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Editor: David L. Williams

President's Message

IAEE is pleased to produce this special issue of the *Energy Forum* for 2016 focused on papers presented at the recent IAEE International Conference in Bergen, Norway. We are most grateful to Past President, Einar Hope from the Norwegian School of Economics for spending considerable time and effort to select 20 papers that he found noteworthy from 346 presented at the conference. We also thank the authors for agreeing to summarize their papers in a form suitable for the *Energy Forum*.

The IAEE is most appreciative of the Norwegian Association for Energy Economics for raising the bar with an excellent organization of IAEE's largest conference, bringing together 601 participants from 49 countries. We are most grateful to Einar Hope, once again, this time in his role as the General Conference Chair of the Bergen conference.

We are looking forward to our upcoming conferences later this year, the regional ones in Baku and Tulsa, as well as our Affiliate conferences in Oxford, Ljubljana and Milan. Besides the well-established 34th IAEE/USAEE North American Conference coming up in Tulsa, USA, and the 11th BIEE Academic Conference coming up in Oxford, UK, we have three newcomers: First, the 1st IAEE Eurasian Conference in Baku, Azerbaijan on 28-31 August 2016 focussed on "Energy Economics Emerging from the Caspian Region: Challenges and Opportunities"; Second, the 1st SAEE Energy Conference in Ljubljana, Slovenia on 29 September 2016, covering "A Unique Opportunity to Connect Energy and Industry, Leading to a Better Economy"; and finally, the 1st AIEE Energy Symposium in Milan, Italy on 30 November – 2 December 2016, with the theme of "Current and Future Challenges to Energy Security".

I would like to encourage all members to attend at least one conference a year. It is not only the professional development, the exchange of ideas and experience, but also the networking and social events at conferences which are most important to keep the family atmosphere at IAEE. Our conferences are like family gatherings that bring together energy colleagues and friends from all over the world. I am looking forward to seeing you at one of our upcoming conferences.



Gurkan Kumbaroglu

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NEWSLETTER DISCLAIMER

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IAEE Mission Statement

The International Association for Energy Economics is an independent, non-profit, global membership organisation for business, government, academic and other professionals concerned with energy and related issues in the international community. We advance the knowledge, understanding and application of economics across all aspects of energy and foster communication amongst energy concerned professionals.

We facilitate:

- Worldwide information flow and exchange of ideas on energy issues
- High quality research
- Development and education of students and energy professionals

We accomplish this through:

- Providing leading edge publications and electronic media
- Organizing international and regional conferences
- Building networks of energy concerned professionals

Corrigendum

The Second Quarter issue of the *Energy Forum* carried an article on the “Influence Analysis of Wind Power Variation Generation and Transmission Expansion in U.S. Eastern Interconnection”, by Stanton Hadley and Shutang You. As noted in the article this work was supported primarily by the U.S. Department of Energy. An article based on this research and on this subject also appeared in the April, 2016 issue of *Electric Power Systems Research*.

Editor's Notes

Once again I have had the pleasure of organizing a selection of papers presented at the 39 International IAEE Conference in Bergen/Norwegian School of Economics (NHH), 19 – 22 June 2016, like I was asked to do for the New York 2014 and Antalya 2015 IAEE International Conferences. And again I have to make the same reservation as before: It is impossible to make a representative selection from among the close to 400 papers that were presented at the conference, including posters. Hopefully, I will be perceived as unbiased in my selection, though, since I was the General Conference Chair and am an Emeritus Professor of NHH.

For this issue of the *Energy Forum* we ended up with 20 articles from the presented conference papers. In the selection process I have had an eye to the IAEE Specialization Codes with regard to topics, the majority of articles selected from the Codes with the largest number of submissions. I have also put some emphasis on the geographical dispersion of topics and authors. The IAEE is becoming a truly international association and its International Conference should reflect the international composition of the portfolio of papers represented there. At the Bergen Conference delegates came from 49 countries.

Invited authors were asked to write a summary version of their papers on the standard *Energy Forum* format, limited to approximately 1500 words, taking account of the space for tables and/or figures that might be included. I would like to thank all the authors for their willingness and extra effort to prepare an article for this *Energy Forum* issue and for pleasant cooperation in the editing process.

I hope that *Energy Forum* readers will find the collection of articles interesting and worthwhile to study. If this editing exercise may stimulate members of the IAEE and others to come to the international conferences of the Association (and to its regional conferences as well) to get access to the wealth, scope, breadth and depth, of knowledge and insights of the changing international energy scene represented in the large volume of papers presented there, plus in the many plenary sessions, that would indeed be an additional stimulus and incentive in itself. Next year the IAEE International Conference will be held in Singapore, 18-21 June 2017.



Einar Hope

Note: Beginning on page 28 and threading through the balance of the newsletter is an overview of the Conference which is of interest.



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THE 40th IAEE INTERNATIONAL CONFERENCE

Meeting the Energy Demands of Emerging Economies Implications for Energy and Environmental Markets

18-21 JUNE 2017 | SINGAPORE

Skyline of Marina Bay, Singapore. Photo courtesy of the Singapore Tourism Board.

CONFERENCE OVERVIEW

The Energy Studies Institute of the National University of Singapore invites you to participate in the 40th IAEE International Conference, which will be held at the iconic Marina Bay Sands Hotel, Singapore, 18-21 June 2017, with the main theme *Meeting the Energy Demands of Emerging Economies: Implications for Energy and Environmental Markets*.

The ten countries that make up the Association of Southeast Asian Nations (ASEAN) are exerting an increasingly important influence on global energy trends. Underpinned by rapid economic and demographic growth, energy demand in the region has more than doubled in the last 25 years, a trend that is set to continue over the period to 2040. Given Southeast Asia's role as a global growth engine, understanding what is shaping energy markets in this vibrant region and the implications for energy security and the environment is vital for policy makers and anyone with a stake in the energy sector. (IEA, *Southeast Asia Energy Outlook*, 2015).

However, this will be a truly international conference, so the focus will be on energy issues interpreted in their broadest global context. Of course, energy policies cannot be addressed in isolation from their local and global environmental impacts, and many conference sessions will address issues relating to this interdependence.

www.iaee2017.sg

CONFERENCE VENUE

In addition to its convention facilities, the Marina Bay Sands complex also hosts a hotel, a casino, and a large shopping and dining complex, all in a sweeping garden setting overlooking Marina Bay. The hotel itself has the world's largest rooftop pool, which stretches 150 metres across the hotel and offers breath-taking city-skyline views. A room reservation block has been negotiated with the hotel at a very favourable rate, but this is expected to be filled very quickly. Rooms in nearby hotels around Marina Bay will also be offered, as will less expensive accommodation located elsewhere in the city. The Marina Bay Sands complex has its own MRT (train) station, Bayfront, making it easily accessible to those staying off-site. For further information about the venue please refer to: <https://www.marinabaysands.com>.

The Energy Studies Institute (ESI) was established in 2007 with the aim of conducting policy-related research in energy issues of regional and global significance, with specific reference to Singapore and the ASEAN region. In the 2015 *Global Go To Think Tank Index Report*, published by the University of Pennsylvania, ESI was ranked 8th in the *Energy and Resource Policy Think Tanks* category.

Singapore is a thriving global commercial, transport, and financial hub that offers visitors a fascinating insight into an Asian tiger economy. It has a great diversity of attractions to suit all interests, so why not stay a couple of days beyond the conference to experience these in addition to visiting some of the region's leading cultural and vacation sites en route to or from Singapore.

THE 40th IAEE INTERNATIONAL CONFERENCE

MEETING THE ENERGY DEMANDS OF EMERGING ECONOMIES: IMPLICATIONS FOR ENERGY AND ENVIRONMENTAL MARKETS

CALL FOR PAPERS

TOPICS TO BE ADDRESSED

The conference will address the full range of energy issues that may be expected to be commanding the attention of academics, analysts, policy-makers, and industry participants in 2017. Possible topics include, but are not limited to:

- Security of energy supply: at what price?
- A growing role for nuclear?
- Energy poverty and energy subsidies: how can the link be broken?
- The economics of gas spot trading
- Renewable and alternative sources of energy
- Energy policy options in a carbon constrained world
- Developments in LNG markets
- Energy modelling
- Emission trading schemes
- The econometrics of oil and gas markets
- Energy sector investment
- Liberalised power markets: way to go?
- Oil and gas: global resources, reserves, and production.

**Abstract submission
deadline**

Friday 13 January 2017

www.iaee2017.sg

CONCURRENT SESSION ABSTRACT FORMAT

Those offering to make concurrent session presentations must submit an abstract that briefly describes the research or case study to be presented no later than 13 January 2017. The abstract must be no more than two pages in length, and must include an overview of the topic including its background and potential significance, methodology, results, conclusions, and references (if any). All abstracts must conform to the structure outlined in the template. Abstracts must be submitted online. Please see www.iaee2017.sg for details.

PRESENTER ATTENDANCE AT THE CONFERENCE

At least one author of an accepted paper or poster must pay the registration fees and attend the conference to present the paper or poster. The corresponding author submitting the abstract must provide complete contact details. Authors will be notified of the status of their presentation or poster by 1 March 2017. Authors whose abstracts are accepted will have until 14 April 2017 to submit their final papers or posters for publication in the online conference proceedings. While multiple submissions by individuals or groups of authors are welcome, the abstract selection process will seek to ensure as broad participation as possible. Therefore, each author may present only one paper or one poster in the conference. No author should submit more than one abstract as its single author. If multiple submissions are accepted, then a different author will be required to pay the registration fee and present each paper or poster. Otherwise, authors will be contacted and requested to withdraw one (or more) paper(s) or poster(s) for presentation.

STUDENT EVENTS

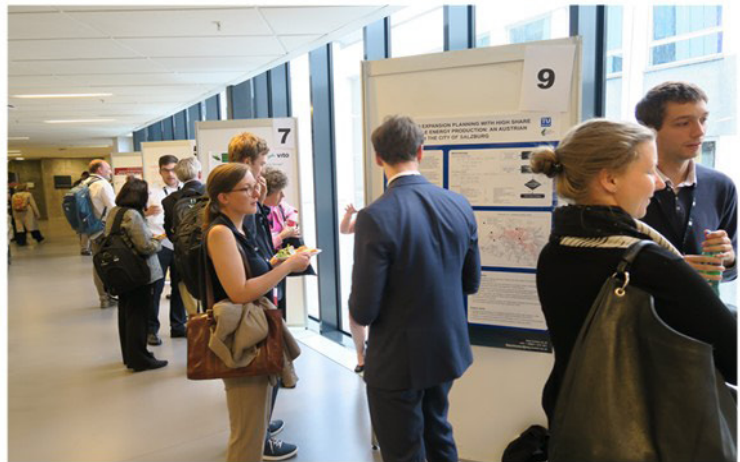
Students may, in addition to submitting an abstract, submit a paper for consideration in the IAEE Best Student Paper Award Competition.

Students are also encouraged to participate in the Student Poster Session and to submit a paper for consideration in the Special PhD session. The abstract format and submission process for the poster session is identical to that for concurrent session papers.

Students may inquire about scholarships covering conference registration fee. For more information, please visit www.iaee2017.sg.

SCENES FROM THE 39TH IAAE INTERNATIONAL CONFERENCE JUNE 19-22, 2016







CONFERENCE OVERVIEW

North America, if not the United States alone, is expected by many to soon be energy self-sufficient. Horizontal drilling, coupled with hydraulic fracturing, reversed the downward trend in production of both crude oil and natural gas. As a result, the lower-48 US will be exporting natural gas by the time we meet in Tulsa. The debate over crude oil exports from the US will likely still be raging, and is likely to be an element of the 2016 US Presidential election. The production turnaround has shaken world energy markets, and the operation of our energy markets produced substantial reductions in CO₂ emissions through economic substitution from coal to natural gas in power generation. When we add advances in renewables and the promise of industrial-capacity battery systems, the potential for North American energy self-sufficiency appears to be on the near horizon. So, the focus of the 34th USAEE/IAEE Conference will be to provide a constructive and collegial forum for extensive debate and discussion, based on solid research and evidence, to facilitate deeper and broader understanding of the implications of this transformation for North America and the rest of the world.

The Tulsa conference will bring together business, government, academic and other professionals to explore these themes through a series of plenary, concurrent, and poster sessions. Your research will be a significant contribution to this discussion. Speakers will address current issues and offer ideas for improved policies taking full account of the evolution of the North American energy sector and its implications for the rest of the world. The conference also will provide networking opportunities for participants through informal receptions, breaks between sessions, public outreach, and student recruitment. There also will be offsite tours to provide a direct and close-up perspective on Oklahoma's dynamic energy landscape.

Tulsa became known as the Oil Capital of the World at the turn of the twentieth century, and, for a time, Oklahoma was the number one oil producer in the world. The first oil field waterflood was carried out in Oklahoma in May 1931, and the first commercial hydraulic fracturing was performed in Oklahoma in 1949. More recently, Oklahoma companies have led the way with the application of horizontal drilling and hydraulic fracturing techniques to commercialize the vast shale gas and oil resources in Oklahoma and across the country.

Cushing, Oklahoma is the pricing point for the most active commodity futures contract in the world, home to nearly 80 million barrels of crude oil storage, and is the junction for numerous crude oil pipelines collecting and moving crude oil from around the Mid-Continent and Canada to refining centers. The influence reaches from the wellhead, through the midstream, to the refinery and beyond.

In addition to Oklahoma's long-standing role in oil and gas, it is the fourth largest generator of wind energy in the country. The State has five hydroelectric projects, including a rare pump storage facility.

HOSTED BY



TOPICS TO BE ADDRESSED INCLUDE:

The general topics below are indicative of the types of subject matter to be considered at the conference. A more detailed listing of topics and subtopics can be found by clicking here: <http://www.usaee.org/usaee2016/topics.html>

- US oil and gas exports
- Energy Demand and Economic Growth
- Energy Research and Development
- Non-fossil Fuel Energy: Renewables & Nuclear
- Energy Efficiency and Storage
- Financial Markets and Energy Markets
- Political Economy
- OPEC's role in a changing energy world
- Energy Supply and Economic Growth
- Energy and the Environment
- International Energy Markets
- Energy Research and Development
- Public Understanding of and Attitudes towards Energy
- Other topics of interest include new oil and gas projects, transportation fuels and vehicles, generation, transmission and distribution issues in electricity markets, etc.

34TH USAEE/IAEE NORTH AMERICAN CONFERENCE SESSIONS & SPEAKERS

Visit our conference website at: www.usaee.org/usaee2016/

PLENARY SESSIONS

The 34th USAEE/IAEE North American Conference will attract noteworthy energy professionals who will address a wide variety of energy topics. Plenary sessions will include the following:

Energy Policy –
Competing Visions from the Two Parties

Managing in a Low-Price Environment

Challenges and Opportunities in
the Transport Sector

U.S. Oil and Natural Gas Exports –
How have the Economics Changed?

Challenges and Opportunities
for Renewables

Shale and the Future of World Oil

Clean Power Plan –
Implications and Strategies

Across the Borders –
Updates from Canada and Mexico

On the Other Side of the Meter –
Demand Side Issues

Outlook and Global Perspectives



SPEAKERS INCLUDE

Angela S Becker-Dippmann (Invited)
Democratic Staff Director, Senate Committee
on Energy and Natural Resources

Seth Blumsack
Associate Professor, Penn State University

Jeff Brown
Energy Efficiency & Consumer Programs
Manager, Public Service Company of Oklahoma

Sanya Carley
Associate Professor, Indiana University

David E Chenier
GM, Contracts, Sourcing & Supplier
Management, ConocoPhillips

Melanie Craxton
PhD Candidate, Stanford University

Jeffrey R Currie
Global Head of Commodities Research, Global
Investment Research Division, Goldman Sachs

Kathleen Eisbrenner
Founder, Chairman & CEO, NextDecade

John Felmy
Consultant, Midnight Energy Economics

Fereidun Fesharaki
Chairman, FACTS Global Energy

Mark Finley
GM Global Energy Markets, BP America Inc

Randy A Foutch
Chairman and CEO,
Laredo Petroleum Holdings Inc

Kenneth Gillingham
Assistant Professor of Economics,
Yale University

James M Griffin
Texas A & M University

Miriam Grunstein
Nonresident Scholar at the Baker Institute
Mexico Center, Rice University

Peter R Hartley
Professor and Baker Institute Scholar,
Rice University

Colin Hayes
Staff Director, Senate Energy and Natural Resources

Eric Hittinger
Assistant Professor,
Rochester Institute of Technology

Marianne S Kah
Chief Economist, ConocoPhillips

David H Knapp
Chief Energy Economist, Energy Intelligence Group

Andre Plourde
Dean Faculty of Public Affairs, Carleton University

Juan Rosellon
Professor, CIDE

Charles Rossmann
Forecasting & Model Development Manager,
Southern Company

Benjamin Schlesinger
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Adam E Sieminski
Administrator, Energy Information Administration

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Director, Policy Studies, MISO

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In today's economy you need to keep up-to-date on energy policy and developments. To be ahead of the others, you need timely, relevant material on current energy thought and comment, on data, trends and key policy issues. You need a network of professional individuals that specialize in the field of energy economics so that you may have access to their valuable ideas, opinions and services. Membership in the IAEE does just this, keeps you abreast of current energy related issues and broadens your professional outlook.

The IAEE currently meets the professional needs of over 3400 energy economists in many areas: private industry, non-profit and trade organizations, consulting, government and academe. Below is a listing of the publications and services the Association offers its membership.

• **Professional Journals:** *The Energy Journal* is the Association's distinguished quarterly publication published by the Energy Economics Education Foundation, the IAEE's educational affiliate. *Economics of Energy & Environmental Policy* is a new journal published twice a year. Both journals contains articles on a wide range of energy economic and environmental issues, as well as book reviews, notes and special notices to members. Topics addressed include the following:

Alternative Transportation Fuels
Conservation of Energy
Electricity and Coal
Emission Trading
Energy & Economic Development
Energy & Environmental Development

Energy Management
Energy Policy Issues
Energy Security
Environmental Issues & Concerns
Hydrocarbons Issues
Markets for Crude Oil

Natural Gas Topics
Natural Resource Issues
Nuclear Power Issues
Renewable Energy Issues
Sustainability of Energy Systems
Taxation & Fiscal Policy

• **Newsletter:** The IAEE *Energy Forum*, published four times a year, contains articles dealing with applied energy economics throughout the world. The Newsletter also contains announcements of coming events, such as conferences and workshops; gives detail of IAEE international affiliate activities; and provides special reports and information of international interest.

• **Directory:** The Online Membership Directory lists members around the world, their affiliation, areas of specialization, address and telephone/fax numbers. A most valuable networking resource.

• **Conferences:** IAEE Conferences attract delegates who represent some of the most influential government, corporate and academic energy decision-making institutions. Conference programs address critical issues of vital concern and importance to governments and industry and provide a forum where policy issues can be presented, considered and discussed at both formal sessions and informal social functions. Major conferences held each year include the North American, European and Asian Conferences and the International Conference. IAEE members attend a reduced rates.

• **Proceedings:** IAEE Conferences generate valuable proceedings which are available to members at reduced rates.

To join the IAEE and avail yourself of our outstanding publications and services please clip and complete the application below and send it with your check, payable to the IAEE, in U.S. dollars, drawn on a U.S. bank to: International Association for Energy Economics, 28790 Chagrin Blvd., Suite 350, Cleveland, OH 44122. Phone: 216-464-5365.

☐ **Yes**, I wish to become a member of the International Association for Energy Economics. My check for \$100.00 (U.S. members \$120 - includes USAEE membership) is enclosed to cover regular individual membership for twelve months from the end of the month in which my payment is received. I understand that I will receive all of the above publications and announcements to all IAEE sponsored meetings.

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Phasing Out Nuclear Power in Europe

By Rolf Golombek, Finn Roar Aune and Hilde Hallre Le Tissier

INTRODUCTION

Until the Fukushima accident in Japan in February 2011, nuclear power was by many seen as an important part of a low-carbon future. The accident sparked security concerns and anti-nuclear sentiments in many European countries causing three EU member states – Belgium, Germany and Switzerland – to phase out nuclear power over time. For other EU countries, the response to the Fukushima accident was more mixed. For example, in France a European Pressurized Reactor is under construction but the President has pledged to reduce the share of nuclear electricity production to 50 percent by 2025. In some East-European countries, there are plans to either extend the lifetime of current reactors (for example Bulgaria) or build new reactors (for example Romania), but currently plans are on hold because of lack of financing. Hence, the future of nuclear power in Europe is uncertain.

In this note (see Aune et al. (2015) for the complete version of the paper) we examine the outcome if all EU member states follow the long-run strategy of Belgium, Germany and Switzerland to phase out nuclear power. We focus on two questions. First, to what extent will a phase-out of nuclear power be replaced by supply from other electricity technologies? Second, how will a phase-out change the composition of electricity technologies?

We make three contributions to the literature. First, we believe we are the first to examine the impact of an EU-wide nuclear phase out. Second, we offer a strategy to model profitable investment in solar power and wind power taking into account that i) the production sites of these technologies differ, that is, the number of solar and wind hours differ between sites, and ii) access to sites is regulated. Both wind power and solar power will in general use surface area that has an opportunity cost; we therefore make assumptions on how much land that may be available for this type of electricity production in each country. The endogenous determination of investment in solar power and wind power is based on a combination of technical factors – the degree to which production sites differ – political factors – the degree to which actors get access to production sites – and economic factors – the profitability of investment given access to a set of production sites.

Third, we present an overview of costs of producing electricity by comparing total cost of electricity, as well as different cost elements, between different electricity technologies. These cost elements have consistent assumptions about factors like duration of a new plant, rate of interest, operational hours throughout the year, and fossil fuel prices. We also compare our cost assumptions to other studies.

MODELING THE EUROPEAN ENERGY MARKETS

We use the numerical multi-good, multi-period model LIBEMOD to analyze impacts of a nuclear phase-out by 2030, see Aune et al. (2008) and LIBEMOD (2014). This model covers the entire energy industry in 30 European countries (EU-27 plus Iceland, Norway and Switzerland). In the model, eight energy goods, that is, three types of coal, oil, natural gas, two types of bioenergy and electricity, are extracted, produced, traded and consumed in *each* of the 30 European countries. In each country, electricity can be produced by a number of technologies; nuclear, fuel based technologies (using either steam coal, lignite, oil, natural gas or biomass as an input), fossil-fuel based CCS (using either steam coal or natural gas), hydro (reservoir hydro, run-of-river hydro and pumped storage hydro), wind power and solar. We make a distinction between plants with pre-existing capacities in the data year of the model (2009) and new plants; the latter are built if such investments are profitable.

All markets for energy goods are assumed to be competitive in 2030. While steam coal, coking coal and biofuel are traded in global markets in LIBEMOD, natural gas, electricity and biomass are traded in European markets, although there is import of these goods from non-European countries. For the latter group of energy goods, trade takes place between pairs of countries, and such trade requires electricity transmission lines and gas pipelines. These networks have pre-existing capacities in the data year of the model, but through profitable investments capacities can be expanded.

LIBEMOD determines all prices and quantities in the European energy industry, as well as prices and quantities of energy goods traded globally. In addition, the model determines emissions of CO₂ by country and sectors (households; services and the public sector; manufacturing; transport; electricity generation).

Rolf Golombek is Senior researcher, at Frisch Centre, Norway; **Finn Roar Aune** is a Researcher at Statistics Norway; and **Hilde Hallre Le Tissier** is a research assistant at Frisch Centre, Norway. Golombek may be reached at rolf.golombek@frisch.uio.no

RESULTS

In our reference scenario, nuclear capacity in 2030 is according the present plans, that is, about 20 percent lower than in 2009. Moreover, the 2030 EU policy to reduce GHG emissions by 40 percent relative to 1990 and to reach a renewable share in final energy consumption of (at least) 27 percent is implemented. These goals are achieved by imposing EU-wide prices on emissions in the ETS and non-ETS sector, as well as renewable subsidies.

We then study the impact of a complete nuclear phase-out in EU-30 by 2030, that is, the planned nuclear capacity in 2030 is replaced by no nuclear capacity. We find that there is a moderate impact on total production of electricity (4 percent reduction) and only a tiny impact on total consumption of energy (1 percent reduction). A nuclear phase-out is to a large extent replaced by more natural gas power and renewable electricity. After the phase-out, the aggregate market share in electricity production of bio power, hydro, wind and solar is 78 percent. There is a tiny production of coal power, and no Carbon Capture and Storage in the electricity industry.

We find that the annual cost of a nuclear phase-out is around 60 billion euro, which corresponds to 0.5 percent of GDP in EU-30 (in 2009). End users lose, mainly due to higher end-user prices of energy. Higher electricity prices benefit several electricity plants, but the group of electricity producers lose due to the lost profit from nuclear power. The government sector gains, mainly because a nuclear phase out promotes more renewables such that less subsidies (than in the reference scenario) is paid to renewable electricity plants.

We have run a number of other scenarios to examine how the equilibrium with a complete phase-out of nuclear power changes if one of the main assumptions of the reference scenario is changed, that is, we vary factors like i) the GHG emissions target, ii) the policy instruments imposed by the EU, and iii) cost of electricity production, for example, cost of investment in CCS power stations. We find that typically the impact on production of electricity and consumption of energy of a complete nuclear phase is minor. On the other hand, the equilibrium composition of electricity technologies reflects the stringency of the climate target and whether some technologies are being promoted through subsidies.

We have also examined a case in which the rate of energy efficiency is so high that end-user demand for energy does not increase over time, that is, demand for energy in 2030 is equal to demand in 2009. Then production of electricity is as much as 18 percent lower than in the complete phase-out scenario. Lower demand for energy decreases the ETS price of emissions, and hence strengthen the competitive position of coal power (relative to the complete phase-out scenario).

CONCLUSIONS

We explore the impact of an EU-wide nuclear phase-out by 2030 provided the EU energy and climate policy for 2030 is implemented. Using a numerical simulation model of the European energy industry (LIBEMOD), we find that a complete nuclear phase-out in Europe by 2030 has a moderate impact on total production of electricity (4 percent reduction). Lower nuclear production is to a large extent replaced by more gas power and renewables.

In all scenarios, we have assumed all markets to be competitive; this is in line with the EU policy to transform the European electricity and natural gas markets into efficient ("internal") markets. However, the transition has been partial and incremental. This suggests to run LIBEMOD under different assumptions about market structure; the market structure in LIBEMOD can be represented by a number of parameters that reflect the degree of deviation from the competitive outcome in different parts of the European energy industry, see Golombek et al. (2013).

Finally, we have assumed no uncertainty. Needless to say, actors in the energy market face a number of uncertainties, for example, future growth rates and prices. In the stochastic version of LIBEMOD, see Brekke et al. (2013), different sources of uncertainties can be imposed. The stochastic LIBEMOD can be used to study the impact of a nuclear phase-out when actors face uncertainty in, for example, future growth rates, or nuclear policy is uncertain.

See references on page 19

Ambiguity Aversion and the Expected Cost of Rare Energy Disasters: An Application to Nuclear Power Accidents

By Romain Bizet and François Lévêque

OVERVIEW

Assessing the risks of rare disasters due to the production of energy is of paramount importance when making energy policy decisions. Yet, the costs associated with these risks are most often not calculable due to the high uncertainties that characterize their potential consequences. In this paper, we try to shed light on this issue by giving an axiomatic representation of preferences among portfolios of energy production technologies. We derive from this representation a non-Bayesian method for the calculation of the expected cost of rare energy disasters that accounts for the ambiguity that characterizes the probabilities of these events. Ambiguity is embodied by the existence of multiple and conflicting sources of information regarding these probabilities. We then apply this method to the particular case of nuclear accidents in new builds. Our results suggest that the expected cost of a nuclear accident in an EPR reactor is approximately 1.7 €/MWh, which confirms the results of most recent estimates. This expected cost rises to 7 €/MWh when the macroeconomic damage caused by a nuclear accident is taken into account. This paper follows the efforts of Eeckhoudt et al (2000), who tried to account for risk aversion in the assessment of the cost of nuclear power accident. It provides a non-Bayesian method, which can be compared to the more traditional statistical methods applied to the cost and probabilities of nuclear accidents that can be found in Hofert and Wüthrich (2011) or Escobar Rangel and Lévêque (2014).

METHODS

Our paper develops a method for the evaluation of the expected cost of rare disasters characterized by ambiguous probabilities. Indeed, rare catastrophes related to the production of energy often fail to be well described by a single probability distribution over their potential outcomes. First, the frequency of observed past events fail to meet Savage's definition of an objective probability (1954). Besides, other sources of information regarding these events are available, such as subjective probabilities perceived by the public, or probabilistic safety assessments. When these sources of information are contradictory, performing cost-benefit analysis with respect to either of these may seem like an *ad hoc* choice rather than a rational calculation on which sound decisions may be made. Therefore, we propose a new method that accounts for this ambiguity. The method is based on the α -maxmin rule of decision making under uncertainty derived by Ghirardato et al (2004). It consists in calculating a weighted sum of the minimum and maximum expected costs of a given accident, calculated with respect to a worst-case and a best-case probability distributions. From a normative standpoint, the rule is appealing because of its axiomatic foundation: a firm or social planner who would want his energy choices to follow Ghirardato's axioms should feel compelled to using our rule. It also generalizes cost-benefit analysis. Indeed, when facing a situation characterized by a single (objective or subjective) probability distribution, our rule boils down to cost-benefit analysis. Finally, the rule embodies rather well the prescriptions of the precautionary principle: the existence of ambiguity over the probabilities of an event is translated by an increased level of pessimism (characterized by α) in the decision rule.

In order to apply this rule to the particular case of nuclear accidents, we use the state-of-the-art literature on the damage and probabilities of nuclear power accidents in order to identify the parameters of the model (the various types of accidents, their associated damage, or the "best-case" and "worst-case" probability distributions). We account for two distinct categories of nuclear accidents. We distinguish core-damage accidents, in which the core of a reactor is damaged, but lead to no radioactive leakage (but may cause outside damage such as a widespread panic among local residents); and large-release accidents, in which the containment of a nuclear reactor is breached, and large amounts of radioactive materials are released into the environment. The damage associated with each type of accidents is taken from recent post-Fukushima estimates and reviews. Regarding the probabilities associated with these accidents, the frequency of past nuclear accidents is taken as the worst-case prior, and the best-case prior is derived from the industry's probabilistic safety assessments. The rationale for these choices

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	<i>Damage (b€)</i>	<i>Probability best-case</i>	<i>Probability worst-case</i>
Core Damage Accident	2.6	10^{-3}	10^{-4}
Large Release Accident	180	10^{-4}	10^{-7}
Other parameters	<i>Ambiguity-aversion</i>	<i>Nominal power</i>	<i>Load factor</i>
	1	1650 MW	90%

Table 1: Parameters of the numerical application

is the following. Probabilistic safety assessments conducted by the industry capture the work of forty years of nuclear engineering, yet this method is based on simulations and event trees. It also assumes that operators are complying with safety regulations. As compliance may be imperfect, and event trees may not account for all potential triggering factors, this source of information may underestimate the probabilities of nuclear accidents. Regarding the worst-case prior, past events were witnessed on existing reactors that do not share the design basis of new builds. Therefore, this source of information is likely to be an overestimation of the probabilities of nuclear

accidents. The values chosen for the different parameters are listed on tables 1. The results of our calculations are presented in the next paragraph.

RESULTS AND POLICY IMPLICATIONS

The results of this paper are twofold. First, we present a new method that generalizes cost-benefit analysis to situations of uncertainty characterized by ambiguous probability distributions: it provides a rational way of accounting for the existence of multiple probability distributions that may characterize rare energy disasters. Second, our application of this method to nuclear power accidents in new builds suggests that the expected cost of such accidents is approximately 1.7€/MWh, which is consistent with most of the recent estimates reviewed in the D'Haeseleer report for the European Commission (2013). Some sensitivity tests are carried out on this result, and show that this number is particularly sensitive to the damage associated with large release accidents. Furthermore, when we account for a potential macroeconomic shock induced by a large release of radioactive materials, we obtain an expected cost of 7€/MWh. This estimation is based on the assessment of macroeconomic damage performed by the French Institute for Radioprotection and Nuclear Safety (IRSN) for the hypothetical case of a major nuclear accident occurring in France. This number is to be interpreted with caution, as the estimation of the macroeconomic damage depends highly on the location of the accident.

The cost provided by this method is no longer the result of the aggregation of the different damage incurred by society in the aftermath of an accident, but an index associated with any decision that may bring about a nuclear accident. The relevance of this index lies in its axiomatic foundation: a decision-maker who would want her choices related to energy to be consistent with our axioms should evaluate rare disasters according to the rule we derived. The main policy implication of this paper is that public perceptions as well as technical expertise ought to be taken into account by policy-makers. This paper provides a tool that allows the combination of these two sources of information. More practically, the method we propose could also be used to assess other catastrophic risks, such as oil spills or dam failures; or in the elaboration of other policies, such as nuclear mitigation plans or safety standards. Our numerical results suggest that, even under maximum pessimism, the expected costs of nuclear accidents remain small when compared to the total LCOE of nuclear new builds.

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Changing Oil Market Fundamentals and the Implications for OPEC Production Strategy

By Daniel Scheitrum, Amy Myers Jaffe and Lew Fulton

Since the industrial revolution, oil has been key to economic growth and human mobility. Roughly a third of the world's total primary energy consumption is met by oil, with natural gas taking up a further 21%. Prevailing oil demand projections indicate a strong source of growth in oil consumption will arise from the transportation sector as the multitudes of the world's poor move into the middle class in the coming decades.¹

Still, in recent years, there have been two dramatic changes impacting oil markets. First, recent evidence from the slowing of many of the BRICS economies and now sluggish growth in China is raising questions about the longer term trajectory for global oil demand. Oil use has already peaked in the OECD through efficiency improvements and government regulation. The question is whether that trend line is soon to spread to major developing economies as well as technological advances and automation proliferate more rapidly than expected across the globe. At the same time, the world is also experiencing a structural shift in the oil production industry. New technologies and techniques have led to an increase in recoverable production of oil from shale and source rock, particularly in the non-OPEC regions (Huppmann and Holz 2015).

We examine projected global oil demand sensitivity to slower economic growth in the developing world in addition to other important trends including wider adoption of improved logistics and shipping through big data, ridesharing-induced reductions in travel, congestion in high population regions, and advances in vehicle efficiency, among other factors. There are many oil scenario projections which evaluate oil demand under various policy environments as well as projections that set emissions or fuel use targets and solve for the requisite future fuel consumption to satisfy such targets. By contrast, we are evaluating various non-policy-driven states of the world which may result in reduced oil demand to analyze the sensitivity of oil demand to another dimension of consumption uncertainty.²

We find that the one of the most sensitive element influencing oil demand forecasting outcomes is uncertainty about vehicle adoption rates. Reducing non-OECD vehicle saturation levels and speed of private ownership adoption rates by 25 percent can reduce projected 2050 oil consumption by approximately 13 percent. This is roughly the same impact as a 20% reduction in GDP growth rates for all countries. Twenty percent lower GDP yields a 12 percent reduction in 2050 projected oil consumption. We examine the combined effect of reduced vehicle adoption, slower global growth, as well as 20 percent reduction in passenger car vehicle miles travelled (VMT) and 20 percent fuel efficiency improvement in road freight, air, and shipping and find the combined effect could yield a 34 percent reduction in 2050 projected oil consumption. This combination scenario produces a near term peak in oil demand into the 2030s but eventually rising population impacts produce a resumption in oil demand growth.

The persistent element of long term growth in oil consumption appears to be driven by developing countries and Southeast Asian nations. Current levels of vehicle ownership in these nations are very low compared to OECD nations. As a significant portion of these populations move into the middle class and purchase vehicles, their consumption of oil will increase dramatically. However, some analysts are increasingly questioning whether the ASEAN economies will converge with the United States.³ Should this Asian migration to the middle class happen more slowly or elevates only a small portion of the middle class to vehicle ownership, the consequences on oil demand would be profound.

Another large source in oil demand forecast uncertainty is rates for vehicles miles traveled (VMT). Emerging technologies are reshaping personal transit. While smart phone-assisted ridesharing services may have an ambiguous impact on VMT, the services offering "algorithmic carpooling", a function which pairs riders travelling in similar directions into the same vehicle, can certainly lead to large reductions in VMT. Further, ridesharing has the potential to enable greater use of public transit allowing travelers to rely on ridesharing to go the last mile. Lastly, the contribution of autonomous vehicles to VMT is surrounded in great uncertainty. Autonomous vehicles can provide large efficiency gains due to optimized driving behavior and aerodynamic advantages that result from vehicles being able to follow each other more closely. On the other hand, autonomous vehicles have the potential to drastically reduce the inconvenience of driving allowing passengers to work or relax during long commutes resulting in more

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See footnotes at end of text.

frequent and farther travel.⁴ To test the possible impact of autonomous vehicles on demand trends, we consider adjusting the baseline VMT assumptions from a 30 percent increase to a 50 percent decrease which we attribute to emergent technologies. A 30 percent increase in VMT yields a 12 percent increase in projected 2050 oil consumption and a 50 percent VMT reduction yields a 20 percent reduction in 2050 projected oil consumption. A substantial reduction in VMT significantly reduces the crude oil consumption growth rate and when combined with other demand reducing scenarios or policy interventions could result in a permanent peak in oil consumption by 2050.

Motivated by our projections of uncertain or reduced future oil consumption levels and new evidence of greater recoverable non-OPEC reserves through new drilling techniques, we model optimal resource extraction (Hotelling 1931, Gilbert 1978) on the part of the OPEC in a cartel and fringe setting (Salant 1976, Huppmann 2013). OPEC responds to a variety of factors including geopolitics, competition from non-OPEC supplies and market conditions. In this study, we focus specifically on the market condition of how OPEC can be expected to manage sudden shifts in demand trends. We select this focus because in the future, OPEC may be facing a structural downward shift in oil demand. In past history, OPEC has had marked difficulty as a cartel during periods of demand downturns. In 1997, when Asian economies took a sudden downturn, OPEC heavyweight Saudi Arabia refused to cut production to support oil prices in an effort to force Venezuela to abandon a major oil production capacity expansion program. The result was a collapse of oil prices to \$9/bbl from \$20/bbl and the fall of Venezuela's government in 1998. In another earlier example, global recessionary pressure between 1982 and 1986 prompted Saudi Arabia to initiate a price war against non-OPEC producers, again unleashing a free fall in oil prices from \$34/bbl to \$8/bbl. These historical events provide a window into the challenges facing the cartel today and in the future. The possibility that oil demand might structurally shift from a continually rising trajectory to a flattening or even declining profile over the next few decades changes the calculus for OPEC and all oil producers.

Following a dominant player versus fringe theoretical framework, we find that in the presence of declining demand for oil instead of stationary demand, the optimal resource extraction path on the part of OPEC changes materially. A declining oil demand outlook will prompt OPEC to hasten their production in the near-term, thus crowding out a portion of fringe supplies. This has the effect of delaying the event in which fringe supplies are exhausted. The incentive for OPEC to strategically defer production is diminished in a world of declining oil demand. Both an increase in non-OPEC reserves and a decrease in oil demand outlook shift the optimal OPEC extraction path in favor of elevated near-term production. This finding fits with recent developments of increased production from shale resources in non-OPEC, an unexpected slowdown in oil demand (i.e. demand is increasing at a reduced rate) and a decision by OPEC to end its apparent production restraint. Even when faced with large budget shortfalls due to depressed oil prices, our research suggests that perhaps abandoning oil production restraint is the best course of action for OPEC members who may seek to prevent an eventual depreciation or even stranding of large resources.

In conclusion, we find that technology and global economic patterns are creating a new sense of uncertainty about long term oil consumption trends. This newfound uncertainty has clear and present consequences in the near- and intermediate-term oil market. In the context of an exhaustible resource, a change in demand outlook from steadily increasing growth to a stagnant or declining demand outlook in the long-term has implications for present day oil production strategy and can possibly explain the apparent end OPEC's production restraint strategy.

Footnotes

¹ IEA World Energy Outlook 2015, ExxonMobil: The Outlook of Energy, BP Energy Outlook, to name a few.

² To undertake these scenarios, we adjust the modeling architecture of the New Policies case of the 2014 mobility model of the International Energy Agency.

³ A recent Economist magazine article for example says "the gap between the rich and the rest is closing ever more slowly". "Daily Chart: Developing economies are catching up ever more slowly." *The Economist*. June 14, 2016, <http://www.economist.com/blogs/graphicdetail/2016/06/daily-chart-7>

⁴ Brown, Gonder and Repac (2014) find that impact of autonomous vehicles on energy demand could range from -75% to +50% while Wadud, MacKenzie and Leiby (2016) find the impact to range between -40% to +100%.E

See references on page 26

Nearshore Versus Offshore: Comparative Cost and Competitive Advantages

By Henrik Klinge Jacobsen, Pablo Hevia-Koch and Christoph Wolter

BACKGROUND

Currently there exist high expectations for the development of wind energy, particularly in Europe, out of which offshore wind turbine developments will be central as tools to achieve current energy targets. The choice between nearshore and (far)-offshore is particularly relevant, both because of increased public resistance due to visual disamenities produced by nearshore projects, and because of the potential cost reduction benefits attained by building wind farms closer to the shore.

Based on this need, an analysis of the differences between costs and cost drivers for both offshore and nearshore is needed, as well as an exploration towards other possible factors that might affect the relative advantage of nearshore compared to offshore projects. We compare Danish nearshore sites with further ashore wind potentials in Denmark and elsewhere. Costs for nearshore are expected to be lower due to fewer costs of connection, foundation, and to some extent, operation and maintenance. These lower costs must be balanced by the less favourable wind conditions and the costs associated with public resistance. Carefully selecting the nearshore sites with low resistance and low cost characteristics can hopefully reduce the cost of expanding the offshore wind capacity in Denmark where there is a considerable amount of coast line compared to the area of the country.

METHODS

We define nearshore wind as turbines that are up to 15 km off the coast. The distance is not the only important cost driver, but it is the attribute related both to cost advantages for nearshore development and disadvantages arising from public preferences against close to shore wind turbines. We begin by analysing the main cost drivers for offshore wind turbine projects, disaggregating by variables including site conditions (wind potentials, distance to shore, depth of sea bed) and construction variables (size of wind turbines, capacity, foundation). Then we compare the influence of the most important drivers for both offshore and nearshore projects. Based on some Danish nearshore sites we examine the cost ranges and compare to the cost range from comparable further ashore sites in Denmark.

To quantify the potential cost advantages, we use one international source (EEA, 2009) that provides scaling factors based on only distance to shore and water depth. We then recalculate and calibrate based on investment data from one Danish wind farm.

FINDINGS

Denmark is probably positioned in the low end of the international average cost for off-shore wind development. This is evident from a comparison of levelised cost of offshore wind energy (LCOE) including projections from major agencies and associations in the wind sector. In Figure 1 we compare cost levels across the projections of several reports. The wideness of the cost range for each source reflects both the uncertainty in technology development and the underlying difference in cost driving characteristics within the area examined (country/region). The Danish Energy Agency numbers and forecasts are at the lowest level compared to the levels provided by other sources. Therefore, we must expect that the cost benefits from moving wind farms from average off-shore to nearshore locations in Denmark is less than for most other countries (in line with the generally shallow seabed conditions in Denmark).

The cost projections in Figure 1 assume a considerable cost reduction over time, but it is

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Water depth\ Distance from shore	4 km	8 km	10 km	12 km	15 km	20 km	25 km
5m							
10m	0.967	0.974	0.978	0.982	0.988	0.998	1.008
15m	1.000	1.008	1.012	1.016	1.022	1.033	1.043
20m	1.034	1.042	1.046	1.050	1.056	1.067	1.078
25m	1.067	1.075	1.080	1.084	1.090	1.102	1.113
30m	1.124	1.133	1.137	1.141	1.148	1.160	1.172
35m	1.237	1.247	1.252	1.257	1.264	1.277	1.290

Table 1 Investment cost scaling factors used for DK comparison

Source: Calculated based on EEA, 2009 (Table 6.4)

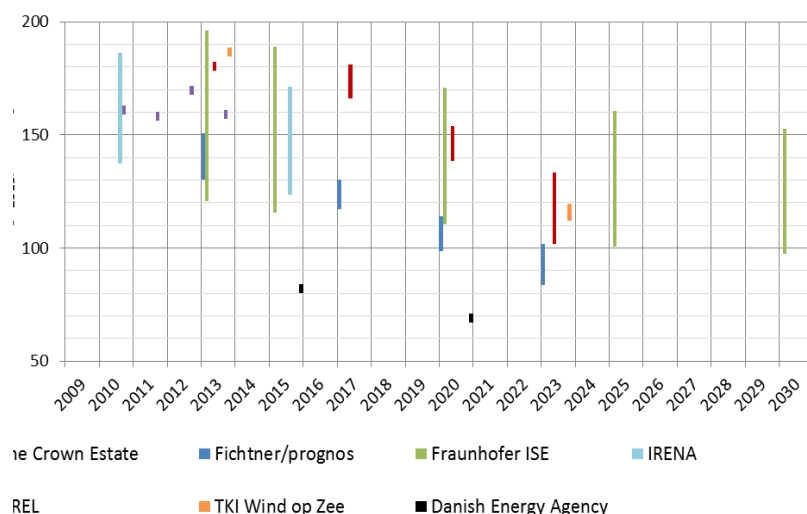


Figure 1 Comparison of levelised cost estimates and ranges for offshore wind in the literature

seabed characteristic differences and connection costs seems to dominate the generalizable cost drivers. The connection costs for example vary more among nearshore Danish sites than between average nearshore and average offshore DK sites.

However, we illustrate the potential cost advantage based on one of the international sources of cost drivers (EEA, 2009). We calibrate the scaling factors from Table 1 to one particular Danish wind

not clear whether this is expected to cover mainly the far off-shore projects in deeper waters. If cost decreases are expected to be dominated by foundation technology improvement and installation cost reductions, then the nearshore projects may benefit less and thus the relative cost advantage of nearshore wind will decline over time.

The ability to generalise the cost curves from a Danish sample of nearshore wind farm sites, was investigated but it is very difficult to characterise other potential sites in DK depending on the few cost drivers that can be extracted from existing developments/projects. The historical data are covering many years and a tremendous development in turbine size and technology. The amount of local conditions affecting the optimal farm layout,

farm development (Rødsand II, 2010) and then compare to other Danish wind farm developments.

The shares of cost components are different for near-shore and far offshore wind farms, but the cost drivers are basically the same. Connection cabling, as well as installation (and mostly foundations) represent a smaller cost share for nearshore wind, but due to the more varying local conditions for connection, the distance from shore is less important as cost driver compared to the depth. The sea depth and wind conditions are the main drivers, similar to far offshore, and the turbines/steel costs are providing similar cost impacts for the two categories. We therefore chose to illustrate a potential cost advantage based on two cost drivers only as given in Table 1.

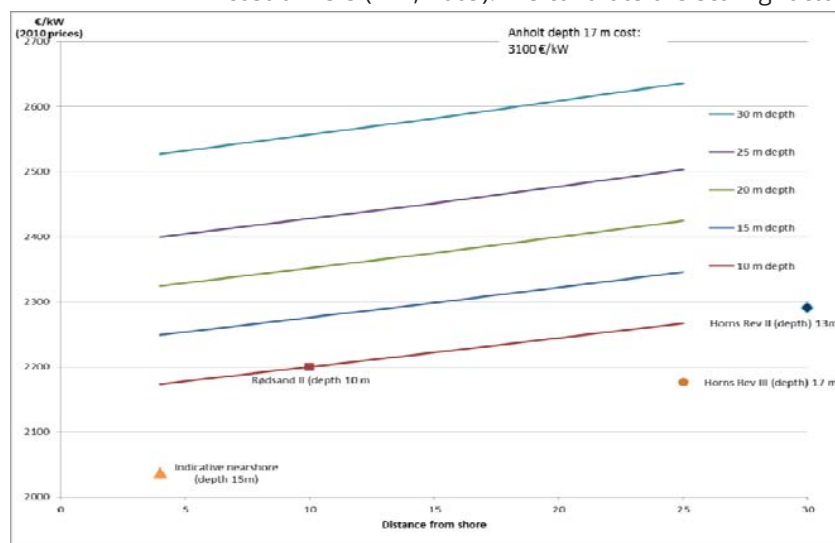


Figure 2 Investment cost illustration for DK in 2010 with indicative benefit (Based on investment cost for Rødsand II and EEA scaling factors in Table 1)

The illustration for potential benefits in DK clearly shows that the main cost benefit will be achieved if it is possible to reduce the water depth by locating the wind farms closer to shore (moving left and down in the figure). If water depth is not reduced, then the cost reduction of moving from a location similar to Horns Rev III to a location just 4-5km from shore will be only 4% (just moving left). If conditions regarding water depth like Horns Rev III (approx. 17m) are very scarce, the relevant comparison might be between average water depths of 25m versus water depths similar to some DK nearshore sites, of around 15m. The benefit in this case will be around 10% reduction of CAPEX

CONCLUSIONS

Nearshore wind potentials exist in Denmark, and they have potentially lower costs than further offshore, but the cost advantage is probably lower than in other countries, because offshore costs are comparatively lower in Denmark due to shallow waters. The nearshore potentials are smaller, and

possible wind farm sizing is also limited for some sites in Denmark. However, there are still potentials with lower costs than further ashore sites. It is difficult to identify one main contribution as e.g. more shallow water as the source of expected lower costs based on a small sample of data examined for Denmark. Significant cost advantages are however only expected if water depth is considerably lower than at more offshore sites.

An illustrative calculation of benefits indicates that cost could be only 4% lower nearshore if no reduction in water depth is achieved. Compared to this, moving from 25 km distance at the same time as reducing water depth from 25m to 15m may provide cost reductions of around 10%.

Finally, the smaller possible size of the projects may facilitate more competition, especially from domestic developers, but it may also lead to less participation from the global offshore developers that exploit economies of scale in wind farms. If dominated by the first, this produces a more competitive environment for the bidding process of the smaller nearshore projects that may allow new entrants into the offshore development and eventually pushes for lower prices.

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“Energy Economics Emerging from the Caspian Region: Challenges and Opportunities”

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Conference Program

<u>Sunday, August 28</u>	<u>Monday, August 29</u>	<u>Tuesday, August 30</u>
Registration	Welcome Speech	Plenary Session 1: Oil & Gas Price Dynamics and Expectations
IAEE Council Lunch (by invitation)	Opening Plenary Session: Global Energy Market Trends: Challenges & Opportunities	Concurrent Sessions 9-12 (<i>Renewable Integration, Energy Security and Geopolitics-2, Renewable Energy Policy, Technical Scientific Considerations</i>)
IAEE Council Meeting (by invitation)	Concurrent Sessions 1-4 (<i>Energy Policy, Energy Demand, Oil & Gas Modelling-1, Electricity Market</i>)	Plenary Session 2: Regional Energy Security
Student Happy Hour	Concurrent Session 5-8 (<i>Electricity Modelling, Oil & Gas Modelling-2, Energy Governance, Energy Security and Geopolitics-1</i>)	Concurrent Sessions 13-15 (<i>Energy Efficiency, Oil Price Impact, Energy Regulation</i>)
Opening Reception	Gala Dinner	<u>Wednesday, August 31</u>
		Plenary Session 3: Regional Strategies to Alternative and Renewable Energy
		Workshop: Developing a Competent Workforce for Today and the Future
		Plenary Session 4: Unlocking Caspian Energy Potential
		Tour to Sangachal Terminal of BP (optional)



Plenary Speakers:

Dr. Mohammad Hossein Adeli (GECF)

Natig Aliyev (Minister of Energy, Republic of Azerbaijan)

Prof. Kostas Andriosopoulos (ESCP Europe Business School & Greek Public Gas Corporation DEPA)

Bakhtiyar Aslanbayli (BP)

Prof. Georg Erdmann (Berlin University of Technology)

Prof. Ying Fan (Beihang University)

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Dr. Tatiana Mitrova (ERI RAS)

Nurkhanbek Momunaliev (Minister of the Kyrgyz Republic)

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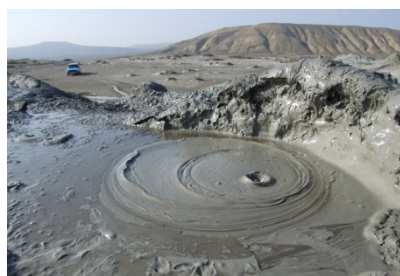
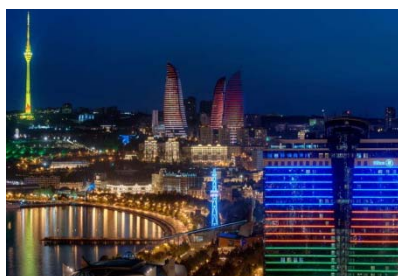
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You can find all the information regarding the conference organisation (programme, registration fees, student scholarship funds, registration and accommodation forms and the social events) on the conference website <http://www.iaeebaku16.org>

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Automotive Exposition IAEE Bergen International Conference

On the second day of the conference, Jonas Høva and Daniel Janzen from the NHH Energi group arranged a unique opportunity for delegates to ride in an alternative propulsion automobile to the conference at NHH to set the tone for the Plenary Session: Technological Change and Energy in Transport. All together more than 20 delegates took part in this opportunity including IAEE President, Gürkan Kumbaroğlu. After the plenary session, delegates were invited to go outside to see and learn about nine different automobiles from six different automakers that were present. As shown by the diversity of different automobiles present at the conference, the automotive industry is still in an early state of change and there are many different views on how the industry standard will evolve. This was a great way for delegates to investigate how the industry is responding to changes in technology, consumer preferences and government regulations and to get an idea of what the future may look like.



News Coverage of the Bergen Conference

Einar Hope, General Conference Chair of the Bergen IAEE Conference, wrote an article on the Conference that was published in the regional newspaper, *Bergens Tidende*, in Norwegian, on the opening day of the conference, and the same day in English on the webpage of Academia Europaea (AE). The purpose was to give a popularized account for the general public of the main conference theme: *Energy. Expectations and Uncertainty*, with illustrative examples from the Norwegian energy scene, and also to inform outside of the IAEE circles of the conference and IAEE. The translation has been made by the AE, of which Einar is a member.

For those interested, the web address below will take you to the coverage:

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Can Accounting Inventory Data Shed Light on Physical Oil Market Speculation?

By Ivan Diaz-Rainey, Helen Roberts and David Lont

The oil spike of 2008 has generated intense academic and policy debate. Specifically, researchers have sought to ascertain what role, if any, speculation played in causing this spike. The majority of these studies have explored what impact financial institutions (non-commercial speculators) have had on price dynamics in the oil derivatives markets (principally oil futures).

Another less prominent concern in the oil price spike debate is what impact 'speculation' in the physical oil market had on prices. Consequently a number of papers have explored the relationship between physical inventories and oil prices (Hamilton, 2009; Kaufmann, 2011; Kilian and Murphy, 2013; Singleton, 2014). However, these efforts have relied on two aggregate data sources (OECD inventories from the IEA and US inventories from the EIA).

By way of contrast our paper (see Diaz-Rainey et al. 2016), uses an alternative data source, namely the companies' own financial accounts, and asks the following research question: Can we infer from accounting inventory numbers whether companies involved in the physical oil market have been speculating in the run-up to 2008?

Our contributions relative to the existing work using inventories are twofold: (1) we use an alternative data source that is more global and covers "oil at sea" (unlike IEA and EIA datasets), and (2) we explore individual company data and, therefore, can explore the heterogeneity of company behavior. The former is important, since both the IEA and EIA datasets do not capture emerging markets and do not cover 'oil at sea', which is critical since physical speculation in oil often involves holding positions in oil tankers. The latter is also important because past research on inventories has not been able to explore individual company behaviors, and thus our results challenge anecdotal and research-based conclusions drawn from aggregate data that suggested either all companies or none were involved in speculation. The reality is more nuanced; the evidence we find is consistent with some companies speculating and others not.

More specifically, using quarterly inventory data over the period 1990Q4 to 2012Q1 and an initial sample of 15 of the largest listed oil companies in the world, we derive an Index of Scaled Physical Inventories (ISPI). We employ three methods to explore the research question: (1) a descriptive evolution of ISPI over time; (2) statistical structural break tests on individual company time series (a positive structural breaks during the 'speculation period' would be suggestive of speculative activity) and econometric models of operating profit using estimates of barrels of oil as an explanatory variable.

We hypothesize a state dependent relationship between inventory, oil prices and, in turn, the operating profitability of commercial traders. Intuitively, if oil prices are rising and are expected to continue to rise ($E(P_{t+n}) > P_t$), momentum trades holding physical inventory will be profitable, so long as capital gains are greater than the cost of carry (s), hence $(E(P_{t+n}) - P_t) - s > 0$. This trade is, however, risky since prices may not in fact rise. Alternatively, traders can make a riskless profit through the contango and carry trade. Expectation of rising prices are likely reflected in a futures contango market, whereby futures prices are higher than spot prices (i.e., $F_{t,T} > P_t$). Traders can buy spot oil and sell it into the future instantly and make a riskless profit, so long as the capital gain is greater than the cost of carry, that is, $(F_{t,T} - P_t) - s > 0$. Indeed, Singleton (2014) finds evidence of the inventory and price relationship switching from negative to positive in 2004 when the oil market had considerable momentum and just before the market moved towards contango in 2005.

The ISPI measure ± 1 standard deviation using the inventory to sales measure (left axis) together with the Brent crude oil price (right axis) is shown in Figure 1. ISPI declines until the turn of the century. The declining standard deviation suggests a drive for efficiency shared by most industry participants (homogeneity in behavior). However, this changes as the Brent crude oil price starts to increase after Q3 in 2003 and continues to rise up to a maximum in Q2 of 2008. The one-standard-deviation band around the ISPI measure begins to widen at the turn of the century. The greater standard deviation supports heterogeneity of inventory behaviors among the companies included in the ISPI. This is consistent with more variation in decisions concerning the amount of inventory being held by each firm as the market enters a momentum phase.

The descriptive evolution of ISPI illustrates declining ISPI during the pre-speculation period (1990Q4

This short article is a summary of the working paper Diaz-Rainey et al. (2016) presented at (See list of references.).
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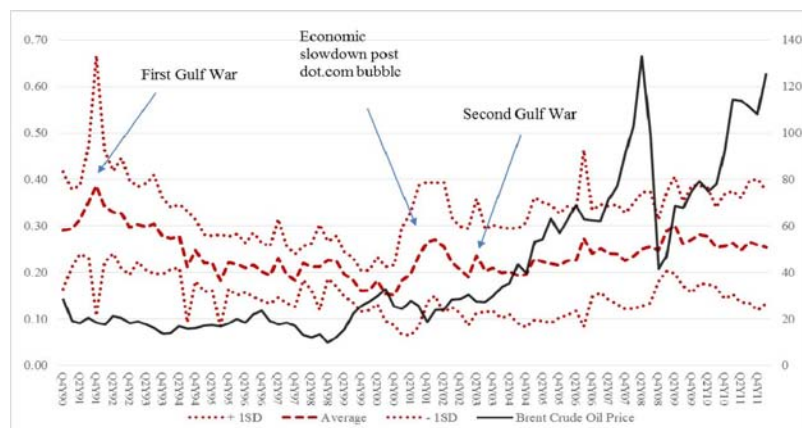


Figure 1: Descriptive Results for ISPI \pm 1 SD Measured by Inventory Scaled by Sales

to 2004Q3) and an increasing ISPI during the speculation period (2004Q4 to 2007Q4). This evidence is broadly consistent with the evidence presented by Kaufmann (2011) and Singleton (2014) for the US, namely that the momentum market in oil prices between 2003 and 2008 was associated with rising inventories. As such, we add global evidence to their US findings. Further, the ± 1 standard deviation of ISPI highlights the heterogeneity of oil company behavior in the period leading up to a further examination of the heterogeneous behavior of oil companies based on the Bai-Perron structural break tests shows that nine of the 12 companies tested experience a structural break during the speculation period. British Petroleum, Royal Dutch Shell, Statoil, Total,

Gazprom and Lukoil all have significant, positive structural breaks during the speculation period (see Diaz-Rainey et al. 2016 for further details). Conoco, Mobil Exxon and Petrobras experience negative structural breaks in the speculation period, while Chevron, Eni, Valero, China, Sasol and Repsol show no evidence of structural breaks. Evidence of a positive structural break in inventory as oil prices increase is suggestive of commercial traders speculating though it is not the only possible explanation for a positive break (see below). Conversely, negative or no structural breaks during the speculation period is consistent with non-speculative behavior.

We also examine the relationship between changes in operating earnings before depreciation and amortization to changes in oil inventory over the pre-speculation and speculation period. The latter is defined by structural breaks in the oil price. We report some evidence of switching in the coefficients for the change in the quantity of inventory variable over the two periods. There is also consistent but statistically insignificant sign changes in the sensitivity of the quantity of oil held by firms to changes in operating profitability. This is consistent with evidence reported by Singleton (2014). The conclusion based on these models is that switching has not materially affected performance, save for the cases of Royal Dutch Shell, Total and Gazprom (see Diaz-Rainey et al. 2016 for further details).

Overall, our evidence is strongly suggestive that at least some oil companies were involved in speculative activity, though this does not represent 'smoking gun' unassailable proof that they did so – the possibility remains that other factors caused individual inventory numbers to increase. For instance lengthening supply chains could be a plausible alternative explanation and it would seem this might explain the positive structural break for Statoil whom started delivering oil beyond Europe in the relevant period. However, it seems unlikely that all positive breaks can be explained by a third factor. Overall, our results are highly consistent with the evidence presented in Kaufmann (2011) and thereby add to the 'smell test' that physical markets speculation could have contributed to the run-up in prices between 2004 and 2008.

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Cost Overruns in Norwegian Oil and Gas Projects: A Long-tailed Tale

By Atle Oglend, Petter Osmundsen and Sindre Lorentzen

Given the significant reduction in oil prices during the recent years, a renewed focus and interest for the cost aspect of the oil and gas industry has emerged. Delivering at or below the estimated cost is considered a pivotal criterion, alongside quality, delivery on schedule and production attainment, for evaluating the success of project execution. The presence of cost overruns¹ has the potential to distort the profitability ranking of the investment opportunity set. Subsequently, the company might allocate capital sub-optimally. As such, further insight into the drivers of cost overruns can be useful for oil and gas companies undertaking large investments.

The literature is saturated with examples of in-depth case studies on oil and gas projects on the Norwegian Continental Shelf (NCS), see for instance NOU (1999:11), Norwegian Petroleum Department (2013) and Office of the Auditor General (2003). However, limited effort has been devoted to studying cost overruns on the NCS through an empirical approach. In Oglend, Osmundsen and Lorentzen (2016), we attempt to address this shortcoming of the literature, by utilizing a multivariate longitudinal econometric analysis to examine the drivers of cost overruns in Norwegian development projects in the oil and gas sector. A unique and detailed dataset of 238 longitudinal observations, consisting of 80 different projects between 2000 and 2013, is applied. The data was extracted from the national budget and the Norwegian Petroleum Directorate.

Analysis of the statistical moments of the distribution of the cost overruns reveals that projects in the oil and gas sector on the NCS conform with findings in the transport infrastructure projects (Flyvbjerg et al, 2002). In accordance with Flyvbjerg's categorization of cost overrun theories, as the distribution exhibits both a positive mean and skewness with temporal stability, it is likely that the underlying driver or the root cause of the cost overruns is not exclusively technical. The observed statistical moments appear to be consistent with the distributional predictions from psychological biases and strategic reporting theories. Further analysis of the temporal dynamics reveals that cost overruns tend to accumulate throughout the project lifetime. By disaggregating the distribution of the cost overruns, the distribution of the initial in-progress cost overrun is far more symmetric and centered around zero compared to the distribution of the realized cost overrun. This finding is in line with the ex-ante expectation, however, unlike conventional wisdom, the current control estimates do not converge towards the true cost with declining volatility. Rather, the updates or changes in the estimate (transitional cost overrun) are initially small, but tend to increase as the project reaches its maturity. That is, the cost estimate errors are increasing as the project uncertainty, presumably, should be monotonically decreasing. Whether this finding is caused by strategic reporting, lack of effort in updating the estimates or other unspecified dynamics, remains to be explained.

Univariate regression analysis reveals that there is a positive relation between cost overruns and various proxies for economic activity. For instance, cost overruns tend to increase when oil prices, investment on the NCS, rig rates or number of employees in the sector increase. While the effect is significant, it is moderate. However, the unexpected change in the economic activity (approximated through a random walk) appears to have a greater impact. With the exception of the project size, experience and execution time, project specific variables, related to technical complexity and operator and ownership characteristics, appear to be predominantly insignificant. The combination of these two findings seems to indicate that cost overruns are driven by the element of surprise.

Through a forward selection, we specify a multivariate model consisting of four explanatory variables: the unexpected change in the number of employees in the sector (SecEmpSur); the transitional cost

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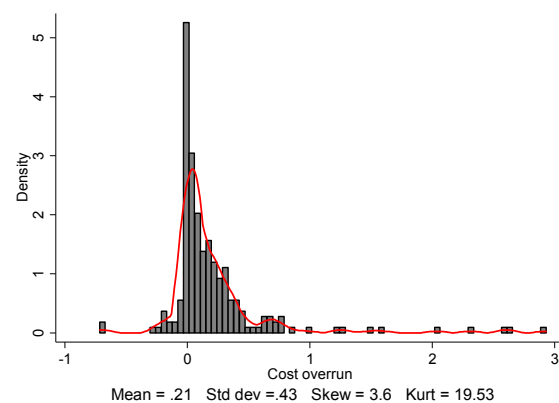


Figure 1: Cost overrun distribution

overrun (TraCO) – speed of the information updating in the control estimates; the project size (ProInvestEndInv); and the amount of experience exhibited by the project operator (exp). The specified model yields a considerable explanatory power of approximately 45 percent, which is considerable given the volatile nature of cost overruns. However, despite the effort of predicting the cost overruns, inspection of the residual unpredicted cost overrun reveals that the positive skewness persists. More research is required in order to fully uncover and explain the dynamics of cost overruns.

This table displays the regression output from a model with cost overrun as the dependent variable and four independent variables. The explanatory variables are (1) the sector employee surprise (SecEmpSur), calculated as the relative difference between the number of employees on the NCS today and at the time of the decision, (2) the transitional cost overrun (TraCO) between two subsequent periods, (3) the inverse of the project realised investment size (ProInvestEndInv) in NOK, and (4) the operator's experience in terms of the number of licenses it holds.

Regressor	Coefficient	t-value	p-value	Own R2	Cumulative R2
SecEmpSur	1.77	3.29	0	0.2938	0.2938
TraCO	0.8	6.28	0	0.2676	0.4189
ProInvestEndInv	-188.91	-1.66	0.1	0.0627	0.4456
log(exp)	-0.06	-2.22	0.03	0.0535	0.4467

Note: random effect panel data with cluster- and heteroscedasticity-robust standard errors

Table 1: Multivariate model results

Footnote

¹ A cost overrun is here defined as the inflation-adjusted deviation between realised and estimated costs.

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Cross-Border Effects of Capacity Remuneration Schemes in Interconnected Markets: Who is Free-Riding?

By Xavier Lambin and Thomas-Olivier Léautier

OVERVIEW

Since the liberalization process began in the early 90s, the European power sector has been increasingly exposed to market-based mechanisms, as opposed to national planning. Investments are increasingly market-driven, with prices supposed to give life to a socially optimal capacity mix and adequacy level. However, the power market still suffers from market imperfections and failures such as inelastic demand and the absence of liquid long term contract markets, leading to the implementation of regulatory firewalls such as price caps that may not be consistent with the security of supply targets. Many regulators have recently observed that the price signal alone no longer generated an “adequate” level of capacity according to their Security of Supply standards (that are set in some countries), a trend that was accentuated by fast renewables development. CRMs are seen as a solution to directly remunerate capacity (and not only energy) in some countries but without harmonization with their neighbors. The assessment of CRMs in a single market is very complex, so much so that all CRM designs ignore cross-border effects or at best take account of imports in an implicit manner. This research shows that a lack of harmonization might prove very costly in the long run, as capacity support schemes have a cross-border impact on prices and in turn, on investment.

We first analyse the benchmark cases of isolated markets. In a second section we study interconnected markets with correlated demands, and limited or unlimited interconnection capacity. This case provides the main insights while keeping the analytics very simple. The third part studies the more general case of non-correlated demands. Those results are then discussed and potential policy responses are considered.

METHODS

In a stylized analytical model, we study bilaterally interconnected markets with different market designs. The designs we considered are:

1. an energy-only market with no support scheme
2. a market with a payment for capacity. This payment could be a regulated amount, or the outcome of an auction.
3. a market with strategic reserve (“dormant” capacity, activated only in case of scarcity).

The transmission line may be congested. Demand is stochastic, can be correlated in the two countries or not. In a first stage, investors build capacity. There is free-entry. In a second stage, demand materializes in both markets and prices emerge.

RESULTS

The second stage, the spot market, is largely harmonized in Europe: markets are coupled, meaning prices are the same in all countries, up to technical limitations of transmission lines. However, this spot market relies heavily on the outcome of the first stage (How much capacity is available, and where?). With unilaterally implemented support schemes, the first stage does not emerge from a coordinated approach, paving the way to undesired effects of the support scheme on future price formation. In particular, promoting capacity in a given market (first stage) will mechanically depress market prices (second stage), not only in the local market, but also abroad if interconnection capacity is large enough. In turn, investors give a cold shoulder to the foreign market, and invest more in the local market where capacity is supported.

We show that with spot market integration and if transmission is large enough, rather than a *creation* of capacity, the long-run outcome is a shift of capacity from the market without capacity support to the market with support. If transmission system operators (TSOs) can't control exports (under the internal market rules) and if neighbours stick to an energy-only paradigm, a capacity payment is ineffective unless transmission capacity is small. If TSOs can limit exports to serve their local consumers in times of scarcity (in line with most national network codes), the security of supply in the neighbouring energy-only market shrinks while the security of supply in the market with capacity support increases

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at low cost –a direct consequence of the capacity shift. A neighbouring energy-only or strategic reserve market will thus suffer in the long-run and may have to implement a capacity payment as well in order to meet its security of supply standard.

Table 1 summarizes the cross-border effects of CRMs, when price the cap is set at a (common) Value of Lost Load and TSOs are allowed to control exports:

CONCLUSIONS

Local scheme	Enjoys positive externality from	Endures negative externality from
Energy – Only	Strategic Reserve ¹	Capacity Payment ²
Strategic Reserve	Energy Only	Capacity Payment
Capacity Payment	Strategic Reserve ~ Energy Only	-

Table 1: Externalities endured/enjoyed by a market with a given design, interconnected with another market

While the day-ahead market integration has made much progress in Europe, security of supply policies in Europe remain to a large extent in the

hands of national governments –as opposed to the European level. The consequence is a patchwork of market designs that are assessed neglecting the potential spillover effects to neighboring countries. Our simple model proves that cross-border effects do exists, and they might be far from negligible. On top of that, the victim might not be the one who first crosses our mind: in the long-run, the problem does not lie so much in capacity free-riding (at the expense of the market with capacity support), but rather in unfair investment competition (at the benefit of the market with capacity support). Our conclusions urge for the harmonization of capacity remuneration schemes across Europe.

Footnotes

- ¹ EO is welfare-neutral, but gets improved Security of Supply
- ² EO is welfare-neutral, but gets degraded Security of Supply

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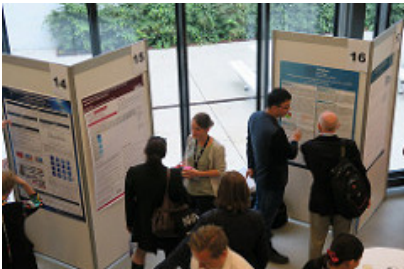
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Bergen Conference Overview

The 39th IAEE 2016 International Conference in Bergen, at the Norwegian School of Economics (NHH), was filled with robust activities and events for an entire week. It was also the largest conference recorded in the IAEE history until now, in terms of registered attendees (605) and papers. (387, including 41 posters), presented in 71 concurrent sessions during three full conference days, in addition to three plenary and six dual plenary sessions.

It started with an IAEE/NHH Summer School on the Management of Energy Price Risk, organized and taught by NHH-Professor Petter Bjerksund, 16-18 June, and ended with two Technical Tours to, respectively, the Dale and Sima hydroelectric power plants and the Mongstad combined heat and power plant, on 23 June, all well attended.



Cross-border Exchange and Sharing of Generation Reserve Capacity

By Fridrik Mar Baldursson, Ewa Lazarczyk, Marten Ovaere and Stef Proost

Electricity balancing is the continuous process, in all time horizons, through which Transmission System Operators (TSOs) ensure that a sufficient amount of upward and downward reserves are available to deal with real-time imbalances between supply and demand in their electricity transmission system. Imbalances occur due to forecast errors of demand and renewable supply, and unforeseen events such as line failures and generation outages. To ensure that sufficient reserves are available for real-time balancing, TSOs procure an amount of reserves – so-called reserve capacity or balancing capacity – in advance.

Since system frequency is shared within a synchronous network, persistent imbalances in part of the network can lead to a widespread blackout throughout the network. To prevent this ‘Tragedy of the Commons’, all TSOs in a synchronous area are obliged to provide sufficient reserves. Network codes and guidelines stipulate the reserve requirements that a TSO should meet.

Under the impulse of increasing renewable energy integration, supranational legislation (ENTSO-E,

2014), and a general drive for more cost efficiency and reliability, some TSOs have started to coordinate electricity balancing and reserve procurement between neighbouring TSO zones. Often cited benefits of cross-border balancing and reserve procurement include reduced reserves needs (NREL, 2011); a more efficient use of electricity generation, including reduced renewable energy curtailment (Mott MacDonald, 2013); a higher reliability level; a standardization of the rules and products, which creates a level-playing field; improved market liquidity, which increases competition (Hobbs et al., 2005); and internalisation of external effects on neighbouring TSOs (Tangerås, 2012).

DEGREES OF CROSS-BORDER COOPERATION

Cross-border cooperation yield benefits both in procurement of reserve capacity and activation of balancing energy. Table 1 structures the different degrees of cooperation that are possible in procurement and in activation.

Imbalance netting avoids counteracting activation of balancing energy in adjacent TSO zones. For example, activating upward reserves in response to a negative imbalance in one TSO zone, and separately activating downward reserves in response to a positive imbalance in another TSO zone, is inefficient since counteracting imbalances naturally net out on synchronous networks. Imbalance netting is a constrained version of exchange of balancing energy.

Exchange of balancing energy is a further degree of cooperation in activation of balancing capacity. It implies that cooperating TSOs construct a common merit order of balancing energy bids and select the least-cost activation that meets the net imbalance of the joint TSO zone. Imbalance netting and exchange of balancing capacity increase supply efficiency by decreasing the activation costs.

Reserves exchange makes it possible to procure part of the required level of reserves in adjacent TSO zones. These reserves are contractually obliged to be available for activation by the contracting TSO and they can only contribute to meeting this TSO's required level of reserves. Reserves exchange changes the geographical distribution of reserves. More reserves are procured in cheap TSO zones and less in expensive TSO zones. Reserves exchange also increases supply efficiency by decreasing the procurement costs.

Reserves sharing is a further degree of cooperation in procurement. It allows multiple TSOs to take into account the same reserves to meet their reserve requirements resulting from reserve dimensioning. A TSO in need of balancing energy can use this shared capacity, if other TSOs do not. Reserves sharing

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PROCUREMENT of reserve capacity	ACTIVATION of balancing energy
to meet the reserve requirements resulting from reserve dimensioning	to meet real-time imbalances resulting from forecast errors and unforeseen events
Autarky: no cross-border cooperation	Autarky: no cross-border cooperation
Exchange: procure reserves in other zones	Imbalance netting: avoid counteracting activation
Sharing: multiple zones take into account the same reserves	Exchange: activate reserves in other zones

Table 1: Degrees of cooperation in cross-border balancing between TSO zones

leads to both supply efficiency and dimensioning efficiency.

BENEFITS OF CROSS-BORDER COOPERATION

Our model studies analytically the efficiency gains of cross-border cooperation in reserves procurement. Broadly, cooperation increases supply efficiency and dimensioning efficiency.

- **Supply efficiency:** balancing services, both procurement of reserve capacity to meet reserve requirements and activation of balancing energy to meet real-time imbalances, are supplied by the cheapest balancing service providers. That is, if the market is enlarged, expensive balancing services in one part of the market can be substituted for cheaper ones in a different part of the market. The scope for supply efficiency depends on the difference of procurement and activation costs between cooperating TSO zones.
- **Dimensioning efficiency:** less reserve capacity is needed if a TSO in need of capacity can use idle reserve capacity of adjacent TSO zones. The scope for dimensioning efficiency depends on the correlation of imbalance variability between cooperating TSO zones.

Our model analytically derives the optimal procurement of reserve capacity, and the resulting procurement and interruption costs, for both TSO zones for the three degrees of reserve procurement cooperation: autarky, reserves exchange and reserves sharing.

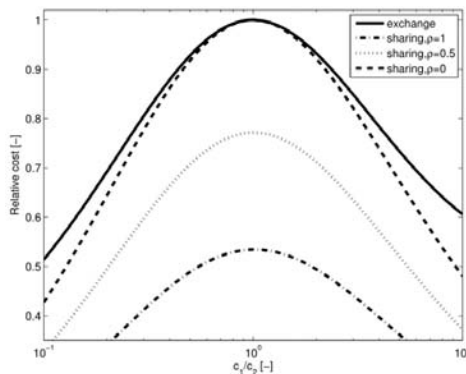


Figure 1: Relative cost of reserves exchange and reserves sharing, as a function of cost asymmetry (c_2/c_1) and reserve needs correlation (p).

Figure 1 displays numerical results from a parameterized example and shows that benefits increase when reserve procurement costs become more asymmetric and reserve needs are less correlated. With low cost asymmetry and low correlation, reserves sharing yields the major part of the cost reduction, while with high cost asymmetry and a high correlation, reserves exchange yields the major part of the cost reduction. With symmetric costs and high correlation, cross-border cooperation in reserves yields limited benefits. We also show that the relative gains of cooperation decrease if TSO zones differ in size and that sharing reduces the total amount of procured reserves and increases the reliability level by allowing cooperating TSOs in need of balancing energy to use the shared capacity.

INCENTIVES FOR CROSS-BORDER COOPERATION

Overall social surplus improves with each step in cooperation. But this entails distributional consequences. With reserves exchange, procurement costs will fall in one zone and rise in the other. With reserve sharing there are distributional consequences both for costs and expected interruptions.

These may create disincentives for TSOs focused on procurement cost efficiency and consumer surplus. To ensure cooperation in exchange and sharing, contracts are needed that guarantee all cooperating TSOs a proper portion of the benefits. A benchmark contract involves a lump-sum payment from the high-cost to the low-cost TSO. If this side-payment is determined using Nash bargaining, the overall surplus resulting from exchange or sharing is split evenly between the TSOs so their post-payment surplus improves by the same amount.

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Reducing Rebound Without Sacrificing Macroeconomic Benefits of Increased Energy Efficiency?

By Karen Turner, Gioele Figus, Patrizio Lecca and Kim Swales

INTRODUCTION

Increased efficiency in the use of energy will trigger a series of price and income effects that result in cost-push or demand-led economic expansionary processes (depending on whether efficiency improves on the production or consumption side of the economy). However, the same set of processes will also generate rebound in energy use at the economy-wide level, acting to partially offset expected energy savings in the more efficient activity. The question then arises as to whether rebound is a necessary 'evil' that we must accept in order to enjoy economic gains of increased energy efficiency. Or, are the possibilities for expansion due to increased efficiency limited if we wish to maximise energy (and related emissions) savings? Or, can economy-wide rebound effects from increased energy efficiency be reduced without sacrificing macroeconomic benefits? We hypothesise that this may be possible if we focus on energy-using *service* needs and consider increased efficiency in the production/delivery of a less energy intensive competitor in the household consumption choice. That is, by changing the *composition of consumption* - here with focus on the demand of UK households for mobility and increasing the energy efficiency and attractiveness of less energy intensive (per person mile) public over private transport options - the net economic welfare gains of increased energy efficiency may be preserved while reducing associated rebound effects.

MODELLING APPROACH

We use a multi-sector economy-wide computable general equilibrium (CGE) model of the UK economy, UKENVI, to simulate the impacts of a simple 10% increase in energy efficiency in the industry that supplies road and rail public and freight transport services, 'Road and Rail Transport'. We include four energy types (with both domestic and imported supply): refined fuels, electricity, gas and coal. The key assumption in our analysis is that private transport is a competing and relatively energy-intensive substitute for the more efficient public transport provision (particularly in refined fuel, petrol and diesel, use).¹ Our simulations involve examining the impacts on a range of economic variables and economy-wide rebound in different energy uses if we vary just one parameter in the model. This is the elasticity governing the extent to which households are prepared to substitute away from private in favour of public transport as the relative price changes in favour of the (more energy efficient) public option.

COST-PUSH EXPANSION ACCOMPANIED BY ECONOMY-WIDE REBOUND EFFECTS

The improvement in energy use in the UK 'Road and Rail Transport' sector triggers a cost-push or productivity-led expansion. The reduced cost of production is assumed to translate to a lower output price in the sector, which spills forward through sectors that use transport services as an input. Generally, the energy efficiency improvement translates to a small but positive supply-side shock to the UK economy. Over time, as the economy adjusts through accumulation of capital (we assume a fixed national labour supply²) and there are positive impacts on all key macroeconomic indicators, as illustrated in Figure 1.

However, while we find a net decrease in energy use in the more efficient 'Road and Rail Transport' sector of 7.4%, this represents 36% rebound on the technical improvement of 10%. Our main focus of attention, however, is the full economy-wide rebound. That is, how energy use across the economy is impacted by the economic expansion. In particular, we are interested in whether and how this may vary if the more efficient public transport option becomes a more attractive competitor to private transport in the consumption choice of UK households.

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See footnotes at end of text.

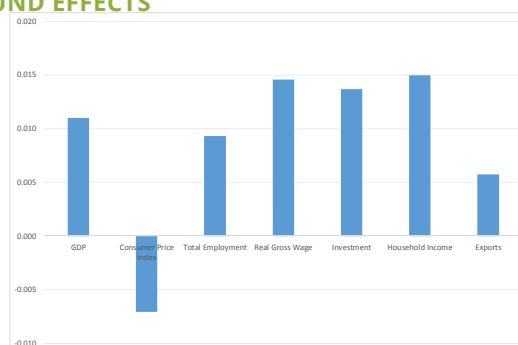


Figure 1. Key long-run macroeconomic impacts (% change from base values) of a 10% increase in energy efficiency in the UK 'Road and Rail Transport' sector

DE-COUPLING ECONOMIC EXPANSION AND ECONOMY-WIDE REBOUND

We repeat our simulations varying just one element of model specification – the price elasticity of substitution between public and private transport options in the household consumption choice (varying from an inelastic value of 0.1 to an elastic value of 1.1). A crucial result emerges: all of the macroeconomic benefits (including but not limited to those in Figure 1) remain unchanged while the *composition* of household consumption, specifically the composition of transport activity, is variable. Crucially, the contribution to economy-wide rebound, particularly in refined fuel use, is reduced as we increase the extent to which households respond to the increased competitiveness of the public transport option.

This is illustrated in Figure 2.

POLICY IMPLICATIONS?

The specific analysis presented here suggests that a key focus for policy attention may be to encourage public transport to become more energy efficient and more attractive as a substitute for personal transport. We acknowledge that pricing, and how people actually pay for public transport, may be a more complex issue in practice than reflected in the simple modelling analysis above. Then the key issue may be whether cost savings from increased efficiency in public transport provision can somehow be used to increase the attractiveness of public transport options. This is an issue worthy of further investigation.

However, our intention here is to consider a more general possibility. Research is required to assess whether the type of result reported above would occur in a wider set of cases. That is, can the proposition presented here be more widely applied to consider the role of improving efficiency (not just in energy

use) and competitiveness of low carbon options in delivering a range of services? In particular, would such a policy approach permit low carbon expansion with limited, and less harmful (in terms of emissions), rebound in energy use?

Footnotes

¹ Fuller explanation of the UKENVI CGE model and the simulations performed are reported in a discussion paper available to download at <http://strathprints.strath.ac.uk/56448/>.

² The qualitative nature of the results reported below is not sensitive to this assumption. See the discussion paper in the previous endnote.

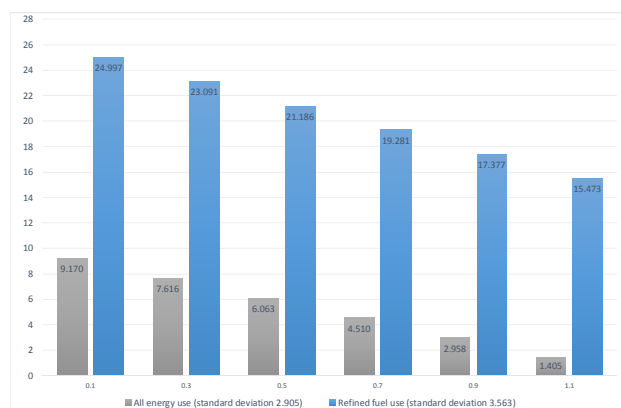


Figure 2. Impact on long-run rebound effects (%) of varying elasticity of substitution between public and private transport options in the household consumption choice

Bergen Overview (continued)

Summer School

The purpose of the first IAEE/NHH Summer School was to provide insight on the basics and principles of pricing and risks of financial derivatives, and how prices and traded instruments can be used to assess and manage the energy price risk exposure at the corporate level. Twenty-one delegates attended the Summer School over three days of intensive teaching. Professor Petter Bjerksund from NHH taught the course, Bjerksund's research interests include capital budgeting, investments, financial derivatives, risk management as well as real options. On Friday 17 June, the attendees were invited to join a business visit at Bergen Energy AS. The aim of the visit was to present the core businesses of the company within three segments: physical delivery of gas and electricity, financial products as well as the green certificates. Additionally, Bjarte Myksvoll whom is currently working as a Senior Risk Analyst in Sparebanken Vest in Bergen gave a guest lecture on the last day of lectures.



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Problems Created by Financial Trading in U.S. Wholesale Electricity Markets

By John E. Parsons, Cathleen Colbert, Jeremy Larrieu, Taylor Martin and Erin Mastrangelo

The role of financial traders in commodity markets is controversial. Advocates argue that they improve the pricing to better reflect information about expected demand and supply. Detractors complain that they often manipulate prices or otherwise move the market away from the fundamentals of supply and demand. The U.S. Federal Energy Regulatory Commission (FERC) in recent years has vigorously prosecuted a number of cases against financial traders in wholesale electricity markets, and controversy has swirled about whether these prosecutions have hurt or helped the operation of the markets. We recently completed a study of a unique type of financial trading known as Virtual Bidding that is unique to US wholesale electricity markets.⁴ The research helps understand certain situations in which virtual bidding not only fails to improve system performance, but also adds to system costs.

Virtual bidding makes it possible for financial traders to speculate on the spread or difference between the Day-Ahead and the Real-Time hourly prices at a certain location. Virtual Bids are placed in the Day-Ahead auction, and they clear like all other bids. Virtual demand bids clear if the price bid is greater than the auction clearing price, while virtual supply bids clear if the price bid is less. The virtual bidder earns a gross cash payoff on a cleared bid equal to the price spread: demand bids earn the Real-Time price less the Day-Ahead price, while supply bids earn the reverse. The bidder also pays some costs, so the net cash payoff is less than the spread. The payoff is always cash: the bidder never actually takes power, and never actually supplies power. Consequently, financial players can enter the market using these bids.

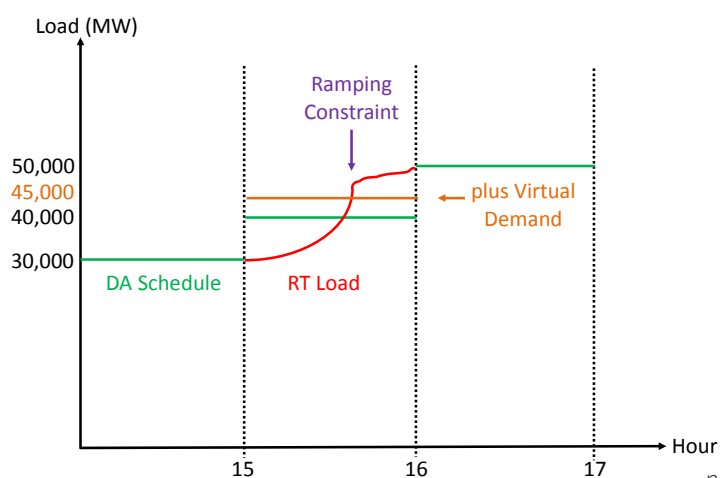
The promise of virtual bidding is that it improves the pricing and dispatch of generation. For example, in order to optimize the commitment of thermal generation, system operators need to forecast the amount of wind generation that will flow the next day. One tool at their disposal is the Day-Ahead offers by wind generators themselves. However, these generators have historically underbid the quantity of generation they end up supplying into the Real-Time market. Financial traders have noticed this, and they make virtual supply bids into the Day-Ahead market which reflect their estimates of the shortfall. As a result, the cleared physical supply in the Day-Ahead market more accurately forecasts the actual physical supply in the Real-Time market.

Unfortunately, this promise is not always realized. Virtual bidding can shape the aggregate level of supply and demand at a given location in a given hour. So long as the system problems crystallize to a shortage or surplus of aggregate supply or demand at a given location and given hour, then virtual bidding has the potential to improve the situation. Unfortunately, the unit commitment and optimal power flow problems that these wholesale market auctions are used to solve are much more complex than is acknowledged in the metaphor of an aggregated supply curve and an aggregated demand curve. The true unit commitment problem has to confront many fixed costs and discrete choices created by things like ramping constraints which raise the computational complexity enormously. The true optimal power flow problem needs to respect an array of complex power flow constraints such as thermal limits on the network cables and voltage limits. These complexities sometimes undermine the effectiveness of virtual bidding.

The paper uses the problems experienced in the California market as a case study to help illustrate the problem. California's new market design began operation in 2009, and immediately it exhibited a peculiar pricing anomaly.

On average, the Real-Time price was higher than the Day-Ahead price. This was due to a very few hours, less than 1% of all hours, when for a short interval of perhaps 5-minutes or so the load was ramping up at an extremely fast rate that exceeded

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the ramping capability of most of the units that had been dispatched in the Day-Ahead market. In the other 99% of the hours, the Day-Ahead price actually exceeded the Real-Time price by a small amount. During those 1% of hours when load was ramping very quickly, there was no general shortage of supply. Many of the units that had been dispatched for that hour had extra capacity. But they did not have the capacity to ramp up quickly enough to take advantage of that capacity within the 5-minute interval that it was required. Therefore, the system operator had to turn to other, expensive units and raise the price dramatically.

This price anomaly was an opportunity exploited by financial traders who placed a large quantity of profitable virtual demand bids. Unfortunately, this did not improve system operation. In 99% of the hours, the Day-Ahead price was already above the Real-Time price, and the virtual demand bids only increased the Day-Ahead price yet further. In 1% of the hours, the virtual demand bids increased the total supply scheduled, raising the Day-Ahead price. Unfortunately, this increased supply often did nothing to solve the ramping problem and the system operator was still forced to turn to other, expensive units. Because virtual bids can only be placed for a full hour of generation, which the system was not short of, and not for the short 5-minutes of ramping capacity that the system actually needed, the virtual bids could not effectively solve the problem. The accompanying figure provides a graphical illustration of the problem. In this case, virtual bidding simply added to total system cost, while also producing profits for financial traders that would have to be paid by customer charges.

The research generalizes this illustrative example, and shows how the underlying problem with virtual bidding can manifest itself in different situations. It explains how the usual diagnostic of convergence can sometimes fail to accurately reflect whether or not virtual bidding is improving system performance. The research emphasizes that task of evaluating the costs and benefits of virtual bidding is a very demanding one.

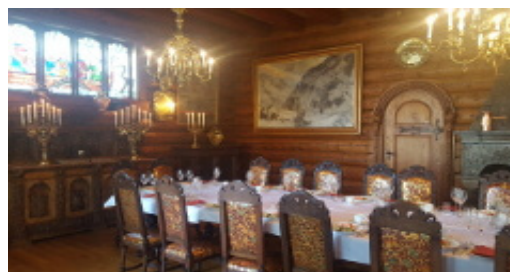
Bergen Overview (continued)

Council Activities

Traditionally, the IAAE Council meeting is held on a Sunday, preceding the conference, followed by a reception and a Council dinner for the members and invited guests. This tradition was continued in Bergen. The Council meeting was held at NHH, with lunch served in the very special dining and reception room, Stupet, dating back to a Bergen manor from the 1880s. The conference opening reception was at the Radisson Blue Royal Bryggen Hotel, located in the old, picturesque Hanseatic quarter of Bergen. Council dinner members and guests were taken by an electric powered sightseeing train through some of the scenic parts of Bergen and on to the fashionable Bellevue restaurant located high up on one of the Bergen hillsides with a beautiful view of the city. When the party left at 11 p.m. to ride the train back to the city centre and the hotels, the sun was still shining and it was light as day.



The historic Bryggen Wharf



NHH's Stupet dining room

Remuneration of Flexibility Using Operating Reserve Demand Curves: A Case Study of Belgium

By Anthony Papavasiliou and Yves Smeers

CONTEXT

The recent proliferation of renewable resources has resulted in a decrease of electricity prices and a reduced remuneration of conventional units, which are progressively being retired from operations. This is occurring at the same time that renewable energy integration increases the need for flexibility in operations. Such flexibility can be provided naturally by conventional units. Operating reserve demand curves (ORDC) have been advocated as an economically justified mechanism for pricing flexible capacity in order to compensate conventional units for the loss of energy revenue Hogan (2005), Hogan (2013), and the mechanism has been implemented recently in Texas. The goal in this study is to quantify its impact and assess its implementation possibilities in the European electricity market, with a specific focus on the Belgian electricity market which experienced severe shortage in capacity in late 2014.

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See footnotes at end of text.

PRINCIPLES OF ORDC

The ORDC design is based on the principle that reserve should be valued according to its contribution in reducing the probability of involuntary load curtailment. Scarcity in reserve implies a high probability of involuntary curtailment and hence a high reserve value, and vice versa. On the other hand, the cost of reserve provision is driven by the opportunity cost of keeping capacity in reserve, instead of allocating it for the provision of energy. The ORDC is a *real-time* mechanism that introduces a real-time reserve capacity price and a corresponding adder to the real-time energy price so as to induce an optimal allocation of generation capacity between energy and reserves. The adder is computed as $(VOLL - MC) \cdot LOLP(R)$, where $VOLL$ is the value of lost load, MC is the marginal cost of the marginal unit, and $LOLP(R)$ is the loss of load probability given a reserve level of R . Although ORDC is a real-time mechanism, given properly functioning forward markets the scarcity signal should back-propagate and signal investment when flexible capacity is short.

The design is appealing for a number of reasons: (i) the adder can be computed ex post, and can therefore be easily integrated to existing operations; (ii) the adder results in more frequent price spikes of lower amplitude, compared to VOLL pricing; (iii) gaming can be mitigated without suppressing scarcity signals; (iv) resources are paid on the basis of their actual performance; (v) in the case of Europe, the mechanism is seen as an alternative to capacity markets that may balkanize European market design and undermine the transition to a common European energy market.

An important question that arises naturally is whether the proposed design can be implemented in the European Union. The ORDC entails a number of assumptions (including co-optimization of energy and reserves in real time) which are not necessarily consistent with present European market design. Before undertaking this more challenging question, the first order of business in the present study is to understand the functioning of the current market. Our study focuses on the Belgian market.

SIMULATING THE BELGIAN MARKET

With the exception of Italy and Spain, there is no day ahead co-optimization of energy and reserves in the EU market design. Reserves and energy are cleared sequentially, with reserve capacity auctions (typically monthly or annual) followed by day-ahead energy market clearing. We solve a unit commitment model with a monthly horizon against real-time demand, as a proxy of the Central Western European market design where reserve auctions are followed by the running of a day-ahead market clearing algorithm (known as EUPHEMIA). We then check whether this proxy fits reality by comparing the predictions of our model to observed outcomes in terms of dispatch by fuel and in terms of market prices.

Figure 1 presents the dispatch of CCGT units (i) using a co-optimized unit commitment (left panel), and (ii) based on the profit maximizing dispatch against observed prices (right panel), which is used as a benchmark for comparison. The centralized unit commitment model is observed to more accurately predict the dispatch of CCGT units, which are the main resources offering operating reserve, and therefore the main driv-

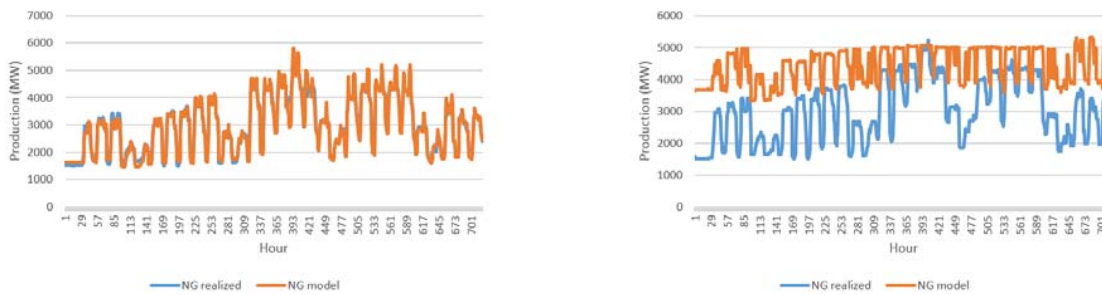


Figure 1: Production of CCGT, in reality (in blue) and according to the model (in orange) for January 2013. The left panel corresponds to a unit commitment model, the right model corresponds to dispatch against realized prices.

'Rational expectation' is a common (but usually untested ex post) assumption in economics. Consequently, even though EUPHEMIA is not a unit commitment model³, it results in a commitment schedule which is close to the result of a centralized unit commitment model. We thus verify that the unit commitment model provides a reasonable approximation for the use of the machines when capacities are tight. This is a necessary condition for being able to simulate the ORDC add up.

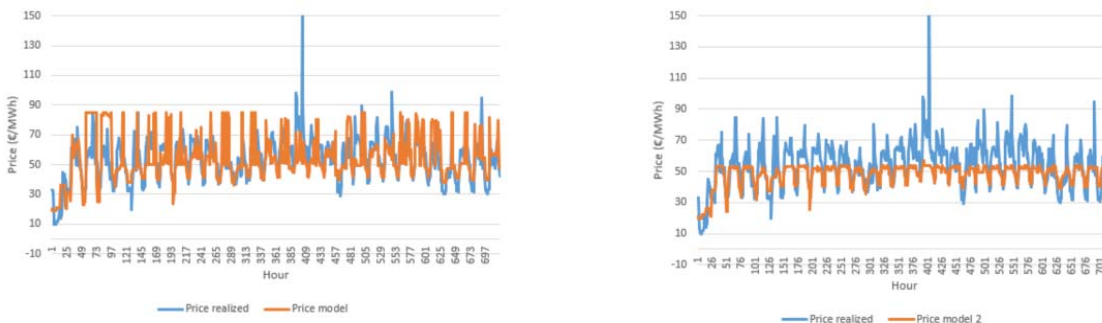


Figure 2: Day-ahead prices in reality (in blue) and according to the model (in orange) for January 2013. The left graph corresponds to the model that account for block bids, the right graph corresponds to the model that ignores block bids.

by the unit commitment model; (ii) render block bids found by the unit commitment model in the money; (iii) while minimizing welfare degradation with respect to the unit commitment solution. This results in a bi-level program that seeks prices which minimize deviations from optimal welfare, while being consistent with the solution of the unit commitment model. A benchmark model which sets the price on the basis of the marginal cost of the most expensive slack unit is presented in the right panel. The bi-level model seems to outperform the benchmark. We note that the bi-level model can explain price drops in off-peak hours (due to excessive energy supply stemming from minimum load requirements of units that offer reserve) as well as price spikes in peak load hours (due to the recovery of fixed costs that cannot be recovered in off-peak hours). This further strengthens our confidence in the dispatch schedules determined by the co-optimization unit commitment model.

CASE STUDY

Our study covers the interval from January 2013 until September 2014. The Belgian system consists of 14765 MW of installed capacity. In order to estimate the profits of individual units, we use the historical energy and reserves prices and the output of the unit commitment model in order to estimate revenues and operating costs. We focus specifically on CCGT units, which are the main source of reserve in Belgium. The profits of CCGT units are computed for historical prices as they occurred over the duration of the study, as well as for profits that would have occurred if the ORDC price adder were applied to the energy price. Table 1 presents the profitability of each unit before and after the introduction of price adders. These profits should be compared against the running investment cost of a typical CCGT unit in order to ascertain the economic viability of CCGT resources. The running investment cost of CCGT is estimated at 4.5 €/MWh. Profits that do not exceed 4.5 €/MWh in the table are highlighted in bold font in order to indicate that the given unit cannot recover its investment cost. The profit in

ers for the ORDC adder. This validation procedure seems to verify a 'rational expectation' principle, whereby agents reasonably anticipate the value of the capacity in the energy market and bid accordingly in the reserve market.

Figure 2 addresses the question of whether the unit commitment model can simulate the prices generated by EUPHEMIA. The prices presented in the left panel are based on a model that seeks prices that (i) support continuous bids determined

the first column is computed as the profit over the entire duration of the study given historically realized prices, normalized by the capacity of each unit and the number of hours in the study period. The profit in the second column is computed in the same way, where prices have been adjusted according to the price adder. The final column represents the extra profit earned by each CCGT unit due to the introduction of the adder, normalized by the total output of each unit.

CONCLUSIONS

Three notable conclusions can be drawn from the first two columns of Table 1: (i) CCGT profits, as estimated by the methodology set forth in the present paper, are adequate for covering the *variable* costs of all *existing* CCGT units; (ii) CCGT profits are not sufficient for covering the investment costs of *any* CCGT unit. (iii) Adders, as computed in the study, could potentially render the majority (eight out of eleven) of CCGT units economically viable. These findings are consistent with the ongoing policy debate which centers on the fact that the current EU market design is not sufficient for ensuring the economic viability of flexible resources, although these resources are necessary for supporting the integration of renewable energy resources.

Footnotes

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³ EUPHEMIA maximizes welfare subject to a constraint on prices (solutions must be supported by an anonymous price system) that is not part of a unit commitment model. This is detrimental to the efficiency of the commitment, but apparently not much in the case of the Central Western European market.

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	Profit (€/MWh) no adder	Profit (€/MWh) with adder	Adder benefit (€/MWh)
CCGT1	3.6	10.6	8.5
CCGT2	1.3	3.6	11.6
CCGT3	1.1	10.0	7.7
CCGT4	3.8	11.1	10.0
CCGT5	0.9	6.4	7.5
CCGT6	3.9	8.3	6.8
CCGT7	1.0	3.2	6.8
CCGT8	1.1	8.0	8.0
CCGT9	2.3	11.1	10.1
CCGT10	1.7	7.4	14.9
CCGT11	1.7	4.3	8.6

Table 1: Profitability of CCGT units before and after adding ORDC price adders, and average adder benefit.

Bergen Overview (continued)

Bergen Conference Environmental Considerations

The ride on the electric train was one small symbol of a more general intention of the organizers, i.e. to try to make the conference as environmentally friendly as possible. Other such efforts were to supply conference delegates with a bus card for public transportation between the city centre and the conference venue, the NHH, ca. 7 kilometers each way, and otherwise around in the city and its surroundings; to serve local, short-travelled food for the conference meals; to minimize printing of conference material; and the arranging of an electric car show and parade for delegates to learn about properties of such vehicles, of which Norway has the highest share in the world.



Scenes from the electric car parade

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Policy Design and Environmental Benefits of Electric Vehicles

By Amela Ajanovic and Reinhard Haas

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The interest in electric vehicles (EVs) has increased over the last decade mostly due to the pressing environmental problems. EVs are considered to be environmentally benign and to have the potential to contribute remarkably to GHG emission reduction. However, since the total driving costs of electric vehicles are still significantly higher than those of gasoline or diesel cars, see Fig. 1, different policies and measures are needed to foster their market introduction. As Fig. 1 clearly shows fuel cell vehicles (FCV) and battery electric vehicles (BEV) are by far most expensive.

Currently, a broad portfolio of monetary and non-monetary policy measures exists which is able to increase the attractiveness of EVs as well as their competitiveness in the market. However, they are not able to ensure realization of their full environmental benefits. In this context it has to be borne in mind that the final goal of transport electrification is not just to increase the number of EVs but to reduce GHG emissions and air pollution.

The core objective of this work is to show that promotions strategies for EVs have to depend on the energy used for electricity generation and hydrogen production.

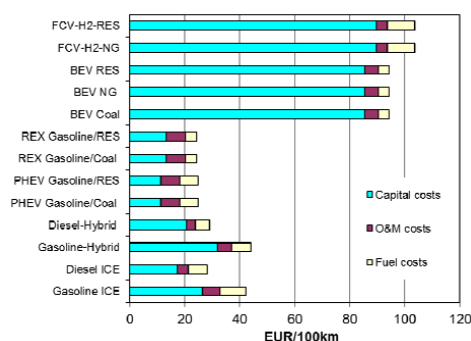


Figure 1. Total specific cost per 100 kilometre driven (EUR/100km) in 2014

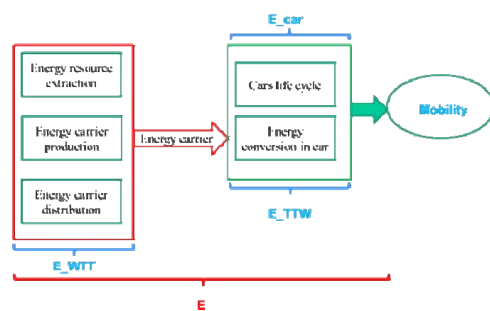


Figure 2. Method of approach for the environmental assessment of GHG emissions

METHOD

The method of approach applied in this article is based on research published in Ajanovic and Haas, 2015. In our work we conduct a comprehensive environmental investigation, and provide recommendations for promotion policies for electric vehicles. We have estimated environmental benefits of different types of electric vehicles (battery electric vehicles (BEV), hybrid electric vehicles (HEV), plug-in hybrid electric vehicles (PHEV), range extenders (REX) as well as fuel cell vehicles (FCV)).

Electric vehicles could be more or less environmental friendly technology depending on the carbon-intensity of electricity used. We analyze the whole well-to-wheel (WTW) emissions related to the provision of the energy service mobility including also the embedded life-cycle emissions of the car. Figure 2 shows the basic method of approach used in this paper. Total emissions of passenger car mobility (E) can be very different depending on the energy and material flows in the well-to-tank (WTT) part of the energy supply chain, the efficiency of the energy use in cars (in the tank-to-wheel (TTW) part), as well as emissions associated with the car production and scrapping.

ENVIRONMENTAL ASSESSMENT

The environmental benefits of electric vehicles could be very different depending on type of car, as well as energy mix for generating electricity used in cars. Figure 3 shows CO₂ emissions per 100 km driven for the whole energy supply chain and for various types of EVs in comparison to gasoline and diesel cars. Power of all analyzed cars is 80 kW. We have used average data for EU-15 (for data and basic assumptions see Ajanovic/Haas, 2016)).

It is obvious that all types of EVs contribute to CO₂ emission reduction in the TTW part of the energy supply chain. The largest reduction in total CO₂ emission could be reached with BEV powered by electricity from renewable energy sources (RES) – wind or hydropower – and FCV powered by hydrogen produced from RES. For all BEVs and FCVs TTW-fuel emissions are zero. To harvest the full environmental benefits of rechargeable EVs and to contribute effectively to heading toward sustainability in transport, it is most important to ensure that EVs use to a large extent electricity from renewable energy sources (RES). Unfortunately, this is currently not specified in policies for the promotion of EVs. Consequently, in most European countries the full potential of GHG emission reduction due to EVs cannot be reaped. If old coal power plants are used for electricity generation, total emissions from EVs could be even higher than those of conventional cars.

THE ENVIRONMENTAL RELEVANCE OF EVS PROMOTION POLICIES

To foster market introduction of EVs different policies and measures are implemented worldwide. The use of electric vehicles in Europa is directly or indirectly promoted by various regulations and strategies, such as:

- Directive 2009/28/EC (Directive, 2009), which states that 10% of the energy used in transport must be provided by renewable sources by 2020;
- The EC regulation 443/2009 (EC, 2009), which imposes reductions in average emission levels for vehicle manufacturers, setting objectives of 130 gCO₂/km for 2015, and 95 gCO₂/km for 2020;
- The European strategy (EC, 2010) which establishes as priorities the development of electric vehicles that are at least as safe as conventional ones, a European standard for charging points, a public charging network, a smart grid and research programs for the safe recycling of batteries (Perdiguerro and Jimenez, 2012).

In addition to these measures which are set at the EU level, there are different national/local supporting measures implemented in various countries with the goal to make electric vehicles more attractive. These measures can be divided in two categories: monetary (such as financial incentives, tax relief, exemption from tolls, free parking, etc.) and non-monetary (such as use of bus lanes, availability of suitable charging options, permission to enter city center and zero emission zones, etc.) measures (Kilian, 2012, Ajanovic, 2015). Yet, the core question is whether these strategies really lead to reduction of GHG emissions.

A comprehensive overview on current financial incentives and taxation in European countries is given by Ajanovic and Haas, 2015. This survey reveals that there is no country whose financial incentives on federal level depend on the source of electricity or on the specific CO₂ emissions of electricity generation. Depending on the average electricity-specific emission factors BEVs could have very different CO₂ emissions per km driven in different countries. Hence, from a static point of view – looking at the current electricity generation mix and the resulting average CO₂ emissions in the countries analyzed only in Norway, Sweden and France, the use of BEVs can significantly reduce GHG emissions, see Fig. 4.

Due to the fact that most of the promotion measures for EVs currently implemented are not sustainable in the long run, new policies will be needed. Most important is that future promotion strategies depend on the carbon content of the electricity used and its dynamic development. Moreover, CO₂-based fuel- and registration taxes would be very important complementary policy tools. Furthermore, indirectly, all measures supporting an increase in the use of RES lead to the reduction of electricity-specific CO₂ emission factors, and consequently, to a better environmental performance of EVs.

CONCLUSIONS

The major conclusions of this work are:

- To harvest the full potential of GHG reduction of rechargeable EVs it is most important to ensure that these EVs are using electricity from RES;
- Yet, promotion policies implemented so far in almost all countries do not properly address the aspect of the source of electricity generation, and, consequently, have not yet led gain the full GHG emission reduction potential of electric vehicles.
- In the future all promotion strategies should depend on the carbon content of the electricity used.
- Only in countries with a high share of RES in the electricity mix, e.g., by certificates ensuring the source of electricity, significant positive effects of EVs on the environment can be expected.

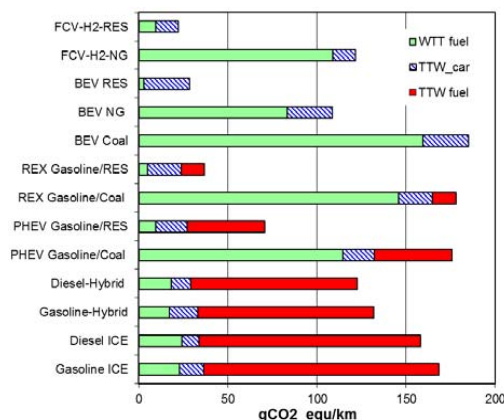


Figure 3. CO₂ emissions per km driven in for various types of EV in comparison to conventional cars, in 2012 (power of car: 80kW)

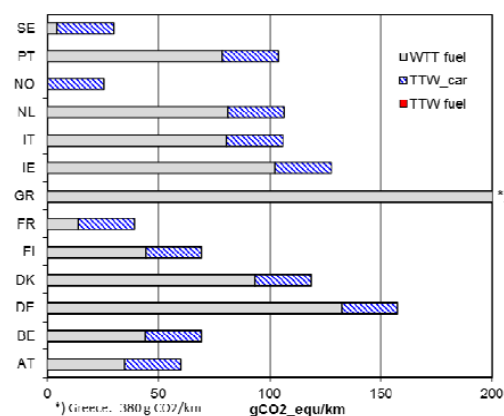


Figure 4. CO₂ emissions per km driven for BEV powered by grid electricity in different countries

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Bergen Overview (continued) (Environmental Considerations)

Norway is also in the rather special situation that virtually all of its electric power comes from renewable sources, with 98% from hydro power. As a token of what hydro power has meant for the economic development of the country for a period of more a century, and for the general welfare of its people, a monument in the form of a turbine wheel that had been running for almost 50 years in a local hydro power station was donated by the regional power company. BKK, to NHH. It was handed over by the CEO of the company, Jannicke Hilland, to NHH's Rector, Frøystein Gjesdal, in a ceremony on Monday morning outside the main building. Originally, this initiative was taken by NHH-Professor of Environmental Economics and Chair of the Conference Programme Committee, Gunnar Eskeland.



Bergen Conference Sessions and Seminars

In parallel with the Council meeting on Sunday, three pre-conference seminars were arranged. Professors Georg Erdman and Markus Graebig from Berlin Technical University started up in the morning with a workshop on Enhancing academic presentation skills, followed by Professor Sebastian Schwenen from Munich University on Capacity markets, and finally, Fereidoon Sioshansi from Menlo Energy Economics on the Future of utilities – utilities of the future. The seminars had 40-70 participants throughout the day, a remarkable turnout on a sunny and pleasant Sunday in Bergen!

With over 600 conference attendees, the capacity of the largest auditorium of NHH was exceeded by some 100. Instead of restricting the number of participants to the maximum capacity of the auditorium, and thus losing valuable contributions from speakers and authors of papers, the organizers decided to video transfer the plenary sessions over to an adjacent auditorium. Technically, this worked quite well and only positive feedback was received. For the dual plenaries and concurrent sessions, capacity of auditoriums and other conference functions was sufficient.

The plenary and dual-plenary sessions spanned a wide area of current energy and environmental economics and policy issues. The titles of these sessions were as follows: Energy and environmental policy formation in an uncertain world; Technological change and energy in transport; Business strategies in an uncertain world; Petroleum market fundamentals and risks, Energy and the economy; Institutional investors and the energy sector; Gas: Russia and European markets, Financial aspects of power markets; In the aftermath of Paris. All sessions were very well attended and there were lively discussions, within the panels and between the audience and the panels.



Seminars and sessions were well attended throughout the conference

Impact of RE Policy on Technology Costs-PV System Costs in Germany

By Barbara Breitschopf

OVERVIEW

Since the adoption of its Renewable Energy (RE) act in 2000, Germany has intensified its effort for renewable energy technology (RET) deployment. The primary instrument has been feed-in tariffs, which have faced several adjustments in magnitude and specific designs. While costs for consumers have increased considerably from 4.7 bill Euro in 2008 to almost 19 billion Euro in 2014 (Monitoring Report 2015), benefits for consumers are more difficult to capture and quantify. To do so, the approach relies on a const benefit concept, which looks at additional costs and benefits at system-, micro- and macroeconomic levels (Breitschopf, B., Held, A. 2014). While additional costs for final electricity consumers occur at the micro level, benefits serve special attention as they accrue across all levels and are difficult to allocate to individual actors. Among them, the contribution to innovation and technology cost development is considered as one major positive aspect of RE policy support. Technology costs, especially PV system costs have shown a tremendous decline over time. This paper strives to assess the impact of the German RE policy on RET costs in the case of PV in Germany. Increased attention has been paid to the learning curve concept (Ek & Söderholm, 2009). This concept will be extended by taking into account interdependencies between technology, demand, and supply.

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LITERATURE REVIEW ON LEARNING CURVE APPROACH

Decreasing cost of production have been observed and first described by {Wright 1936}. He explained them by learning effects, i.e. workers became more efficient as they produced more units of the same product with the same technology. Based on these observations, Arrow (1962) sketched a model explaining technological changes as a function of learning (Nemet, 2006). Learning curves in their basic form are derived by regressing the price or cost (De La Tour et al., 2013) of the technology in question on cumulative production. The derived One-Factor-Learning-Curve (OFLC) relates cost development to accumulated learning, usually represented by cumulative capacity. As the high level of aggregation in OFLC considerably simplifies cost dynamics (Wiesenthal et al., 2012), researchers started to extend the OFLC approach to a Two-Factor-Learning-Curve (TFLC). In TFLC models, investments costs are not only explained by cumulative capacity but also by an R&D based knowledge stock (Klaassen, Miketa, Larsen, & Sundqvist, 2005). Although Wiesenthal et al. (2012) point out, that it is already questionable whether the effects of learning-by-doing and learning-by-searching should be disentangled since they are both parts (and not the only parts) of one integral learning process, steps towards a Multi-Factor-Learning-Curves (MFLC) have been proposed. In particular, researchers (e.g. De La Tour et al. (2013) , Yu (2012)) draw on details given by Henderson (1972) concerning the originating idea of the experience curve by the Boston Consulting Group. He recalled that the experience curve does not solely refer to the relationship between productivity and output but should regard learning effects, scale effects, cost rationalization and technology improvement jointly (Henderson, 1972). While Yu et al. (2011) show significant results by incorporating scale effects, silicon price, silver price and a proxy for other input prices, De La Tour et al. (2013) report a notably higher learning rate by just incorporating experience and silicon price. Nemet (2006) develops a bottom-up cost model using the example of PV technology. The approach disaggregates historical cost reductions into observable technical factors. He suggests a set of observable technical (e.g. efficiency improvements) factors whose impact on cost can be immediately calculated. Nevertheless, Nemet (2006) isn't able to fully explain the cost development.

APPROACH

This paper analyses how strongly the demand pull policy (FIT) in Germany has driven the technology costs of PV installations over time. The analysis relies on historical cost data, i.e. on levelized cost of electricity (LCOE) generation from PV installation. The starting point are learning curves. But this approach has a flaw as the data used to depict "costs" of RET in learning curves represent not costs but market prices determined by demand and supply. This calls for taking market pricing into account,

which embeds implicitly utility or profit maximization at the demand side as well. In addition, market pricing is an interaction between demand and supply. Subsequently, apart from “original” learning effects, interactions and economies of scale and, as Kahouli-Brahmi (2008) states, learning-by-using, which reflects the user’s feedback, and learning-by-interacting, which takes place at a large diffusion stage, push costs. For this study, LCOE is modeled as a function of demand for PV (annual installations), input prices, PV market development (production and structure), R&D spending, learning (cumulated installations) and external factors. As there are interactions between demand and LCOE, demand is depicted as a function of LCOE, expected returns on PV investments, preferences (environmental) and external factors. Finally, returns depend on LCOE and revenues that are triggered by RE support, i.e. demand-pull policies. The approach is depicted in Figure 1. Learning-by-using or interacting are not separately

addressed and might be captured by cumulated installations while economies of scale might be reflected by average production per firm. Using the structural equation approach (SEM in Stata), the specified model are assessed by simultaneous (observed information matrix and robust estimator variance, see Annex with standardized and non-standardised coefficients), and non-simultaneous estimations. The observations mainly cover the period 1983 to 2015.

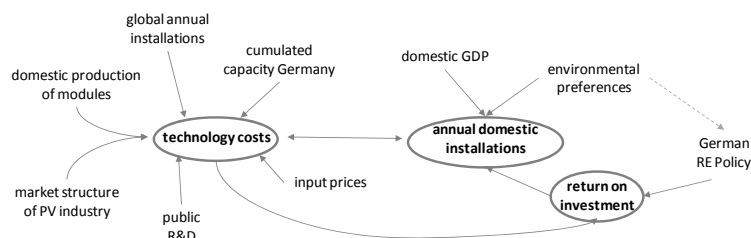


Figure 1: Structural model and dependent and explaining factors

RESULTS AND DISCUSSION

Demand (annual capacity) affects LCOE by about 0.1% in the short-run. The strongest impact on LCOE (price) has the input price with 0.3% followed by learning-by-doing effect (cumulated capacities), considered as long-term effects with about -0.2%, and the global deployment. Demand is strongly and significantly affected by costs (-4%). Finally, the return depends on LCOE, but if these are skipped, then the pull effect explains to a small degree returns, and hence the impact on demand. The primary impact of demand pushing policies augments prices through increased demand but as demand immediately is reflected in growing cumulated installations (learning), which significantly reduce costs, policy has, in a second step, a declining effect on technology costs. Simultaneous and nonsimultaneous regressions show different impacts, but they consistently report significant results for the LCOE regression for capacities, while other factors are either not well captured or insignificant. Inconsistent results are obtained regarding demand: the non-simultaneous approach does not report significant coefficients for demand. Even so this approach builds on learning curve approaches, there remains one major drawback: the estimator is based on cross-sectional data while time series data (mainly non-stationary) are applied. Applying time series based estimators requires an adjustment of the initial research question. This also includes the design of the exogenous variable capturing demand-pull policies. Finally, one problem can only be solved over time: the limited number of observations.

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Annex

Structural equation model			Number of obs		=		30	
Estimation method = ml								
Log likelihood = -49.063726								
	OIM							
Standardized	Coeff.	Std. Err.	z	P> z	[95% Conf. Interval]			
Structural								
lnlcoe <-								
lncapann	.4301312	.1542895	2.79	0.005	.1277294	.7325331		
lnpricesi	.132838	.0281547	4.72	0.000	.0776558	.1880202		
lnmodul	.0775672	.1647408	0.47	0.638	-.2453189	.4004533		
lnrd3yav								
L1.	-.0035988	.026749	-0.13	0.893	-.0560259	.0488284		
lncapcum	-.9570727	.1919338	-4.99	0.000	-1.333256	-.5808893		
lnglobanngr	-.4311355	.0932107	-4.63	0.000	-.6138252	-.2484458		
lncompet	-.0267843	.1345776	-0.20	0.842	-.2905515	.2369828		
_cons	1.223865	.5088762	2.41	0.016	.2264859	2.221244		
lncapann <-								
lnlcoe	-1.147056	.2580794	-4.44	0.000	-1.652883	-.64123		
lnmargincorr	.4057717	.2257839	1.80	0.072	-.0367567	.8483001		
lngreenvotes	-.4210799	.1709337	-2.46	0.014	-.7561038	-.086056		
lngdp_r	-.1341459	.3361299	-0.40	0.690	-.7929484	.5245656		
_cons	-12.01877	7.35805	-1.63	0.102	-26.44028	2.402747		
lnmargincorr <-								
lnlcoe	-.6804165	.1300076	-5.23	0.000	-.9352266	-.4256063		
lnpullcorr	.1455613	.1496193	0.97	0.331	-.1476871	.4388097		
_cons	59.84182	6.407214	9.34	0.000	47.28391	72.39973		
var(e.lnlcoe)	.0116485	.0043564			.0055966	.0242443		
var(e.lncapann)	.1100997	.0039745			.0601344	.2015809		
var(e.lnmargincorr)	.4777777	.1052915			.3101988	.7358877		
LR test of model vs. saturated: chi2(17) = 120.62, Prob > chi2 = 0.0000								

Table 1: Regression results OIM model (standardised)

Structural equation model		Number of obs		=		30	
Estimation method = ml							
Log pseudolikelihood= -49.063726							
		Robust					
		Coef.	Std. Err.	z	P> z	[95% Conf. Interval]	
Structural							
lnlcoe <-							
	lnlcapann	.1032998	.0396891	2.60	0.009	.0255106	.181089
	lnpricesi	.3139851	.0712062	4.41	0.000	.1744234	.4535467
	lnmodul	.0220912	.0368689	0.60	0.549	-.0501706	.094353
	lnrd3yav						
	LI.	-.0174183	.0853701	-0.20	0.838	-.1847406	.1499041
	lnlcapcum	-.2309867	.040041	-5.77	0.000	-.3094656	-.1525078
	lnglobanngr	-.1877192	.0343511	-5.46	0.000	-.2550461	-.1203923
	lnlcompct	-.0091076	.0353395	-0.26	0.797	-.0783718	.0601565
	_cons	1.378429	.4996845	2.76	0.006	.3990652	2.357792
lnlcapann <-							
	lnlcoe	-4.776242	.9585098	-4.98	0.000	-6.654887	-2.897597
	lnmargincorr	34.14017	21.52887	1.59	0.113	-8.055633	76.33597
	lngreenvotes	-9.300073	2.712377	-3.43	0.001	-14.61623	-3.983912
	lngdp_r	-4.125356	12.81986	-0.32	0.748	-29.25181	21.0011
	_cons	-56.36537	45.08654	-1.25	0.211	-144.7334	32.00263
lnmargincorr <-							
	lnlcoe	-.0336738	.0094442	-3.57	0.000	-.0521842	-.0151634
	lnpullicor	.0108755	.0075234	1.45	0.148	-.00387	.025621
	_cons	3.335596	.0276801	120.51	0.000	3.281344	3.389848
	var(e.lnlcoe)	.0147765	.0068988			.0059178	.0368959
	var(e.lnlcapann)	2.421537	1.20952			.909765	6.445445
	var(e.lnmargincorr)	.0014844	.0000552			.0007113	.0030978

Table 2: Regression results REV modell

Uncertainty in Benefit Cost Analysis of Smart Grid Demonstration-Projects in the U.S, China, and Italy

By Nihan Karali, Gianluca Flego, Jiancheng Yu, Silvia Vitiello, Dong Zhang and Chris Marnay

INTRODUCTION

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Given the substantial investments required, there has been keen interest in conducting benefits analysis, i.e., quantifying, and often monetizing, the performance of smart grid technologies. In this study, we compare two different approaches; (1) Electric Power Research Institute (EPRI)'s benefits analysis method and its adaptation to the European contexts by the European Commission, Joint Research Centre (JRC), and (2) the Analytic Hierarchy Process (AHP) and fuzzy logic decision making method. These are applied to three case demonstration projects executed in three different countries; the U.S., China, and Italy, considering uncertainty in each case. This work is conducted under the U.S. (United States)-China Climate Change Working Group, smart grid, with an additional major contribution by the European Commission. The following is a brief description of the three demonstration projects.

Tianjin Eco-city

The China demonstration covers several smart grid aspects of a Sino-Singapore endeavor in Tianjin. This project is evaluated using Smart Grid Multi Criteria Analysis (SG-MCA) approach. Three Sub-projects from the Eco-city demonstration project are included in this analysis: (1) Sub-project 2: Microgrid with energy storage (MgS), (2) Sub-project 3: Smart substation, (3) Sub-project 4: Distribution automation.

1.Sub-Project 2 (MgS): The 380 V MgS is composed of 30 kW of PV, 6 kW of wind turbines, 15 kW×4 h of lithium-ion batteries, together with lighting loads of 5 kW to 10 kW, plus EV charging for a total 15 kW. Control is by an economic microgrid energy management system that includes distributed power, an energy storage inverter, microgrid intelligent terminals, a microgrid system controller, the server host, and an operator station.

- 2.Sup-project 3 (Smart Substation): The Cheong 110 kV SS, uses 2x50 MVA electronic transformers, primary equipment on-line monitoring and other intelligent devices.
3. Sub-Project 4 (Distribution Automation): The DA pilot area distribution network uses a ring network power supply, an open-loop operation mode, and the requirement for mutual interconnection capability to meet N-1, important individual line and load reaches the N-2 line break point.

Irvine Smart Grid Demonstration

The U.S. example demonstration is Southern California Edison's Irvine smart grid demonstration project (ISGD). This project is evaluated with EPRI's benefits analysis method. Three Sub-projects from the ISGD project are included in this analysis: (1) Sub-project 1: Zero Net Energy Homes (ZNE), (2) Sub-project 3: Distribution Circuit Constraint Management Using Energy Storage (DBESS), (3) Sub-project 4: Distribution Volt/VAR Control (DVVC).

1. Sub-project 1: (ZNE): ZNE sub-project involves a residential neighborhood with four blocks of homes on the UCI campus used for faculty housing. ISGD has equipped three blocks of homes with an assortment of advanced energy components, including demand response devices, energy efficiency upgrades, residential energy storage units (4 kW/10 kWh), a community energy storage unit (25 kW/50 kWh), and solar PV arrays (ranging 3.2 to 3.9 kW)
2. Sub-project 3 (DBESS): This project domain includes a distribution-level battery energy storage system to help prevent a distribution circuit load from exceeding a set limit, to mitigate overheating of the substation getaway, and reduce peak load on the circuit. DBESS has a rating of 2 MW of real power and 500 kWh of energy.
3. Sub-project 4 (DVVC): DVVC optimizes the customer voltage profiles in pursuit of conservation voltage reduction. Field experiments showed an average 2.6 % energy savings, making this demonstration a major success, and SCE intends to gradually roll the technology out system wide; however, it may not be applicable to all distribution networks depending on pre-existing equipment.

City of Rome

The Italy demonstration involves a pilot project in Rome conducted by ACEA, Italy's third largest distribution network operator. This project is evaluated with JRC's cost benefits method, which is a derivative of the same approach used by ISGD. JRC demonstration was conducted in the Malagrotta area, west of Rome, and involved the installation of new technical solutions on 6 feeders, about 69.5 km of medium voltage (MV) (20 kV) and low voltage (LV) (8.4 kV) lines. There are 4 distributed generation plants directly connected at MV (1 PV array and 3 biomass plants accounting for about 20 MW of installed capacity), and 7 users directly connected to the MV grid accounting for about 3.5 MW of load. The project is made up of 3 main additive components:

1. MV grid automation focuses on enabling the automatic selection of fault line segments, and allows remote distributed generator management based on actual grid conditions
2. At both MV and LV levels, ACEA set up a remote control and monitoring system that allows remote operation of more than 60,000 switches. This sub-project included real-time measurements at secondary substations including technical characteristics of the grid at both voltage levels.
3. Centrally, the development and set up of a new grid management algorithm will allow further benefit capture from sub-projects a and b, allowing: load flow management, optimization of load profiles, and minimization of technical losses.

METHODS

Benefit Analysis with SG-MCA

SG-MCA is a method combining AHP and fuzzy logic to assess the benefits of smart grid projects. In this method, a hierarchy structure is used to evaluate the project's performance. In each hierarchy, all of the indexes (i.e., technical, economic, social, and practical indexes) are assigned with a weight value determined by experts' judgements. Projects are evaluated in four domains, which are technology, economy, sociality, and practicality. Ultimately, a final score is calculated for the project to qualify the performance in both four aspects and as an entity.

Benefit Analysis with EPRI and JRC Approach

Both EPRI and JRC approaches define benefit as a monetized value of the impact of a smart grid project to all stakeholders involved (e.g., consumer, utility, society). All the benefits must be expressed in monetary terms. For smart grid systems, there are four fundamental categories of benefits, as identified by EPRI:

- Economic – reduced costs, or increased production at the same cost, that result from improved utility system efficiency and asset utilization
- Reliability and Power Quality – reduction in interruptions and power quality events
- Environmental – reduced impacts of climate change and effects on human health and ecosystems due to pollution
- Security and Safety – improved energy security (i.e., reduced oil dependence); increased cyber security; and reductions in injuries, loss of life and property damage.

The benefits analysis in the EPRI method is based on the difference between the benefits and costs associated with a baseline scenario. In the EPRI adapted methodology by JRC, the level of detail of assets, functionalities and benefits are different, in order to take into account the contribution of each single physical asset constituting the project and its impact on the total benefits.

RESULTS

Tianjin Eco-city

The overall performance of the Tianjin Eco-city demonstration project from SG-MCA method is good, with a score of 87 of 100, but the economy is relatively poor with a score of 64. The technology, sociality, and practicality scores are 96, 93, and 80.

ISGD

ISGD demonstration results from EPRI method, shown in Table 1, indicate that ZNE is far from being economically attractive at current project performance and expenditures. The equipment cost, about \$146 k/home would need to be about 94% lower to achieve break even, i.e., B/C ratio, greater than 1. The results of this analysis should only be considered illustrative, not financial, for the purpose of evaluating the SGCT. In contrast, DBESS and DVVC appear to be economic.

City of Rome

NPV	ZNE	DBESS	DVVC
Cost	\$(4.64M)	\$(0.85M)	\$(0.59M)
Benefit	\$0.30M	\$2.14M	\$7.58M
Net Benefit	\$(4.34)M	\$1.30M	\$6.99M
B/C Ratio	0.1	2.5	12.9

Table 1. Results for ISGD Sub-Projects

Malaggrata demonstration results from JRC approach indicates that LV remote control and monitoring are the most important in monetary terms. Summing up, the results of the application of JRC's benefits analysis method to the Malagrotta pilot project are extremely promising. The outcome of the analysis points to an internal rate of return for Malagrotta of 1.23%, that however becomes 16.60% when scaling up the solutions tested in the pilot to the whole Rome network.

CONCLUSIONS

Uncertainties in the estimates from all methods and cases are relatively high, based on the range of estimates provided by the studies drawn upon for this report, and the judgment of the authors. Both methodologies present some difficulties in the evaluation of smart grid benefits. SG-MCA, for instance, is not effectively representing public and private costs, but only their effectiveness in achieving the overall goal. EPRI and JRC methodologies are not appropriate in managing intangible impacts, such as practicability, which could be more relevant to policies and strategies at this scale for achieving smart grid benefits.

Italian Affiliate Elects New Officers

At its July Annual Meeting AIEE elected new officers and board members.

Reelected President was **Carlo Andrea Bollino**

To serve with him, Carlo Di Primio Vice President and CEO; and Vittorio D'Ermo, Director of the AIEE Energy Analysis & Forecasting Service.

Board members elected were Luigi Napoli, Rita Pistachio, Marco Porro, Lucia Parisio Visconti, Mario Taraborelli and G.B. Zorzoli.

Bergen Overview (continued)

IAEE Awards Dinner

The IAEE Awards dinner was held in Grieghallen, named after the Bergen composer, Edvard Grieg (1843-1907), and venue of the Bergen Philharmonic Orchestra, one of the oldest orchestras in the world and celebrating its 250-ieth anniversary this year. The Managing Director of NHH, Nina Skage, was an elegant and eloquent master of ceremony of the dinner. She dressed in her national costume, as did several of the other Norwegians attending the dinner. The musical entertainment was performed by the Concertmaster of BFO, Melina Mandozzi on violin, accompanied by Alina Letyagina on piano, and playing music of Norwegian composers, including Grieg. They were followed by Åse Teigland on the special Norwegian music instrument, the Hardanger fiddle, a violin but with five "understrings" in addition to the ordinary ones. She played Norwegian folk music and accompanied two young dancers with music to a Norwegian folk dance called "springar". The musicians and the dancers received well-deserved and long applause from the audience of almost 600 dinner guests.

In addition to IAEE-awards bestowed on the members of the Organizing Committee, Past President Wumi Iledare received the Outstanding Contributions to the IAEE Award from the IAEE President, Gürkan Kumbaroglu, and responded with a short and well-formulated speech of thanks. Immediate Past President Peter Hartley received the Best Energy Journal Article Award and Frank Obermüller the Best Student Paper Competition Award. Finally, the General Conference Chair, Einar Hope, was called on to the stage to receive a gift and a word of thanks from Nina Skage.



Gala dinner attendees were given an introduction to the beautiful cultural heritage of Norway.

Assessing the Impact of Renewable Support Policies – Modelling Investors and Investment Decisions

By Francesco Hipp and Christoph Weber

INTRODUCTION

One key issue for renewable energy policy design is the estimation of possible impacts of specific support mechanisms such as feed-in-tariffs or quota systems. To assess the impact of different promotion schemes one has to be able to forecast future investment in renewable energies. Most models aiming at modelling investments in the energy sector focus on the assessment of the profitability of possible investments. This means capital demand is modelled but since every profitable investment is realized there is no consideration of capital availability and capital supply among the different investor groups. Every investment decision in reality is linked with a matching of capital supply and demand. Thus to model investment decisions in renewable energies it is necessary to model both aspects. In the proposed Renewable Energy Investment model (REInv model), the profitability of different renewable energy investments and the associated risk are assessed and on this basis the capital demand curve is derived. The corresponding capital supply is dependent on the financial resources of the investors and their requested return on investments. The model is used to assess the future development of renewable energies in Germany under different support schemes and allows to compute key figures like renewable energy production, installed capacity, investment volume and height of the renewable surcharge.

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THE REINV-MODEL

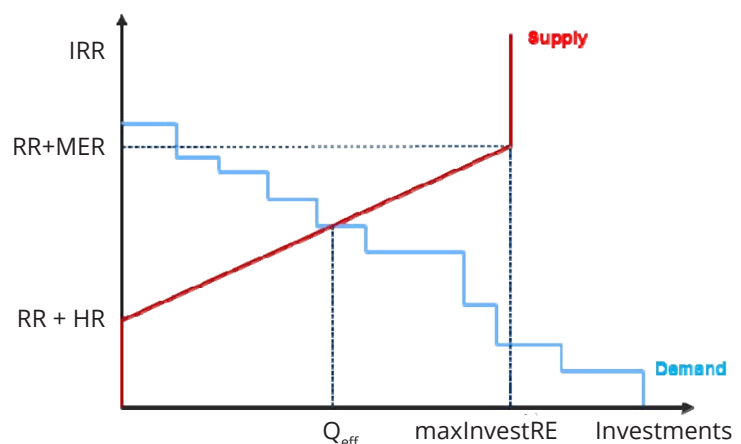
As in other markets, capital supply is expected to be an increasing function of the price of capital, i. e., the interest rate or expected return on investment. A parsimonious yet realistic model is needed to describe the investment behavior of different investor groups dependent on the profitability of the investment alternatives. Therefore a piecewise linear capital supply function is designed (see Figure 1). It is characterized by three key parameters: the minimum profitability above the relevant rate (which can be the risk free interest rate or the weighted average cost of capital depending on the specific investor group) required for any investment (the so-called hurdle rate), the maximum available capital for renewable energies and the level of profitability necessary to make full use of the available capital (maximum excess return). Because investors are heterogeneous the capital supply represented by the investment function has to be modelled separately for the different investor groups considered (e.g., private households, farmers, insurance companies).

$$Investment = maxInvestRE * \max \left\{ \min \left(\frac{IRR - (RR + HR)}{MER - HR}, 1 \right), 0 \right\}$$

<i>maxInvestRE</i>	Maximum investments in renewable energies
<i>IRR</i>	Internal rate of return
<i>HR</i>	Hurdle rate
<i>RR</i>	relevant rate
<i>MER</i>	Maximum Excess Return

. Therefore functions similar to cost potential curves are implemented for most of the 18 included investment alternatives. For each investment alternative, the IRR is calculated taking into account detailed information on the revenues depending on the policy support mechanism and market environment as well as technical and application characteristics like full-load hours and possible self consumption. The corresponding cost are derived using CAPEX, OPEX, depreciation time, physical lifetime etc.

The introduced modelling of capital supply and demand leads to an equilibrium solution, which may



be computed in a dynamic recursive manner for a sequence of future years.

RESULTS

The impact of support schemes in energy markets can be measured in various dimensions. When it comes to the promotion of renewable energies key impacts are the annual electricity generation, necessary investments and the costs to society (measured notably through the height of the renewable surcharge for electricity consumers). The developed model is used to forecast the development of renewable energies in Germany until 2030 with a focus on these key impacts. By modelling different support schemes it is possible to compare the influence of these promotion schemes on the electricity market. Preliminary results cover the German feed-in tariff EEG 2012, a renewable energy premium and a renewable energy quota scheme. For the EEG 2012, also sensitivity analyses on the influence of several input parameter like central bank interest rates on the results have been made.

The highest investment in renewable energies is observed with the conventional feed-in tariff. Because of a missing adjustment of regulation we see an overachievement of the German goals. Under the considered premium scheme the support level adjusts as a function of the growth of renewable energies. Therefore only a temporary overachievement of policy goals is observed in this scheme and the amount of investment is lower. The quota is the mechanism with the lowest investment volume due to the fact that there is no overshooting of pre-established targets (as with the planned reform of the EEG 2016/2017) and no technology-specific support. This is accompanied by a similar ranking in social costs of policies. In our calculations the capital resources in all three mechanisms are sufficient to realise all profitable investments.

CONCLUSIONS

The developed model is a useful tool to forecast the investments in renewable energies by different investor groups depending on the policy support mechanism and the development of the market environment. Capital demand and supply are modelled which enables the assessment of a possible shortcoming of capital in the market. Among other things this allows a consideration of risk which is crucial when comparing the impact of different support policies. So far, risk adjustment is done based on risk scorings transformed into interest rate adjustments – as is current practice in companies. One possible model improvement would be an endogeneous calculation of risk-adjustment factors to better describe the influence of different support policies on the cost of capital. Furthermore the model may be extended to cover further support policies, investor groups or technologies.

While no final conclusions should be drawn based on the preliminary calculations, the results indicate that cost-efficiency of the promotion of renewable energies is strongly supported by technology-unspecific promotion which is adjusted as a result of the observed growth of renewable energies. Sensitivity analyses demonstrate a high robustness of the model results against variations of single input parameters like central bank interest rates.

Bergen Overview (continued)

Social Events

Apropos Edvard Grieg: A private tour and concert for accompanying persons was arranged on Wednesday to the composer's home, Troidhaugen, (the Hill of Trolls) outside Bergen. The Director of the Troidhaugen museum, Sigurd Sandmo, received the busload of visitors, introducing them to the place and its history, and the renowned pianist, Håvard Gimse, played some of Grieg's music. It was a most memorable musical and historic event in beautiful surroundings.



Conference delegates had many opportunities to both network and enjoy the history and culture of Bergen

Optimal Storage Management Under Uncertainty

By Joachim Geske and Richard Green

OVERVIEW

In electrical systems storage has the technical potential to increase efficiency significantly - especially in the context of integrating intermittent renewable technologies. This is achieved by shifting energy from periods of low residual demand to periods of high demand. This raises the utilization of base load power plants and reduces that of peak load power plants. The full gain is achieved if generation capacity is adapted to the "equilibrated" load situation - with a higher base load capacity and fewer peaking stations. In this case, the installed fossil generation capacity might fall below peak load level. Since the amount of energy stored is limited, there is a risk of expensive outages in cases of prolonged demand peaks.

Many previous analyses of storage are based on perfect foresight models in which the operator could ensure that the store always approaches a prolonged peak with just enough energy to avoid an outage. In the real world, it may be impossible to predict the length of a peak, and a different strategy is needed: taking this issue into account, our aim is to derive the optimal way of integrating the storage into the system. Compared to the perfect foresight equivalent, the more realistic storage management strategy includes more "waiting" and "reserve" holding to prevent outages. As result, the storage cannot be operated as efficiently as in the perfect foresight case, reducing the cost savings available. We also find that an increasing risk of reaching peak load further reduces the efficiency potential of the storage. Since the optimal storage strategy is not implemented "naturally" by competitive storage operators, it might be advisable not to adjust generation fully in response to the growth of storage, reducing the difficulty of regulating it.

METHODS

We have derived the expected cost minimizing way of operating energy storage and non-intermittent generation and adjusting non-intermittent capacities for a given storage capacity (300 GWh in our case study). The operator aims to satisfy demand while processing sequentially revealed information about the uncertain residual load. The problem is stochastic and multiscale as it includes short term information processing, storage management and generation decisions as well as long term investment decisions in generation capacities. We develop a dynamic stochastic electricity system optimization model as a Markov Decision Process. A solution is an optimal strategy that assigns each state - defined by the amount of stored energy, residual demand and non-intermittent generation capacities - a probability distribution over possible charging and discharging values. The non-intermittent generators run in merit order to meet the residual demand plus charging (or minus discharging). The model is quantified with an estimated homogeneous Markov Chain representation of the residual load (demand minus wind and solar output) in Germany in 2014 on an hourly basis and with technology cost data. The model is solved for a stationary policy using a linear optimization approach embedded in a hill climbing capacity optimization environment. This strategy and the stationary probabilities are analysed using counterfactual experiments and they are compared to the optimal solution derived under perfect foresight of explicit drawings of the stochastic load process. Thus features of the optimal strategy can be derived and the perfect foresight "error" can be quantified.

RESULTS

Figure 1 shows the optimal stationary strategy for the case we analysed. Although the peak residual load is 80 GW, it is optimal to build only 70 GW of capacity (note that our model currently simplifies the actual data to work in multiples of 10 GW). Therefore, the peak residual load of 80 GW cannot be covered without unloading the storage. If the state of charge is zero, it cannot be discharged any further and load is lost. Lost load is valued by the social planner at 100 times the marginal cost of the most expensive non intermittent technology.

For most charging levels, storage is used for arbitrage and charged below a residual load of 50 GW and discharged above - more strongly, the greater the deviation from 50 GW. This increases the utilization of non-intermittent generation capacity and therefore efficiency. Thus an after-storage-load of 50 GW is achieved over a wide range of the states, making an expansion of base load capacity profitable.

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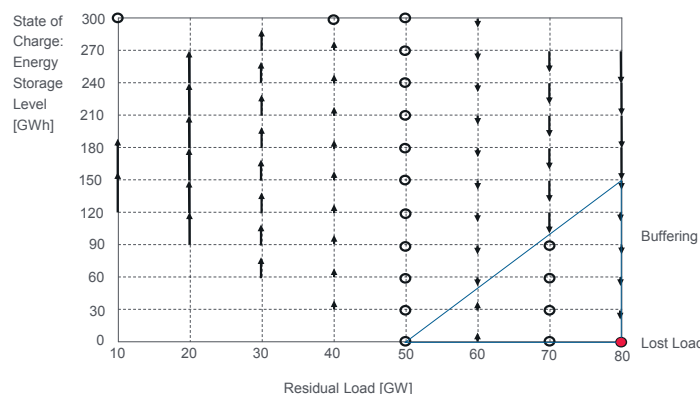


Figure 1: Optimal storage strategy as a function of the state of charge (SOC) and residual load and non-intermittent generation capacities. Black arrows and circles (no operation) indicate the change in SOC.

There is a different pattern in the states included in the red triangle ("Buffering"-area) in the lower right corner. In this area the storage is only unloaded in the case of peak load. Equilibration is limited by three forms of "stabilization actions" to reduce the risk of losing load:

1. At peak load, the storage is discharged in 30 GW steps to keep the load on generators at 50 GW, as long as the charge level is above 130 GWh. Below this level discharging is reduced to 10 GW steps to delay any lost load, which requires all 70 GW of generators to run.
2. At the next load, 70 GW, discharging continues at the load-equilibrating rate (20 GW steps) until a state of charge of 100 GWh is reached. Full load is then accepted to keep a higher "distance" from lost load.
3. With a residual load of 60 GW, the storage would switch to charging, using all the generation

available, if the stored energy fell below 50 GWh.

The "stabilizing" actions result in a reserve ("buffering") area with very low probabilities of staying in a state of charge below 50 GWh.

Under the perfect foresight hypothesis with 20 simulated time series from the residual load Markov modelling, system costs can be reduced by 4.4% using 300 GWh storage capacity. The solution with a stochastic residual load without storage is slightly more expensive, but storage replaces peak load capacity and enables an extension of the base load capacity of 10 GW with a reduction in the mid-merit capacity. Therefore, system costs fall by 2.9%, which is one-third lower than with perfect foresight modelling. The consideration of unpredictable changes in residual load and thus holding reserves to avoid lost load seemingly reduced efficiency gains by energy storage.

CONCLUSIONS

It is shown that under uncertainty at high demand an increasing share of the storage is "frozen" in its charged state to avoid lost load (outages). Therefore, a "buffering" share of the storage is not used actively for the equilibration of load any more. Furthermore, this buffer state of charge is established, if necessary, even in periods of high demand when a fully-charged store would be able to de-stress the system. It can be shown that the size of the buffering area rises as the risk of losing load rises. Thus the efficiency gains of storage decrease as uncertainty in the system rises.

This "buffering" does not occur in the perfect foresight analyses that are still the paradigm of energy systems analysis. Estimates of the potential of storage based on perfect foresight are thus overestimated. Furthermore, the welfare maximizing strategy includes "not unloading" in high marginal cost/price cases. The market implementation of this strategy requires the communalization of lost load costs. We propose a contract solution that includes a premium paid in high load cases for not unloading. This contract makes the storage operator indifferent between reserve holding and unloading. A further option to implement the welfare maximizing strategy would be to operate a sufficiently sized store explicitly as a buffer in the public interest.

Such contracts might be difficult to implement in practice, and so a further option might be the operation of the system with imperfectly adjusted capacities such that non-intermittent generation capacity exceeds peak load. In this case it has to be decided whether the storage is operated "inefficiently" with respect to "full" capacity adjustments, or "efficiently" when peak load capacity is not decommissioned "one for one". The challenges of sustaining rarely-used capacity were a frequent topic at the Bergen conference, however.

Optimal Level of Supply Security in the Power Sector with Growing Shares of Fluctuating Renewable Energy

By Aaron Praktiknjo and Lars Dittmar

In many countries a rapid expansion of intermittent renewable power generation has occurred in recent years. Simultaneously, conventional power plants such as nuclear generators are being phased-out of the energy system. Especially the German power system is characterized by these two developments.

In this context, appropriate methods for the assessment of the security of electricity supply are more important than ever. In general, there are deterministic and probabilistic methods to assess security of supply or generation adequacy respectively. In the past, the four German transmission system operators (TSOs) have relied on a deterministic approach. However, while there is a continuous debate about methodological details, it is widely acknowledged that probabilistic approaches are more appropriate than deterministic ones especially in light of the stochastic nature of intermittent renewables. We share this opinion and, therefore, revert to probabilistic methods.

While policy makers in Germany circumvent the question of appropriate level supply security by not defining it explicitly, we argue that rational policies must derive the level security from economic considerations. Ideally, investments in supply security should only be made if the resulting benefits outweigh the costs. With our research, we want to contribute to the economic assessment of security of supply and thereby provide a rational guideline on how to derive an economic efficient level of security.

SUPPLY SECURITY OF CONVENTIONAL GENERATORS

In order to assess the contribution of conventional plants to generation adequacy, we use the so-called methodology of recursive convolution. The basic idea behind it is that single production units are allowed to only be in two possible states: available and unavailable. With this, the state 'non-available' of a given plant occurs with a specific probability of (p) while the state 'available' occurs with the complementary probability of ($1 - p$). We differentiate unavailability in scheduled (maintenances) and unscheduled unavailability and formulate an econometric model to account for observed seasonalities, see figure 1.

Using the information of installed capacities and the probabilities of occurrences on availability and unavailability, the result of our recursive convolution will be a cumulated distribution function of the available generation capacity of the entire portfolio of conventional power plants.

CONTRIBUTION TO SUPPLY SECURITY OF RENEWABLE GENERATORS

The distribution of available capacity of renewable is rather continuous (ranging between 0 and 100 %) than discrete binary. We therefore use aggregate data of the feed-in from renewable power generators. We rely on hourly time series published by the German TSOs for the feed-in of wind and photovoltaic plants. The time series for wind ranges from 2006 to 2014, whereas the data for photovoltaic range from 2011 to 2014. In order to increase representativity of our time series we employ two supplementary approaches. First, we formulate a polynomial regression model of order 3 using weather data (e.g. wind speed) from over 60 stations as independent variables and the TSO time series for the period from 2006 to 2014 as dependent variable. The regression yields a high goodness of fit with exceeding 95 % when pitted against the actual data on feed-in from the TSOs from 2006-2014. Using this model, we extend our data on feed-in to a period of over 21 years

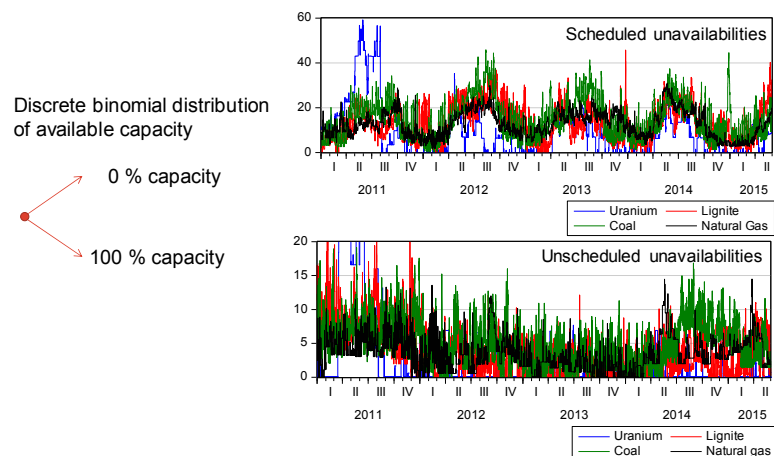


Figure 1. Unscheduled and scheduled unavailabilities of generators

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(from 1994 to 2004), see figure 2. Second, we apply the so-called sliding window technique to increase representativeness of the data, including also feed-ins at times to proximity of the examination time.

Given the information presented above, we can express the available capacity of renewable generators in dependence of the probability of occurrence and time of the year. Therefore, we also receive a cumulated distribution function.

THE OPTIMAL LEVEL OF SUPPLY SECURITY

From an economic and welfare perspective, the optimal level of supply security is achieved if marginal cost for an increase in supply security is equal to marginal utility for an increase in supply security. Ideally, investments in supply security should only be made if the resulting benefits from an increase in supply security amounts at least to the investment outlay.

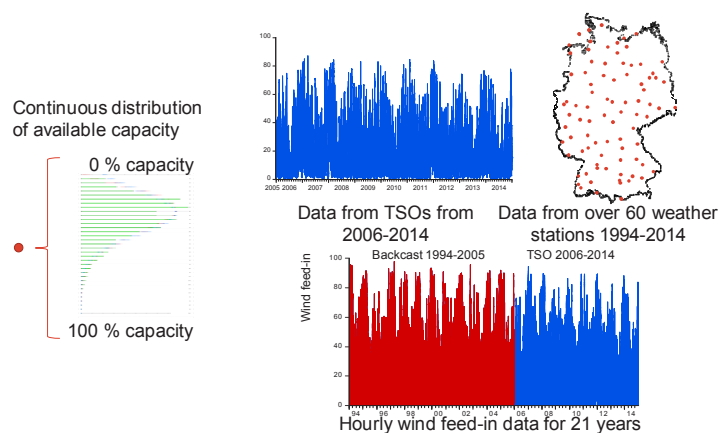


Figure 2. Availabilities of renewable generators

Supply security can be increased by installing additional generation capacities. As we know, the identification of the economically most viable option for the choice of generation technology depends among others on the annual full load hours of operation. In the case of Germany with its already relatively high level of supply security, the full load hours would be very small. Thus, the cheapest option would be to invest in gas turbines. The marginal cost of supply security would be almost equal to the capital cost of an additional gas turbine.

As for the utility of increased supply security, we can interpret it as the avoided cost of reliability issues. In the electricity business, these avoided costs correspond to the so-called value of lost load (VOLL). In a previous publication, we showed that

the VOLL is dependent on the duration of an interruption in supply (VOLL increases significantly with shorter durations of interruption) and estimated it for Germany.

Given the data on marginal cost and marginal utility for an increase in supply security, it becomes possible to estimate the welfare optimal level of supply security.

RESULTS

We convolve cumulated the distribution functions of conventional and renewable generators using Monte Carlo simulation techniques to obtain a cumulated probability density function for our total generation portfolio for every hour of the year. Figure 3 shows the result for the hour of the German peak load in 2014 (79.1 GW on December 3, 2014 between 5 and 6 p.m.). Here, the probability of a deficit in supply compared to the demand for the hour of the peak load alone is lower than 10^{-12} .

After having calculated the secured capacity of the total portfolio of power plants, we evaluate the

contribution of the different types of generators to total supply security. To do so, we estimate the so-called capacity credit. The capacity credit represents the contribution of a group of generators (at a predefined level of supply security) to the secured supply of our total portfolio and can be interpreted as a kind of performance indicator for our group of generators. Figure 4 schematically depicts the methodology for the calculation of the capacity credit and shows the result for the German peak load hour in 2014.

With our results, we can estimate that phasing-out nuclear power plants, *ceteris paribus*, obviously leads to a decrease in supply security. For the peak load hour alone, the level of supply security would drop from almost 100 % to a level of about 95 %.

Carrying out the assessment for the welfare optimal level of supply security, our results indicate that the optimal level of supply security over a year would be equal to about 99.99994 %. Translated to the level of supply security of the peak load hour, this would also amount to approximately 95 %.

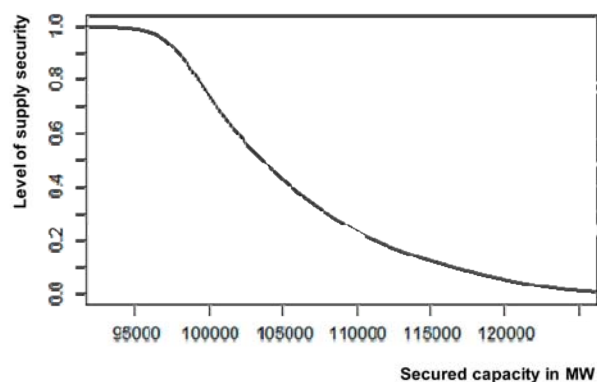


Figure 3. Cumulated probability density function for the entire generation portfolio

DISCUSSION AND CONCLUSION

Our results indicate that the overall level of supply security in Germany in 2014 is extremely high with a probability of a deficit for the peak load hour alone of almost 0 % (below 10^{-12}). Our results confirm that the contribution of intermittent renewable capacities is much less than the contribution of conventional generation capacities. For the peak load hour, wind power contributes to supply security only by about 7.2 % of the installed capacity, while conventional capacities can contribute by about 95 % of the installed capacity. In other words, 1 GW of conventional power generation (e.g. nuclear power) has the same contribution to system adequacy as 13 to 14 GW of installed wind power. At the peak load, photovoltaic generation does not contribute to security of supply at all. This is caused by the fact that the peak load in Germany regularly occurs in the evening hours of the winter.

From our analysis we can conclude that the phase-out of nuclear power will ultimately lead to a decrease in the total level of supply security (from 100 % to 95 % for the peak load hour) while the installation of new renewable generators alone will hardly compensate for it. However, we have shown that the theoretically optimal level of supply security is equal to 99.9994 % in a year, which is equal to approximately 95 % for the peak load hour. Therefore, from an economic perspective, the decrease in supply security resulting from the phase-out of nuclear power plants would still be at a tolerable level. With this, new investments to re-increase the level of national supply security would be unnecessary and a waste of funds. But in the end, it is the German society that will be the one to decide on the final level of supply security, economic welfare or not.

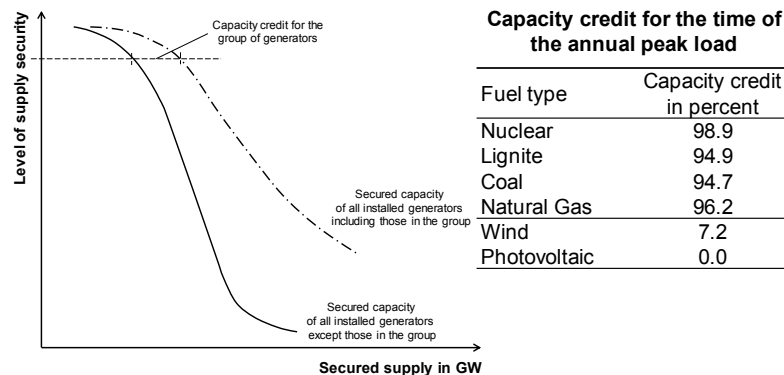


Figure 4. Calculating the capacity credit (at a level of 95 %)

Bergen Overview (continued) (Social Events)

On Tuesday evening the City of Bergen gave a reception in the magnificent Håkonshallen, King Håkon's Hall, represented by the Mayor of Bergen, Marte Mjøs Persen. Håkonshallen is a large medieval stone hall, built from 1247 to 1261 and inaugurated for the wedding of a King Magnus Håkonsson in 1261, with 2000 guests attending. The Mayor gave a brief account of the history of the hall and then dwelt upon the importance of energy for the economic development of Bergen and the region around it and the role of Bergen as the "energy capital" of Norway.

Bergen Conference Wrap-Up

All in all, the conference seemed to work well and many positive comments and feedback were received from conference participants. The conference facilities at NHH functioned quite satisfactorily and NHH was most generous and supportive in hosting the conference. Much praise was also received for the quality of the food served during the conference and for the service.

Last but not least: A sincere word of thanks and appreciation to the conference sponsors for their financial support, which made it possible to organize a qualitatively better conference than otherwise.



The Bergen Conference Team--Their hard work was instrumental to the conference's success

The Impact of Auctioning in the EU ETS: Are Utilities Still Profiting?

By Dominik Möst, Hannes Hobbie and Matthew Schmidt

REFORMING THE EU ETS: WHAT TO DO ABOUT WINDFALL PROFITS?

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In the run up to the end of the second phase of the European Emission Trading Scheme (EU ETS) in 2012 an intense political discussion was devoted to how CO₂ emission certificates are allocated. Considering that allocations to power generation plants account for ca. 50% of the certificates in the EU ETS, the power sector was prominently scrutinized (Trotignon & Delbosc 2008). One central issue concerned whether or not the operating allocation method based by large on grandfathering in emitters by assigning them emission allowances free of charge (based on historical emissions) had enabled compliant power companies to generate large carbon rents or so-called windfall profits¹ (Veith et al. 2009; Matthes 2008). Pahle et al. (2011) provides evidence for Germany that the presence of windfall profits led to an increase in emission-intensive coal investments. Further research establishes correlations between movements in carbon prices and end-user prices, highlighting incidences of cost-pass through in the power market. Estimates on pass-through rates have ranged from 50-100% while more recent studies have ascertained rates of up to and beyond 100% (Sijm et al. 2008; Lise et al. 2010; Fell et al. 2015). Keppler and Cruciani (2010) estimate carbon rents in the power sector in Phase 1 of the EU ETS to have totalled more than EUR 19 billion.

In a move to assuage these concerns, for the third phase of the EU ETS (2013-2020) a dramatic shift towards an exclusively auction based system for allowances allocated to the power sector was instituted. Carbon certificates are now required to be purchased by power producers in accordance with the polluter pays principle² (Woerdman et al. 2009). The reform aims to negate the windfall profits being earned by producers in the power sector by forcing power producers to assume material costs (out-of-pocket costs) for the allocated permits. The measure, however, has prompted fears among utilities and power companies with carbon intensive generation fleets that their business operations are being put at risk by the carbon costs incurred.

Against this backdrop, we address the question as to exactly what kind of welfare impacts increasing carbon prices under an auctioning regime have on electricity producers and how the welfare gains or losses are distributed among the countries part of the EU ETS. Furthermore, we investigate whether the carbon intensity of the generation fleet or the generation structure itself in the respective country has a greater impact on producer surplus.

FRAMING THE DEBATE AROUND WINDFALL PROFITS IN THE EU ETS

While the justification for windfall profits has been scrutinized, economic theory holds that cost pass-through occurs as a result of the opportunity costs that carbon allowances represent (Verbruggen 2008).

The basic concept behind the notion of windfall profits is illustrated in figure 1. The opportunity costs represented by carbon allowances (grey column) are factored into the variable production costs of the respective power generator. As is apparent from the stylised diagram, depending on the carbon intensity of the particular technology in the electricity mix, the carbon markup can vary greatly. Under market efficiency conditions, price equals the marginal costs (of the price-setting technology) and no profit is realized independent from the carbon price. However, carbon rents to lower-emission, infra-marginal technologies accrue due to the difference between the market price and their respective marginal costs (Keppler & Cruciani

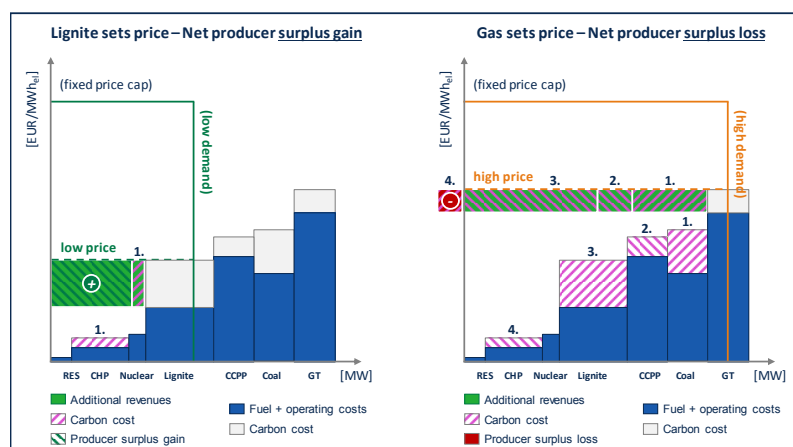


Figure 1: Impact of the price setting technologies on carbon rents

2010). Hence, the carbon price as well as the emission factor of both technologies have a strong impact on the producers' profits. This is especially true if carbon price increases induce a fuel switch that leads to a more carbon intensive price-setting technology (Pettersson et al. 2012). In addition, the demand structure of the market plays an important role in determining which technology clears the market during the course of the year (see fig. 1).

Utilizing a fundamental model of the European electricity market (ELTRAMOD)³ and developing two basic scenario sets based on 2014 data, we perform a model-based analysis of the electricity market assuming perfect competition and a cost-pass through rate of 100%. We benchmarked and backtested the model with historical data from 2014. The model can explain power prices very well based on fundamental data with an MAE of approx.. 4 €/MWh. The reference case (REF) is based on the data of 2014, while we analyse the impact of changing two parameters: the carbon price and the gas price. We vary the carbon price by two (2xCO₂) and fivefold (5xCO₂). Furthermore, we define a so-called high gas price scenario (HGas), where we increase the gas price by a factor of two. We also vary the carbon price in the high gas price scenario by a factor of two (HGas_2xCO₂) and five (HGas_5xCO₂) and analyse the impact of changing carbon prices. The model results for the respective carbon scenario are then compared to the corresponding high or low gas price reference case.

DO UTILITIES PROFIT FROM HIGHER CO₂ PRICES DESPITE AUCTIONING

The overall model results follow the intuitive assumption of an inverse relationship between the price level of emission allowances and the absolute volume of CO₂ emissions from the power plants in the modelled countries. Furthermore, in all high gas price scenarios (HGas_REF, HGas_2xCO₂, HGas_5xCO₂) the emissions are higher than in the reference case. This is to be expected since a higher gas price undercuts the carbon intensity-specific advantage the fuel enjoys over, e.g., coal-fired generation. As figure 2 shows, the gradient between the first set of scenarios (REF, 2xCO₂, 5xCO₂) and the second set of scenarios with higher gas prices (HGas_2xCO₂, HGas_5xCO₂) is also steeper due to the fact that at a low gas price the incidence of fuel switching is much higher than when the gas price is twice as high.

Furthermore, as expected the electricity mix in the various countries analysed shows a general shift away from more carbon intensive generation units, e.g. lignite coal, in the higher CO₂ price scenarios towards more low-emission sources, e.g., natural gas. In sum, due to the 100% pass-through rate assumed, higher carbon and gas costs imputed in the respective scenarios generate larger system costs (meaning higher costs to meet the consumer's inelastic demand⁴) which in turn are reflected in net welfare losses.

As to the first question posed, the scenarios with higher CO₂ prices (2xCO₂ and 5xCO₂) show that contrary to the intuitive assumption, relative to the reference case gains in producer surplus do accrue to electric utilities part of the EU ETS. Higher carbon prices induce higher power prices. In the case where CO₂ intensive power plants are dispatched as the market clearing generation technology, the market price is respectively higher, creating a higher carbon rent for infra-marginal technologies in the merit order. For countries such as France with a low carbon fleet (nuclear), the margin between the new market price and the prevailing variable cost structure is greater, yielding a larger carbon rent and in turn a higher producer surplus. A similar trend is also detected for countries with a generation structure dominated by carbon intensive power plants. For example, in Poland where a large coal-fired capacity is installed, the carbon intensive fleet functions as the price-setting technology increasing the relative carbon rents for infra-marginal generators⁵.

While this is the case for almost all countries analysed, Italy stands out as the only electricity market where a drop in the relative producer surplus is observed in the reference cases. This result provides interesting insight into our subsequent question, namely, what impact the country's respective generation structure has on carbon rents. Power capacity in Italy is dominated by gas-fired plants, which as noted have a much lower emission factor and are thus are less sensitive to carbon price increases. The model results indicate that natural gas maintains its price-setting status throughout the year in the scenarios with the low gas price. This results in a relatively small carbon mark-up on the market

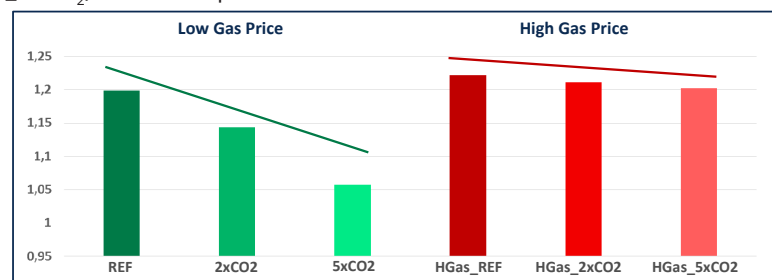


Figure 2: Absolute volume of CO₂ emissions (Bill. Metric Tonnes) in low and high gas price scenarios

price that is not large enough to offset the increase in the variable costs of the carbon intensive infra-marginal technologies. The outcome is a net relative decrease in producer surplus.

Increasing the gas price by twofold in the model delivers some interesting insights: In Italy, the increase in the gas price does not affect the technology's price-setting status. Once again, a relative net drop in producer surplus is observed. In Great Britain, however, diverging from the prior set of scenarios (Ref, 2xCO₂ and 5xCO₂) where a higher carbon price results in a fuel switch where gas is displaced by coal-fired generation as the price-setting technology and induces a relative increase in rents for infra-marginal producers, in the high gas price scenario this does not occur. This results in a situation that is similar to the one in Italy, where gas prevails as the market clearing technology and carbon intensive plants cannot recover their carbon costs resulting in relative drops in producer surplus. This implies that in markets where gas-fired generation capacity is the prevailing technology, the carbon intensity of the fleet is secondary to the structure itself.

SUMMARY

The analysis clearly shows that countries with a carbon intensive generation fleet that function as the price-setting technology in the power market profit from increases in carbon prices. Thus, auctioning off carbon allowances does not have a net negative effect on electricity producers (with CO₂ intensive technologies) per se. Of course, depending on the specific nature of the producer's generation portfolio, differences in the scale of profits resulting from higher CO₂ prices are to be expected. For instance, utilities with a portfolio dominated by nuclear power are better equipped to profit as those with more carbon intensive fleets.

However, in the case that the generation structure is dominated by low-emission producers, e.g. gas-fired plants, so that the fuel constitutes the price-setting technology in the merit order, the carbon mark-up earned is not large enough to outweigh the losses incurred by carbon intensive infra-marginal plants. This proved to be the case for Italy in both scenario sets and Great Britain in the high gas price scenario.

It is worth noting that the analysis is conducted with a bottom-up model based on 2014 data and thus does not reflect intertemporal changes in a country's power supply structure. Nevertheless, the results highlight that contrary to much of the focus being given to the carbon intensity of the respective generation fleet, its underlying structure can have the ultimate bearing on the effect of the EU ETS on power producer's bottom line. Summarising, it can be concluded that contrary to intuitive notions, nearly all utilities in Europe would profit from higher CO₂ prices in the current market situation and not only utilities with a (nearly) CO₂ free portfolio. Thereby, the shape of the merit order curve and the price setting technologies during the whole year are of crucial importance.

Footnotes

¹ Windfall profit is defined as the additional carbon rent accruing to plant operators under a carbon trading regime. Operating under free allocation, a direct windfall profit is earned by both the price-setting and the infra-marginal technologies in the merit order if opportunity costs are priced into their bidding price. Under an auction-based allocation, an indirect windfall profit accrues ceteris paribus to infra-marginal plants in the merit order whereas the rent for the price-setting technology is negated.

² Polluters are responsible for paying for the damage incurred by the natural environment.

³ ELTRAMOD is a bottom-up electricity market model covering the electricity markets of the EU-27 states, Norway, Switzerland and the Balkan region (excludes Cyprus and Malta). Further model features and results from previous applications can be found in e.g. Gunkel et al. (2012).

⁴ The assumption of an inelastic demand curve can be critically discussed, however several papers show a fully inelastic electricity demand in the short-term and still a very inelastic demand also in the long term. See e.g. (Dahl & Erdogan 1994) and (Wietschel et al. 1997)

⁵ Due to model-specific restrictions, in Poland a large number of CHP plants function as must-run technologies, whereby operate on a cost-free basis. This, of course, exaggerates the respective windfall profit effect.

See references on page 59

The Political Economy of Carbon Pricing

By G.G. Dolphin, M.G. Pollitt and D.M. Newbery

By the end of 2015, the concentration of CO₂ in the atmosphere had reached 405 parts per million (Tans and Keeling, 2016). This level, a 40% increase from the pre-industrial era, is the consequence of the techno-economic system chosen since the Industrial Revolution. Yet, if we want a 50% chance of keeping the rise in Global Mean Temperatures below 2°C and avoid the most dramatic effects of climate change, global 2050 emissions levels must be 40 to 70% lower than in 2010 and global 2100 emissions levels must be near zero or below (IPCC, 2014)¹.

To reach this objective in a timely and cost-efficient way, policymakers need a workable strategy. Economists have argued that this strategy should include a credible carbon pricing mechanism. However, we recognize that carbon pricing has been at best a very limited part of any climate change strategy.² At the end of 2015, carbon pricing covered only 12% of global GHGs (World Bank, 2015) and in most jurisdictions where they existed, they were modest in their coverage and/or level. As a result, the world emissions-weighted price of carbon is currently around US\$ 0.74/tCO₂e, falling a long way short of what is required to internalize the environmental externality arising from GHG emissions.³ The US EPA figures for 2015 ranged from a low of US\$12 - 62/t CO₂ depending on the discount rate.⁴

Reasons for the weakness of carbon pricing regimes abound. The most salient ones, however, are political. Pricing carbon imposes costs on some producers and all energy consumers that triggers opposition. Producers are concerned about decreased profits and capital losses, although some of them often benefitted from massive windfall gains from the free allocation of emissions allowances in emissions trading schemes and hence did not oppose them; consumers worry about higher retail energy prices, especially in liberalized electricity markets where wholesale and retail prices are more sensitive to carbon prices (Pollitt, 2012). Policy makers are, in turn, reluctant to introduce explicit carbon taxes or charges and favour less visible policy tools such as efficiency standards. Given recent developments one may be tempted to think that some of these political barriers have been overcome. Between 2010 and 2015, the share of covered GHGs increased from 5% to 12% and some of the newly created price signals will push average carbon prices up. However, a careful analysis of these developments calls for more cautious conclusions. Progress toward comprehensive carbon pricing requires that we look at the economy-wide coverage and the resulting average price. The emissions-weighted (or effective) price of carbon (ECP), measured by the ratio of the total economy-wide carbon price revenue divided by total GHG emissions, is a better metric to assess progress on carbon pricing. The figure below provides such a metric for selected jurisdictions over the period 1990- 2012.

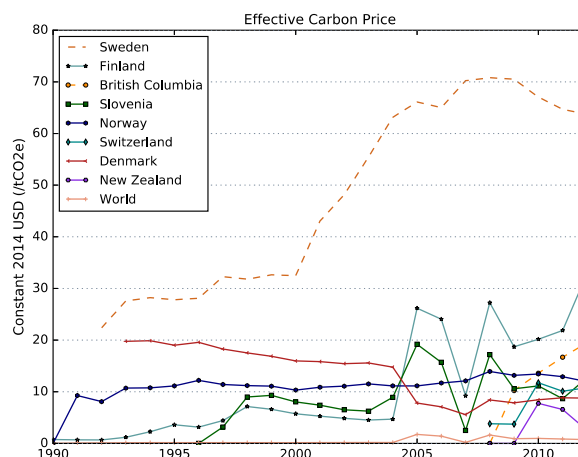
The figure gives rise to two major observations. First, all jurisdictions except for Sweden and Finland had modest effective carbon prices. Given the Scandinavian high share of zero carbon power (hydro, nuclear, biomass) and the widespread high willingness to tax petroleum in transport use, this is hardly surprising.

Moreover, if the World effective price of carbon is any guide, the current global willingness to pay for carbon emissions remains quite low. Hence, if anything, the ability of jurisdictions to price carbon continues to look constrained. That constraint on effective prices of carbon induces a coverage-price tradeoff: a higher coverage could only be introduced at the cost of a lower price (or vice-versa). This is particularly apparent in the initial stages of introduction of carbon pricing schemes. For instance, Norway managed to introduce a relatively high price (US\$28.5/tCO₂e) at the cost of a lower, yet not insignificant, coverage (32.5%); Japan on the other hand achieved broad coverage (69%) by 2012 but at a low carbon price (0.91US\$/tCO₂e), although where Emissions Trading Schemes have been introduced, they typically have much broader coverage and higher prices (at least initially).

Second, initial constraints on pricing persist over time. Hence no jurisdiction (except Sweden) showed a

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See footnotes at end of text.



coherent pattern of increase in its effective carbon price (Finland's ECP only changed after the introduction of the EU-ETS and British Columbia froze the level of its carbon tax in 2012), as theory would prescribe and carbon pricing enthusiasts had hoped. Consequently, the policy gap, i.e. the difference between actual price signals and any plausible estimate of the Social Cost of Carbon has widened over time.

These two observations suggest that, despite positive developments, there appears to be an upper limit on the *stringency* of carbon pricing schemes. Our analysis (Dolphin et al. 2016) has examined the political economy barriers that continue to hamper their development. On the consumption side, the willingness to pay for carbon remains limited and well below the central estimates of the Social Cost of Carbon, even in richer countries.⁵ On the production side, we find evidence of the negative impact of the coal-intensity of the electricity generation sector and the relative size of the industrial sector. Our regression analysis of 138 jurisdictions estimates that moving from a 25% coal share to a 75% coal share in electricity is associated with a US\$2/tCO₂e reduction in the effective carbon price. The relative share of industry in the whole economy affects the stringency of a scheme in a similar fashion.

From a policy-making perspective, these findings raise at least two sets of questions. First, what are the preconditions that make a positive price of carbon politically feasible and, crucially, how do they constrain its evolution over time? Second, since the stringency of carbon pricing policies is likely to remain bounded above at socially sub-optimal levels, is it still worth keeping it in the policy mix? Let us address each question in turn. First, the evidence suggests that the level of economic development positively influences the existence and stringency of carbon pricing mechanisms. In fact, a thousand US\$ increase in GDP per capita is associated with a rise in the effective carbon price of 25 US cents/tCO₂e on average. This result may, however, be driven by the fact that richer Annex-I countries to the Kyoto Protocol had to take GHG emissions reduction actions. Second, it appears that introducing carbon-pricing policies becomes easier once the electricity sector (and the economy in a broader sense) has already been partially "de-carbonized", possibly by means of other policies or favourable changes in technology and fuel prices. This supports the design of a climate change mitigation strategy that comprises a mix of complementary tools, particularly those that improve energy efficiency and so lower total energy use and hence GHG emissions. It also suggests that carbon pricing may not be the first policy to introduce when designing a climate change mitigation strategy. This is in line with the rationale behind the development of some carbon pricing schemes, such as the California cap-and-trade program, which have been introduced after renewable energy support policies and serve as a backstop to those – and other – GHGs abatement policies.

The above discussion does not, however, imply that we should refrain from introducing carbon-pricing mechanisms, even at a sub-optimal level. Both static and dynamic arguments support a positive price of carbon. From a static perspective, pricing carbon, even at relatively modest levels, helps internalize at least some of the environmental externality and makes some contribution to GHG emissions reduction. From a dynamic perspective, a positive (albeit sub-optimal) price of carbon may in itself contribute to the creation of a "clean" path dependency and foster the political acceptability of socially optimal prices in later periods. It also signals a commitment to decarbonize that may influence the expectations of those making durable investment decisions in e.g. generation assets. However, as the data presented above suggest, evidence of a willingness to embrace more significant levels of carbon pricing has yet to materialize. There are, however, encouraging signs in the gradual extension of the coverage of carbon pricing at the global level.

Footnotes

¹ Based on IPCC mitigation scenarios reaching 450 ppm CO₂-eq by 2100.

² Moreover, policymakers have meanwhile continued to subsidise the consumption of fossil fuels: consumption subsidies worldwide amounted to \$493 billion in 2014 (IEA, 2015).

³ All figures expressed in 2014 US\$. This figure does not account for taxes on other GHGs than CO₂.

⁴ EPA's social cost of carbon is from <https://www3.epa.gov/climatechange/EPAactivities/economics/scc.html>

⁵ Evidence of this is provided for the U.S. by Jenkins (2014).

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**First
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HEADING TOWARDS SUSTAINABLE ENERGY SYSTEMS: EVOLUTION OR REVOLUTION?



CONFERENCE OVERVIEW

In recent years, energy systems as well as energy markets underwent remarkable changes world-wide. Developments in oil, natural gas as well as electricity markets brought challenges of redesigning these markets. In addition, to cope with the problem of global warming and heading towards sustainable energy systems a global climate policy is required. Global change in thinking is required and solutions must be sought that can cover the diverse needs like affordability, environmental compatibility and economic feasibility.

The conference focuses on new developments of energy conversion technologies, energy policies and their effects on individual countries as well as at a global level, the efficient use of different types of primary energy resources and possible solutions to stop global warming.

The main question of this conference will be: In heading towards sustainability – is an evolutionary steady development possible or is a revolution necessary?

TOPICS TO BE ADDRESSED

The general topics for this conference include:

- Review and redesign of electricity markets
- Efficient exploitation and use of renewable and exhaustible energy sources
- Review of national and international energy and climate policy strategies and scenarios
- Evolving geopolitics: The economics of changing oil and gas markets
- Energy demand and greenhouse gas emission modelling
- Energy asset valuation and energy sector investment;
- Adaption technologies for climate change
- Exploitation of demand-side efficiency in all end-use sectors: households, industry, transport and commercial buildings
- New business models and fundamental change in doing business in energy markets

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Congestion Management in a Stochastic Dispatch Model for Electricity Markets

By Endre Bjørndal, Mette Bjørndal, Kjetil Midthun, and Golbon Zakeri

Recently, more renewable generation resources have been introduced in electricity systems around the world. A large part of these resources have an intermittent nature, with variable generation capacity, which is uncertain until close to real-time delivery. This development has presented a need for more balancing resources, and research into dispatch models that takes uncertainty about real-time availability of generation capacity and load into consideration when determining the day-ahead dispatch.

In this paper, we study an energy-only market with two settlements, for instance day-ahead and real-time. In the day-ahead market intermittent generation and load is uncertain, while all uncertainty is resolved at the real-time stage. Moreover, we assume that real-time flexibility comes at a cost, i.e., extra costs will be incurred if a flexible generator or consumer has to deviate from initial (day-ahead) plans in real-time. In this setting, we consider and compare two different dispatch models:

- A myopic or conventional dispatch, where day-ahead and real-time markets are cleared separately and sequentially, based on bids to each market.
- A stochastic or integrated dispatch, where the day-ahead plan is determined by taking into account the uncertainty in real-time generation and load, i.e. solving a stochastic programming problem for the two markets simultaneously.

A key question is which operating constraints should be included in the two market stages. In real-time all relevant constraints must be complied with, however this is not the case for the day-ahead stage. In particular, we consider different types of congestion management regimes (nodal, zonal or uniform pricing) for the day-ahead part of the market, and for the stochastic dispatch model, we also consider if it can make sense to relax the energy balance constraints in the day-ahead part of the problem.

Our results show that for the stochastic dispatch model, given that the uncertainty is accurately reflected in the model, there is no need to include network flow constraints and even energy balance constraints in the day-ahead part of the problem. If the stochastic programming problem representing the dispatch is convex, it is easy to show that the following ranking of the solutions holds:

- Unconstrained: no network flow constraints and energy balance constraints in day-ahead.
- Balanced: no network flow constraints, but energy balance in day-ahead.
- Max [Zonal, Nodal]: includes zonal or nodal network flow constraints as well as energy balance.

The ranking is due to the fact that moving up the list involves removing constraints from the optimal dispatch problem. The ranking between zonal or nodal pricing for the day-ahead market depends on which parameters are used for the power transfer limits between zones in the zonal model. If the transfer limits are set equal to or higher than the sum of capacities on the lines between zones, then the zonal model is a relaxation of the nodal model, and the zonal model will yield at least as good results as the nodal model. However, if the aggregated transfer capacities are lower than the capacities of individual lines, and this happens often in practical implementations of zonal pricing, then the zonal model may be a restriction of the nodal model, and may yield inferior results. Table 1, which is based

on a three-node example from Bjørndal et al. (2016), illustrates how the different model variants may differ with respect to expected cost. The unconstrained model gives a cost value that is 114.9 % of the wait-and-see value, i.e. the expected optimal value with perfect information, while the corresponding values for the balanced and nodal models are 117.4 % and 127.4 %, respectively. Hence, the relaxation of the balance constraint and the network capacities will improve the solution in this case. The zonal network constraints can be tighter or looser than the corresponding nodal constraints. When the interzonal capacity is set at 10000 MWh/h, i.e., equal to the sum of the individual line capacities, the zonal model is a relaxation of the nodal model, and we see that the objective function value is slightly better, at 124.4 % of the wait-and-see value. However, if the interzonal capacity is set too tight, e.g., at 5000 MWh/h, the value of the zonal model becomes much worse than the nodal model, at 352.8 % of the wait-and-see value.

The unconstrained solution, i.e. without energy balance constraints in the day-ahead part, may involve day-ahead over- or under-booking, depending on the relative cost for up- and down-regulation. If up-regulation is expensive and down-regulation is cheap, solving the unconstrained stochastic dispatch model may for instance involve over-booking of generation in the day-ahead schedule, i.e.,

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Model	€	Relative
Wait-and-see	66360	100.0 %
Unconstrained	76250	114.9 %
Balanced	77922	117.4 %
Nodal	84515	127.4 %
Zonal (cap _{{{(1),(2,3)}}} = 5000)	234144	352.8 %
Zonal (cap _{{{(1),(2,3)}}} = 10000)	82578	124.4 %

Table 1. Optimal expected cost with stochastic market clearing.

the dispatch depends both on the bids to the day-ahead market from the uncertain generators, AND on the network flow constraints in the day-ahead part of the problem. For the myopic model we only consider different congestion management methods. Removing the energy balance constraints can also be done in the myopic case, but then the sum of over- or under-booking of generators and load must be determined explicitly before clearing the day-ahead market.

Entity	Node	Nodal model				Unconstrained model			
		Day-ahead schedule	Real-time adjustment			Day-ahead schedule	Real-time adjustment		
Wind	1	153	-153	6847	9849	0	7000	10000	
Thermal	1	5000		-5000	-5000	5000		-5000	-5000
Load	1	-15000				-15000			
Nuclear	2	4998				5000			
Hydro	2	155	-153	245	-155	1500	-1500		-1500
Hydro	3	4694	306	-2092	-4694	5000		-3500	-5000
Total		0	0	0	0	1500	-1500	-1500	-1500

Table 2. Optimal schedules (MWh/h) with stochastic market clearing.

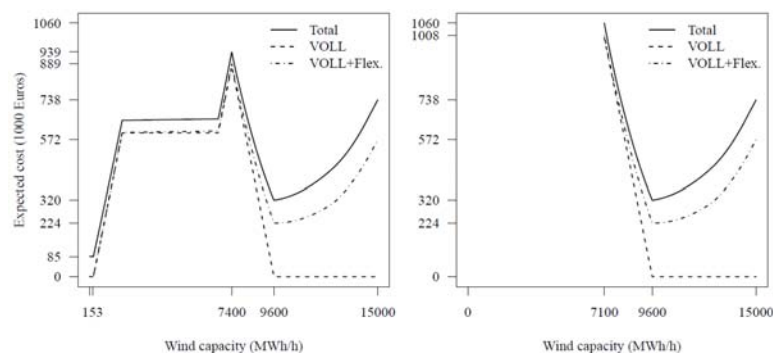


Figure 1. Myopic model with nodal (left) or balance (right) constraints.

extra flexibility costs related to real-time regulation. Below the wind bid value of 9600 MWh/h, load shedding is necessary, and VOLL makes up an increasing part of total cost. For wind bid values below 7100 MWh/h, the balanced model will generate a day-ahead schedule that is infeasible with respect to network capacities, and which includes so much inflexible nuclear generation that it is not possible to achieve feasibility by making real-time adjustments.

Solving a stochastic dispatch model to accommodate more intermittent generation in the dispatches may seem to be a fruitful choice in a market with more emphasis on renewable resources. However, a stochastic dispatch model also poses many different issues when it comes to information and implementation. Bidding formats, distribution of revenues, and incentive issues are important topics to address in future research.

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An Opportunity to Plan Your Future Career

The Student Mentoring Breakfast at the 39th IAEE International Conference in Bergen

First conference day started at 7 sharp in the morning. Despite the early time and the previous night's student happy hour, forty students made their way to the Student Mentoring Breakfast. "It's a chance I'm not going to miss!" PhD student Fernando Oster said.

Professor Lars Mathiesen, from the Norwegian School of Economics, organized the first-time session at one of our International conferences. "It is very important that students engage directly with seasoned professionals to hear first-hand about real careers and hard-won experiences."

Ten top executives from the energy sector volunteered as mentors; among them representatives from Statoil, Statkraft and Vattenfall. While having coffee and sumptuous sandwiches, we students circled around and took seats at the mentor's tables. After some snappy and interesting presentations about their work and experience, the mentors opened up for our questions. What I enjoyed best was that the mentors were really communicative and enjoyed their discussions with students. "It's refreshing to engage with the younger members of our Association; they are our future," said mentor Lori Schell (Empowered Energy). At 8.30, everyone was still deep in conversation and needed to be reminded that the opening plenary session was about to start.

Are mentoring sessions becoming part of our established student program? I hope so. It gives us another chance to talk informally with highly skilled professionals.

Lisa Marina Koch
IAEE Student Representative



Ottar Skagen (Statoil) with PhD Students



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