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IAEE Energy Forum

Antalya Special Issue, 2015 International Association for Energy Economics

President's Message

IAEE is pleased to produce this additional issue of the *Energy Forum* for 2015 focused on papers presented at the recent IAEE International Conference in Antalya, Turkey. We are most grateful to Einar Hope from the Norwegian School of Economics for spending considerable time and effort to select 16 papers that he found noteworthy for various reasons from more than 300 presented at the conference. We also thank the authors for agreeing to summarize their papers in the form of articles suitable for the *Energy Forum*.

Almost all of these papers were presented in Concurrent Sessions at the conference. Copies of the presentations that accompany the papers are available on the conference web site. In a few cases, however, the titles of the papers in this publication differ somewhat from the title on the web site (which reflects the title given in the abstract), but it is possible to locate the relevant presentation by searching on the author names.

We also remind members that all the plenary sessions at the conference were videotaped. Those recordings are available on the conference web site for complementary member download. Please visit https://www.iaee.org/en/conferences/antalya_videos.aspx

We hope that this collection of papers, and the associated online resources, will remind those of you who attended the Antalya conference of the valuable intellectual content of the conference. For those of you who could not make it to Antalya, we hope that this selection of conference content will encourage you to come to future IAEE conferences.

It is more difficult to convey in print the extra value that you get by attending our conferences in person. IAEE conferences enable you to get feedback on your latest research, or the seeds of ideas for new research papers. Our conferences also keep our members up to date with the latest thinking on the critical issues facing the energy industry. They are a great way to meet new people working on energy economics from around the world, and to renew old acquaintances. Antalya was also a terrific conference location and those of you who did not come missed a wonderful experience. The IAEE is most appreciative of the Turkish Association for Energy Economics for once again showing us that no-one is better at organizing an IAEE conference than they are.

Peter Hartley

Editor's Note: The regular Third Quarter issue of the *Energy Forum* will follow in several weeks.

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Editor: David L. Williams

Call for Editor-in-Chief EEEP

The *Economics of Energy & Environmental Policy* (EEEP) invites applications for the position of Editor-in-Chief (EIC). A search committee has been appointed by the Vice President for Publications, who has the responsibility to nominate a candidate for the approval of the IAEE Council, to initiate the search for a distinguished individual.

The journal focuses on policy issues involving energy and environmental economics. EEEP is a peer-reviewed, multidisciplinary publication that provides a scholarly and research-based, yet easily readable and accessible source of information on contemporary economic thinking and analysis of energy and environmental policy issues. The publication encourages dialogue between business, government and academics and improves the knowledge base for energy and environmental policy formation and decision-making. EEEP produces original papers, policy notes, organized symposia on specific policy issues, feature articles, book reviews and commentaries on current energy and environmental policy issues and studies.

Candidates should bring along exceptional skills in energy and environmental economics and research, teamwork and communication. The EIC has the responsibility for nominating the Associate Editors, a Managing Editor and the Editorial Board, and for proposing future directions for the content of the journal. Candidates should have broad experience in peer-review and publication of scientific manuscripts as well as superior leadership and management skills. As a member of the scientific community, the Editor will also have strong interpersonal skills and the ability to bring/build a broad network of contacts, domestically and internationally. The EIC must be free of any political agenda or ideological slant related to energy. This search is effective immediately. The ideal starting point for the successful applicant is Sept 1, 2016. Applicants should compile the following as a single pdf document and send by email to anne.neumann@iaee.org:

Cover letter
CV (including record of peer-reviewed publication, editorial experience, and other prior involvement with professional journals).
A short statement (max 1 page) about your leadership and management philosophy and experience.
A short statement (max 1 page) describing your vision for the future of EEEP and how it should serve its readers.
A sample of recently published peer-reviewed work

The deadline for applications is 5:00pm CET on September 30, 2015. We consider candidates without regard to race, sex, color, creed, religion, age, national origin or sexual orientation. Current compensation is $7,500 per published issue plus reimbursement of necessary travel costs.

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

Introduction to the Selected Conference Papers

The IAEE Executive Director and Energy Forum Editor, David Williams, has asked me once again if I would be willing to select and edit for the Energy Forum a dozen or so papers to be presented at the 38the IAEE International Conference in Antalya, Turkey, in May like I did for the New York IAEE International Conference last year. I accepted the invitation with the same reservation as last year, i.e. that it is, of course, not possible to make a representative selection of a dozen papers from among the more than 300 papers presented at the Antalya Conference. The number dozen was not considered to be binding, though, so I have ended up with 16 selected articles for the EF edition.

The majority of papers have been selected from four of the fifteen IAEE Specialization Codes with the largest number of submissions to the Conference, i.e., Energy and the Economy, Electricity, Energy Modeling, and Renewables, but there are also papers from Petroleum, Natural Gas and Coal. In the selection process 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.

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. In spite of a rather tight deadline for the submission of articles to the issue the invited authors, without exception, enthusiastically accepted and delivered within the deadline.

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. Thanks go also to David Williams for again inviting me as editor for this section of the Energy Forum and for stimulating cooperation in the production process of the EF volume. I hope that readers will find the collection of articles interesting and worthwhile to study. If this editing exercise may also stimulate readers of the Energy Forum and members of the IAEE 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 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 Bergen, Norway, 19 – 22 June, and I very much welcome you here.

Einar Hope
Norwegian School of Economics, Bergen

Joy Dunkerley

Joy Dunkerley, economist, and one of a handful of co-founders of the International Association for Energy Economics (IAEE), died peacefully at the Washington hospice on June 5, aged 82.

A longtime resident of Washington DC, Joy contributed to many aspects of the city, through her professional and charitable work, through her sponsorship of the arts and associations, and at a personal level in the many friends she made and helped in the District.

Joy was born in Paignton, Devon in England, although her seafaring family came from Tynemouth in the North East of England, where she spent her wartime childhood. As a young woman, Joy studied economics at the London School of Economics (an institution that she remained closely involved with throughout her life), before winning a Fulbright Scholarship to study in the US. Returning to London, she worked at the Economist, before moving to Paris, where she took a post at the OECD. She was married in Paris to Harold Dunkerley, also an economist, enjoying a partnership that lasted until his death in 1996.

The following years involved a succession of moves across the globe including time spent in Viet Nam, Colombia (where her children were born), Ghana and the UK. She arrived in Washington on the inauguration day of Richard Nixon in 1969.

Her more than 45 years in the city were fruitful ones. Working at the Brookings Institution and at Resources for The Future, Joy was at the forefront of the burgeoning field of Energy Economics, a branch of the discipline which acquired particular importance in the aftermath of the 1970's oil shocks. Her co-authored books (A Time to Choose, and How Industrial Societies Use Energy), as well as numerous articles and projects, helped influence energy policy both in the US and abroad, particularly in India.

Not simply a researcher and author, Joy was also a keen and talented organizer, helping to turn a fledging IAEE, from a local collection of experts, in academia, industry and government, into a respected international body with nearly 100 chapters world -wide and a membership of over 4000. She was a lead organizer of the first annual meeting of the IAEE in 1979, was elected one of its first Presidents, and was instrumental to building the IAEE's activities in the UK, its first international chapter.

Although it looks simple in retrospect, it was extremely difficult to work out the protocols and institutional relationships to support a far-flung institution that attempted to be much more than an academic association. Its objective was to actively involve experts in industry and government as well, so it could become an institution that could affect government energy policies worldwide. By 1985, 6 years after its founding, the IAEE had become successful, and much of this was due to Joy's extraordinary organizational skills and intelligence.

She received the Adelman-Frankel Award from the IAEE, its top honor, for her unique and innovating contributions to the field of Energy Economics in 2000. In her later years she worked for the Office of Technology Assessment (OTA), and authored a comprehensive study on the future of Nuclear Energy for the Atlantic Council. In retirement, she continued to do research in other fields, publishing On Eagle's Wings, a definitive English language history of the pioneering aviation company Aeropostale, as well as her autobiography.

Outside her professional work, Joy threw herself into the life of the city, working on Walter Fauntroy's election campaign for mayor, providing meals for the homeless through her church, and actively supporting a range of cultural groups, including the Opera Lafayette, and numerous local theatre companies. One of the first women members of the Cosmos Club, she spent many years in various organizing roles helping to promote and develop the Club.

Always elegant, of cheerful disposition, and quick to welcome and entertain, she continued to develop an eclectic group of friends, welcoming newcomers to the District right up to a week before her death. A tennis player of great quality, she retained a deadly drop shot into her 80s.

Joy is survived by her sons Mark and Guy, her stepdaughter Madeleine, her stepdaughters-in-law Marilia and Ildiko, and five grandchildren.

Energy Sector Liberalisation: Pricing and Subsidy Reform and the Poor

By Tooraj Jamasb and Rabindra Nepa*

Introduction

This article revisits the recent evidence on the state of reforms and innovative pricing and subsidies schemes to unravel the hiatus between the theory and practice of pricing and subsidies policies and sectoral reforms in developing countries.

The energy sector reforms commencing in the 1990s in developing countries were aimed at reducing the inefficiency of the sector and remove the energy supply and financial deficits that impeded social and economic progress in these countries. It gradually became evident post-reform that the restructuring, market reform, and institutional reform of the sector, though necessary, were not sufficient to ensure the socio-economic success of the market-oriented reforms.

Instead, the pre-reform pricing and subsidy schemes had partially acheived their economic and social purpose. However, the burden of the policies grew to unsustainable levels and became the source of many ills of the sector and the economy such as poor technical and financial performance of the sector and ballooning fiscal deficit leading to the need for subsequent changes. Energy subsidies were increasingly serving the better-off groups leaving no surplus to increase the quantity and quality supply and extend the service to those deprived of access to modern commercial energy in many countries.

Energy sector reforms and the poor

The restructuring of the energy sector had made the sources of the inefficiencies of the sector clearer. However, market oriented reforms cannot not deliver the expected efficiency gains without cost-reflective price signals. The sector reforms soon revealed that there is also a need for pricing and subsidies reforms that specifically served the poor contrary to the belief that market reform and private actors would help increase access to energy services. Expanding energy access to the poor consumers with low consumption was not attractive to the private sector and new forms of public intervention was required. A pricing and subsidies reform and access provision, for political economy and equity reasons, could not be delegated to the market. Rather, they continue to firmly belong to the sphere of public and social policy.

Sector reforms have generally been successful in improving the technical efficiency of the sector. However, the consumers have not benefitted from the efficiency gains. Many energy sector reforms are ineffective due to the lack of workable pricing and subsidy reforms while the scale of energy subsidies do not show signs of abating. The global 'pre-tax' subsidies for petroleum products, electricity, natural gas and coal amounted to 480 billion US dollars equivalent to a 0.7% of the global GDP in 2011 (IMF, 2013).

It is helpful to distinguish between energy subsidies in terms of 'access' versus 'end use' support. Access to modern energy has positive socio-economic externalities. Subsidies aimed at energy consumption cause inefficiency, over consumption, and negative externalities. Therefore, pro-poor subsidies need to aim at provision of access to realise the positive externalities, while energy consumption may be priced at its social cost to avoid inefficient use and negative externalities. The, competition based capital subsidy programmes for accelerating energy access, as in some countries such as Chile, can be the basis of access subsidies polices.

Evidence from pro-poor pricing and subsidies

Petroleum products received 44% of the US$480 billion global energy subsidies, electricity 31%, and natural gas 23%, while coal received 1% of global direct subsidies (IMF, 2011). The economic costs of subsidies include misallocation of resources, incentives for inefficient energy use, increased fiscal imbalances, lower economic growth, lower investments in alternative energy sources, and encourage fuel smuggling (UNEP, 2008; Hassanzadeh, 2012). The total an-

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Note: This article is based on research done for a forthcoming World Bank Policy Research Report on 'Energy and Poverty'. The authors are solely responsible for the content of the article.

nual deadweight loss from global fuel subsides is estimated at US$44 billion. Incorporating the external costs will increase the economic costs substantially (Davis, 2013). Evidence suggests that the subsidies have mostly benefited the higher income groups rather than the intended poor making the subsidy programmes inefficient, costly, and unequitable.

Subsidies removal have micro and macro economic impacts on the poor. The microeconomic impacts can be direct and indirect (Arze del Granado et al., 2012). The direct impacts arise as poor households face higher energy prices. Although fuel subsidies mainly benefit the rich, the poor are affected given their higher budget share of energy expenditure. The indirect impacts arise as the economy adjusts to higher energy prices that translate into increased production costs for other goods and services. Over time, the economy would benefit from the increased efficiency of factor utilization.

There is also a distinction between the motives behind subsidies in energy-rich countries and in poor countries. In resource-poor countries, the subsidies constitute transfers from public budget or cross-subsidies from better-off consumers to the poor. In energy-rich countries, subsidies are also means for distribution of the resource rent among the population. For example, subsidies account for 82% of the cost of electricity and fuel in Venezuela, 80% in Libya, 70% in Saudi Arabia, 74% in Iran, 56% in Iraq and 18% in Algeria (Kemp, 2014). However, as in other countries, these policies were inevitably inefficient and inequitable. In poorer countries, pricing and subsidies policies are linked to the issue of access to energy for the rural poor.

Some policies provide lower charges for limited quantities of energy for the poor. "Lifeline" block subsides for low levels of electricity use is one example; another is providing discounts on limited quantities of energy, such as LPG, while charging market prices for additional purchases. However, lifeline tariffs are less efficient than direct income transfers. First, they subsidize the same basic consumption level for all users, rich and poor, so they are poorly targeted. Second, they are usually financed by raising the rates for consumption at higher levels (i.e. a cross-subsidy). Lifeline rates redistribute income among all users and are prone to leakage to non-poor, which dilutes the effectiveness of the policy (Kebede, 2006).

In recent years, some countries have risen to the challenge and devised new policies and schemes. Brazil, Iran, Mexico, and the Phillipines have begun to adopt a combination of subsidy reduction with cash transfers to households. The economic intuition of this approach in terms of choice and efficiency is appealing. However, this appeal needs to be matched with the practical implementation of the scheme. The political economy of subsidy reform is, however, sensitive due to the vested interests and a sense of entitlement and the fact that much of the resistance to subsidy removals is from higher income groups who benefit more from the subsidies than the very poor.

Conclusions

Energy sector reforms were not inherently pro-poor. This created the need for targeted social pricing and subsidies policies. Poorly targeted subsidies tend to benefit the non-poor more as benefits of blanket subsidies are regressive given the low share of energy spending in poor household income. Market oriented capital subsidy schemes such as competition for rural electrification projects can be effective in extending access to commercial energy to the poor.

There are substantial long term gains from subsides reforms, though short-term benefits are smaller and tempered by adjustment costs justifying a gradual approach to reforms. A gradual elimination of subsides, combined with lifeline tariffs and cash transfers, can hold down short-term losses and maximize economic benefits over time.

Finally, a major obstacle to innovative subsidy reforms is the weaknesses of the administrations and institutions. Some new policies such as cash supports have been less effective due to underdeveloped administrative capabilities in developing countries. The existence of multiple different channels for providing explicit and implicit energy subsidies means that exact measurement and distribution of subsides can also be difficult, complicated and non transparent in developing countries characterised with possessing weaker energy sector institutional environment and arrangements.

(See references on page 9)

Considering the Welfare Impacts of Energy Efficiency and Rebound

By Lisa Ryan, Karen Turner, Patrizio Lecca, and Nina Campbell.*

Overview

Improving energy efficiency is widely accepted as one of the most cost-effective means to reduce CO_2 emissions through reduction in fossil fuel energy consumption (IEA, 2014a). However, the benefits are not limited to energy and greenhouse gas emission savings. There are other considerable benefits from improving energy efficiency that are now being coined the 'multiple benefits of energy efficiency' (IEA, 2014b). These benefits extend from individual level to regional and national level and across economic, social and environmental outcomes.

Notwithstanding this, the merit of energy efficiency as a mitigation measure is regularly called into question with allusions to the 'rebound effect'. Rebound occurs when the realised reduction in energy demand is less than the engineering estimates predict, because of price and income effects occurring directly or indirectly in different areas of the economic system.

The research question in this paper is whether energy efficiency rebound effects are in fact welfare-enhancing from a societal perspective. We go a step further and propose that without rebound, the benefits of energy efficiency would be limited to the single vector of energy use.

Energy efficiency, rebound effects and welfare

A multiple benefits perspective on energy efficiency improvements contextualises them within a wider system of impacts where energy demand reduction is but one vector of many outcomes. While all are driven by the energy efficiency measure, some of these some economic and social benefits imply increased energy consumption overall and could therefore be seen as synonymous with the resulting rebound effects.

The relationship between rebound effects and welfare is an important subject in the context of the highly contentious recent media debate around the potential rebound effects associated with energy efficiency measures (Revkin, 2014). A significant part of the literature on energy efficiency rebound effects deals with classifying and estimating the rebound effects (Turner, 2013). Several papers acknowledge that the rebound effect is likely to have positive welfare implications (Gillingham et al., 2014, Borenstein, 2015). Chan and Gillingham show that when the externalities or other costs associated with increased energy use (i.e. the rebound effect) are lower than the benefits from increased energy use, then the rebound effect is welfare enhancing. However there is little analysis and few examples of explicit estimations of the welfare implications of rebound in the literature.

EE improvement	GDP	HH consumption	Employment	HH energy consumption	Total energy demand	Rebound
5%	0.10%	0.25%	0.10%	-1.62%	-0.70%	59.3%
5% (Cost of living reflected in lowr wage demands)	0.24%	0.29%	0.25%	-1.59%	-0.62%	63.9%

Table 1: Macroeconomic impacts of 5% energy efficiency improvement in UK household sector

Results

In this paper, we present some illustrative results of the macroeconomic and microeconomic welfare impacts of the rebound effect associated with an increase in energy efficiency in the (UK) household sector. Because fuel poverty remains a major societal challenge in the UK, we also examine the distributive effects of these rebound effects in the household sector.

The first part of these results is based on a paper by Lecca et al (2014) - one of the few economy-wide modelling studies that considers the impact of energy efficiency improvements on energy demand with a range of macroeconomic indicators and considers the rebound effect this engenders. They use a CGE model with 21 industries, including four energy supply sectors (coal; oil and nuclear fuels; gas; electricity) and an aggregate household sector.

The model results suggest that a 5% improvement in efficiency in household

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energy use (introduced as a costless public good in order to focus on the response to the pure efficiency effect) would have positive effects on the national economy (Table 1). In this case, if we compare the value of an increase of 0.1% GDP (£1713.9 million in 2013) with the value of the energy not saved as a result of the rebound effect (£526.8 million), it appears a priori that the net rebound effect is welfare-increasing.

Policy makers concerned with fuel poverty will question the impact of these welfare effects at a microeconomic level on different household income groups. To answer this question, we have run an illustrative simulation using Lecca et al's model[1], but focussing on an improvement in the efficiency of electricity and gas use in household heating and lighting, as these are are the main concern in a fuel poverty context. We do not simulate a change in efficiency in the fuel use involved in running private cars, but this could be one area where households decide to reallocate income savings. The results are presented in Table 2 for UK households broken into income quintiles, with the lowest household income group identified as HH 1. There we focus, for electricity and gas in turn, on what happens to (a) overall household expenditure on physical energy (taking the impacts of full economy-wide adjustment into account); (b) this spend as a share of total income (as an indicator of whether the degree of 'fuel poverty' rises or falls); (c) total household rebound in this energy use (which equates to (a) and, again, is not limited to direct rebound).

	Change in household electricity use (%)			Change in household gas use (%)		
	Overall	As share income	Total rebound	Overall	As share income	Total rebound
HH 1	-3.02	-3.17	39.69	-3.01	-3.17	39.72
HH 2	-3.51	-3.66	29.76	-3.51	-3.66	29.79
HH 3	-3.27	-3.42	34.70	-3.26	-3.42	34.73
HH 4	-3.04	-3.19	39.23	-3.04	-3.19	39.26
HH 5	-2.90	-3.06	41.91	-2.90	-3.05	41.94

Table 2: Impacts on electricity and gas use in different household income quintiles from 5% increase in the efficiency of use of both fuels

The results in Table 2 indicate that the lowest and highest income groups rebound the most in their use of electricity and gas, due to a combination of energy intensity (with lower income groups spending a larger share of their income on energy) and the strength of income effects (where higher income households have a greater share of their income deriving from returns to labour and capital).

The key result in terms of welfare, however, is that all income groups enjoy the benefit of a reduced share of their income spent on electricity and gas bills as a result of the energy efficiency improvement. Mid-range income groups (HH 2 and HH 3) are the greatest beneficiaries in this respect (both actually increase the share of income that they are able to save) . The lowest household income group (HH 1) also realises a net welfare benefit in this respect, although it is also the group that reallocates the largest share of its expenditure towards other energy uses, with expenditure on refined oils (primarily petrol and diesel to run cars) rising overall and as a share of total income by just over 12%. Therefore, in terms of welfare, the benefit of energy savings is distributed quite equally across income groups.

Conclusions

Macroeconomic rebound effects appear to be generally welfare-enhancing, with, for example, Lecca et al. (2014) showing that a 5% average increase in household energy efficiency in the UK can increase GDP by 0.1% with a rebound effect of approximately 60%. While the rebound effects are significant, the welfare gains are likely to compensate the energy loss. The results also showed in this case that all income groups benefit from the welfare impacts of energy efficiency improvements, with a greater drop in the real share of income spent on electricity and gas than the drop in energy use.

For policy makers, these results suggest that when, as in this case, the net welfare effects of rebound are positive, the policy should not attempt to remove the rebound effect but rather attempt to maximise the net benefits, while adjusting CO2 emissions emissions forecasts to account for the rebound effects and the reduced CO2 emissions savings that will be achieved through energy efficiency measures. When carrying out a regulatory impact assessment of potential energy efficiency policies, a full welfare analysis should be included and policy decisions based on the multiple benefits of energy efficiency measures, beyond energy and CO2 emissions savings alone.

Footnote

[1] Using a broad-brush energy efficiency increase of 5% as in Lecca et al.

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The Intended and Unintended Consequences of Renewable Portfolio Standards

By Gregory B. Upton Jr .and Brian F. Snyder*

Introduction

Over the past two decades, the federal government and many state governments have implemented a wide array of policies aimed at reducing the CO_2 intensity of the electricity sector by increasing the market penetration of renewable energy technology. Renewable portfolio standards (RPSs) are state-level policies in the U.S. that require a proportion of state electrical generation be produced by renewable sources. RPSs target electric utilities and require that they comply with the regulatory mandate, typically including a system of renewable energy credits (RECs) in which renewable energy providers generate one REC for every MWh of renewable electricity produced. RECs can be bought and sold independently of the electricity to help electricity providers meet their RPS obligations.[1] To date, thirty states have implemented RPSs. There are a number of potential impacts of RPSs on statewide electricity markets, both intended and unintended. This article will discuss recent research on RPSs and in particular focus on recent research presented at the 2015 IAEE conference in Antalya Turkey.[2]

Potential Impacts of RPS on Electricity Markets

There are three potential hypotheses on the impact of RPSs on renewable energy generation and electricity prices. The first hypothesis is based on the assumption that renewable energy generation is more expensive than traditional fossil fuel or nuclear powered generation, and therefore, increases in renewable energy generation spurred by an RPS will lead to increases in electricity prices. Thus, the first hypothesis is that RPSs will lead to increases in both renewable energy generation and electricity prices. Both proponents[3] and opponents[4] of RPSs have acknowledged that higher electricity prices are a likely side effect of RPSs.

The second hypothesis is that RPSs will neither lead to increases in electricity rates nor renewable energy generation. RPSs are just one mechanism that allows state utility commissions to approve utility scale renewable energy projects. While an RPS legislatively puts a very specific renewable energy target in place, the normal regulatory framework in most states already allows regulators to approve relatively expensive renewable projects and pass these costs onto ratepayers. Therefore, both RPS and non-RPS states might experience increases in renewable energy generation and electricity prices due to the implementation of renewable energy projects.

The third hypothesis is that RPSs lead to increases in electricity prices but do not increase renewable energy generation. There are two potential explanations for why this is plausible. First, the mechanism by which RPSs spur renewable energy generation is through renewable energy credit (REC) markets. Utilities have the choice to either produce enough renewable energy themselves to meet the RPS requirement and retire the RECs at the end of the year, or to purchase the needed RECs from the market. RECs purchased on the market may be generated within the state, or in some cases, may be imported from other states. While some states have attempted to limit RECs such that they can only be produced in-state, utilities have been known to import RECs from out of state[5], therefore subsidizing renewable generation in surrounding states while passing the cost onto in-state ratepayers.

Second, there are multiple potential funding sources for renewable energy, only one of which is higher electricity prices. When a utility builds more expensive renewable capacity, or purchases RECs from the market, this cost is passed onto ratepayers in the form of higher electricity prices. But this is not the only mechanism by which a state can choose to incent renewable energy generation; the obvious alternative is direct taxing and spending. For instance, many states without RPS policies have implemented other financial incentives such as property tax exemptions for utility scale renewable energy projects (Nebraska, Tennessee), sales tax exemptions for expenditures associated with renewable energy projects (Georgia, Utah) or state renewable production tax credits (Nebraska, Oklahoma, South Carolina, Utah) that serve as direct subsidies to renewable projects. These states might still experience increases in renewable energy generation and still have to pay a premium for this generation, but the cost passes through to taxpayers through the form of increased taxes or decreased spending on other government services—not increased electricity rates.

RPSs also have the potential to impact CO_2 emissions associated with elec-

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See footnotes at end of text.

tricity generation. There are two potential mechanisms through which CO_2 emissions can plausibly be reduced. First, if emission free renewable energy generation displaces fossil fuel electricity sources, then CO_2 emissions associated with electricity generation would logically decrease. This effect is through the *supply side* of the electricity market. The second mechanism that could cause RPSs to decrease CO_2 emissions is through the *demand side* of the electricity market. If electricity prices increase after an RPS is implemented, basic economic theory predicts that a decrease in electricity demand will also occur and therefore a decrease in emissions.

Prior Empirical Estimates

Due to the number of plausible scenarios discussed above, understanding RPSs impact on electricity markets is therefore an empirical question and has been analyzed in a number of studies. For instance, a number of studies test the impact of RPSs on renewable energy capacity[6] and while results have varied, have generally found that RPS states have relatively more renewable energy generation to non-RPS states. Recently, there have also been empirical studies that have analyzed the potential impact of RPSs on CO_2 emissions.[7] These studies have found that RPS states have lower CO_2 emissions than non-RPS states.

While there have been no empirical tests to examine the impact of RPSs on electricity prices, theoretical models suggest that RPSs will lead to increases in electricity prices of about 2 to 3 percent.[8] Due to the estimated long run elasticity of demand of approximately -.5,[9] this implies that we should also see a reduction in electricity demand by 1 to 1.5 percent.

Nonrandom selection into policy serves as a threat to our ability to unbiasedly estimate the impact of RPSs on these outcomes of interest.[10] For instance, if states that are comprised of citizens concerned about emissions reductions are more likely to implement an RPS, but are also more likely to (a) pass other policies that aim to reduce emissions and (b) whose citizens make personal lifestyle chances to reduce their personal carbon footprint, then any decrease in emissions observed after an RPS is passed might be associated with these other factors—not the RPS. Similar logic can be applied for each outcome of interest. For this reason, careful attention must be given to non-random policy adoption, as changes in outcomes in RPS states relative to non-RPS states after adoption are *not* necessarily due to the implementation of the RPS. Empirical microeconomists refer to this phenomenon as *endogenous policy adoption* and a large literature has emerged that addresses this issue.

Results

After addressing non-random selection through a number of empirical techniques, placebo treatment tests and falsification tests, we find that RPSs lead to an increase in electricity prices by approximately .9-1¢/kwh, or about 12-13 percent. We also estimate that energy demand decreases by approximately 7 percent due to the price increase induced by the RPS. The implied elasticity of demand comparing the change in electricity prices and electricity demand is similar to prior empirical estimates. We find no evidence that RPSs have led to increases in renewable energy generation and weak evidence that RPSs are associated with declines in CO_2 emissions of 3 to 4 percent. Due to lack of evidence of RPSs increasing renewable energy generation, any reductions in CO_2 emissions are therefore likely associated with the observed decrease in electricity demand.

Conclusions

The results of this research have profound policy implications. RPS states have chosen to fund renewable energy through increased electricity prices, while other states have also chosen to fund renewable energy generation, but have done so through other channels. The obvious alternative channel is taxing and spending. Who bears the burden of increased costs associated with electricity generation should be considered when implementing policies aimed at funding renewable energy.

Footnotes

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(footnotes continued on page 15)

Technology-neutral or Technology-specific? Designing Support Schemes for Renewable Energies Cost-effectively

By Paul Lehmann and Patrik Söderholm*

Most support schemes for electricity generation from renewable energy sources (RES-E) in Europe grant technology-specific subsidies. That is, they differentiate subsidies to RES-E plants on the basis of the energy source used, the technology employed, the size of the plant, or the location of the plant (or a combination of these). Technology-specific approaches have however been criticized for making the attainment of climate and energy targets – be it a greenhouse gas reduction target or a RES-E deployment target – unnecessarily costly (see, e.g., Frontier Economics and r2b, 2013; Jägemann, 2014; Jägemann et al., 2013). In turn, technology-neutral approaches to RES-E support have been praised for their cost-effectiveness as they promote the deployment of the cheapest technologies first.

Assumptions Underlying Pleas for Technology-Neutral Support

This critique notwithstanding, it has also been argued that technology-specific RES support schemes may decrease final consumer prices despite increasing overall generation costs, basically because price discrimination across technologies with dfferent costs may help to reap producer rents (see, e.g., Del Rio and Cerdá, 2014; Held et al., 2014; Resch et al., 2014). This argument is inspired by distributional concerns (distribution of rents across power producers and consumers), rather than by strict cost-effectiveness considerations.

However, under certain conditions, there may also be benefits from technology differentiation in terms of reducing long-run generation costs of, for instance, reaching climate policy targets. Here it is important to acknowledge that the economic critique of technology-specific support rests on at least two important assumptions: (1) The market failures associated with the development and deployment of RES-E technologies are absent, or properly addressed by other policies, and (2) the costs of renewables deployment beyond the private generation costs – e.g., system integration and environmental costs – are absent, or properly internalized by other policies. Consequently, RES-E technologies are assumed to compete among each other efficiently on the basis of their generation costs. Yet, we argue that rationales for technology-specific RES-E support may emerge once these assumptions are relaxed.

Technology Market Failures Impairing Technological Change

The development of RES-E technologies may be impaired by technology market failures. A basic assumption in this respect is that RES-E technologies experience learning: increased RES-E generation today may help to bring down generation costs in the future due to learning-by-doing (i.e., tacit knowledge acquired through manufacturing) and/or learning-by-using (i.e., improvements in the technology as a result of feedback from user experiences). However, RES-E investors may only partly be able to appropriate these learning benefits as part of the knowledge gained through learning will spill over to other competitors – e.g., by reverse engineering or personnel movements between firms. To avoid undervestment in RES-E deployment in this case, investors should receive a deployment subsidy. This subsidy (e.g., price premium) needs to be technology-specific as long as the degree of learning and the importance of spillovers effects varies across RES-E technologies. This variation exists in reality as the maturity differs across the various RES-E technologies (IEA, 2010), and due to differences in the complexity of the relevant actor networks as well as the role of users in the technology development process (see, e.g., Huenteler et al. (2012) comparing wind power and solar PV).

Capital Market Failures Resulting in Improper Treatment of Investment Uncertainties

Future benefits and costs, and thus the economic profitability of technology learning today, are by definition uncertain. Uncertainties are related inter alia to the degree of learning rates, resource costs and the political framework (Purkus et al., 2015). In theory, private investors could hedge against the resulting risks. However, they may be unable to do so efficiently if capital and insurance markets fail, e.g. because of moral hazard or significant transactions costs. This market failure may materialize through private investors discounting uncertain future income streams more strongly than public investors (Arrow and Lind, 1970). As a consequence, private investors will under-invest in more risky RES-E technologies, such as those characterized by capital intensity and technologi-

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cal complexity (e.g., second-generation biofuels). The RES-E subsidy to correct for this shortcoming has to be technology-specific if these learning effects and risks vary across RES-E technologies. Certainly, such a subsidy would only be a second-best policy instrument compared to measures strengthening capital and insurance markets in the first place.

Negative Externalities Produced by Renewables Deployment

While RES-E generation is meant to substitute fossil generation producing carbon dioxide emissions, it may also generate significant external costs next to the private generation costs. First, RES-E deployment may produce environmental costs. These costs can be site-specific (e.g., habitat losses) and/or distance-related, i.e. dependent on the distance to human settlements (e.g., noise emissions or aesthetical changes to landscapes). Second, RES-E generation produces system integration costs. Following Hirth et al. (2015), these costs include profile costs, grid-related costs and balancing costs. Both environmental and system integration costs may vary significantly across different RES-E technologies. At the same time, neither environmental nor system integration costs are typically fully borne by the RES-E generators. This distortion may be corrected by RES-E support schemes that differentiate subsidies on the basis of the externalities produced by them. Again, of course, such an approach would only be a second-best means to address RES-E externalities. Regarding system integration costs, for example, optimal technology choices and operation can be spurred if (1) the RES-E remuneration reflects market prices, as under a premium tariff, and if (2) the market value of power is properly reflected in spot, future and balance markets. In practice, however, these requirements are not met in many cases because of the use of fixed feed-in tariffs, or because power markets fail in turn due to, e.g., the absence of locational price signals, regulatory uncertainty and/or market power. While the first-best response would be the reduction of these failures, this may not be feasible due to politico-economic constraints or administrative hurdles. In this case, technology-specific RES-E support may help promote a system-friendly RES-E portfolio and reduce integration costs.

The economic significance of the above market failures is likely aggravated by the fact that technology choices in the power sector are strongly path-dependent (Acemoglu et al., 2012). As a consequence, the benefits of having technology-specific RES-E schemes may even be higher compared to a setting in which investment decisions were continuously modifiable and reversible.

Caveats to Technology-Specific Renewables Support

Obviously, designing technology-specific RES-E support schemes cost-effectively taking into account also the future development of the technologies may be quite challenging in practice. Addressing the technological variations in learning and spillover effects, risks and externalities properly is quite demanding for the regulator in terms of the information required. Nevertheless, these transaction costs do not necessarily question technology-specific RES-E support as a whole but rather the depth of the differentiation. Moreover, technology-specific schemes may be more prone to interventions by political interest groups trying to maximize their individual rents. Some argue that in this respect there may be a "premium of simplicity" (Helm, 2010), in turn tending to speak in favour of technology-neutral schemes. However, also technology-neutral policy instruments may be eroded in part due to lobbying efforts (e.g., the EU Emissions Trading Scheme). Finally, technology-specific support schemes may be blamed for picking winners and creating path dependencies politically. However, technology-neutral schemes will also pick technologies, namely those that have the lowest cost in the present time, such as onshore wind power. Given the diverse market failures discussed above, the path dependencies created by technology-neutral schemes may by no means be better than those generated under technology-specific policies.

Conclusion

Overall, technology-specific support schemes may thus produce economic benefits, particularly if technology markets work imperfectly and in second-best settings with additional uncorrected market failures. This is not to say that technology-specific support schemes are by definition welfare-increasing. In fact, there may be practical impediments to getting technology-specific subsidies right. Nevertheless, it becomes clear that technology-neutral schemes are neither by definition superior. In the end this boils down to the notion that a RES-E target cannot be a desirable goal in itself; it must be logically derivable by analysis of more basic motives and of the relevant costs and constraints. Our point is that almost regardless of which these motives are, there is generally a stronger case to be made for technology differentiation compared to technology neutrality.

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The Role of the Financial Sector in EU Emissions Trading

By Regina Betz, Johanna Cludius, and Anne Schopp*

Emissions trading schemes theoretically lead to an efficient achievement of a given reduction target since companies with the lowest marginal cost of abatement reduce their emissions and may sell surplus permits, while companies that face high abatement costs purchase permits to cover their greenhouse gas emissions (Baumol and Oates 1975). These trading activities should achieve an efficient final allocation of permits between regulated entities where the marginal abatement costs are equalised. Textbook theory of emissions trading usually focusses on trading of regulated entities. But in reality non-regulated entities are also actively involved in the market for emission allowances. In the context of the EU Emissions Trading Scheme (EU ETS), the financial sector has been particularly active on the market for EUAs (Betz and Schmidt 2015). The total trading volume during the first trading period at 1.8 million EUAs was about five times higher than the minimum trading volume necessary for all installations to become compliant (350 million EUA, i.e. the sum across all short positions over the whole trading period). That shows that trading was not done for compliance purposes only. In fact, 45 % of the total volumes traded during the first trading period, involved one or two accounts of companies without a liability on the market (banks, brokers, traders, exchanges and investment trusts and funds). More than half of this volume goes through accounts of banks (24 % of the total), via exchanges (8 %), through a dedicated future clearing account (London Clearing House – LCH, 6 %) and the remainder via brokers, (own-account) traders and trusts and funds (7 %). Thus, our analysis of EUTL data highlights the important role of financial actors in the first trading period. We are therefore particularly interesting in the following two questions (Cludius and Betz, forthcoming): First, how has the financial sector shaped or supported the behaviour of regulated companies in the first trading phase? Second, what will be the potential implications of the new regulations for the financial sector on the roles banks have played in the past and how will this impact regulated entities?

Figure 1 shows the involvement of the different types of financial actors over time. Prominent spikes can be observed in March-April and December each year, corresponding to activity related to the allocation and surrendering of allowances and the delivery of forward and future contracts respectively.

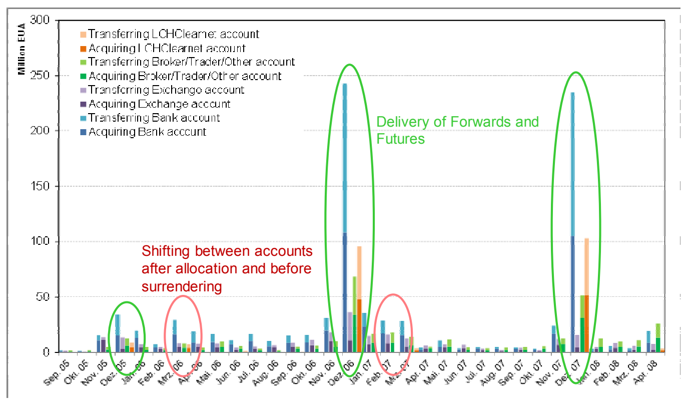

Figure 1 Market transfers involving accounts belonging to the financial sector

Source: EUTL, own estimation and illustration

Note: Transactions shown starting in September 2005 for ease of illustration and as volumes were very small beforehand; all transactions shown only involve Period I EUAs.

Plethora of Roles of Financial Sector in EU Emissions Trading

In order to investigate the role of the finanacial sector in EU Emissions Trading, we employ two different methods. On the one hand we analyse data from the EU Transaction Log (EUTL), giving insights into market participants and their trading behaviour during the first trading period of the EU ETS (January 2005 – April 2008, when permits for 2007 had to be submited). In order to extend the insights gained from the data analysis, we conduct a number of semi-structured interviews with key players active in EU Emissions Trading (e.g., banks, electricity companies).

Banks and other financial actors can and have played a variety of roles in EU Emissions Trading. We differentiate six different roles that are often played by different trading accounts of the same bank. First, banks have acted as intermediaries to facilitate trading and taken on a role similar to brokers. Second, they have provided liquidity to the market by acting as market makers that provide bids and asks within a certain corridor on exchanges and get rewarded by special access conditions to these exchanges. Third, they have lowered transaction costs by aggregating trading activity of smaller entities (Heindl 2012a, 2012b). In particular, banks and other financial actors have bought allowances from small firms that were overallocated and sold them as forward contracts to – for example – electricity providers. Fourth, and connected to the previous point, banks have developed and offered derivative products to pursue cost of carry arbitrage, as they have access to cheap capital. These derivate products, e.g. EUA forward sales, helped manage price risk for regulated entities. Fifth, banks may trade on their own account in order to gener-

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Name of company	Volume purchase (M EUA)	Volume sales (M EUA)	Number of accounts (PHA/OHA)	Accounts opened in registries
BARCLAYS PLC	77	83	9 / 3	GB, NL, DE, FR, ES, DK, IT
UBS AG	74	71	4 / 0	FR, GB
AGEAS SA/NV	44	44	9 / 3	NL, GB, FR
Calyon Financial	40	40	2 / 0	FR, GB
BNP PARIBAS	24	22	3 / 1	GB, FR
MORGAN STANLEY	23	20	11 / 1	GB, DK, NL, DE, FR
SOCIETE GENERALE	19	18	4 / 0	GB, CZ, FR
COMMERZBANK AG	17	17	3 / 0	FR, DE, GB
GOLDMAN SACHS GROUP, INC	16	16	8 / 0	ES, GB, NL, DK
ROYAL BANK OF SCOTLAND	11	15	3 / 1	GB, NL

Table 1 Most active banks in Period 1 EU Emissions Trading

Source: EUTL, Jaraite et al. (2013), own estimation

Notes: EUI ownership links dataset (Jaraite et al. 2013) used to match accounts to parent companies, enhanced with own analysis

The fact that Barclays Bank and the Royal Bank of Scotland seemingly sold more EUAs than they boughtis due to transactions missing from the dataset whose 'status' changed from 'not completed' to 'completed', and which were therefore not recorded on the EUTL (personal communication with the Commission).

ate profits (speculation). Sixth, they may borrow permits from companies and return them with a certain interest rate (not buying them, but rather using them as speculative capital) or may also directly manage the permits for clients using their own accounts. Finally, banks have provided information to the market (market analysis) through publications such as newsletters (e.g., Deutsche Bank, Barclays).

Taking a look at the most active banks participating during the first period of the EU ETS (Table 1) reads like a who-is-who of the financial world. Banks often opened accounts in the British or French registries, which has to do with the fact that important exchanges or clearing houses were situated in those countries. Often it was a requirement to hold an account in the same registry if trading was to take place with these exchanges. The majority of banks do not hold any OHA accounts. One prominent exception is Unicredit that holds OHA accounts of sugar making factories.

…they may no longer be able to play those roles in the future

However, following new requirements from the Markets in Financial Instruments Directive (MiFID), many banks have closed down their commodity trading desks (including for carbon) as of the start of the third trading period and it is unclear how this will impact their future role in the market. Some banks had already left the market earlier on which may have been due to the fact that it is likely that a number of banks made losses in the market for (e.g., due to a wrong strategy/expectations or less information compared to regulated participants). Argualby, if banks leave the market, this may decrease liquidity, as their tradind activities - encompassing the brokering of trades to reduce transaction costs or being a market maker and thus increasing market liquidity directly – would cease. Given the frequent and high auction volumes under the EU ETS since the start of the third trading period in 2013, the liquidity of the market seems to be less of a worry at present. However, banks also reduce the cost of carry and help to hedge price risks by serving as hedging counterparties mainly for the electricity industry. It is unclear at this stage if banks will continue to play this role or if other service and trading companies will take over their role as hedging counterparties since they do not fall under the new EU regulations regarding financial markets. Finally, the role of actively aggregating EUAs from small companies and selling them on exchanges / as derivates, which helped to reduce the number of expired EUAs, may be given up by banks and if not taken over by others may reduce the efficiency of the EU ETS.

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Making 'Smart Meters' Smarter?

By Simon Bager and Luis Mundaca*

The importance of energy efficiency in the context of green economic growth, climate change mitigation and sustainable development keeps gaining scientific, policy and media attention. Historically, large cost-effective energy saving potentials have been estimated for the European residential sector. However, despite multiple economic, social and environmental benefits embedded in increased energy efficiency (e.g., reduce greenhouse gas [GHG] emissions, increase energy security, job creation), a number of market failures and barriers have traditionally prevented efficiency improvements due to, for example, information asymmetries (see e.g., Gillingham & Palmer, 2014). In Europe, consumers have inferred knowledge about their electricity demand mostly through billing estimates and infrequent meter readings, meaning that they have had imperfect or partial information on the impact of their energy-use behaviour.

As part of the development of the European electricity grid, and to address information barriers that prevent the diffusion of profitable efficient technologies, the European Union (EU) has decided that by 2020 electronic electricity meters, or 'Smart Meters' (SMs), should be installed in 80% of the households in the EU (Directive 2009/72/EC). The European Commission expects that the introduction of SMs will result in a 10% reduction of energy use in the residential sector (EC, 2011). A central assumption of this policy measure is that the provision of real-time information via SMs will enable end-users to make more rational decisions about their demands for energy services (e.g., lighting). Whereas much attention has been given to technological aspects and the pure provision of information, with and without using SMs, much less is known about the role of behavioural biases and cognitive issues (e.g., loss aversion and salience) associated with SMs and energy use.

In order to contribute to this debate, we examined the potential effects of SMs on behavioural aspects of electricity use. From a theoretical point of view, we departed heavily from behavioural economics. That is, that cognitive, emotional and social factors influence how information is understood and limit the possibility to display purely rational behaviour, in turn affecting human (economic) decision-making (Kolstad et al., 2014). In order to examine whether and how behavioural biases affect consumers' response to energy-use information, we designed two experiments with SMs and electricity users that were carried out in real-life settings, where consumers actually used and paid for their electricity use.

First, a simple experiment took place: whether the installation of SMs could (or not) yield reductions in electricity use. To that end, SMs were installed in 92 households in Copenhagen (Denmark) and the electricity use data was collected (See Figure 1). No other intervention was made. The rationale behind this experiment was to explore whether the EU prediction of a reduction in electricity use of 10% due to the simple installation of SMs is in any way reflected in electricity use profiles of customers with SMs installed. The second experiment tested the effect of two behavioural biases, namely *salience* (understood as the ease with which data can be understood and processed by humans [Kahnemann, 2003]) and *loss aversion* (seeing a reduction in consumption as reducing a loss should induce a more significant change in behaviour) on consumer behaviour with regards to electricity use and related decisions. In this case, the participating households were divided into two groups. The reference group received information about their electricity in a conventional manner (in kilowatt-hours [kWh]) and how much their consumption aligned with a pre-determined budget (in Danish Krone [DKK] per year), which had been set by the household. The intervention group was subjected to the same information given to the reference group, along with information on the running costs of electricity use and the estimated weekly cost (framed as a *loss*), and the cost of passive and standby electricity use per day and per year (framed as a *loss* and made *salient*) (Figure 2).

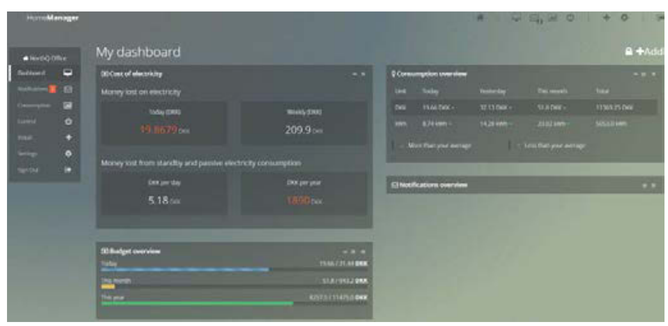

Figure 1 – Snapshot of consumption information available to SM customers online. ©NorthQ and Bager (www.northq.com). The top-left widget ("Cost of electricity")

The results of the first experiment (i.e. installation of SMs without further intervention) generally aligned with electricity use reductions found in previous research (e.g., Fischer, 2008), and indicate that it may be possible to expect a reduction in electricity use in the medium-term (weeks/months) of 6-7% ap-

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Figure 2 – Loss Aversion widget as seen by participants in the second SM experiment. ©Bager & NorthQ.

proximately. However, the large standard deviation (43% [n=47]) underscored the need for large-scale longitudinal studies. Results of the second experiment (i.e., introduction of SMs with and without intervention) show that subjecting participants to loss aversion and salience seemed to affect their behaviour toward more efficient electricity use. Whereas the reference group reduced their daily electricity consumption by 7% on average, those subjected to loss aversion and salience reduced their consumption by 18%. The reduction in standby consumption was 3% for the reference group, but found to be 28% for the intervention group. Setting aside socio-economic factors (e.g., income, household composition, education level) the intervention had a larger effect than when no framing was applied. Findings revealed that reductions in electricity use were also larger than the average electricity reduction found in other studies of feedback on electricity use (e.g., Fischer, 2008).

At the risk of oversimplifying, our results suggest that the delivery of information to energy users needs to take into account not only its pure provision, but also how feedback is designed, framed and presented. In turn, the deployment of SMs should not be conceived only about the provision of the 'right' information, but 'how' information is actually provided within a mix of effective and efficient policy instruments (e.g., market-based incentives, regulatory approaches). Our study supports the hypotheses that increasing the salience and framing reductions as avoiding a loss, rather than obtaining a gain, can trigger behavioural responses leading to conservation and energy efficiency measures. Whether or not the behavioural-based intervention used in the second experiment can actually reduce electricity consumption with the magnitude expected in the EU policy proposal (EC, 2011) hinges to a large extent on the scalability and long-term effects of such interventions (e.g. considerations of the 'rebound effect'). Our research suggests that there is a strong need to conduct large-scale, longitudinal and comparative studies in this area.

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How Does Market Power Affect the Impact of Large Scale Wind Investment in 'Energy Only' Wholesale Electricity Markets?

By Stephen Poletti, Oliver Browne and David Young*

The rise of wind and solar in electricity networks has raised concerns about the reliability of supply in, and the design of, electricity markets with large amounts of intermittent generation. Two well understood facts in the literature are: Firstly, increasing the penetration of intermittent generation requires an increase in peaking generation to ensure security of supply during periods where the resource is unavailable. Secondly, increasing wind capacity leads to greater price and dispatch volatility due to the 'Merit Order effect', intermittents dispatch first when available pushing down price relative to periods whens they are not.

These issues raise concerns in 'energy only' electricity markets where firms do not receive side payments for available capacity outside of the revenue they generate on the spot market. In such a market it is unclear whether increasing intermittent penetration will provide a sufficiently large market incentive for firms to invest in the peaking capacity necessary to gurantee security of supply - particularly if regulators are reluctant to see significiant outage hours with high price spikes. In such a scenario returns for peakers will depend on the degree to which firms are able to exercise market power; For peaking plants to make a return on their investments they need sufficient market power to push prices above their short run marginal costs during periods of peak demand. Thus to assess security of supply under intermittent investment it is crucial to combine aspects of a model with capacity investment with one in which firms can exercise market power.

This paper examines the interaction between capacity investment, wind penetration and market power by firstly, using a least-cost generation expansion model to simulate capacity investment with increasing amounts of wind generation, and then secondly using a computer agent-based model to predict electricity prices in the presence of market power. We find the degree to which firms are able to exercise market power depends critically on the level of total installed capacity relative to peak demand. For our preferred long run generation scenario we show market power increases as wind penetration increases and prices overall increase. The market power in turn leads to inefficient dispatch, which is exacerbated, with large amounts of wind generation.

Our setting, the New Zealand Electricity Market (NZEM) provides an excellent laboratory for studying the effects of wind integration for several reasons. Firstly it is one of the purest examples of an 'energy only' electricity market, there is no formal price cap and firms receive no capacity payments. Secondly New Zealand has highly economic wind resource which unlike many countries is not subsidsed. Thirdly the market has a small number of firms and market power is known to be an issue. And finally the NZEM is relatively small hand has no interconnection to other markets which enables each plant in the market to be modelled at high resolution.

Methods

To simulate capacity investment we used the NZ Electricity Authority (EA)'s Generation Expansion Model (GEM) to generate a number of capacity investment scenarios for the year 2025 with varying amounts of intermittent wind generation (EA, 2010). GEM takes as inputs forecast demand and the operating and investment costs of new and existing generation and transmission throughout the country. It then solves assuming competitive dispatch for the generation and transmission mix that minimizes system cost, including capital, operating, and maintenance costs, over the horizon of the model.

Then to model realistic high frequency market dispatch and prices under market power we use SWEM, a computer agent based model developed by Young et. al. (2014). In SWEM, computer agents bid into the market with a portfolio of generation assets. Profits are computed using a simplified 19-node dispatch model of the NZEM These profits are fed into a Modified Erev-Roth computer-learning algorithm (Nicolaisen et. al., 2001). Each iteration, agents update their strategies, construct new bids and the process is repeated until prices converge. Half-hourly wind levels are obtained from National Institute of Water and Atmosphere (NIWA) simulated data. Demand is assumed inelastic and constructed by projecting forward current demand patterns using forecasts from the Statement of Opportunity (EA, 2010), which is also used to model expected future transmission upgrades.

Scenarios are constructed with different amounts of installed wind capacity whilst holding constant the ratio of the 'effective installed capacity' (where wind is discounted by its capacity factor) to peak demand. Firstly we run the long run GEM to determine the capacity mix for each wind penetration scenario. Then we

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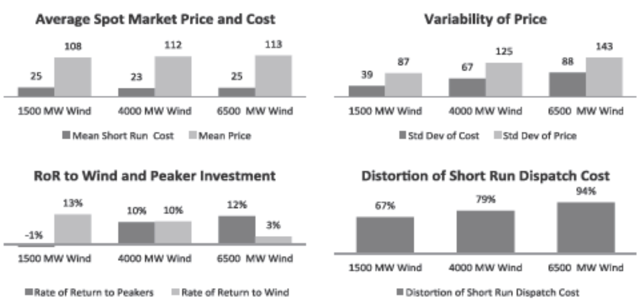
simulate strategic spot market bidding behaviour in the agent-based model SWEM to model dispatch and wholesale prices for each of our wind capacity scenarios.

Results

There are three factors which drive trends in average prices as wind penetration increases. Firstly there is the previously described 'Merit Order' effect. Secondly there is an 'Investment Response' effect; as wind penetration increases, the expected capacity factors for other generation in the market falls, so there will be a substitution towards plants with relatively lower capital costs and higher marginal costs. Thirdly there is a 'Market power' effect, as wind capacity increases, during low wind periods supply is tighter relative to demand which enables peakers to exercise more market power pushing prices up.

In out simulations we find that as wind penetration increases the merit order and substitution effects almost balance, the average marginal cost of dispatch is flat as wind penetration increases across our preferred scenarios. However the 'market power' effect is significant as the degree to which firms price above marginal cost increases dramatically. Our results support Twomey and Neuhoff's (2010) theoretical result that with market power thermal plants are able to exercise market power more than the intermittent wind generators. Increasing wind penetration leads to increasing price variance; both more periods where there is a zero equilibrium price of electricity and more periods when price is above the marginal cost of a peaking plant.

As the wind penetration increase, we predictably find the rate of return for wind generators falls, however counterintuitively the rate of returns to peakers increases. In our model when wind penetration is around 4000MW (31% of built capacity) both wind and peakers make sufficient returns to incentivse investment. Below this level of penetration there is inadequate returns to incentivise building new peaking capacity, above it there are inadequate returns to incentivise further wind investment.



Although market power enables peakers to make a return on their capital costs, it also leads to a loss of efficiency in our model. Firms have a systematic incentive to withhold capacity to push prices up and there is an asymettric asset allocation among firms. This leads to some low cost generation being withheld and high cost generation dispatching out of merit order. This leads to a loss of efficiency by distorting dispatch from its marginal cost optimal. The loss of efficiency is significant and increases as wind penetration increases. This also leads to increased greenhouse gas emissions compared to competitive dispatch.

Conclusion

To conclude, our results suggest that energy only markets can work with large scale wind penetration. In our simulations there is a 'sweet spot' where both wind and peakers make sufficent returns to invest in an energy only market. However this market would be characterised by highly volatile prices, significant market power and inefficient dispatch.

It is unclear if these are desirable features for electricity markets, some have argued that this implies markets need redesigining. For example (Hall, 2014) quotes "… capacity remuneration mechanisms [are] 'unavoidable' in countries with large shares of renewables with zero marginal costs, such as Germany, said Paul Giesbertz, head of infrastructure and market policies at Statkraft Markets … [because] … with regular high prices in some hours, it was unrealistic to think the public would accept a 'structural appearance of scarcity". Our results suggest that increasing market power seen in our simulations alongside increasing ineffeciciency of dispatch will exacerbate such concerns.

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Establishing the Economic Co-benefits from Aligning Controlled EV Charging and Solar PV Generation in the Australian National Electricity Market

By Graham Mills and Iain MacGill*

The emergence of Electric Vehicles (EVs) represents a historic coupling of the transport and electricity system which for the first time will see private transport energy needs impact electricity system load. In addition, the electricity system itself is going through a period of dramatic change with the emergence of transformative technologies such as solar PV at high penetration levels. Both of these technologies (PV and EVs) have implications for electricity system economics and may represent an opportunity or a threat depending on how they are integrated into the existing system. The challenge for policy makers and the community is to maximise the benefits possible from the emergence of these technologies while avoiding the potential for adverse outcomes.

Key to appreciating how both technologies could be integrated in order to maximise benefits may lie in understanding how their respective characteristics are different but complementary. PV generation is driven by the diurnal solar cycle and therefore lacks inherent temporal flexibility. Given this, beneficial integration of high PV is constrained by the extent to which the underlying power system is able to reduce output to accommodate it while maintaining system security. By contrast, EV charging is fundamentally flexible and able to move across time. The factors which constrain EV charging flexibility however, relate to the temporal and locational alignment between vehicle travel patterns, transport energy requirements, and charging infrastructure availability.

The challenge of high PV penetration is illustrated in Figure 1 a) which shows curtailment should PV generation result in net system load falling below allowable minimum synchronous generation levels. Illustrating the extent to which charging infrastructure availability constrains EV flexibility is Figure 1 b) which presents results from [1] showing the extent to which EV battery energy exceeds that required for reservation against future transport needs. This 'distributed energy resource potential' is clearly enhanced by the availability of non-residential charging infrastructure indicating an enhanced ability to shift charging so as to align with PV generation.

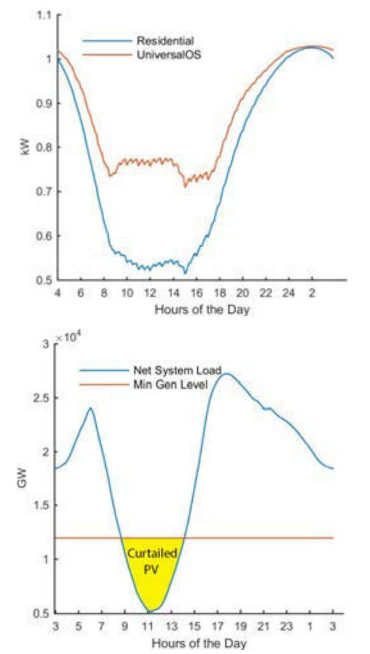

Figure 1 – a) Average sunny autumn day including 25% annual PV penetration by energy and a minimum synchronous generation level corresponding to 35% of peak NEM load; b) Extent to which the SOC of the batteries of connected EVs is excess to the level required for future transport requirements.

The extent to which EV charging can be aligned with PV generation therefore will rely on 1) management of EV charging behaviour to occur in the middle of the day through incentives or control and is enhanced by 2) the availability of charging infrastructure at high dwell time locations such as workplaces, shopping centres, educational facilities and the like. Should these conditions be met, benefits arising from the interaction between aligned PV generation and EV charging load may be realised in a range of areas including a reduction in: GHG emissions, the cost of generation, PV curtailment, as well as gasoline consumption relative to the case in which EV charging and PV generation are un-aligned or daytime EV charging is constrained by a lack of charging infrastructure availability.

This article investigates the co-benefits possible from aligning controlled EV charging with solar PV generation with specific reference to the value of additional non-residential EV charging infrastructure. To illustrate, results are presented from a case study of the Australian National Electricity Market.

Method

A bottom up simulation approach was adopted with the goal of scheduling EV charging during periods of minimum net system load subject to infrastructure and travel constraints. A Plug in Hybrid Electric Vehicle (PHEV) model, approximating a General Motors Volt was used to simulate EV charging and gasoline consumption outcomes. Trip data from the New South Wales Household Transport Survey in respect of 51,800 conventional vehicles was obtained for the Sydney Greater Metropolitan Area and an optimum charging strategy was determined for each vehicle given net system load, travel requirements, and infrastructure availability through the use of a dynamic program. The model scheduled EV charging into periods of minimum system load, specifically the daytime minimum load period which arises with high PV penetrations. Once

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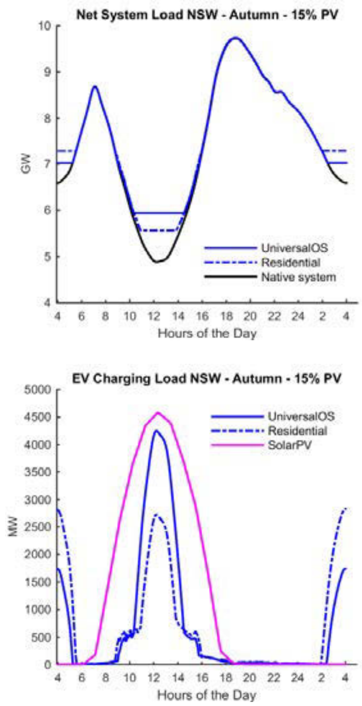

Figure 2 – a) Average autumn day NSW load with 25% PV penetration and controlled charging of an EV fleet of 20% penetration given residential and universal off street EV charging infrastructure; b) corresponding EV fleet charging profile.

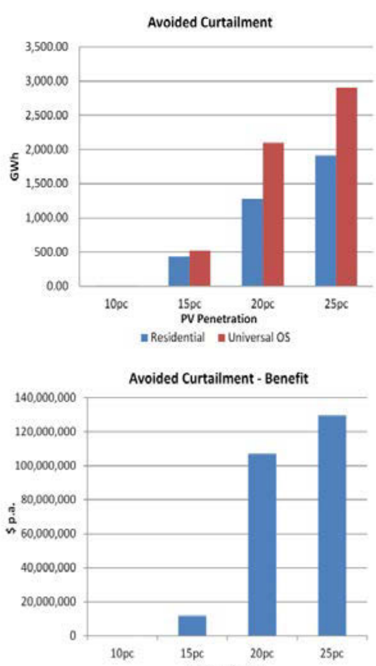

Figure 3 – a) the reduction in annual PV energy curtailment under each EV charging infrastructure case; b) financial benefit from avoided curtailment from the provision of non-residential charging infrastructure relative to the residential charging case.

this mid-day minimum net load period becomes dominant, EV charging preferentially fills the 'solar' daytime load valley to the maximum extent possible. Charging requirements then unable to be satisfied during the day occur during the overnight diurnal load valley.

Solar PV penetrations between 10% and 25% of native system energy were assessed for an EV penetration level of 20% of the eastern Australian light duty vehicle fleet with benefits established from applying EV charging load to a simplified generation model of the Australian National Electricity Market (NEM). Generation dispatch in the NEM was then simulated using system load from 2011 with a minimum synchronous load constraint corresponding to 35% of peak load and a carbon price of \$20/t CO2. The minimum synchronous load constraint corresponds to the aggregate minimum generation levels of thermal NEM generators dispatched during 2011 and is consistent with [2] who found a similar figure in respect of PJM Interconnection in the United States. Two charging infrastructure availability cases were considered: Residential charging, which involved provided charging infrastructure at any location which was denoted in the NSW HTS as being a residential address; and Universal Off-street (OS) parking which provided charging infrastructure at all residential addresses and parking locations denoted as being off street.

Results

In order to demonstrate outcomes for EV charging load under the approach adopted, Figure 2 shows the extent to which EV charging load can be shifted into the middle of an average Autumn weekday under each of the charging infrastructure cases. The increase in daytime charging given non-residential charging infrastructure is clear with the majority of charging occurring during the 'solar' net system load valley. Residential charging infrastructure by contrast sees a majority of charging occur overnight. This difference is reflected by the reduction in curtailed PV which Figure 3 shows to be increased through access to non-residential charging infrastructure. When avoided curtailment is valued at the levelized cost of solar PV reported by the US Energy Information Administration in its 2015 Annual Energy Outlook, \$130/MWh [3], the annual financial benefit, relative to the residential only case, is found to exceed \$120 million dollars a year at 25% PV penetration.

GHG Emissions and the cost of satisfying EV charging depend on the mix of generators supplying EV load. From Figure 4 it can be seen that the generation mix attributable to EV charging transitions from being overwhelmingly black and brown coal to being majority PV at 25% penetration. While the same general trend is noted in respect of both charging infrastructure cases, the rate at which coal sourced generation declines and PV sourced generation increases is greater with additional charging infrastructure. It should also be noted however, that in the absence of avoided PV curtailment (penetrations rates of 15% or below) EV charging in the Australian NEM results in additional generation sourced from existing, primarily coal, generation sources.

Combining results in respect of electricity generation and gasoline costs, GHG emissions, avoided PV curtailment allows the total combined benefit achieved by providing additional non-residential charging infrastructure to be assessed. From Figure 5, it can be seen that the total benefit increases as a function of PV penetration rising from slightly under \$80 per vehicle per year, to slightly over \$140 per vehicle per year. While a net benefit is seen for all penetration levels, electricity system benefits are initially negative and only become significantly positive once PV penetration levels exceed 15%. The largest single contribution is the financial savings is from avoided gasoline consumption attributable to vehicles being able to satisfy a greater proportion of their travel needs from electricity given non-residential charging availability. The benefit associated with avoided PV curtailment also becomes significant at higher PV penetration levels. By contrast, electricity generation and emission cost savings make a much smaller contribution.

Discussion/Conclusion

The results presented here demonstrate the extent to which the provision of non-residential charging infrastructure can enhance the alignment of EV charging and PV generation leading to co-benefits from the integration of EVs and PV at high penetrations. While the benefits identified may be significant, they still only represent a subset of those possible from greater access to EV charging infrastructure. In addition, benefits may also exist in areas such as: avoided generation and network investment costs; energy security benefits associated with reduced oil importation; urban air emission benefits from reduced particulate emissions; and increased EV uptake through a reduction in range anxiety.

While benefits exist, the provision of non-residential charging infrastructure also faces a number of barriers which create a case for public policy intervention. It has been found that revenues from the sale of electricity are in-sufficient to support a viable independent business model for non-residential EV charging [4]. This situation creates the potential for market failure due to the external benefits accruing to all parties and members of the community not being reflected in the private benefit realised by an independent investor relying on revenues from the sale of electricity. These 'external' benefits accrue to a range of parties other than the investor such as non-priced benefits for the the electricity system; a reduction in the social costs associated with climate change; benefits to vehicle manufacturers through an increase in the rate of EV adoption; benefits to individual drivers, and society, from reduction in gasoline consumption; as well as benefits for PV investors through a reduction in levels of future PV curtailment. Such market failure can be expected to result in suboptimal investment levels and inefficiently foregone benefits for society.

In addition to the presence of positive externalities in a general sense, a specific case of market failure impacting non-residential charging infrastructure deployment is that of the tenant landlord problem. The tenant landlord problem relates to the situation where one party (either the tenant or landlord) is unwilling to make an investment the benefits of which will accrue to the other party. The tenant landlord problem was investigated by [5] who found that one of the principle barriers to EV charging infrastructure investment in multi-unit developments in the Los Angeles area was determining whether the building owner, or tenant was responsible for paying for the equipment and installation costs given that the residual value would pass to the building owner at the end of the tenancy period. The presence of such market failures therefore require policy solutions which are not only limited to financial support, but also include legal and contractual frameworks which reduce the transaction costs created due to negotiations between parties.

This article presented results form a case study involving a single vehicle battery size, assessed using vehicle travel information from a conventional vehicle fleet, with benefits established in respect of the thermal coal heavy existing Australian NEM. Both EV battery sizes and the physical electricity generation system can be expected to change over the period during which EV and PV penetrations become significant. Therefore, care should be taken in generalising the findings presented here. Instead, these results should be viewed as creating a case for the development of public policy to encourage efficient long term investment in non-residential charging infrastructure rather than a definitive and predictive assessment of future outcomes.

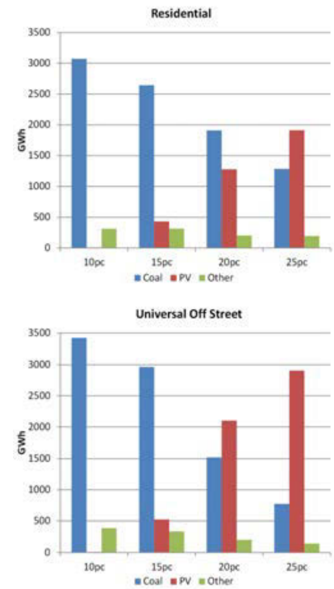

Figure 4 – a) Source of generation attributable to EV charging given residential charging infrastructure; b) Source of generation attributable to EV charging given residential and universal off street charging infrastructure.

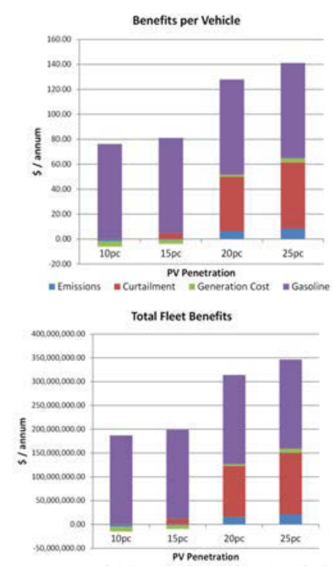

Figure 5 – a) Total combined benefits for an average vehicle due to the provision of residential and universal off street charging infrastructure relative to residential infrastructure; b) Total combined benefits in respect of the provision of residential and universal off street charging infrastructure relative to residential infrastructure for a 20% NEM state light duty vehicle fleet.

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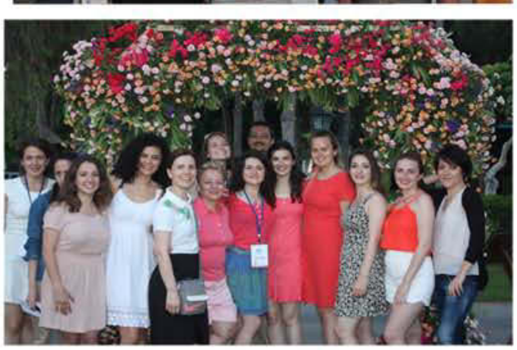




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The Long-Run Impact of Energy Storage on Electricity Prices and Generating Capacity

By Richard Green and Iain Staffell*

Energy storage technologies can potentially help with integrating variable renewable electricity generators such as wind farms and PV panels. At times of high generation and otherwise low demand, putting energy into storage is a valuable alternative to simply spilling excess power, and means that fossil generation can be displaced later at times of higher demand or lower renewable output. Increasing levels of variable renewable output have been associated with more volatile wholesale prices, which of course makes arbitrage strategies more profitable – the economic signal for energy storage complements the technical one. The use of storage to absorb excess renewable power could also counter the tendency for renewable output to become less valuable as more is produced (Swider and Weber, 2006; Lamont, 2008; Bushnell, 2010; Hirth, 2015).[1]

There is a natural limit on the amount of arbitrage that can be profitable, since it reduces the price differences that incentivise it. Furthermore, Green and Vasilakos (2011) have shown that the effect of renewables increasing price variability (and lowering average prices in some countries) is primarily a short-term phenomenon. Once the capacity mix has adjusted to the new shape of the load-duration curve (net of renewable output), the price-duration curve ought to revert to a similar form as without the renewable generators. We ask whether a similar result holds if energy storage technologies are widely deployed. If so, the need for energy storage might be quite limited.

Modelling the Impact of Storage on Generator Operations

A lot of papers in electricity economics (including many of our own) take a simplified approach to dispatching power stations, using the classic merit order stack. However, to get a full picture of how storage can affect the task of matching generation to demand over time, it is important to take intertemporal operating constraints into account. We use an open-source mixed-integer model – the Unit Commitment Capacity Optimiser (UCCO) – that decides which power stations to turn on and off over the course of a year, trading off the cost of starting a plant against the cost of keeping it running part-loaded, and the impossibility of running below its minimum stable level (Staffell and Green, 2015). UCCO calculates the marginal cost of energy in each hour, and hence the revenues that each type of station would earn over the year's operations, together with their costs. If the station is found to earn more than its costs, then UCCO will add more of that type of capacity and re-run the operating stage; if some stations are unable to recover their costs, then UCCO will reduce capacity. The process stops when every type of station is just breaking even (within model tolerances), thus giving the outcome a competitive market with perfect foresight would produce.

A fixed amount of storage, measured both in terms of power (MW) and energy (MWh) capacity, can be added to the model, and is dispatched as part of UCCO's cost-minimising operating stage. UCCO does not vary the amount of storage to meet a break-even constraint, but records the profits that it makes (net of energy purchase costs), and hence the fixed costs that these could cover.

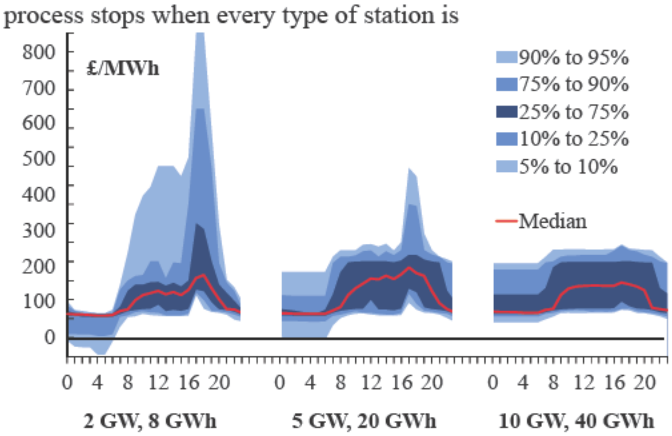

Figure 1: Distribution of prices over winter days.

We model the power system in Great Britain in 2030, assuming the demand level and renewable generation from the National Grid (2014) "Gone Green" scenario. This has 51 GW of wind, 16 GW of solar energy and total demand of 345 TWh – the same level as 2014. Demand is kept down by significant investments in energy efficiency and because the electrification of transport and heating is not assumed to take off until the 2030s. Our plant costs are taken from National Grid and DECC (2013), including a carbon price of £76/tonne. We follow the approach taken in DECC (2013), which is to take the expected net present value of the carbon price over the station's lifetime, a more relevant guide to investment than the current (low) value.

Results

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See footnote at end of text.

Figure 1 shows that as storage is added to the power system, the distribution of prices is compressed. The figure takes prices for 90 days between late November and the end of February (excluding the period around Christmas) – the very highest prices are suppressed as the amount of storage available increases. In contrast, the highest overnight prices increase – the effective demand rises as most power can be taken into storage at these times, and the plant mix is also changing – the storage actually displaces CCGT stations rather than the peaking plants that we might expect to be its direct competitors.

Figure 2 shows that the price-duration curve does not change significantly over the year as a whole – as Green and Vasilakos (2011) found, capacity will adjust so that the baseload technology continues to be able to cover its costs over the year as a whole, and this anchors the time-weighted price. Since storage cuts off some of the very highest prices, the new equilibrium requires higher prices than before in the near-peak hours: it also eliminates some (but not all) of the hours in which renewables have to be displaced and ask for a negative price to offset their lost subsidy. The demand-weighted average electricity price falls by 6% as storage is added, while the average market value of wind energy rises by 6%. The value of storage also falls; the energy arbitrage and peak capacity value captured in this work decreases by 60% as we move from 2 GW to 10 GW of storage power capacity. Storage has other uses, however, providing operating reserves and relaxing grid constraints; Strbac et al (2012) show that the marginal value of these is significant and not particularly sensitive to the amount deployed. Coordinating the use of storage between these different opportunities remains a challenge.

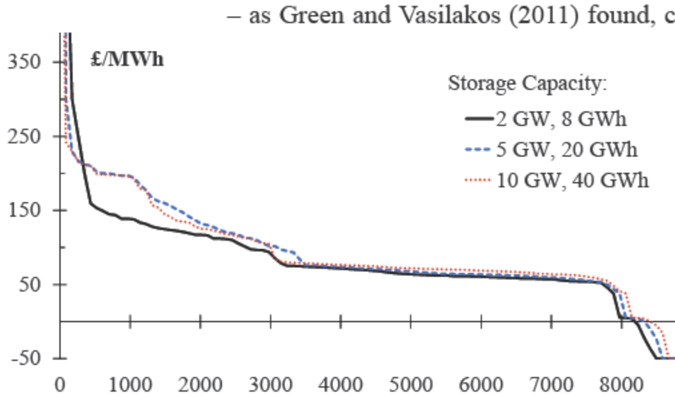

Figure 2: Price-duration curves

Footnote

[1] This is because power prices are positively correlated with the amount of thermal generation, which after correcting for the pattern of demand will be negatively correlated with the amount of renewable output. With enough renewable capacity, this can offset any tendency to have more output at times of high demand.

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Economies of Scale in Biogas Production

By Lise Skovsgaard and Henrik Klinge Jacobsen*

Biogas production is focused on using domestic resources to generate CO_2 neutral energy production along with reducing environmental damage from waste products in agriculture, industry and households.

The technology is relatively expensive as an energy producer and therefore economies of scale is a way to improve the competitiveness.

The biogas production chain from the farmer, to the biogas plant and through to the use in a combined heat and power plant or alternatively as upgraded biogas supplied to a natural gas grid involve cost drivers that may exhibit different properties with regard to scale. Supply of the feedstock and the capital costs of the biogas plant are elements that may have opposing scale effects for the economic profitability. Collection of resources requires transport over longer and longer distances depending on the scale of operation. This drives up unit costs of inputs. Unit costs on the other hand declines as economies of scale for capital expenditures are realised. Walla and Schneeberger (2008) looks into the optimal size of a biogas plant supplying a combined heat and power plant. They find that transport costs of silage maize increase with scale, but the benefits of scale in terms of capital costs and generation efficiency more than offsets this. We consider larger scales and a situation with manure as primary input and allowing the choice of upgrading biogas to the natural gas grid.

Methods

Based on a case study for an area in Denmark we compare the two opposing effects for three specific sizes of a biogas plant. Like Delzeit and and Kellner (2013) we include transport costs for manure, co-substrate sugar beet and the output digestate. In the considered area manure is found in large amounts allowing large scale biogas plants. We use a small model to calculate costs of input collection, biogas production and upgrade to natural gas grid. Revenues from the operation is based on the various choices for supplying the biogas output to a local combined heat and power unit (CHP) or to the natural gas grid based on the gas prices + subsidies that can be obtained. The approach is focusing on the private profitability of operation as we examine private incentives for choice of scale and input composition.

The model first calculates input costs based on required input amounts for each scale of operation. First we examine scale effects with a technology entirely based on manure as input. Secondly, we examine the effect of a co-substrate (sugar-beet) on the total cost and scale effects.

For the case with the input mix of manure and sugar-beet we use the local resource constraints for existing sugar-beet output, not considering change in cultivated crops. Transport distances, type of vehicles, loading costs etc are taken into account like in Walla and Schneeberger (2008). Increasing the scale of operation results in longer distances driven to collect, but it varies substantially between the manure and the sugar-beet. All operational and capital expenditures of the biogas plant itself is added dependend on the three different scales. For scale effects there is a choice between using the output from the biogas plant directly in a combined heat and power plant or upgrading the biogas to natural gas standard and connecting to this grid. The larger the scale, the more necessary the final upgrade of biogas become, due to limited demand for the heat output from the CHP. This upgrade involves additional capital and operational expenditures.

Findings

Three scales of operation are compared: Small(110) 110,000 tonnes of input p.a.; Medium(320) 320,000 tonnes of input p.a; Large(500) 500,000 tonnes of input p.a. We use the farms specific locations and calculate the necessary travel distance to collect the manure under some simplified assumptions on actual travel distance while assuming that these transports also return to the same farms with the treated manure/digestate. The travel distance determines the variable part of the transport costs whereas the fixed part per load concists of both loading and unloading time. Scaling up the plant to the largest size will increase the total transport costs per unit with around 50%, in which case the fixed transport costs constitute only 25% of total transport costs. Yabe (2013) using GIS also examines manure treatment in biogas plants and finds finds even higher transport costs (56% of running costs, compared to our 26%).

This rise in unit cost must be compared to the benefits of scale in other cost components. In Figure 1 all unit cost components for the case with only manure is compared. Transport costs are rising as well as operational costs at the biogas plant. For capex there is considerable benefit of scale, that dominates the diseconomies of scale from the transport and opex costs. Even for the very large

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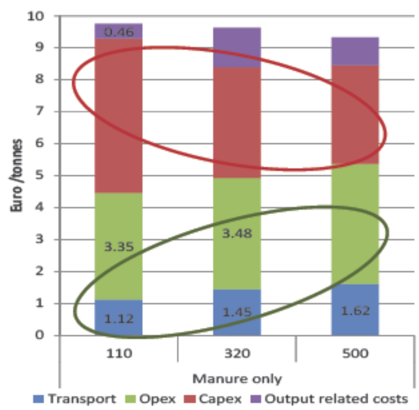
scale of operation Large(500), where biogas production considerably exceeds local CHP demand for biogas, there are substantial benefits to scale.

Biogas production based on manure and no co-substrate is not yielding a high biogas output per input volume. Therefore, we also examine two cases with addition of 12½% and 25% of suger beet as co-substrate. This provide higher yields, but also higher costs. Focusing first on the transport costs we find that sugar beet availability in the local area is dispersed and requires longer transport distances than the manure. Hereby, the total transport costs per unit increase by around 140% when moving from zero to 25% sugarbeet (represented by vertical arrow). For the sugar beet cases the unit cost also rise with scale, and as the level of transport cost is higher the absolute increase in transport cost from 110-500,000 tonnes result in a larger contribution to diseconomies of scale than for the zero sugar beet case. In Figure 3 this larger effect is also observed when all cost components are compared between the three different input cases.



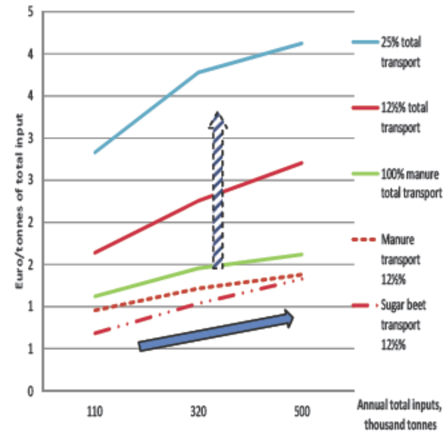


Figure 1: Trade off between rising transport and operational costs against reduced capital costs in a manure case for three different scales of operation (left)
Figure 2: Transport costs per total input 110-500 000 tonnes (right)

In Figure 3 it is shown that total cost per unit of total input more than doubles when 25% of sugar beet is added. The main contributer to this is the purchasing cost of sugar beet (top arrow), but also the rising transport costs (bottom arrow), and output related costs are important. Both elements reveal the importance of securing low cost co-substrates and collecting the resources available close to the plant. For scale effects in sugar beet cases the pattern is almost stable unit cost when increasing from 110-500,000 tonnes of input. Thus, we do not find the same economies of scale as found for the pure manure case.

The explanation is the larger increase in transport costs for sugar beet and digestate and larger increase in output related unit costs. Overall, the economies of scale and the constant unit cost in sugar beet cases both suggest that the largest scale plant is the most attractive provided that operation is profitable and feasible feasible.

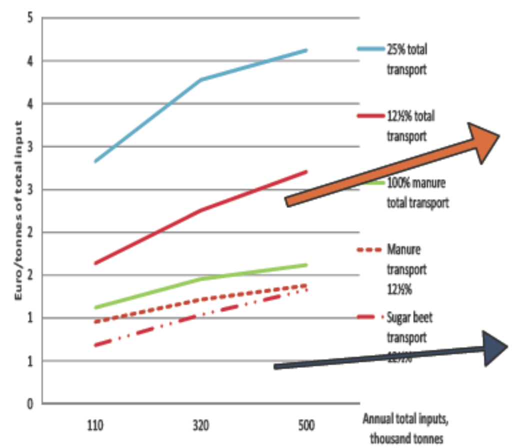


Figure 3: Costs per input unit when adding sugar beet to the input in three different scales (110-500000 tonnes)

Conclusions

In a Danish case study we find that per unit transport costs for biogas plants are rising with scale, partly offsetting the economies of scale found for capital expenditures. A detailed modelling of manure resources available, the fixed and variable transport costs and digestate transport costs suggest that in certain areas in Denmark centralised large scale biogas plants are the most economical provided that all biogas production can be upgraded to natural gas grid and receive the existing support.

When the biogas plant size is scaled up from 110,000 tonnes of annual inputs to 500,000 tonnes, the opposing contributors to scale effects and the net result found are:

- A unit cost reducing effect in capex, where unit costs are reduced by 35%
- A *unit cost increasing* effect from transport, with an increase of 45% for manure input and 96% for sugarbeet input
- For the only manure case the net effect (trade-off) is a total unit cost reduction of 4½ %
- For the two cases with sugar beet the net effect is a slight increase in unit cost, where the economies of scale disappear due to faster rising sugar beettransport cost and output related cost.

We can conclude that there is a case for larger scale biogas plants in Denmark based on economies of scale in costs, but that the effect with co-substrates such as sugar beet requires availability relatively close to the plant.

(see references on page 38)

Is CCR a Viable Technology Option for Investors? A Multi-stage Model Analysis Under Uncertainties

By Jian-Lei Mo and Ying Fan*

Introduction

Electricity sector contributes more than 41% of the total energy-related CO_2 emission of the world (IEA, 2013), and carbon capture and storage (CCS) is a critical technology option to realize large-scale CO_2 abatement in this sector (IEA, 2010). However, CCS investment seems not to be viable in its current stage and short-term future because of its high cost and high future risk. More specific, adding CCS increases capital costs as well as ongoing operating and maintenance costs, including additional capital expenditure, energy penalty, and additional cost for CO_2 transportation and storage, etc. In addition, CCS investors are facing many kinds of risk such as market uncertainty, technology uncertainty, policy uncertainty, etc (IEA, 2007a). In this situation, CCS technology diffusion might be restrained when new fossil fuel power plants are built without option for CO_2 abatement, and a large amount of CO_2 emission to the atmosphere would be 'locked-in' for many years (IEA, 2007b), especially in the emerging economies.

As a potential solution for this conundrum, the concept of 'carbon capture ready' (CCR) therefore comes into being. A CCR plant is one which can be retrofitted with CO_2 capture when the necessary regulatory or economic drivers are in place at a later date. It would have a higher initial capital cost than a conventional plant without CCR (No-CCR plant) but would cost less to be retrofitted with carbon capture. Conversely, a No-CCR plant would have a lower initial capital cost but a higher cost for future CO_2 capture retrofit, even there is no possibility for the plant to be retrofitted because of the lack of the necessary space for retrofit facilities and site for storage (IEA, 2007b). As a result, the investors of new power plants would face decision on choice between CCR and No-CCR plant currently[1]. In addition, because of high capital cost and irreversibility of the CCS investment, the potential plant investors may probably delay CCS retrofit and wait for better conditions even if the emission regulation has been in place faced with future uncertainty (Abadie and Chamorro, 2008). At last, as a result of higher operation and maintenance cost and energy penalty cost, as well as the additional transportation and storage cost, even after CCS retrofit, the investors can suspend CCS operation if market conditions were not favorable in future (Mo and Zhu, 2014), especially for the post-combustion capture technology. In summary, a newly-built power plant investment is a long-term multi-stage decision problem and the decision in each stage could be affected by the decision in subsequent stage.

With future uncertainties and a long term complex process, CCR investment decision is a challenging issue faced by potential investors. In this paper, a newly-built power plant investment decision model was built. As a case study, it was employed to evaluate the CCR investment in China[2], and the critical factors affecting the plant type choice were explored.

Model and Methods

We build a multi-stage power plant investment and operation decision model under multiple uncertainties.

It is assumed that power plant investment occurs *before* the ETS is in place, which is a realistic scenario for many projects in many countries, e.g. China. Then the plant lifetime was divided into three stages. The first stage is from the beginning of the decision until when the ETS is introduced. During this period, the investors would decide what type of plant to build. In the second stage, after ETS is introduced, the investors would decide whether and when to retrofit the plant with CCS. In the third stage after CCS retrofit is finished, in each period the investors would decide whether to run CCS to capture CO_2 or to suspend CCS operation temporarily according to market conditions, until the end of the plant lifetime. At last, the investors also have the option to permanently shut down the plant in each period if they expect that ongoing operation of the plant would lead to loss.

Three kinds of risk affecting future costs and revenues are considered. First is the policy risk, and time uncertainty on when to introduce a carbon emission regulation (e.g. emission trade scheme (ETS)) is considered. Second is the technology risk, and learning uncertainty of CCS technology is considered. Third is the market risk, including electricity price, fuel price (coal price), and carbon price. For the first two kinds of uncertainties, scenario analysis was conducted to analyze their effect on the CCR investment, and for the market risk, non-

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See footnotes at end of text.

stationary stochastic processes were employed to model the future price evolution.

To solve the model, least squares Monte Carlo simulation methods were employed (Longstaff and Schwartz, 2001).

Results and Implication

CCS operation flexibility means that the investors can choose CCS operation mode after CCS retrofit according to specific market conditions. For example, if the future carbon price is low, CCS-off mode may be optimal. CCS operation flexibility has a significant effect on CCS retrofit and CO_2 abatement, which means it would increase CCS retrofit probability, but would decrease the CO_2 abatement amount. Furthermore, CCS operation flexibility would also affect CCR investment decision by affecting CO_2 abatement and CCS retrofit decision, and it would decrease CCR investment probability, indicating that neglecting operation flexibility would overestimate the viability of CCR investment.

Carbon price has a significant effect on plant type choice decision. CCR investment would increase with carbon price being higher and carbon price risk being lower. Learning effect of CCS technology means that CCS investment cost would decrease in future, and CCR investment cost would decrease with learning effect being more significant. In addition, CCR investment would decrease with CCR investment cost being higher, while early implementation of a CO_2 emission regulation would promote CCR investment. These simulation results referred above have significant policy implication, and the details are as follow.

CCS operation flexibility would restrain current CCR investment for new power plants, and then the future CCS retrofit would be expensive and even impossible. However, CCS operation flexibility would render the current CCS investment less irreversible, and promote current CCS retrofit investment for existing power plant. These two effects of operation flexibility should be balanced: allowing for CCS operation flexibility can promote current CCS investment, but would restrain current CCR investment and then restrain the future CCS retrofit. For the policy makers, whether the operation flexibility is allowed should be assessed carefully.

Carbon price is an important driver for the CCR investment. For China, seven pilot ETSs have been built, and a national ETS is being planned. This would provide incentive for current CCR investment. However, the carbon prices in the pilot ETSs range from 20RMB/t CO_2 to 80RMB/t CO_2, and the average carbon price is about 50 RMB/t CO_2. At this carbon price level, CCR investment probability is low (far less than 50%) even in the low carbon price risk scenario. So it is inferred that China ETS pilots cannot support CCR investment, especially if the CCR investment needs large-scale capital expenditure. As a consequence, although CCR can make the power plant avoid “lock-in” risk and is optimal from the perspective of society, it may not be optimal for the private investors.

The simulation results also have important implication for R&D policy of CCS technology, and the potential interaction between CCS R&D policy and CCR investment policy should be carefully considered. More specific, if the government makes great efforts to reduce the future CCS investment cost by R&D, the current incentive to make investment in CCR may be undermined, and to promote current CCR investment, much more policy measures would be needed. As a result, the two policies should be coordinated in practice.

Footnotes

[1] Here it’s assumed that CCR is not mandated.

[2] China is the world’s largest CO_2 emitter, and electricity sector contributes about 49% of the total energy-related CO_2 emission (IEA, 2013). It is also expected that a significant quantity of extra capacity will be required in order to maintain power supplies in future. So CCR investment in China was chosen as case study.

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Modelling the Socio-economic Implications of Mitigation Actions in Colombia

By Ricardo Delgado, Camilo Matajira, Ángela Cadena, and Camilo Alvarez*

Overview

Climate change requires worldwide efforts in order to reach greenhouse gases abatement. Despite the fact that some developing countries are not considerable emitters, some of these countries are implementing measures to deviate its emission patterns. In this paper, a methodological approach to assess the socio-economic implications of some of these potential measures is proposed and implemented to evaluate the Colombian case. The most frequent way used to assess these implications have been the use of either sectorial models or General Equilibrium Models. The proposed methodology consists on the linkage of these two kind of models in order to assess the impacts in both,at the sectorial and the economic wide levels. A set of mitigation actions were evaluated. These mitigation actions included: renewable portfolios for power generation; carbon taxes with and without recycler mechanisms; and mandatory limits on emissions. The results shows the abatement potentials, the costs that the energy sector must face and the macroeconomic impacts of this class of measures. The main finding is that a carbon tax does not affect significantly the macroeconomic indicators and yet reached important abatements, especially if low oil prices are considered as baseline.

Methods

To reach the paper goal –to assess relevant mitigation actions and its expected impacts in the Colombian economy– we use a set of modeling tools that enable us to evaluate these measures. The Colombian version of MARKAL model was used to evaluate the impacts of carbon tax and mitigation actions the energy sector. On the other hand, a CGE model (MEG4C and is based on the GREEN model) was used to assess the macroeconomic impacts of such kind of measures. An intermediate endogenous growth model –M– was formulated and used in the linking procedure.

The linking approach proposed here consists on three stages in the following sequence. First, the endogenous growth model –M– provides the CGE –MEG4C– with GDP projections. Second, MEG4C produces sectorial GDP, used as energy demand drivers in MARKAL. Third, MARKAL optimizes the energy sector and provides M with new annual total energy costs. The idea behind the three model approach is that GDP growth is inversely related to the cost of energy: higher energy costs mean less money available for either consumption or investment; this translates into less investment on productive capital and lower GDP growth. In turn, lower GDP growth leads to lower energy demand, and lower energy costs, which raise GDP. Concerning the carbon tax, it is placed in MARKAL. MARKAL total energy cost will raise causing investment and GDP growth to decline in the other models. The recycling mechanism considered was direct transfer to households and this transfer was implemented in model M.

Results

Results with and without recycler mechanism are similar, with a slightly trend to reduce more emissions in absence of the recycle, especially in the last periods. In total, a \$50 per CO_2 ton carbon tax can reduce Colombian energy related cumulative emissions by 33% until 2045; it is up to 10.4% of the emissions in the considered sectors. In contrast, total abatement is less than 1% of the national emissions for a \$10 tax and less than 1.5% for a \$20 tax.

Regarding to the limit on the emissions, despite the fact that the total abatement is equivalent, the abatement path is different. In the limit on emissions, the investments and changes are postponed to the last periods. This behavior can be explained by the assumption of decreasing costs of new technologies in time. The responses of the energy sector to the evaluated measures are: increase on the penetration of electric vehicles; increase in the penetration of non conventional renewable sources for the power generation; and, in the case of the industries, there is a small substitution of coal towards natural gas. The remaining final consumption sectors are not able to substitute fuels or to incorporate more efficient technologies since they are already included in the baseline.

Two energy programs were assessed. The first one consisted on a renewable portfolio for power generation. The second, evaluated the substitution of fossil fuels in the industry by electricity. The modeled substitution was devoted to fulfill a share of the heat and steam requirements. These programs, in terms of

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abatement, obtain results comparable with the carbon tax of $20 per CO_2 ton. However, the abatement keeps a growing path, while in the tax and in the cap measures the size of the abatement varies between periods. The total abatement of these measures is 0.64% and 1.56% of the emissions in the baseline until 2045 for the renewable portfolio and for the use of electricity in the industry, respectively.

A sensitivity analysis to international price of oil was performed, so there are results for two oil price scenarios.

Regarding to the macroeconomic impacts there are four main ideas concerning the results: first, imposing a carbon tax lowers GDP. In fact, in 2020 GDP decreased with respect to BAU by 0.58% for a USD $10 carbon tax; 0.56%, for a USD $20; 0.77%, for $50. However, we have reasons to consider that this result is biased –it's smaller in magnitude that it should be. One reason is that the model is only taxing the energy sector –which represent a third of total GHG emissions–. The other reason is that we are ignoring the costs of enforcing the tax.

Second, implementing a recycling mechanism can reduce the GDP impact of a carbon tax in the long run. Imposing a $10 carbon tax without recycling reduced GDP by -0.31% and with transfer by -0.25%; a $20, -0.45% and -0.22%; and a $50, -0.79% and -0.36%. This means that the potential side effect of a carbon tax can be reduced by transferring the collected money to the households. Nevertheless, carbon tax with transfer still has a negative effect on GDP, this means "there is no free lunch" in mitigation actions.

Third, GDP reduction due to carbon cap results very similar to carbon tax with recycling. In fact, except for carbon cap 10$ scenario, the others differ very little with they counterparts. Yet, our analysis ignores the mechanism of how GHG emissions are allocated. MARKAL works like a central planner allocating resources to minimize cost, but in real life we ignore how emissions will be distributed among people and firms. This, in turn, can rise energy costs, so cost may be underestimated. This issue is under further research.

Fourth, both the Renewable Portfolio and the Electricity for Industry scenarios had the same negative impact on the economy. Difference in energy costs where very small between both scenarios, so the GDP projection was practically the same –in other words, the difference between GDP growth in both was below our convergence criterion, so results here cannot be diferentiated between them. The imptact on GDP reduction is, in magnitude, very similar to the impact of a $10 carbon tax without recycling, to a $20 carbon tax with recycling and to a $20 carbon cap equivalent, but with less mitigation.

Conclusions

It was observed that a $50 carbon tax can reduce Colombian energy related cumulative emissions by 33% until 2045. In all the evaluated measures, the mitigation could be obtained from changes in the transportation sector (use of electric vehicles and metro systems) and in the power sector by the increase of non conventional renewable energies as primary sources (geothermal, wind and solar). In this exercise we did not considered the use of nuclear as source for electricity production (sectoral experts rejected consider this option). Penetration of electricity in the transportation sector would be part of the least cost energy mix (baseline) if the future oil price does is above US$100 per barrel by mid 2014; it would be too expensive otherwise. Part of the coal used currently in industries might be substituted by natural gas in presence of a carbon tax. With the evaluated measures: there is always a share of the industrial energy requirements that are met by using coal and, the energy mix in commerce and households is not likely to change. It was observed that recycling mechanism have not significant results neither in the abatement potential nor in the resulting energy mix..

Regarding the results economy wide impacts, there are two main conclusions of imposing a carbon tax . First, a carbon tax reduces GDP with respect to the business as usual scenario. The mechanism through which this tax reduces GDP is that as energy cost rise, the economy as a whole will have less money to spend on either consumption or investment, lower investment translates into a smaller capital stock, and less GDP growth. Second, the carbon tax impact on GDP can be reduced by transferring the collected money to the households. Yet, carbon tax with transfers still has a negative effect on GDP. In other words, "there is no free lunch" in mitigating GHG emissions with a carbon tax.

The Increasing Role of Coal in the Energy Balance of APEC Economies for the Period till 2040

By Dmitry Sokolov*

With the continuation of economic turbulence, APEC is needed a stable energy supply of energy to continue achieving fairly high economic growth, in the long run. The region faces some significant energy challenges even in the period of non-tight oil and gas markets we observed in late 2014-early 2015.

Too many uncertainties including constraints on infrastructure to deliver energy sources to the market, geopolitical instability in some key energy exporting regions and threats of possible natural disasters bringing acute misbalance of supply of certain energy sources have all resulted.

Coal with development of clean coal technology and more efficient coal production and utilization is becoming an energy source which allow to provide the stability on energy markets in the APEC economies, taking into consideration that coal has the advantages of being widely available and relatively inexpensive in many APEC economies.

With the primary objective of the Asia Pacific Energy Centre (APERC) to conduct studies to foster understanding among APEC members of regional energy outlook, market developments and policy issues, in 2014-2015 APERC has conducted the 6th edition of the APEC Energy Demand and Supply Outlook, representing a 28 year look-ahead (2012-2040) assuming business-as-usual and several alternative cases.

This study summarizes findings of the Outlook on development of coal industry and it includes an economy-by-economy projection of APEC's energy demand and supply for the years 2012 to 2040 in the business-as-usual case and the role of coal in energy balance. 'Business-as-usual' means no major changes in policy except for changes required by existing law. The special attention in the Study is given to the economics of the prospects of clean coal technology and more efficient coal production in APEC region.

APERC has used its model to project energy demand and supply by economy and for APEC as a whole. APEC-wide results are simply sums of results for the relevant economies. The modeling process included assembling a database of key assumptions for each economy, including historical data base of the coal industry. Four sub-models (transport demand model, industrial demand model, electricity supply model and other sector demand model) estimate energy demand in key sectors. The result tables put together the results of all four sub-models and present them in an organized fashion.

In 2012, coal was the largest energy resource in energy balance of APEC economies, accounted for around 36% of total primary energy supply in APEC, up from nearly 27.9% in 1990, which is equivalent to a growth rate of 3.2% per year. The share of coal in the energy mix continue to increase and expected to reach 38% in 2040.

Coal is and will be a largest energy source in APEC, almost two times bigger than natural gas (19% in 2040). In absolute value, coal supply will increase by 1.7 during the forecast period.

Advantages of coal in power generation will allow the coal base generation to experience significant growth: from 6094 terawatt-hours (TWh) in 2011 to 12477 TWh in 2040. Growth in China's output of electricity from coal accounts for most of this growth (4632 TWh), while coal generation in the United States is projected to decrease.

Under business-as-usual assumptions, coal production in the APEC region will continue to grow by about 1% per year during the outlook period. It will amount to 4466 million tonnes of oil equivalent (Mtoe) in 2040 or about 46% more than in 2011. All 15 existing coal producing APEC economies will continue to produce coal while Papua New Guinea may start some minor production. China will continue to be the major coal producing economy not just among the APEC economies, but worldwide. Production in China will be 2234 Mtoe in 2040 or about 50% of the APEC region's production; it was 58% in 2012.

By 2040, there will be seven net coal exporting economies in APEC, and 13 more APEC economies that are net importers of coal. Brunei Darussalam is projected to have no production, consumption, imports, or exports of coal during the outlook period. Coal currently accounts for more than half of the CO2 emissions from fuel combustion in the APEC region, and we project in our business-as-usual scenario that these CO2 emissions from coal will grow by more than 45% between 2012 and 2040.

However, it is expected that APEC economies continue their policies of accelerating the deployment of advanced coal combustion technologies, coal beneficiation technologies and coal mine methane recovery and utilization technologies.

Special attention should be made to improving economics of coal liquefication

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technologies and integrated gasification combined cycle for power generation. These measures will allow to decrease the impact of the coal industry to the climate change.

After 2020, APEC economies will need further development of carbon capture and storage development in economic evaluation for an integrated CO2 transport, utilization and storage infrastructure in the region.

Conclusions

According to the results of the Study, APEC region continues to be a major player in the global coal industry. Even in the period of "Golden age for natural gas", the coal industry continue to be the main fossil fuel based industry in the region.

Driving forces in the coal sector of APEC include those with positive impacts, such as economic growth, urbanization, market development, and technology breakthroughs. Among others, and those that have negative impacts like environment and social concerns.

Coal industry should accelerate the deployment of advanced coal combustion technologies, coal beneficiation technologies and coal mine methane recovery and utilization technologies. Improving economics of coal liquefication technologies and integrated gasification combined cycle for power generation will allow to decrease environment and social concerns.

Depending on the strength of these driving forces, APEC coal development industries and utilization policies may undergo different transformations, even that APEC may see a Renaissance of the coal industry in the forecasting period.

Lise Skovsgaard and Henrik Klinge Jacobsen (continued from page 32)

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Changing Gas Price Mechanisms in Europe and Russia`s Gas Pricing Policy

By Tatiana Mitrova*

Since 2009 European gas market is undergoing a deep transformation process accompanied by a dramatic change of the gas pricing mechanism with the expanding share of spot-indexed gas supplies. Russia is traditionally one of the key players on this market so the question of Russian gas export strategy adaptation to these changes is extremely important for understanding of the future European gas pricing evolution.

Russia's traditional export strategy in the European gas market, which was successful for almost five decades, has noticeably lost traction in recent years, with gas pricing becoming the most critical issue: Russia is still officially preserving the traditional pricing model of oil indexation, while all European stakeholders demand of competitive, spot-linked pricing. But statistical analyses, undertaken by the author, demonstrate that although Gazprom still formally follows the traditional oil-indexation rhetoric, it has in fact already significantly reviewed its pricing policy. During the period 2009 –2014 nearly 60 gas supply contracts were reviewed with 40 clients, providing price discounts, easing of take-or-pay obligations and a certain introduction of a spot component.

In 2013 Gazprom started to implement a new price discount model with so-called retroactive payments. According to this model the company has to compensate its customers for the difference between contract price and spot price by the end of the year. This was an elegant way of executing a de-facto switch to spot indexation, while remaining formally within the framework of oil-indexed contracts (and to protect these contracts that were signed under the auspices of intergovernmental agreements). All these "compensations" are presented as temporary, and Gazprom has a right to remove them should the market become tighter.

Calculations using Russian Customs Service statistics, Gazprom reports and the Nexant World Gas Model, clearly show the increasing differential between calculated traditional oil-linked price and real Russian gas export prices to Europe. By 2014 Gazprom had already provided nearly a 15% average discount (around 70 $/mcm) to its European customers compared to its pre-crisis traditional oil-linked price formulas and this process is ongoing further – this figure exceeded 20% in 2014.

As a result of all these price discounts and also the tightening European gas balance, by the end of 2013 Gazprom`s contract price at the German border equalled NBP hub price level and Russian gas exports had partially been restored, though they did not recover to their pre-crisis levels. But at least Gazprom managed to restore its market share of 30%.

The future development of Russia's position in the European gas market is still unclear. The basic question is whether Russia will go for explicit spot pricing or if it will continue to provide all price reviews within the framework of oil indexation. Theoretically, Russia can choose between two strategies:

Post-facto adaptation by providing limited concessions to its buyers. In this way, Russia can continue to focus on price maximization, staunchly refuse to move to spot pricing, employ the tactic of minimal price concessions, or defend its position on oil indexation in arbitration and even go for further reduction of delivery volumes for the sake of maintaining the pricing principle. The following arguments work in favour of this strategy:

- A global LNG surplus is not expected for the next two years, and consequently the absence of any gas oversupply on the European gas market in the medium term will most likely narrow the gap between oil-indexed and spot prices;
- With higher prices, even lower export volumes guarantee growth in revenue;
- Gazprom's major contracts only expire after 2022, before that time annual contracted quantities exceed 160 bcm, and even minimal contractual quantities guarantee Russia approximately 120 bcm of annual gas export to Europe (equal to the level of 2009 supplies);
- The intensity of any conflict can be somewhat mitigated by further individual concessions by Gazprom to its major buyers;
- Arbitration lasts several years, during which time deliveries continue to be made based on previous conditions;
- Gazprom really needs oil indexation for its new expensive projects financing.

This may be more of a winning strategy in the medium term, though it does

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not allow Russia to expand its exports to Europe. But, most importantly, in the longer term it will undermine the competitiveness of Russian gas vis-à-vis that of the new suppliers targeting the European gas market. In this scenario, if massive new supplies become available, Russian gas can be partially squeezed out of the market by cheaper gas from competitors unless the export strategy is amended.

The alternative is a **strategy of anticipatory adaptation** and a transition to spot pricing. Russia can agree with buyers to a "buyout" of long-term contracts and then set up simultaneous price and volume optimisation, depending on current market conditions. In this case, in order to maintain its market position, Gazprom has to agree to prices that will ensure the competitiveness of its gas in the power sector (no higher than 6-7 $/MBtu) and ensure greater flexibility in supplies. This option is fraught with higher volatility, though it does have the following advantages:

- The possibility of profitably "trading off" changes to contractual terms in exchange for financial compensation (as was done in the review of contracts in the UK in the deregulation period) or regulatory exemptions (like OPAL and NEl exemption from the 3rd party access or more favourable environment for Turkish Stream or restored South Stream);
- An increase in Russian export volumes and European market share;
- If finally Russia should choose (or is forced) to move completely to spot-based pricing, Gazprom with its dominant position in the market fluctuating at around 30% of total European gas consumption (and far exceeding this level in certain countries, especially in Central and Eastern Europe), will be in a good position to manipulate prices through higher or lower supply volumes.

The future strategy choice will largely depend on the market supply-demand balance and the availability of cheaper supply options that are able to compete effectively with Russian gas.

The outlook for European gas demand remains unclear, but most analysts and research organisations assume that European gas demand will only recover to pre-crisis levels post-2020. Nevertheless European import needs will increase even with flat demand due to declining indigenous gas production. Analyses of the current and projected European gas market supply-demand balance and contracts conditions show that until 2022 all demand is covered by existing long-term contracts, the termination of which would result in high penalties for the European consumers. Afterwards a market niche for additional pipeline and LNG supplies is expected to appear and by 2030 it could amount for one third of the European gas market. So the threat to Russia's position will not be that great over the next few years, as there are no real supply alternatives, and Gazprom's export volumes are well protected by long-term contracts and beyond 2028-2030, when much more gas imports would be required from all supply sources.

The most challenging situation for Russian gas is foreseen in 2018-2028: huge growth of liquefaction capacities is expected by this period of time. If massive new LNG and pipeline gas supplies from Africa, the Middle East, North America and East Africa become available to European consumers at spot-indexed prices, these competitors will be able to propose more attractive prices than Gazprom and thus squeeze it partially from the market if it does not change its pricing model.

This means that in the short to medium term there are no incentives for Gazprom to turn its back on oil indexation, but by the end of the decade this discussion will most likely be high on the agenda again, forcing Russia to protect its market position through more thoroughgoing price reviews and stronger spot linkage.

Summing up, Russia is trying to adapt to the fundamental changes occurring in the European gas market, though in a "concealed" manner; formally following the principle of oil indexation, while defacto providing strong price discounts and linking pricing to spot prices via the retroactive payments model. The price concessions provided by Gazprom contributed to recovering of its gas exports volumes to Europe in 2013, though political events in 2014 and the desire to reduce dependency on Russian gas destroyed all these achievements. Nevertheless at least in the next decade the role of Russia in the European market shouldn't be underestimated. With the growth of alternative supply, primarily with the coming wave of LNG glut, Russia will have to enter into stronger price competition with the new suppliers, provide additional discounts, and introduce an explicit spot price component.

Shale Gas and the American Energy Renaissance

By Hillard G. Huntington*

Over many decades energy markets have seen a variety of new technologies with the potential of replacing existing practices for providing conventional fossil fuels. Synthetic fuels during the 1970s, hydrogen during the 2000s and carbon capture and sequestration in today's climate-change constrained times have all captured the fancy of policymakers. And yet, each of these options has not held much promise to date in being major players in the future energy mix. But since about 2006, hydraulic fracturing combined with horizontal drilling have made substantial in-roads in altering America's energy future. The sudden appearance of a cost-effective option that required prices below conventional practices was not what many economists had expected since the oil embargos of the 1970s.

Many have called this development, combined with similar trends in finding and developing its sister source of tight oil from shale deposits, as the renaissance of U.S. fossil fuel resources. To what extent are these new shale sources a renaissance or "game changer"? This article argues that expanding natural gas shale resources have significant implications for North American energy markets, creating new commercial energy opportunities in many sectors across Mexico and Canada as well as the United States. At the same time, it suggests that a realistic assessment must place bounds on what should be expected for some of the major problems of the day: climate change mitigation, economic recovery and energy trade and geopolitics. Directionally, these trends should not hurt these goals, but they will not significantly alleviate these problems. These comments are my personal views, but they have been strongly influenced by the discussions of the Stanford Energy Modeling Forum 31 Working Group, which compared results from 8 separate cases simulated by 14 different models.[1]

Shale Gas and Economic Recovery

Some U.S. industry has responded enthusiastically to these new opportunities (e.g., see Citi GPS, 2012, and Credit Suisse, 2012). In addition to the oil and gas drilling sector and the various sectors supporting it, the chemical industry now plans major investments within North America to take advantage of lower priced natural gas, ethane and other important liquids emanating from natural gas sources. The expanded natural gas supplies have also made electric power more competitive in regions where regulations allow gas-fired plants to set electricity prices. The lower costs and increased domestic investment represent significant gains for these industries and for states like Pennsylvania, Texas and Wyoming. However, they shape aggregate economic conditions in a more muted though positive way, because natural gas expenditures represent only about 1 percent of the total U.S. economy. On average, relative to reference conditions, inflation-adjusted Gross Domestic Product in the EMF results eventually rise by .23 percent for each 10 percent reduction in natural gas prices due to expanding supplies.

Shale Gas and Climate Change Policy

Although expanding natural gas supply displaces more coal than any other fuel, future downstream U.S. carbon dioxide emissions do not decline by much in the projections discussed by the EMF group. Relative to reference conditions, downstream emissions in some model results decline by as much as 1.1 percent by 2030 for each 10 percent reduction in natural gas prices due to expanding supplies. In other model results, emissions are as much as 1.1 percent more, because lower natural gas prices modestly stimulate more energy consumption and faster economic growth. These mixed results suggest that the natural gas shale revolution is not a substitute for coordinated climate change policy if governments want to mitigate future greenhouse gas emissions significantly below current levels.

Shale Gas and LNG Exports

A wide natural gas price differential currently exists between North America and other major demand centers in Europe and Asia. The United States has approved several LNG export facilities, and contracts have been signed to transport surplus production across the sea to some of these centers.[2] Results from the study suggest that near-term market conditions may be a window of opportunity for a few exporting companies. Longer term, it will be more difficult to boost these export volumes unless market conditions change. Adding LNG infrastructure costs for collecting, processing, liquefying, shipping and regasifying to the wellhead cost often make U.S. export volumes uncompetitive relative to sources delivered from other supply regions like Australia, Africa and the Middle East. Regulators in these Asian and European coun-

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See footnotes at end of text.

tries may allow some of the LNG costs to be passed through to “core” customers with limited ability to purchase other supplies, but opportunities to attract more competitive, “non-core” customers appear limited. Overall, however, U.S. producers may find a more attractive market by looking to its North American neighbors, particularly Mexico if that country expands its gas-fired power generation and fails to adopt the institutions for encouraging more domestic drilling.

U.S. LNG exports should penetrate global markets more if future U.S. natural gas supplies should become more abundant and less costly than expected by the U.S. Energy Information Administration and other organizations. These conditions initially widen the price gap between the United States and both Europe and Asia, relative to other supply regions participating in the LNG market. When companies add the required LNG infrastructure, the U.S. improves its competitive advantage.

Opportunities for higher U.S. LNG exports may also exist if Asian natural gas demand should grow more strongly, but these conditions do not change the U.S. competitive advantage relative to other supply regions. With higher Asian demands, the price gap initially rises between the Asian demand centers and all export supply regions. The U.S. export volumes increase but so do those from other supply regions that are closer to the Asian demand centers. The EMF scenarios assume that China adopts policies to replace coal with natural gas use in power generation in order to improve its air quality. Additionally, Korea and Japan decide to slow their construction of new nuclear plants. We developed these simulations as an interesting side case rather than as a projection that these countries would replace coal and nuclear with natural gas. Stronger Asian (China and Korea) demand increases total U.S. exports modestly by at most 1.2 Tcf above reference values in 2035. Wellhead prices in the same year are no more than 5% above reference levels.

Several models also considered the role for U.S. exports when Russian supplies are constrained by logistical constraints on Ukrainian pipelines[3] and higher development costs for Arctic frontier supplies. Despite the removal of Russian supplies from this simulation, results indicate that the U.S. exporters must still compete against other supply regions and that these conditions are often not favorable to the USA playing a significantly expanded role.

Shale Gas and the Clean Power Plan

The potential for U.S. LNG exports will also depend upon what other domestic uses for natural gas develop over this period. The U.S. Environmental Protection Agency (2015) recently promulgated a Clean Power Plan to reduce carbon pollution from the power sector by 30 percent from 2005 levels. It operates at the state level and sets a fleet average target for carbon dioxide emissions within the electric power sector but ignores emissions in other sectors. The emissions rate target would have to be met on average across all existing and new fossil generators, not by each individual unit. The target allows credits for energy efficiency improvements and non-hydroelectric renewable generation that can be traded to achieve the standard.

The EMF Working Group quickly realized that this plan could produce very different market outcomes depending upon how it was implemented: which units would be covered and the amount of coordination between states that could be achieved. Reflecting this uncertainty, participants elected to evaluate a “generic” technology performance standard (TPS) with extensions to the emissions targets beyond 2030. A common theme that emerged from the multiple models (some of which simulated across many cases) was that gas-fired generation spiked during the 2020-2030 period before the shift towards renewable and energy efficiency dampened this effect.

This increased demand for natural gas happens during a period when current investment plans call for expanding U.S. LNG exports. Simulations indicate that U.S. natural gas exports could be temporarily as much as 1.0 to 1.5 Tcf less due to this utility carbon policy by 2025. This finding suggests the possibility of a conflict between the nation’s goal of exporting more natural gas and its commitment to constrain carbon emissions in the electric power sector under proposed federal policies.

Global Implications

One should not view my attempts to place bounds on the natural gas renaissance as an argument that nothing has happened since 2006. Our results clearly indicate that expanding natural gas supplies has had a dramatic impact on North American energy markets. For every 10 percent reduction in natural gas prices resulting from expanded supplies, the average model result indicates that total natural gas consumption by 2035 increases by slightly more than 5 percent, total coal consumption decreases by slightly less than 5 percent, some new nuclear plants are not built and renewable energy use declines by about 2 percent. In addition, electricity sales increase by 2 percent as a result of lower electricity prices. These changes are not insignificant and suggest an important North American energy transition is underway. If exporting the hydraulic fracturing technology (with horizontal drilling) is cheaper than exporting physical natural gas volumes across the Atlantic or Pacific oceans, this development may have major global consequences. This technology transfer will not happen quickly, however, and entrepreneurs must find the right rock formations, institutions and political climate for knowledge spillovers to be economic.

Footnotes

[1] This effort is the second, two-year EMF study that builds upon the previous study summarized in the Energy Modeling Forum (2013).

[2] A number of papers explain the U.S. role in future LNG global trade. For example, see Ebinger, Massy and Avasarala (2012), EIA (2012), Medlock (2012), and NERA Economic Consulting (2012, 2014).

[3] See Richter and Holz (2015) for much more depth on the issues in modeling Ukrainian pipeline constraints.

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MEMBER GET A MEMBER CAMPAIGN A SUCCESS

Nevenka Hrovatin Wins Complimentary Registration at the Antalya IAEE International Conference

IAEE's Member Get a Member campaign was a smashing success with 20 new members added in the January to March period.

Members had their membership expiration date advanced three months for each new member referred. Advancements ranged from three months to 33 months as 20 members referred new members.

Professor Nevenka Hrovatin, Faculty of Economics, University of Ljubljana, Slovenia, referred the most new members – 11! She won complimentary registration to the Antalya International Meeting. In the process, she is helping to establish a new Affiliate of IAEE in Slovenia and hopefully her university will help support a forth coming IAEE conference in the country.

We encourage members to recommend their friend and colleagues to join IAEE.

Oil and Gas Price Drop Offers Reduced Cost Overruns

By Roy Endré Dahl, Atle Oglend and Petter Osmundsen*

Development projects in the oil industry often have cost overruns. With the recent regime shift in oil and gas prices, petroleum projects are re-evaluated and cost control is emphasised in the industry. Through analysis of data from Norwegian offshore development projects, Dahl et al. (2015) investigate the effect of the oil and gas prices on cost overruns. The results show that managers in the industry have an opportunity to invest in a downturn with reduced cost and according to our results, reduced cost overruns.

The recent regime shift seen in oil and natural gas prices confirms the difficultness of price forecasting over longer periods (Hamilton, 2009), and due to the long lead-time from investment commitment to production start, income uncertainty is high for any project in the petroleum industry. By using oil and natural gas prices as an indicator for expectations of future income, our study considers the possible cyclicality of oil investment strategies. Our aim is to capture a common driver for cost overruns in petroleum projects, linked to the business cycle. However, cost overruns also arise due to project specific factors not captured by a common factor such as the business cycles. Cost estimates are adjusted throughout the project due to updates on technical solutions and increased complexity and functionality. Further, uncertainty about subsurface conditions, reservoir quality, the fields size and reserves, may result in delays and increased complexity.

If the cost estimation accuracy of megaprojects initiated in the domestic oil and gas industry depends on exogenous business cycle drivers, the industry may have a pro-cyclical effect on the domestic economy. Because of major investment in infrastructure and production facilities, the oil and gas industry provides growth opportunities in extraction countries. This is particularly true for Norway, where the petroleum industry is a dominant industry and the government is heavily invested in the exploration through tax depreciations and later high tax revenues, the state's direct financial participation in the perceived most profitable fields, and in Statoil through ownership.

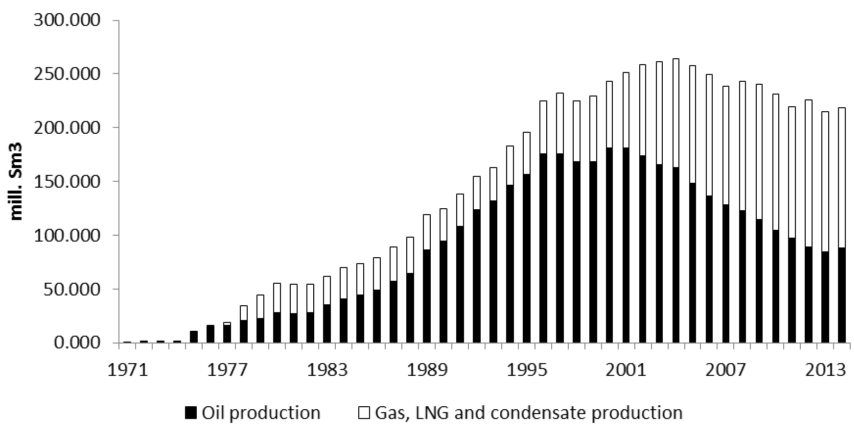

Figure 1 – Yearly oil and gas production on NCS in mill. Sm3

There has been oil and gas drilling on the Norwegian Continental Shelf (NCS) since the early 1970s. Figure 1 shows yearly oil and gas production on the NCS. Oil and gas output from the NCS increased steadily until it peaked in 2004 at 264 000 million Sm3 oil equivalents (o.e.). Recent years have seen a reduction in output and in 2014 production was 219 000 million Sm3 of o.e.. This reduction has come from lower oil production, down from 181 000 million Sm3 in 2001 to 88 000 million Sm3 in 2014.

Previous research finds that cost overruns is typical for megaprojects (Flyvbjerg et al. 2003), and according to Merrow (2011, 2012), the petroleum industry is particularly poor at delivering at budget and on time. The success rate in the petroleum industry is only 25% and Merrow (2012) argues that one key reason is the petroleum industry's high turnover in project leadership. For the NCS, a report written on behalf of the Norwegian Petroleum Directorate (2013), evaluates 5 megaprojects[1] on the Norwegian continental shelf and find several cost overruns, similar to the previous report in NOU (1999). Moreover, Mishra (2014) confirmed the poor results for the NCS.

Unrealistic ambitions and too optimistic estimates are likely correlated with the current business climate and a

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See foot note at end of text.

failure to incorporate the total cost effect of aggregate industry demand for services related to projects when making individual project decisions and projections. Clustering of investments at times when the oil price is increasing, prove to drive up costs. This is confirmed in our empirical analysis of key variables. According to Table 1, correlation is high between key investment cost variables and oil and gas prices.

	Oil price	Gas price	Rig rates	Investments	Wages	Employees
Oil price	1					
Gas price	0.9734	1				
Rig rates	0.9498	0.9259	1			
Investments	0.8963	0.8754	0.9318	1		
Wages	0.8804	0.8435	0.9101	0.9789	1	
Employees	0.9003	0.8640	0.9321	0.9701	0.9946	1

Table 1. Correlations between key investment cost variables

Note: Rig rates refer to average rig rates for floaters, USD per day, on the Norwegian continental shelf (source: RS Platou). Investments are total petroleum related investments on the Norwegian continental shelf (source: Norwegian National Statistics; SSB). Wages are for employees related to Norwegian petroleum activities (source: SSB), and employees are related to Norwegian petroleum activities (source: SSB).

License holders/operators on the Norwegian continental shelf are required to provide a yearly report on actual cost and cost estimates for development projects to the Ministry of Petroleum and Energy. While there are several reasons to make adjustments to the initial budget, Dahl and Osmundsen (2014) find that most projects is finished at a higher cost than predicted and in addition, that larger projects seem to have a higher relative cost overrun compared to smaller projects.

In Dahl et al. (2015), we investigate projects going back to 2000, and compare their cost overruns to our proxies for the business cycle. Our main finding is that cost overruns are higher, in relative terms, when oil and natural gas prices are high. As such, the industry may be pro-cyclical. Although we are able to identify these energy prices as common factors for cost overruns, there is significant heterogeneity in overruns. For instance, large project overruns depend more on price levels than smaller projects.

Our results show that managers in the industry have an opportunity to invest in a downturn with reduced cost and according to our results, reduced cost overruns. We find significant reduction in cost overruns because of oil and gas price drop. This is especially true for megaprojects, where cost overruns are even more vulnerable to the business cycle. Consequently, managers with the opportunity to invest in a downturn have extra incentives, as they will experience reduced cost overruns according to our results. In practice, and contrary to our results' advice, during a downturn period the industry often ends up trimming their project portfolio, thus contributing to the current business cycle. However, by exploiting excess capacity and expertise in the supplier market, projects reduce cost overruns and increase profitability.

Footnote

[1] Skarv, Yme, Valhall redevelopment, Tyrihans and Gjøa.

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CONFERENCE OVERVIEW




Massive transformations in how and where energy is produced and consumed are drastically changing our energy economy. This dynamic energy landscape is challenging government and industry decision makers to formulate a clear path forward. Policy and investment decisions need to balance the use of natural resources with impacts on the environment and local economies. One answer is to stimulate innovative technologies to enable access to increasing supplies of energy as well as more efficient consumption. But doing this requires appropriate policies, incentives and mandates, something that challenges even the most well informed policy makers.

The conference will bring together business, government, academic and other professionals to explore these themes through a series of plenary, concurrent, and poster sessions. Speakers will address current issues and offer ideas for improved technical, commercial, and policies covering all facets of energy development and use. 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 the region's dynamic energy landscape.

The 2015 conference will be held in Pittsburgh, Pennsylvania, one of the main centers of American energy. The region around Pittsburgh contains a rich history of energy, with the discovery of the Coal Hill seam in 1762, the commercialization of the Drake Oil Well in 1859, and the formation of Westinghouse Electric Company in 1886. Today, the Pittsburgh area is a U.S. leader in energy development. The region is ranked 25th for the number of employees in energy-related industries. Among other things, it is the center of one of the most active natural gas plays in North America, the Marcellus Shale, and is the locus of the first U.S. nuclear power plants being built in over 30 years. Over the past three decades, Pittsburgh has had a remarkable environmental evolution and has been repeatedly named one of America's most livable cities. The Pittsburgh region is fortunate to support a diverse mix of energy activities including nuclear, coal, natural gas, and renewables. The region is home to a host of energy businesses, research facilities, industry groups, and world-class colleges and universities, many of which have active energy centered policy and academic programs. Finally, more than $1 billion per year in government-funded research flows through the region's academic, corporate and government energy research centers, assuring that new ideas and new technologies constantly emerge.

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 at: www.usaee.org/usaee2015/topics.html

- Energy Demand and Economic Growth
- Energy Supply and Economic Growth
- Financial and Energy Markets
- Energy and the Environment
- Non-fossil Fuel Energy: Renewables & Nuclear
- International Energy Markets
- Energy Efficiency and Storage
- Energy Research and Development
- Political Economy
- 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.

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33RD USAEE/IAEE NORTH AMERICAN CONFERENCE SESSIONS & SPEAKERS



Visit our conference website at:
www.usaee.org/usaee2015/

PLENARY SESSIONS

The 33rd 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:

- The Dynamic Energy Landscape: Natural Gas in the U.S.
- Renewable Energy Integration
- Water at the Well-site: Production, Handling and Disposal
- Industrial Resurgence
- Future of Coal
- Climate
- Electricity Markets
- Geopolitics
- Energy Infrastructure
- Energy Finance & Risk Management

SPEAKERS INCLUDE

Farid Abolfathi
Senior Director, IHS Risk Center, Member IHS Forecast Steering Committee and International Forecast Council

Jared Anderson
Editor, *Breaking Energy*

Jay Apt
Professor Tepper School of Business and Engineering and Public Policy, Carnegie Mellon University

Peter C Balash
Senior Economist, U.S. Department of Energy

Grace M Bochenek
Director, National Energy Technology Laboratory U.S. Department of Energy

Terry Boss
Senior Vice President of Environment, Safety and Operations, Interstate Natural Gas Association of America

Rusty Braziel
President, RBN Energy

Guy Caruso
Senior Advisor, Energy and National Security Program, CSIS

Kathleen B Cooper
Senior Fellow and Professor of the Practice of Economic Policy, Southern Methodist University

Mario S DePillis
Senior Consultant, ET Analytics

Tom Duesterberg
Program Director, Executive Director, Manufacturing and Society in the 21st Century, Aspen Institute

John Dumas
Director of Wholesale Market Operations, ERCOT

Jerald J Fletcher
Professor and Director Natural Resource Analysis Center, West Virginia University

William Furlow
Senior Manager Business Development, Society of Petroleum Engineers

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Chief Economist, Monitoring Analytics

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Technical Project Monitor, DOE-NETL

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Principal Deputy Director, Department of Energy, Energy Policy and Systems Analysis

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James Spencer
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David J Spigelmyer
President, Marcellus Shale Coalition

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