructure is vulnerable to extreme events and sea level rise, which could affect localization of plants and security of supply (Craig 2011).

Much research is still needed to understand the climate vulnerability of the energy sector and to identify cost-effective adaptation options (Arent et al. 2014). Using MARKAL Norway, Seljom et al. (2011) assessed the impacts of climate change on the energy system of Norway. The objective of this chapter is to explore the coupling of the World TIMES Integrated Assessment Model (TIAM-WORLD) with an emulated version of the climate model Planet-Simulator coupled to the Efficient Numerical Terrestrial Scheme (PLASIM-ENTS) in order to assess the impacts of future temperature and precipitation changes on heating and cooling subsector and available hydropower.

The methodological framework is presented in Sect. 2, and results are described in Sect. 3.

2 Methodological Framework

2.1 TIAM-WORLD

The TIMES Integrated Assessment Model (TIAM-WORLD) is a technology-rich model of the entire energy/emission system of the World split into 16 regions,[1] providing a detailed representation of the procurement, transformation, trade, and consumption of a large number of energy forms (Loulou 2008; Loulou and Labriet 2008).

It is an incarnation of The Integrated MARKAL-EFOM System (TIMES) economic paradigm and computes an inter-temporal dynamic partial equilibrium on energy and emission markets based on the maximization of total surplus, defined as the sum of suppliers and consumers surpluses. In other words, the model finds the optimal (cost-efficient) energy and technology mix to satisfy demands for energy services like lighting, cooking, heating, cooling of houses, car usage, trucks, aluminum production, cement production, etc. Each demand may vary endogenously in alternate scenarios, in response to endogenous price changes.

The model contains explicit detailed descriptions of more than 1500 technologies and several hundred energy, emission and demand flows in each region. Such technological detail provides a precise description of technology and fuel competition in the entire energy system, where changes in one sector may have direct and indirect impacts on other sectors. The model is set up to explore the development of the World energy system until 2100. The model is calibrated to 2005 energy statistics of the International Energy Agency (IEA 2013a, b).

TIAM-WORLD integrates a climate module for the modeling of global changes related to greenhouse gas concentrations, radiative forcing and temperature increase. The module includes separate cycles for CO_2, CH_4, and N_2O, and also accounts for the additional forcing introduced by other causes, natural and anthropogenic. The total atmospheric forcing is then introduced into equations that simulate the changes in mean temperatures of two layers: surface, and deep ocean. The climate module provides a very useful means of simulating scenarios with specific climate targets, be they on concentration, forcing, or temperature.

[1] Africa (AFR), Australia-New Zealand (AUS), Canada (CAN), United States (USA), Mexico (MEX), Central and South America (CSA), China (CHI), India (IND), Japan (JAP), South Korea (SKO), Other Developing Asia (ODA), Middle East (MEA), Europe of 27 + Switzerland, Norway and Iceland (EUR), Other East Europe (OEE), Russia (RUS), Central Asia and Caucasia (CAC). OPEC and Non-OPEC disaggregation is considered within each region, when relevant.

2.2 PLASIM-ENTS

One of the principal obstacles to coupling complex climate models to the range of models needed to assess climate impacts in different sectors is the computational expense of the climate models. Replacing the climate model with an emulated version of its input/output response function circumvents this problem without compromising the possibility of including feedbacks and non-linear responses (Holden and Edwards 2010). The climate model emulator used here is PLASIM-ENTSem (Holden et al. 2014), an emulation of PLASIM (Fraedrich et al. 2005) coupled to the ENTS vegetation and land surface model (Williamson et al. 2006), here run at T21 resolution (approximately 5°).

PLASIM-ENTS has a 3D dynamic atmosphere, flux-corrected slab ocean and slab sea ice, and dynamic coupled vegetation (anthropogenic land use change is not represented in PLASIM-ENTS, but changes due to natural vegetation dynamics are represented). The seasonal and regional validations of both PLASIM-ENTS and PLASIM-ENTSem are described in detail in Holden et al. (2014). Figure 1 presents climate changes at 2100 under a radiative forcing corresponding to the representative concentration pathway RCP8.5 (Moss et al. 2010) where temperature increase reaches 4.7 °C in 2100. In summary, the emulator performs generally very well in capturing the spatial variability and magnitude of warming simulated by more complex models. The neglect of the sea-ice feedback in the configuration used in the current analysis results in understated warming in the Arctic in December-January-February. Although caution will be required, this error dominantly affects temperatures in sparsely populated high-northern latitudes and so may not be problematic for large-scale human impact studies. In terms of precipitation-evaporation, the increase is particularly strong in India in June-July-August as a result of a strengthening of the South-east Asian monsoon in PLASIM-ENTS, attributed as likely due to the neglect of aerosol forcing in the model. This increase should therefore not be regarded as robust.

The climate data required for the assessment of heating and cooling changes due to climate changes can be summarized in terms of Heating Degree Days (HDDs) and Cooling Degree Days (HDDs), which are the number of degrees respectively below and above the temperature levels from which heating or cooling are needed. Seasonal HDDs and CDDs are computed at each of the 2048 PLASIM-ENTS grid cells as described in Holden et al. (2014). The baseline temperature for both heating and cooling is fixed to 18 °C globally (discussion about this choice is included in Sect. 3.1). The mapping of the PLASIM-ENTSem degree-day data onto TIAM-WORLD regions relies on a population-weighted average over the grid cells that comprise a given region of TIAM-WORLD, considering 2005 population distribution data. In other words, while demographic changes *between* TIAM regions are considered in the assessment of energy needs, possible changes in distribution *within* TIAM regions are not considered. Such changes could have important impacts on the future needs for cooling and heating, and would deserve a better

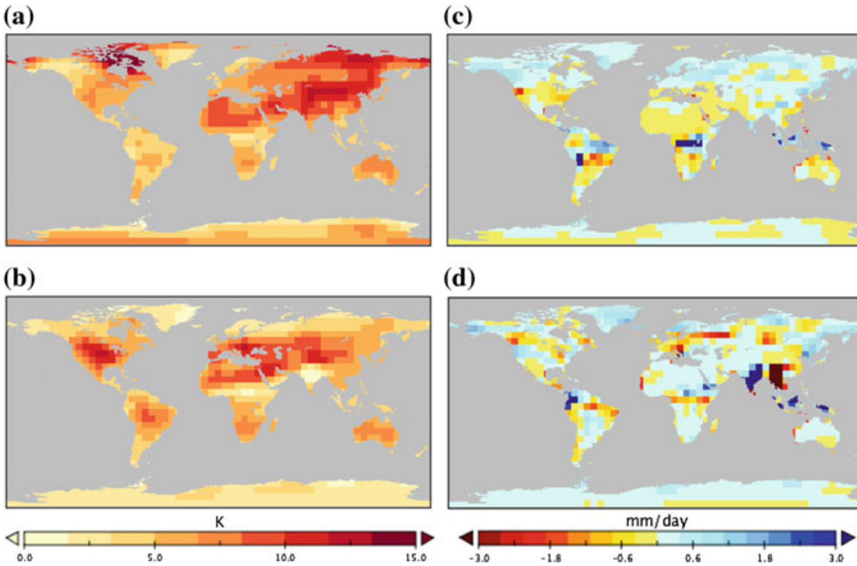

Fig. 1 Emulated climate change 2100–2000 under RCP8.5. **a** Dec-Jan-Feb warming, **b** Jun-Jul-Aug warming, **c** Dec-Jan-Feb precipitation minus evaporation increase, **d** Jun-Jul-Aug precipitation minus evaporation increase. Plotted data was calculated with the released version of PLASIM-ENTSem, which captures dynamic Arctic sea ice. *Note* Scales conceal 3K cooling and 14 mm/day increase in precipitation-evaporation in JJA India; these anomalous changes are driven by a simulated strengthening of the SE Asian monsoon which is not regarded as robust

consideration in future applications. Approximations due to different resolutions of data were addressed in the mapping (Holden et al. 2014).

2.3 Coupling of Models

Figure 2 summarizes the exchange of data between TIAM-WORLD and the emulator of PLASIM-ENTS, described in this section. Information exchange between models is handled by a fully automated script that launches models, reads output of one and creates input for the next.

2.3.1 Heating and Cooling

The drivers of future heating and cooling demands in TIAM-WORLD reflect changes in socio-economical characteristics of the countries, but do not consider changes in future temperature. Moreover, the climate module of TIAM-WORLD does not compute the regional or seasonal temperature changes required for a

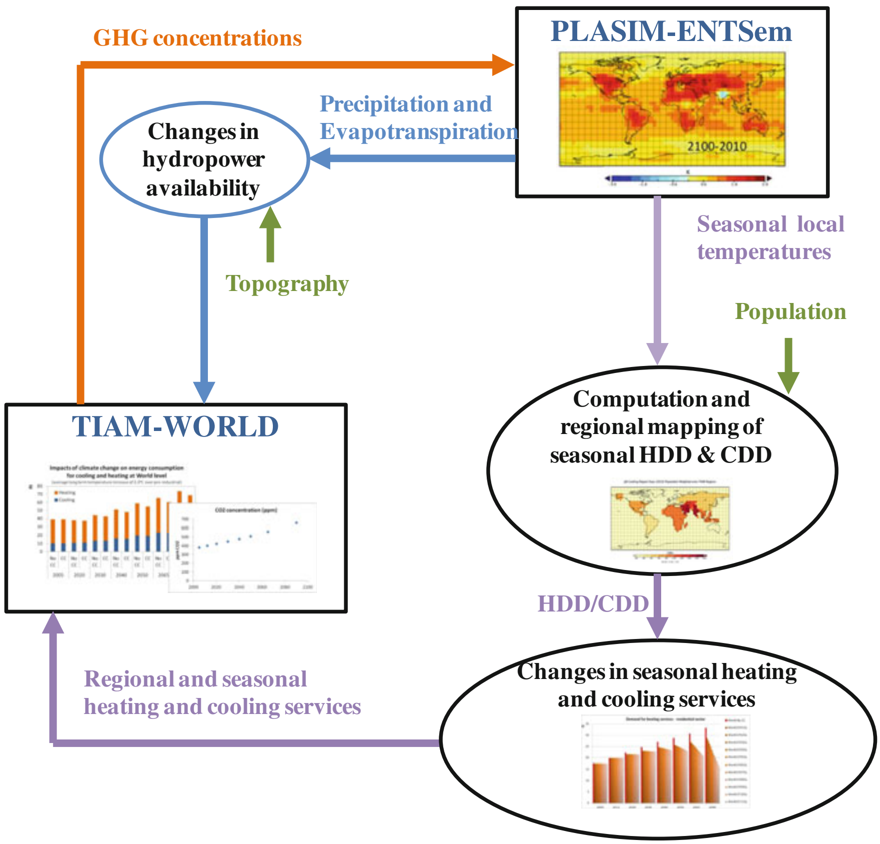

Fig. 2 Principles of the coupling between TIAM-WORLD and PLASIM-ENTSem for heating/cooling and hydropower

relevant representation of the possible heating and cooling adjustments due to climate change. The coupling of TIAM-WORLD with an emulator of the climate model PLASIM-ENTS provides this additional information.

In essence, there is an iterative exchange of data between the two models: TIAM-WORLD sends a time series of endogenously computed total greenhouse gas concentrations to the climate emulator. The climate emulator sends the seasonal and regional temperatures, converted into seasonal heating and cooling degree-days for each of the regions of the model, to TIAM-WORLD. These seasonal and regional degree-days are in turn used to compute new seasonal (3 seasons) and regional (16 regions) heating and cooling demands in TIAM-WORLD, by adjusting these demands proportionally to the changes of HDDs and CDDs of each region with respect to the values of the base year (Labriet et al. 2013). A new supply-demand equilibrium can then be computed by the model.

2.3.2 Hydropower

Following the same principle as heating and cooling impacts, annual and seasonal availability factors of hydropower plants of TIAM-WORLD are iteratively adjusted to reflect the relative changes due to future climate change over the starting year, using the outputs of the hydropower computation presented in the following paragraphs.

The hydropower computation is based on the physical assumption that hydropower potential at a certain location is determined by the potential energy of cumulated run-off water at this location relative to the near neighborhood. The computation of the run-off water relies on topography, monthly precipitation and monthly evapotranspiration. Elevation information provided by topography data (Fischer et al. 2008) is used to define the flow direction (from the grid cell with the highest direction to the neighbor grid cell with the lowest elevation). The cumulated run-off in a single grid cell is determined by inflow into the grid cell from neighboring cells, precipitation in the grid cell and evapotranspiration. The hydropower potential computation is done in a separate module which is coded in c language. Precipitation and evapotranspiration are provided by PLASIM-ENTSem.

The differentiation between run-of-the-river and dam potential is based on the assumption that an elevation difference between two neighboring grid cells below 50 m in altitude on a 5 arc min grid resolution (around 1 km at the equator) belongs to run-of-the-river potential while a higher elevation difference belongs to dam potential.

The gross theoretical hydropower potential is determined by Eq. 1 (Pokhrel et al. 2008):

$$E_i = m_i * g * \Delta h_i \quad \text{for all } i \tag{1}$$

where

E_i potential energy of run-off water in grid cell i
m_i mass of run-off water in grid cell i
g average gravity acceleration
Δh_i elevation difference between grid cell i and lowest neighboring grid cell

Land cover information was used to identify areas such as permanent snow and ice covered areas, protected areas or built-up areas in order to assume a realistic share of utilizable potential compared to the theoretically calculated potential.

This calculation provides a gross theoretically utilizable hydro power potential for each single grid cell, followed by dynamic aggregation of the resulting grid cell based hydropower potential over predefined regions of TIAM-WORLD.

Hydropower potentials computed with the above methodology are of the same order of magnitude as those obtained by Pokhrel et al. (2008) using the same approach except in Asia, where the potential reaches 37 TWh rather than 22 TWh. The high South-east Asian monsoon observed in summer (JJA) in PLASIM-ENTS certainly contributes to this higher potential, reinforced by the high elevation differences in the region. Indeed, small deviations in precipitation and evaporation could translate into much higher deviations in hydropower when multiplied by high elevation difference. In addition to this factor, geographic resolution of the computation of elevation and flow direction is expected to be a possibly high source of differences across studies: since flow direction has a direct impact on the assignment of hydropower potentials to certain locations, an averaging of the flow direction caused by weaker resolutions may result in wrong geographical assignments of the hydro power potential. Finally, not all factors that trigger hydropower potentials are considered, such as changes in sediment loads.

3 Results

3.1 Heating and Cooling

Scenarios. The assessment of climate change impacts on the energy system relies on a series of 12 different future states of the climate system. For the purpose of this exercise, focused on the understanding of the adaptation of the energy system to future climate changes, emission mitigation in the energy system is deliberately excluded and possible changes in the radiative forcing are artificially assumed to be due to non-energy factors.

In all Figures, CCx.x corresponds to scenarios with a long-term mean temperature increase of x.x °C at the global level. The range of long-term global mean temperature increase covered in the study is 1.6–5.7 °C. It is important to remember that regional temperature increases, as computed by PLASIM-ENTSem, will in general be different and these are used to assess the changes in heating and cooling. The case without considering the impact of climate change (NoCC) assumes the same global average temperature as today.

Based on Labriet et al. (2013), with kind permission of Springer Science +Business Media.

The long-term temperature increase obtained with the exogenous radiative forcing included in TIAM-WORLD is 3.3 °C. Regional HDD and CDD in this scenario, calculated with regional temperatures computed by PLASIM-ENTSem, are illustrated in Fig. 3, where different categories of regions can be identified: colder regions (high levels of HDD) where the main expected impact of climate change is a reduction of heating services, warmer regions (high levels of CDD) where the main expected impact of climate change is an increase of cooling services, regions with intermediate climate where both heating and cooling appear to be important and the net impact of climate change may depend on each region.

Global climate feedback. The first question concerns the magnitude of the feedback on the climate system of the changes observed in the energy system due to heating and cooling adaptation. Indeed, the increase of electricity generation for cooling, if not compensated by the decrease of energy use for heating, may be a

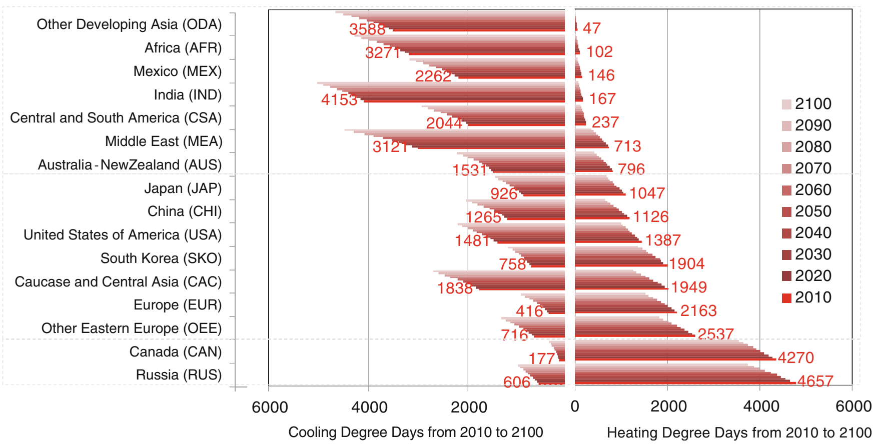

Fig. 3 Annual HDD and CDD corresponding to a long-term global average temperature increase of 3.3 °C. Numbers for 2010 are indicated in *red*. Based on Labriet et al. (2013), with kind permission of Springer Science+Business Media

source of additional greenhouse gases, which could accelerate climate change. Results demonstrate that changes in CO_2 emissions resulting from adjusted heating and cooling (Fig. 4) are not sufficient to have an impact on the climate system; in other words, no feedback between the energy and climate systems at the global level was discernible, on the time horizon considered (2100). This does not mean that the impacts of climate change on heating and cooling are negligible. It means that when aggregated at the global level, some changes compensate others, and that heating and cooling represent relatively small contributors to total energy consumption (Fig. 5).

Combined heating and cooling in the total energy balance. The share of combined heating and cooling energy consumption is small at the global level compared to the total energy consumption (less than 10 %), and varies from less than 3 % in regions like India and Africa, to more than 25 % in regions like Other Eastern Europe, Canada and Russia (Fig. 5). Changes of the share in the case without climate change reflect both socio-economic drivers in energy services (population growth, economic development) and technology dynamics (type and efficiency of technologies to provide the services). The difference between the shares obtained with and without climate change impacts illustrates a small net decrease of total energy consumed for combined heating and cooling needs in regions with a cold climate, and a small net increase of total energy consumed for combined heating and cooling needs in regions with a warm climate.

Fuel perspective. Impacts of heating and cooling adaptation to future climate change vary at the regional level (Fig. 6). In total, energy for heating and cooling decreases in China and Russia (domination of heating changes), increases in India, Central and South America and United States (domination of cooling change), and remains almost stable in Europe and at the World level (compensation).

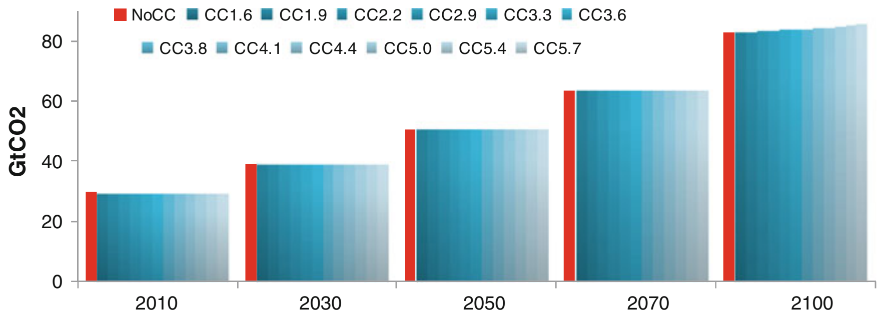

Fig. 4 Global CO_2 emissions from the energy system resulting from changes in heating and cooling in 12 different temperature scenarios

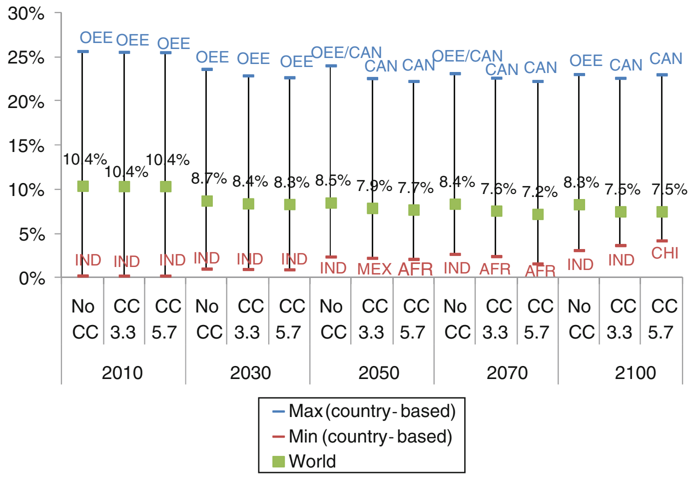

Fig. 5 Share of heating and cooling energy consumption in total final energy, in 3 cases: long-term global average temperature increase of 3.3 °C w/o climate changes (NoCC), with climate changes (CC3.3) and 5.7 °C with climate changes (CC5.7). Countries with the largest and smallest shares are indicated. Based on Labriet et al. (2013), with kind permission of Springer Science +Business Media

Reduced needs for heating affect gas and coal heating systems (reduced consumption of gas and coal for heating) more than biomass and electric heaters, reflecting higher costs of these heating options in the longer term. Solar energy does not appear in the results since it is used mostly for water heating and cooking in TIAM-WORLD.

In all regions, electricity consumption for heating and cooling increases, driven by cooling needs. The increase reaches up to 55 % over the case without climate change at the global level, and more than 60 % in Europe, Central and South America, and China. The seasonal impacts of climate change, especially on peak

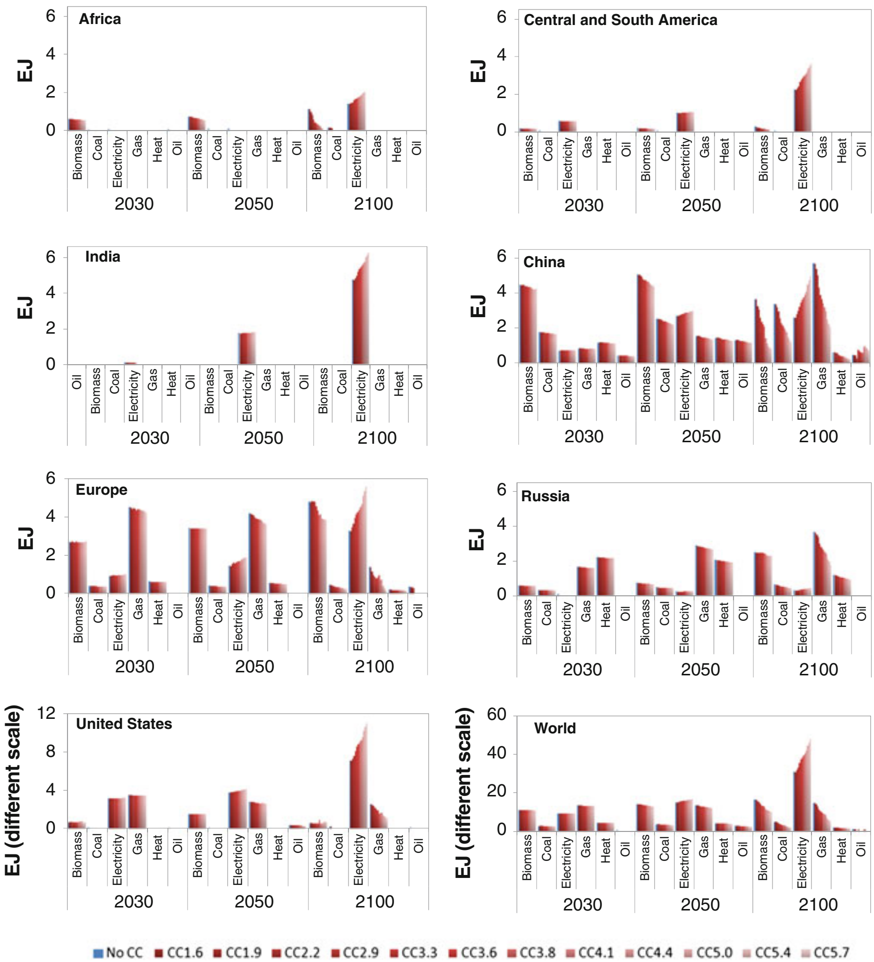

Fig. 6 Final energy consumption for heating and cooling in 12 different temperature scenarios (Results for other regions are available upon request)

electricity generation, are reflected in changes in electricity prices. Electricity prices in Europe increase by up to 45 % in summer days in the mid-term and 66 % at the end of the horizon in Europe (up to 30 and 50 % in the Reference case 3.3 °C scenario). The increase reaches 30 % during summer days in China, 10 % in USA, while electricity prices remain unchanged in Russia. In India, the season with the highest increase of electricity prices is the intermediate one (fall and spring), corresponding to the peak of temperature. The penetration of building shell improvement options, such as efficient windows and insulation, could contribute to the adaptation of the building sector to future increase of cooling needs. These options are however modeled via exogenous scenarios in this version of the model, and only device efficiency options are endogenous. Electric and geothermal heat pumps are the preferred technologies for cooling and represent the same shares of the cooling market in cases with and without climate change.

Not surprisingly, without any emission mitigation constraints, coal power plants appear to be the most cost-efficient power option. Resulting emissions are however compensated by the reduction in fossil fuel consumption for heating.

Threshold temperature. HDD and CDD computation requires the choice of a threshold temperature below/above which heating and cooling are needed. In order to understand the importance of the threshold temperature, CDD was computed for 4 threshold temperatures: 18, 22, 25 and 28 °C (Fig. 7). As expected, absolute values of CDD are smaller when threshold temperature is higher, over the entire time horizon. However, the increase of CDD relative to 2010 due to climate change is higher when threshold temperature is higher. In other words, climate change will result in bigger changes in cooling needs compared to the current situation when a higher reference temperature is used for cooling: if people start cooling after 22 °C, now and in the future, their absolute cooling needs will be smaller, but their cooling needs will increase more, due to climate change, than if they start cooling after 18 °C. In this context, the use of 18 °C to compute HDD and CDD is supported by two ideas. First, HDD and CDD are only an "indicator". Their computation based on 18 °C of course does not represent the real cooling needs, but this convention has the merit of being shared by all and makes comparison across studies possible. Second, in studies as the current one, HDD and CDD are not used to compute the absolute energy consumption but to compute relative changes over a situation without climate change. In conclusion, the use of a default threshold temperature of 18 °C follows the convention of similar studies.

3.2 Hydropower

Hydropower potential. The variation of potentials over time due to climate change was estimated in the reference case, corresponding to long-term temperature increase of 3.3 °C (Fig. 8). A global increase of 6 % in 2050 and 16 % in 2100 of hydropower power on an annual basis is estimated, with higher increases in spring (MAM). Hydropower potentials decrease at some seasons in China, United States and India, and increase in all other regions and seasons. The high increase of potential observed in India in summer (JJA) is associated with the strong SE Asian monsoon simulated by PLASIM-ENTS. These variations appear to be globally more optimistic than assessments proposed by other studies, usually closer to increases of less than 10 % by the end of the century at the global level (Hamududu and Killingtveit 2012; Mima and Criqui 2009). These studies also propose a decrease of hydropower in Europe, while an increase is obtained with our assessment, explained by an increase in Northern Europe higher than the decrease observed in Southern Europe. As mentioned in Sect. 2.3.2, several factors may contribute to these differences, such as the geographic resolution of the computation

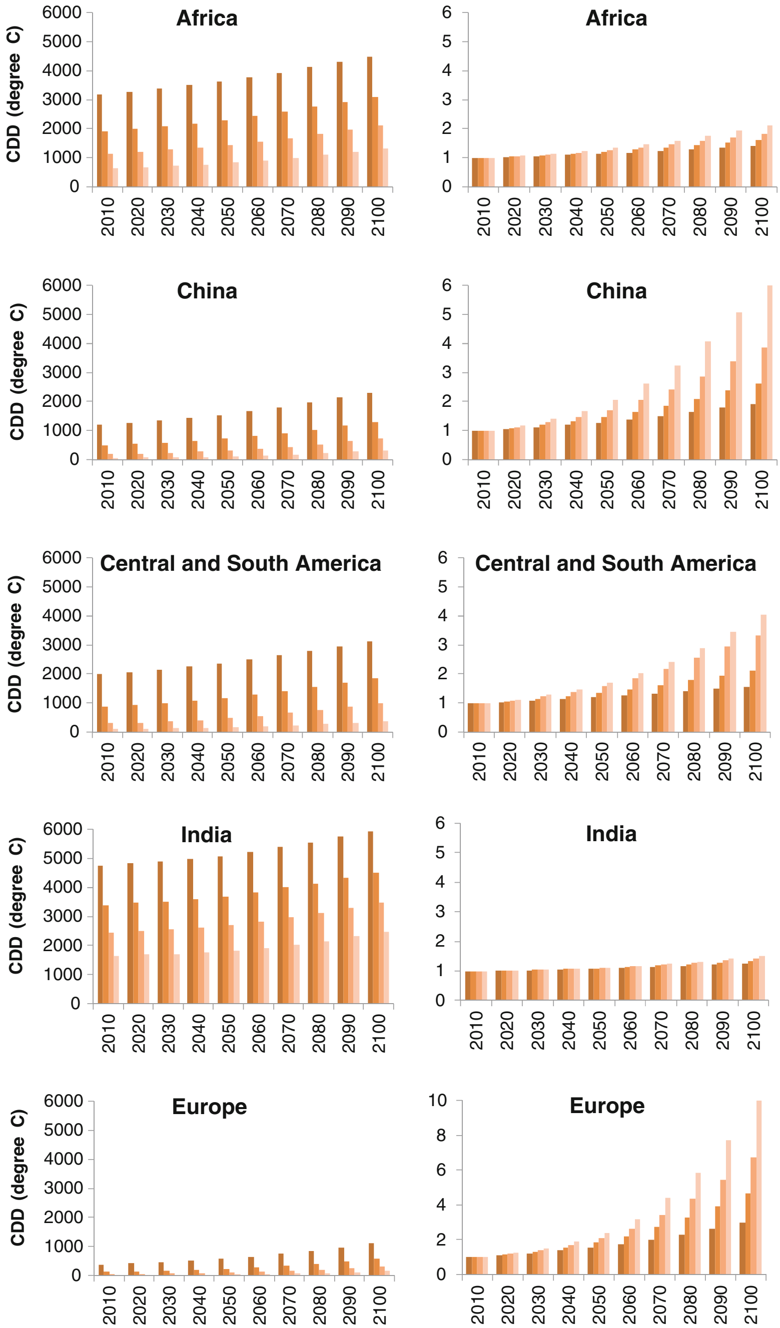

Fig. 7 Impact of temperature threshold on cooling degree days. *Left* Absolute values. *Right* Normalized to 1 in 2010 (Results for other regions are available upon request)

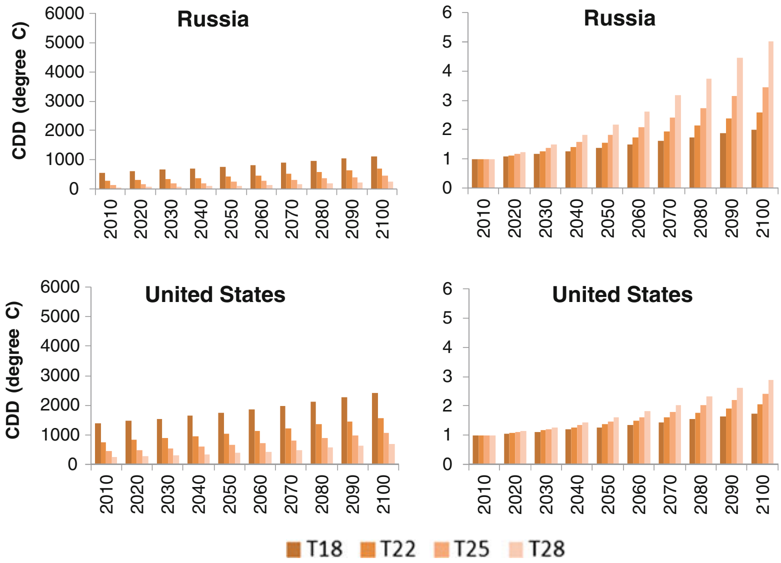

Fig. 7 (continued)

of the hydro potentials and the possibly high uncertainties in regions with high elevation difference in their geography. Numerical results presented below must therefore be considered as indicative of one of the possible futures only. Uncertainty resulting from the implementation at the global level of the analysis of the climate vulnerability of hydropower is also mentioned by Hamududu and Killingtveit (2012) in their study at the World level.

Changes in the energy system. Global increase in hydroelectricity generation reaches 135 TWh in the mid-century and 2000 TWh at the end of the century (Fig. 9), or respectively around 3 and 40 % more than when not considering the impacts of climate change on hydropower. Regions with highest absolute changes are Africa, Central and South America, as well as Other Developing Asia and Canada at the very end of the century. The increase in hydro potential observed in summer in India, acknowledged as not robust (see previous sections), does not produce a large increase of hydroelectricity generation.

Despite the increase of hydroelectricity generation, no change in total electricity generation is observed, neither at global nor regional levels. In other words, the higher availability of hydropower does not result in a higher electrification of the energy system, and additional hydroelectricity substitutes other forms of electricity: coal power plants as baseload power plants in Africa, and gas and wind power in other regions (Fig. 10b). The impact on CO_2 emissions is negligible given the limited degree of substitution (except in the national emission inventories of Africa and Japan in the longer term, where emissions are reduced by up to 15 %). However, the higher seasonal availability of hydropower contributes to the decrease of electricity prices in several regions, such as in Africa in summer.

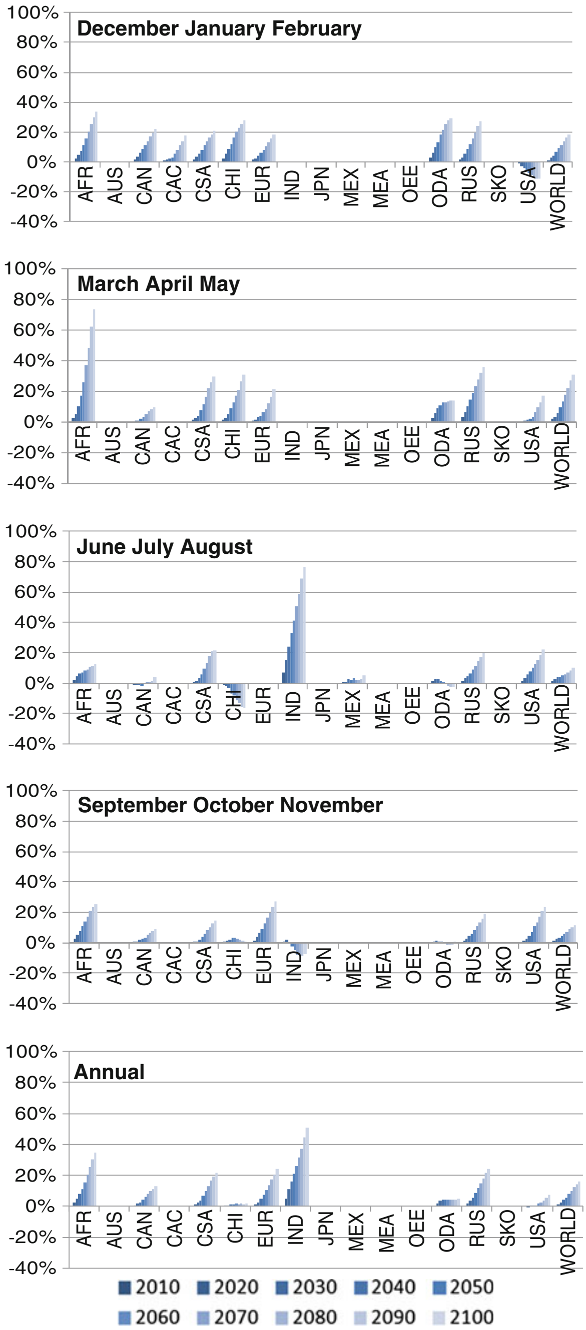

Fig. 8 Variations in hydropower availability in the reference case due to climate changes (long-term temperature increase of 3.3 °C)

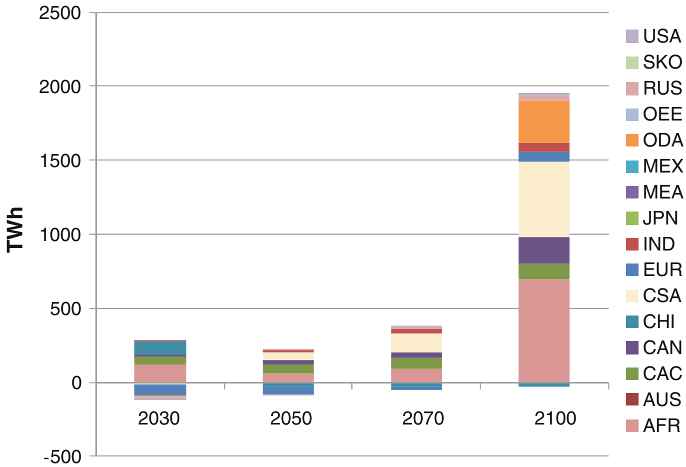

Fig. 9 Variations in hydroelectricity generation by region in the reference case due to climate changes (These variations correspond to the differences in hydroelectricity generation between the reference case without considering the impacts of climate changes, and the Reference case with impacts of climate changes) (long-term temperature increase of 3.3 °C)

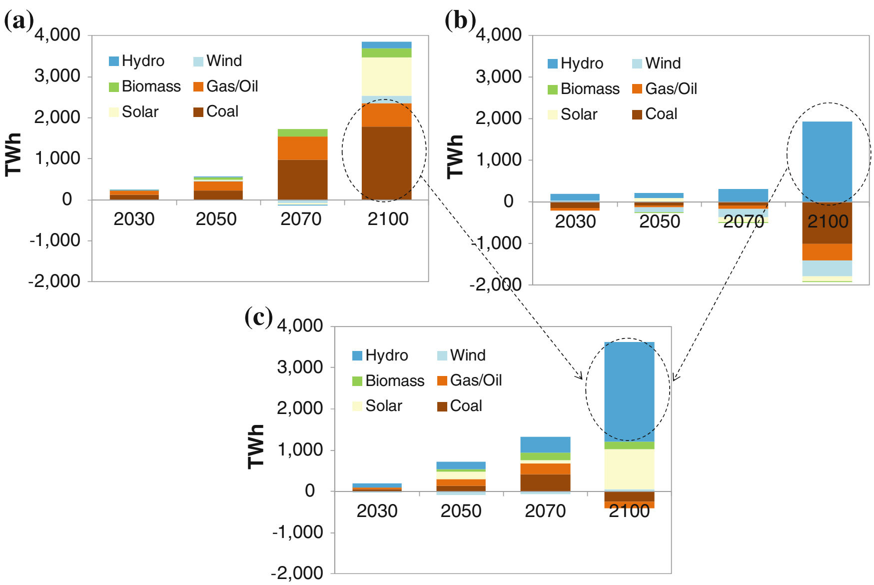

Fig. 10 Variations (These variations correspond to the differences in hydroelectricity generation between the reference case without considering the impacts of climate changes, and the Reference case with impacts of climate changes) in the electricity mix at global level in the reference case due to the impacts of climate change (long-term temperature increase of 3.3 °C)

Combined impacts of climate change. The analysis of the electricity mix at the global level shows that the increase in hydroelectricity availability could contribute to substitute the additional coal power generation needed to satisfy the additional needs in electricity for cooling due to climate change (Fig. 10). Regions like Africa and Central and South America particularly benefit from this substitution, being regions that combine high increases of cooling needs and hydropower potentials due to climate change. Given the important role that transmission and interconnections may play in coping with climate variations, more detailed analysis of the capacity of the energy system to adapt to future climate change would deserve an enhanced consideration of the geographical dispersion and capacity of the transmission grid.

4 Conclusion

The development and application of modeling tools are fundamental to support policy-makers and project implementers in understanding and planning not only the mitigation options but also the adaptation strategies of the energy sector.

The general objective of this chapter is to assess the changes in heating and cooling of buildings and in hydropower capacity and generation resulting from future temperature and precipitation changes. To achieve this, we have coupled the TIAM-WORLD techno-economic model with an emulated version of the climate model PLASIM-ENTS to guarantee a consistent analysis of the linkage between climate and energy dynamics.

Globally, an absence of climate feedback induced by the adaptation of the energy system to future heating and cooling needs was found, but with significant changes at regional levels, most particularly in terms of additional power capacity to satisfy the additional cooling needs. Available hydropower is estimated to increase on a seasonal basis in most regions under future climate change. Hydropower results are however characterized by high uncertainty: projected precipitation changes vary greatly between different climate models, much more so than for temperature projections. This is a significant source of uncertainty for the hydropower potential projections, especially given the relatively coarse resolution of PLASIM-ENTS and its neglect of land use change. Moreover, modeled watershed borders are quite sensitive to the considered spatial resolution of the topographic model, which could result in an inaccuracy in the modeled spatial hydropower potential.

The strength of the study is to assess climate impacts on the energy system taking a system perspective that accounts for impacts on the entire energy system (all sectors) and resulting fuel substitution effects. Future research may include the refinement of the computation of heating and cooling, for example with variable threshold temperatures, as well as the application of the hydropower methodology at a more detailed geographic resolution. Moreover, the PLASIM-ENTS emulator generates an ensemble of climate projections; the work described here has only considered the ensemble mean of these projections. In future work we will apply the ensemble to quantify the contribution of climate model uncertainties on impacts. Other impacts of climate change would of course deserve analysis, such as climate impacts on biomass and bioenergy, as well as on thermal power plants. In that sense, based on a more detailed representation of power plants, the climate vulnerability of thermal power plants could be considered, as well as the capacity of the transmission grid and interconnections to play an active role in the adaptation of the energy system to future climate change. The use of enhanced versions of the climate emulator, including sea-ice feedback and aerosol forcing, is expected in future applications. Finally, complementary to the assessment of techno-economic impacts of climate change on the energy system, macro-economic impacts may deserve more attention. Labriet et al. (2013) show that they are limited at global level but diverse across regions, mainly due to changes in terms of trade resulting from lower fossil fuel exports.

Acknowledgments The research leading to these results has received funding from the EU Seventh Framework Programme under Grant Agreement no. 265170 (Project ERMITAGE—Enhancing Robustness and Model Integration for The Assessment of Global Environmental Change).

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Coupling World and European Models: Energy Trade and Energy Security in Europe

Raffaella Gerboni, Daniele Grosso, Evasio Lavagno, Amit Kanudia and GianCarlo Tosato

Abstract Energy modelling can provide a knowledge basis for tackling the security of energy supply issue at different geographical levels. This chapter presents an application of the coupling of the global TIMES Integrated Assessment Model and of the Pan European TIMES model through a series of trade links described and characterised in the REACCESS corridor model. The coupling was developed during the EU FP7 REACCESS project and was further improved and updated during a follow-up phase. The application focuses on the analysis of security of supply to Europe via energy corridors. A new methodology for the assessment of energy security, addressing the risk associated to each supply, is presented together with a scenario analysis related to some of the most populated of the EU's Member States and to the European Union as a whole. The scenario analysis results show a sample of the possible assessments that stakeholders might be willing to rely on to address the effects of communitarian policies and targets: the preformed analysis, for example, unveils that a risk reduction at communitarian level may not univocally be translated into a benefit for individual Member States.

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G. Giannakidis et al. (eds.), *Informing Energy and Climate Policies Using Energy Systems Models*, Lecture Notes in Energy 30,
DOI 10.1007/978-3-319-16540-0_22

1 Background on the REACCESS Project

In the early 2000s, geopolitical instabilities, new threats and alliances, coupled with the increased availability of fossil fuels in key areas of the world, led the EU needing to strengthen a knowledge base via strategic studies in order to pave the way towards an efficient and pragmatic approach to guarantee (or improve or reinforce) the security of supply. The EU financed a set of research projects to provide strategic studies, overviews and analytical tools to policy makers, and it mostly used the Framework Programmes scheme to support these actions. ENCOURAGED, SECURE and REACCESS projects are examples of these efforts.

The Risk of Energy Availability: Common Corridors for Europe Supply Security (REACCESS) project was carried out under the 7th Framework Programme (FP7). Its main focus was the analysis of the security of energy supply in the European Union. This target was achieved by means of a modelling exercise performed adopting a detailed technical, economical, safety and environmental characterization of the energy corridors for the main commodities, i.e. hard coal, natural gas, crude oil, refined petroleum products, biomass, hydrogen, nuclear material, and electricity from concentrated solar power plants (CSP) (Pregger et al. 2011).

In particular, three TIMES models (Loulou et al. 2005)—two existing/adapted, that is the Pan European TIMES (PET36) and the KanORS TIAM-World, and one newly built (RECOR)—have been linked to define a global optimization model.

The Pan European TIMES (PET36) is a model that describes the whole energy system of 36 European countries (the 28 EU Member States plus Switzerland, Norway, Iceland, Bosnia Herzegovina, Former Yugoslav Republic Of Macedonia, Montenegro, Serbia and Albania), with five end-use sectors (Agriculture, Commerce, Industry, Residential and Transportation) and 70 exogenous demands for energy services. The release used within REACCESS is a revision of the previous version of the model (PET 27+), based on the EU27 countries plus Switzerland, Norway and Iceland (Biberacher et al. 2011).

The TIMES Integrated Assessment Model (TIAM) is a model that describes (in the original ETSAP-TIAM version) the whole energy system of the world divided in 15 macro-areas (Africa, Australia-New Zealand, Canada, Central and South America, China, Eastern Europe, Former Soviet Union, India, Japan, Mexico, Middle-East, Other Developing Asian Countries, South Korea, United States, and Western Europe), with five end-use sectors (Agriculture, Commerce, Industry, Residential and Transportation) and 42 exogenous demands for energy services. In order to satisfy the requirements of the REACCESS project, a new version of the model (KanORS TIAM-WORLD) was developed and some changes were made in the regional disaggregation. In particular, the Eastern Europe, Former Soviet Union and Western Europe regions were replaced by four new regions: Europe, Other Eastern Europe (including Ukraine, Belarus and Moldova), Central Asia and Caucasus and Russia (Biberacher et al. 2011). The region of Europe, for the purposes of the project, was then replaced with the finest description contained in PET36.

1.1 REACCESS CORridor (RECOR) Model

RECOR is the new model developed within REACCESS to fully describe (from the extraction fields to the supply entry point) all the present and planned/possible future energy infrastructures supplying the European countries, taking into account both captive (mainly pipelines, but also railways and electrical power lines) and open sea (ship routes from port to port) corridors. Besides all the European supply infrastructures, the main non-EU corridors have also been considered. For the extraction fields, data on extraction costs and on proven, probable and possible resources were provided. Each corridor has been divided into branches (Fig. 1) and each branch (implemented into the Model as a TIMES process) has been characterized by both technical (length, capacity, activity in the base year of the model, fuel-in, fuel consumption, life, etc.) and economical (investment cost, fixed and variable operating and maintenance costs, etc.) parameters. All along the corridors, supply branches stem as supply branches to the transit countries. The supply branch links the RECOR model to the Reference Energy System (RES) of a PET36 or a TIAM region. The number of the analysed connections by commodity is summarised in Table 1.

One of the main features of this kind of approach to the energy corridors description is the inclusion of their detailed spatial characterisation and the implementation of this topology into the model structure.

Furthermore, the code system adopted for each branch process and each commodity of a corridor allows the full traceability of an energy flow, from the extraction field to the supply point. If a single branch carries a commodity having two or more different origins, two kinds of processes are used:

- the infrastructure process describes the infrastructure itself and it is characterized by technical-economical parameters (capacity, investment cost, O&M cost,…); it has no input or output commodities and there is a single process for each branch;
- the commodity processes represent the topological link necessary for the traceability, without technical and economical features related to it; there is one process for each origin.

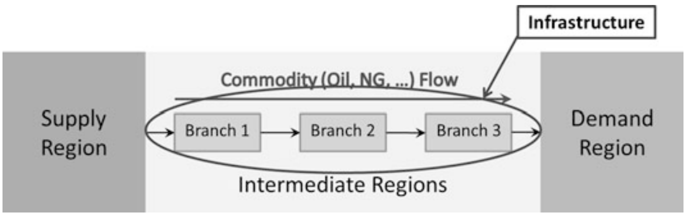


Fig. 1 Process chain scheme adopted to represent an energy infrastructure

Table 1 Number of connections characterised in the database of the RECOR model

Commodity	Number of connections		
Natural gas	No. of pipelines	EU	65
		Non-EU	13
LNG	No. of open sea connections	EU	91
		Non-EU	76
Crude oil	No. of pipelines	EU	34
		Non-EU	1
	No. of open sea connections	EU	321
		Non-EU	126
		Non-EU	1
Refined petroleum	No. of pipelines	EU	1
Products (RPP)	No. of open sea connections	EU	150
		Non-EU	70
Hard coal	No. of open sea connections	EU	210
		Non-EU	37
	No. of railways connections	EU	3
		Non-EU	6
Uranium	No. of open sea connections	EU	6
Biomass	No. of open sea connections	EU	21
Hydrogen	No. of pipelines	EU	5
	No. of open sea connections	EU	7
High voltage direct current (HVDC)	No. of electrical connections	EU	44

A constraint is used in order to link the total activity carried by the commodity processes to the capacity of the infrastructure process (Eq. 1).

$$\sum_{i=1}^{Num.CommodityProcesses} Activity_i \leq Capacity_{Infr.\,Process} \tag{1}$$

where:

i	is the branch, and so it refers to a commodity process;
Activity	is the activity carried by the branch i;
$Capacity_{Infr.\ Process}$	is the capacity of the infrastructure process.

This approach has led to the implementation of more than 3500 processes into the RECOR model in order to represent the corridors system synthetically enumerated in Table 1.

1.2 The Risk Evaluation

In the REACCESS project, a key achievement was the evaluation and use of risk indicators in order to identify weaknesses and threats for the security of energy supply to Europe. Two risk aspects were assessed: the technological risk (based on conventional risk analysis techniques, applied to each branch and part of the energy system) and the socioeconomic risk.

The socioeconomic risk was analysed at a country level by using a statistical technique known as Factor Analysis, assuming that the global country potential risk is the combination of 4 main risk vectors: Social, Political, Economic and Energetic.

For each of these vectors, a set of variables (38 for the Economic, 33 for the Political, 18 for the Social, 12 for the Energetic) has been firstly identified and then an iterative application of the Factor Analysis procedure has allowed the identification of the important variables and finally led to the evaluation of a factor score (ranging between 0 and 100) for each vector. The Overall Risk Index for each country was calculated as a mean of the four risk indexes: its value ranges between 5.4 for Norway and 79.4 for Afghanistan (García-Verdugo et al. 2011).

The worldwide representation of the overall Risk Indexes is shown in Fig. 2.

The RECOR model included both the socioeconomic Risk Indicators for the evaluation of the security of supply and the evaluation of the technological risk.

These indicators have been used in a so called "min/max" procedure that is a Multi Criterion Decision Method (MCDM). This procedure was adopted to encourage the diversification of the supply corridors (Biberacher et al. 2011).

After the end of the project in 2011, a fine-tuning follow-up phase started. During this period, a revision of the model involving both structural and numerical adjustments was performed.

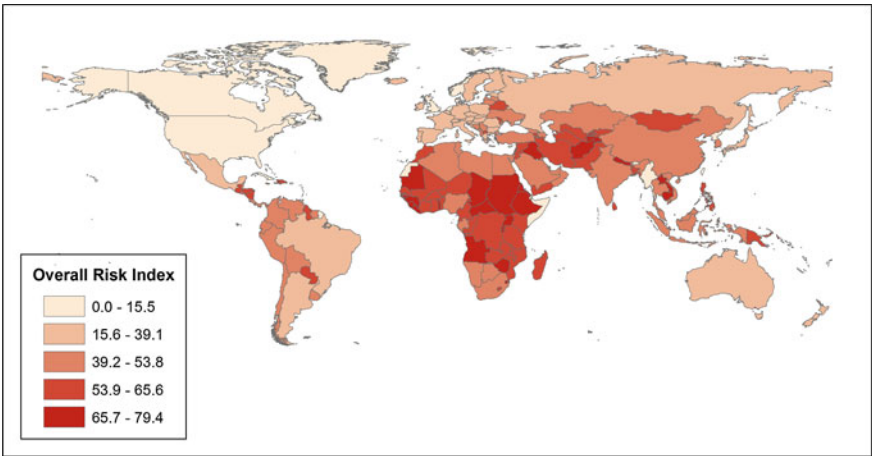


Fig. 2 Overall risk indexes by country, adapted from ESRI (2010)

1.3 Project Results

The REACCESS methodology was firstly used to perform a study on the EU's energy import by corridor from different supply countries, focusing in particular on the Gulf Cooperation Council (GCC) ones, i.e. Bahrain, Kuwait, Oman, Qatar, Saudi Arabia and United Arab Emirates (Kanudia et al. 2013). To achieve this aim four scenarios have been analysed: Reference, Risk avert (that minimises the EU27 risk indicator allowing a maximum increase of the total discounted system cost equal to 0.2 % with respect to the Reference one), Climate change mitigation (that assumes the Energy Modeling Forum target of a 50 % reduction of global emissions in 2050 over 1990) and Climate-Risk (that includes the 2050 targets of the Climate scenario but minimising the risk indicator for the EU27 with a maximum increase of the total system cost equal to 0.2 % in comparison with the Climate one).

The results show that a significant reduction of the risk related to the EU's energy supply can be obtained, with a corresponding little increase of the total system cost. Under the Risk scenario the contribution of GCC countries to the EU supply increases, as well as the diversification of the supply countries. In general, the EU27 shows a high import dependency from North Africa and Middle East (and in particular from GCC countries) in all the analysed scenarios, even if under Risk scenarios the total energy consumption and the fossil fuel imports decrease. Furthermore, cross-effects of risk and climate targets can be noticed.

The additional features introduced in the RECOR model allow a different approach to the risk evaluation—treated like a CO_2 emission, i.e. calculated by multiplying a sort of "emission factor" (corresponding to the risk index related to each supply) by the quantity of imported commodity—and, as a consequence, different kinds of analyses. Examples of scenario runs that might be performed are: the reduction of total CO_2 emissions in a single country or in a group of countries (like the European Union); the reduction of the risk value in the same areas; the simultaneous reduction of both CO_2 emissions and risk by using suitable constraints.

2 Methodology—Additional Features and Analysed Scenarios

During the follow-up phase of the REACCESS project, some major changes to the Data Base Template (DBT, it is the database structure that contains the definition and the technical characterization of all the analysed energy corridors) have been introduced.

In fact, as the international panorama on energy infrastructures is continuously changing, a full amendment of the existing corridors and the redefinition of some planned/possible future infrastructures (regarding their route, their technical and economical features, etc.) have proven necessary (e.g. the introduction of the Trans

Adriatic Pipeline carrying natural gas from Caspian region to Southern and Western European countries).

Another relevant point of the follow-up phase of the REACCESS project was the introduction of annual growth and decay coefficients for the main commodities (hard coal, natural gas, crude oil, refined petroleum products and biomass) delivered by energy corridors, for each supply branch and for each extraction field (only for the proven resources). According to their definition (Loulou et al. 2005), these coefficients allow the identification of a maximum range of variation for each supply by corridor and for each commodity production through the implementation of two typologies of constraints. The introduction of Growth/Decay coefficients on single supply branches provides some benefits that can be summarised as follows:

- to avoid unreasonable oscillation in the supply trends;
- to better simulate the supply composition of each demand region;
- to describe, in a customized way, the possible evolution of energy imports for all the analysed countries, taking into account potential stiffness deriving from long term supply contracts or specific import policies.

2.1 The New Risk Evaluation

The REACCESS project dealt with risk by adopting the min-max approach that is based on a three step procedure. The first step is a minimisation of the total system cost; the second step is a minimisation of the risk indicator (RI): this run is performed allowing a maximum variation of the total cost with respect to the value obtained in the first run; the third step is a new minimisation of the total system cost allowing a certain maximum percentage variation of the risk index in comparison with the value obtained in the second run. The risk indicator used in this procedure is estimated starting from the "Quantity of Risk weighted Energy" (QRE). This parameter is calculated—for each commodity, corridor branch, year and region—by multiplying the energy (expressed in PJ/y) flowing through a branch by the overall risk index associated with the departure country of the branch. The RI is then evaluated by firstly finding the maximum value of the QRE for each region, year and commodity and then by summing over all the regions, years and type of commodities.

The main effect of the min-max approach is to encourage the diversification of the supply, penalising the imports from a unique risky country (or from a limited set of risky countries). Furthermore, the minimisation of the risk indicator indirectly leads to a reduction in the import dependency, a modification of the fuel mix in both primary and end-use sectors and a reduction in the energy consumption.

In the follow-up phase of the project, the original Overall Risk Indexes have been maintained, but a new alternative approach was implemented. In particular, to quantify the total risk related to the activity delivered by energy corridors, two risk indicators and six commodities were introduced in the model. These parameters allow a risk estimation on the basis of two possible methodologies:

Probability of failure:
This approach is based on the introduction of the geopolitical risk indicator $R_{C,PoF}$, which is specific for each energy corridor and is defined by means of an application of elementary reliability theory for series networks. It can be interpreted as the likelihood that a corridor crossing a country will fail (whichever the reason: technological, as due to e.g. poor maintenance, or geopolitical as due to e.g. deliberated disruption). The risk indicator can be applied to all crossed countries or to the Non-EU only in accordance with the Lisbon Treaty. The $R_{C,PoF}$ risk indicator is expressed by Eq. 2.

$$R_{C,PoF} = 100 \cdot \left[1 - \prod_{i=1}^{n}\left(1 - \frac{R_i}{100}\right)\right] \quad (2)$$

where:

R_i (i = 1, 2,... n)	is the Overall Risk Index of the traversed country (n being the total number of crossed countries)

This means that the probability of success of the corridor is the product of the probabilities of success of the crossed countries, assumed independent.

By using the $R_{C,PoF}$ indicator, three additional commodities are defined.

RiskPoF	it is obtained—for each supply branch of the corridor *C*—by multiplying $R_{C,PoF}$ by the activity delivered to the demand country.
TotPoFRisk	it is defined for each demand region; it is the sum of all *RiskPoF* values for a region and it allows to estimate the global risk related to the supply by corridor for that country.
TotPoFRiskEU	it is defined for the 28 Member States of the European Union and, in the same way as *TotPoFRisk,* it is the sum of all *RiskPoF* values for each of the 28 EU countries.

Average:
This approach is based on the introduction of the risk indicator $R_{C,Average}$, which is specific for each energy corridor and it is defined as the average value of the Overall Risk Indexes of all the countries crossed by the corridor *C*.

By using the $R_{C,Average}$ indicator, three other additional commodities are defined.

RiskAverage	it is obtained—for each supply branch of the corridor *C*—by multiplying $R_{C,Average}$ by the activity delivered to the demand country.

TotAverageRisk	it is defined for each demand region; it is the sum of all *RiskAverage* values for a region and it allows the estimation of the global risk related to the supply by corridor for that country.
TotAverageRiskEU	it is defined for the 28 Member States of the European Union and, in the same way as *TotAverageRisk*, it is the sum of all *RiskAverage* values for each of the 28 EU countries.

Another indicator ($R_{C,Source}$) and two more commodities (*RiskSource* and *TotSourceRisk*) were introduced to quantify the risk related to the amount of activity exported through energy corridors for each supply country.

From the modelling point of view, all the risk commodities were implemented in the same way as a CO_2 emission commodity. For each technology, the CO_2 emissions are evaluated by multiplying the quantity of consumed fuel by a suitable emission factor; in the same way, the risk values are calculated by multiplying the quantity of imported commodity by a sort of "emission factor", corresponding to the risk index related to each supply. This means that risk reduction policy scenarios can be defined and introduced in the model by using the same method as for pollutant emissions reduction.

Referring to the risk reduction policy scenarios, the reduction of the total risk value (calculated by means of the *RiskPoF* approach) by a percentage α in a region r and in a milestone year t can be implemented through a fix type constraint.

Another parameter introduced in order to analyse the risk related to the supply of energy commodities is the Specific Risk (*SR*) for the total supply. This variable quantifies the risk associated to the single PJ/y delivered by corridors to the analysed region, thus allowing a comparison between different scenarios and/or countries, and it is defined as the ratio between the total Risk value (i.e. *TotPoFRisk* or *TotPoFRiskEU*) and the delivered activity, expressed in PJ/y (Eq. 3).

$$SR_{r,t} = \frac{TotPoFRisk_{r,t}}{\sum SupplyActivity_{r,t}} \tag{3}$$

where:

r is the region;

t is the milestone year.

2.2 Risk Scenarios

A scenario analysis using the new features on risk evaluation has been carried out, focusing on the effects on the Specific Risk of a policy on risk reduction performed at the Communitarian level or at the national level. For this purpose, the European Union as a whole and the six most populated EU's Member States (Germany,

Table 2 Scenario assumptions

Scenario (%)	Region	Commodity	Risk reduction (%)
Baseline	All regions	–	–
RiskDE15	DE	TotPoFRisk	−15
RiskES15	ES	TotPoFRisk	−15
RiskFR15	FR	TotPoFRisk	−15
RiskIT15	IT	TotPoFRisk	−15
RiskPL15	PL	TotPoFRisk	−15
RiskUK15	UK	TotPoFRisk	−15
RiskEU15	EU	TotPoFRiskEU	−15

France, Italy, Poland, Spain and United Kingdom) were considered, as they account for a large part of the European supply by corridors and represent more than 70 % of the total EU's population in 2013.

Eight runs (a baseline run and seven scenario runs) were performed. In each scenario run and for each milestone year, the risk commodity—*TotPoFRisk* or *TotPoFRiskEU*—value in the analysed region (the whole EU or one of the six EU's Member States taken into account) has been imposed to be less than or equal to the 85 % of the corresponding value obtained from the baseline run, thus simulating a 15 % risk reduction. The main assumptions for the above mentioned scenarios are reported in Table 2.

In each risk scenario run, the constraint on risk was implemented only from 2015 to 2040, while the results for the previous milestone years have been imposed equal to the ones obtained from the baseline run, in order to avoid unreasonable optimization effects on the supply in the past years.

3 Results

Figures 3, 4, 5, 6, 7 and 8 show for each country the comparison among the Specific Risk values related to the total supply by energy corridors in the three typologies of runs that have been performed (baseline, risk reduction for the country, risk reduction for the EU). Figure 9 shows instead the comparison between the baseline run and the scenario run results for the EU.

As expected, in the assumed time horizon, the specific risk value related to the global supply is almost always higher in the Baseline scenario than in the risk reduction scenarios. The only exception is the National risk reduction scenario for Italy: the long-term specific risk related to this scenario becomes slightly higher than the one related to the Baseline scenario (Fig. 6). This trend can be explained by the fact that, in the National risk scenario, the target of risk reduction is reached by a strong reduction in the amount of crude oil imported from Non-EU countries and re-exported towards EU Member States (in the form of crude oil itself or of refined petroleum products) rather than by a change in the supply composition. This is a

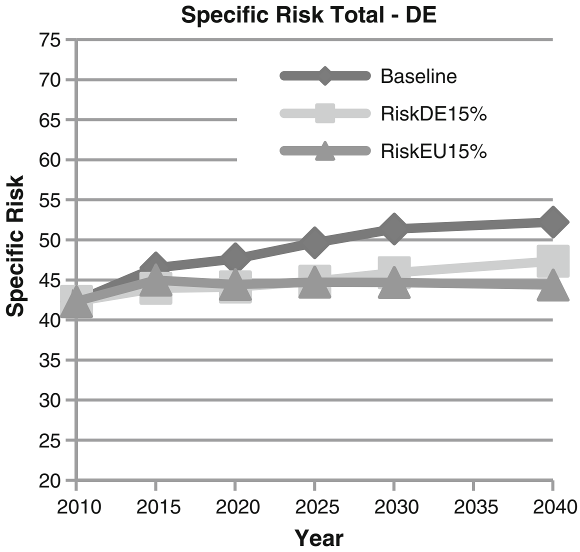


Fig. 3 Total specific risk for Germany

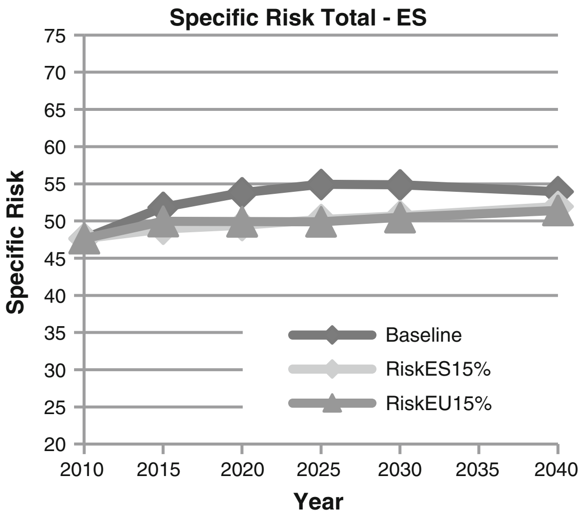


Fig. 4 Total specific risk for Spain

sort of “selfish” behaviour that brings to a national reduction of the total risk (due to the reduced import of commodities that use Italy as a “stop-over”) although each PJ of energy imported is a bit more risky.

Comparing, for each region, the Communitarian risk reduction scenario and the National risk reduction scenario, it can be noticed that the first one leads to a significantly lower trend in Italy. Lower values are also observable in France and in Germany, while in Spain the two lines are almost overlapping. In Poland and in the

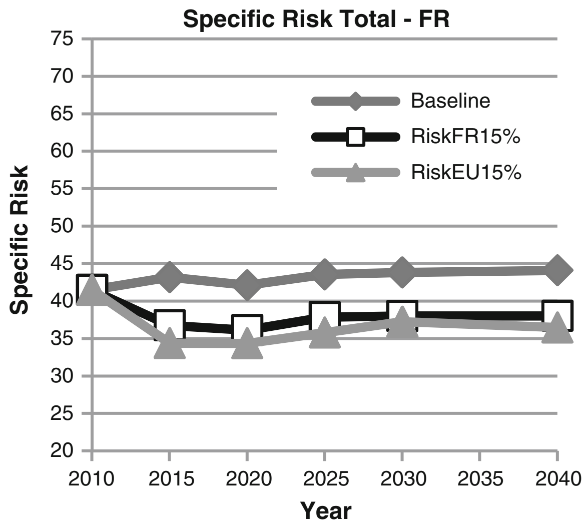


Fig. 5 Total specific risk for France

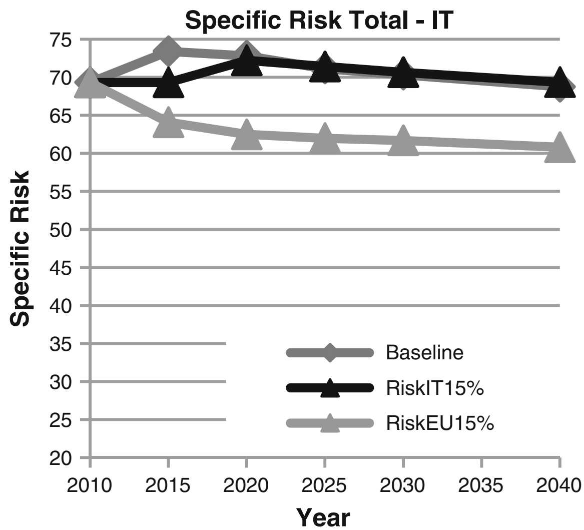


Fig. 6 Total specific risk for Italy

United Kingdom the reduction performed at the National level is more effective from the point of view of the specific risk reduction. Only in Poland the specific risk trend in the period 2015–2040 is monotonically decreasing in both the risk reduction scenarios.

These variations in the specific risk trends are due to the combination of two different effects: a change in the supply composition, that is a different use of the available energy corridors (Fig. 10) and/or fuel shift phenomena, and a change in the amount of the total import.

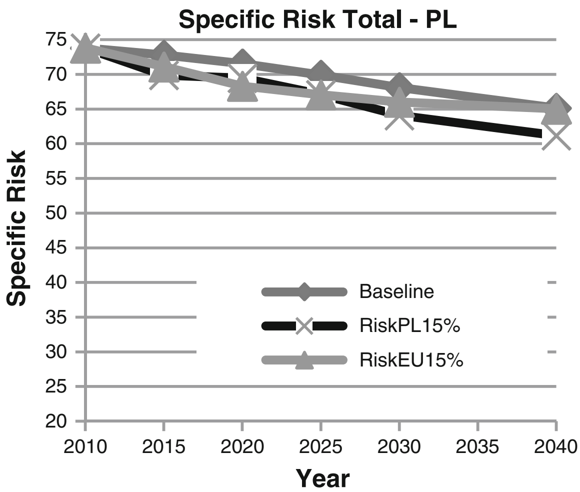


Fig. 7 Total specific risk for Poland

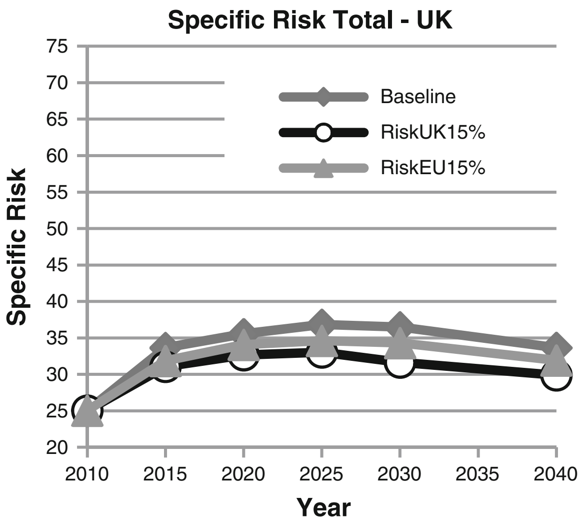


Fig. 8 Total specific risk for the UK

Referring to the last point, in particular, under the National risk scenarios, a significant reduction in the total supply by corridors can be noticed in all the analysed countries. This decrease also causes a slight reduction in the import dependency of each country in comparison with the one of the Baseline scenario over the time horizon 2015–2040, more relevant in Italy than in the other nations (Figs. 11 and 12). On the contrary, a risk reduction performed at a Communitarian level causes an increase in the total import by corridors in Germany, a non-unique behaviour in Italy and a decrease in the other countries lower than the one obtainable in the case of National reduction.

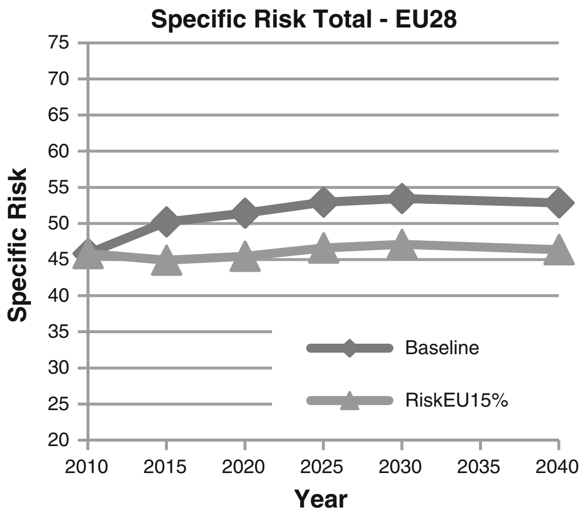


Fig. 9 Total specific risk for the EU-28

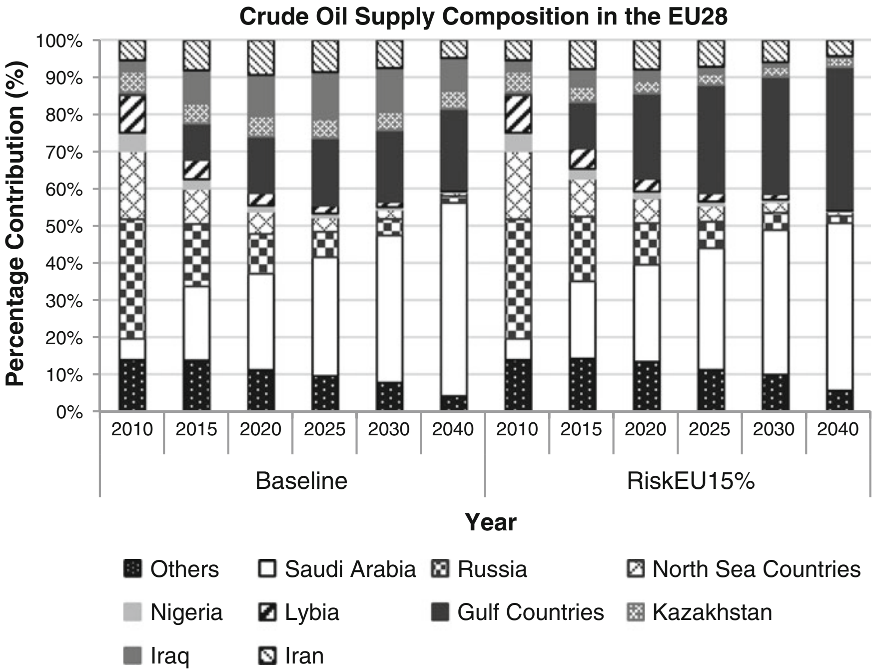


Fig. 10 Crude oil supply composition for the EU-28 (Gulf Countries = Kuwait + UAE; North Sea Countries = Norway + UK)

Fig. 11 Import dependency, baseline

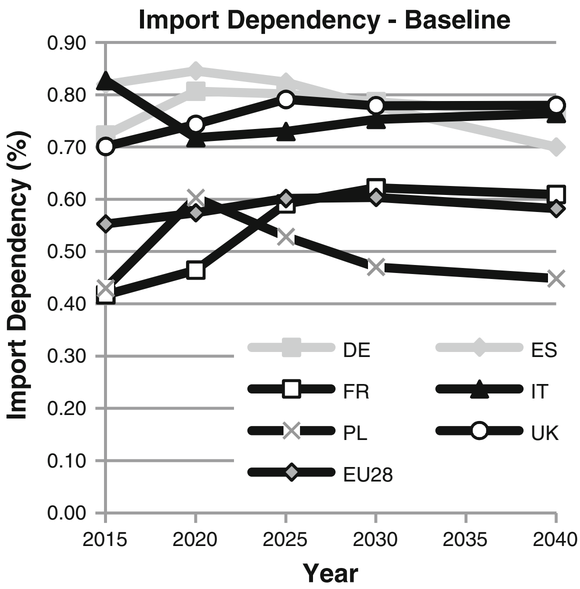
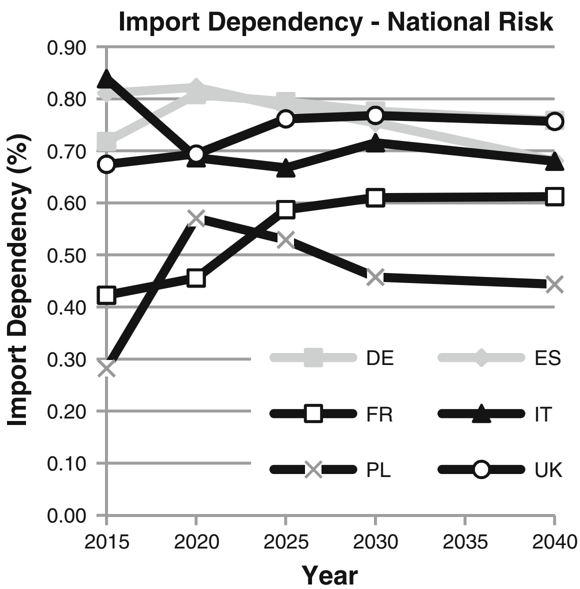


Fig. 12 Import dependency, national risk



The above results seem to suggest that a reduction in the risk of energy supply by corridors carried out at a Communitarian level may not univocally be translated into a benefit for the single Member States, while a predictable result is the increase of the cost for the entire European energy system. In the proposed analysis, this increase can be quantified as 0.23 % and it is shared (although inhomogeneously) among the single Member States. As a consequence, an effective application of European policies on energy supply needs further actions such as the promotion of a common market of the energy commodities in order to ensure also economic benefits from shared strategies in the energy and security field.

4 Conclusions

The REACCESS project has introduced a new methodology for investigating the security of energy supply in the European Union. In fact, by using forecasting optimization models, this approach allows not only evaluation in a qualitative manner but also quantification of the risk related to the supply over a mid/long-term time horizon. Some major refinements have been implemented during the follow-up phase of the project: among these, in particular, a new procedure for risk evaluation, based on single-corridor composite risk indicators and on new commodities similar to the ones modelling CO_2 emissions, and the introduction of Growth/Decay constraints on each supply branch can be mentioned. An application of the Model to compare the effects of risk reduction policies at Communitarian or national level from a security point of view has been performed. The results have shown unclear benefits from common policies and this fact seems to underline the need of further actions to promote a real effectiveness of common strategies on the security of energy supply in Europe.

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