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MIT CEEPR Newsletter

MIT Center for Energy and Environmental Policy Research

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When reflecting on current trends and developments in energy and environmental policy, MIT CEEPR regularly covers the US federal and state levels. The research projects described in this newsletter, however, remind us that important research opportunities also exist elsewhere. In the four decades since its creation, CEEPR has frequently extended the scope of its activities across the globe. Some of its earliest work addressed the economics of petroleum, and the complex interactions of supply and demand in the international oil market. Research on deregulation and liberalization informed electricity market reforms in other countries, just as it guided restructuring efforts at home. In the early years of the EU emissions trading system, a CEEPR research program yielded influential insights on the operation of the European carbon market. More recently, CEEPR has contributed to studying energy policy options for India and China.

An international focus continues to guide CEEPR research to this day, making it a source of trusted and objective analysis for decision makers both within the US and abroad. Recent working papers reflect this global perspective: from the effects of international climate policy on Russian energy exports to power sector reforms in the UK and Sub-Saharan Africa, these studies yield insights whose relevance goes well beyond the respective geographic context. Comparative approaches, exemplified by another working paper on how improved electricity market design can better accommodate rapid renewable energy growth in Europe and the United States, help bridge policy debates across national boundaries. As public and private sector decision makers everywhere struggle with disruptive technologies and changing policy landscapes, new answers to these questions will emerge in unexpected places. CEEPR's global outlook therefore remains as important as ever.

CONTENTS

RESEARCH

EVENTS

PERSONNEL UPDATES

PUBLICATIONS

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Russia and the Post-Paris World: A New Energy Landscape?

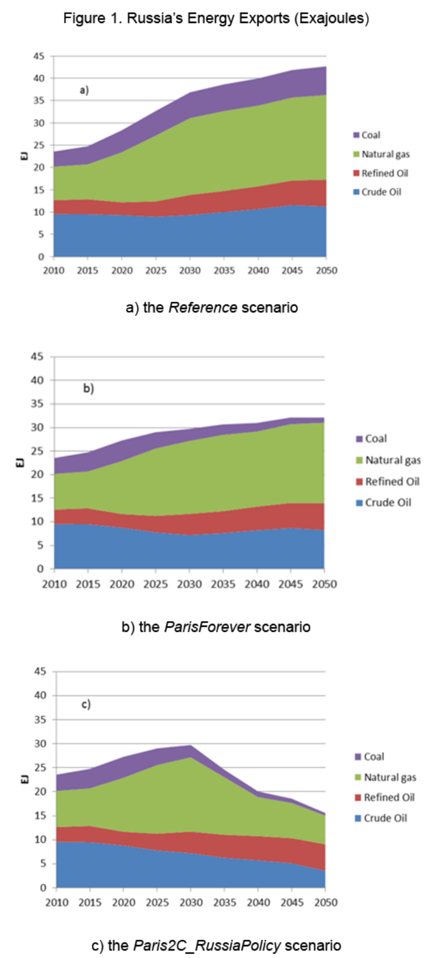
by: Igor Makarov, Y.-H. Henry Chen, and Sergey Paltsev

The Paris Agreement not only writes the rules of the international climate regime for the coming decades, but also reflects the consensus of the world community regarding future evolution of the global energy landscape towards low-carbon development. Our study[1] shows a number of scenarios of how this future landscape would affect the Russian economy, one that is highly dependent on the production and export of fossil fuels. Even relatively modest national targets declared by the parties of the Agreement by 2030 within their Nationally Determined Contributions (NDCs) bring some risks for the Russian economy, for example, those associated with the decreasing demand for energy imports from Russia (see Figure 1) or potential additional market barriers for Russian exporters of energy-intensive products.

However, these risks concern primarily specific sectors, are manageable, and are unlikely to dramatically affect Russia's general economic performance. At the same time, any tightening of NDCs beyond 2030 would become a significant obstacle to Russian economic growth. Risks associated with the Paris Agreement slightly depend on Russia's formal participation in the international climate regime. A potential non-ratification of the Agreement would not improve Russia's position and probably would lead to additional risks for Russian exporters.

For Russia, it is critically important to get ready to mitigate the risks associated with the Paris Agreement by adjusting itself to the new energy landscape. Diversification of the economy is the major response. This paper simulates three simple diversification scenarios showing that redistribution of incomes from the energy sector to the development of human capital would help avoid the worst possible outcomes. We show that the magnitude of GDP increase can be in the order of 1-4% relative to the no-diversification scenario. While the development of a full-scale strategy of adaptation of the Russian economy to a low-carbon future is beyond the scope of any academic paper, we advocate for the acceleration of this process by Russian industrial, academic, and government experts. Our results provide the initial exploration of the major areas to focus on for such a strategy.

Figure 1: Russia's energy exports (Exajoules) in:



We argue that the objective for this strategy should be broader than just the planning of low-carbon development. In addition to the plans to support low-carbon technologies that are most relevant to the Russian market and to introduce new regulations and legislative incentives to promote low-carbon development (including emissions disclosure requirements and carbon pricing schemes), the strategy should find ways to address three types of risks: risks of reducing energy exports, risks of additional market barriers to Russian exporters of energy-intensive goods, and risks of relying on outdated energy technologies. The post-Paris energy landscape poses a challenge for Russia to gradually change the model of its economic development, launch the process of diversification of the economy, and elaborate the new comprehensive development strategy identifying its new position in the world economy. The current way of fossil export based development will be difficult to sustain in the coming decades, regardless of Russia's own climate policy choices.

[1] Igor Makarov, Y.H. Henry Chen, and Sergey Paltsev (2017), "Finding Itself in the Post-Paris World: Russia in the New Global Energy Landscape." *CEEPR WP-2017-022*, MIT, December 2017.

Igor Makarov

Henry Y.-H. Chen

Sergey Paltsev

What's Killing Nuclear Power in US Electricity Markets?

by: Jesse D. Jenkins

Prices in US electricity markets fell precipitously in recent years, driving several nuclear power plants to announce plans to close well before the end of their licensed operation. Several more plants may soon follow suit. Stagnant demand for electricity, the growth of subsidized wind power, and cheap natural gas are variously blamed for driving down electricity prices and thus revenues for nuclear generators.

Average day-ahead electricity market prices across the PJM market fell 55 percent from 2008 to 2016. Declining prices in PJM and other wholesale electricity markets across the United States have contributed to the retirement of several nuclear power stations. Roughly half (BNEF 2016) to two-thirds (Haratyk 2017) of the US nuclear fleet may be operating at a loss in current market conditions. Nuclear power plants generate 20 percent of US electricity and constitute the nation's largest source of emissions-free power. As such, determining the causes of deteriorating economic conditions at these nuclear plants has important implications for both the future of US electricity markets as well as state and national efforts to reduce emissions of carbon dioxide and conventional pollutants.

A new CEEPR Working Paper[1] provides the first empirical estimates of the causal effect of three primary factors that might explain the decline in wholesale day-ahead electricity market prices received by nuclear plants in PJM:

1. stagnant or declining electricity demand;
2. growth in wind energy generation; and
3. declines in natural gas prices.

The study estimates the impact of each factor on electricity prices at the location of 19 different nuclear plants across the PJM market. These plants are home to 33 individual reactors and encompass roughly one-third of the US nuclear fleet, including 11 reactors currently facing possible retirement.

To estimate the effect of changes in daily natural gas prices and daily average electricity demand and wind generation in PJM and the adjoining MISO market region, I employ a time series ordinary least squares regression with time fixed effects using 3,288 daily observations for the nine-year period from January 1, 2008 to December 31, 2016. I then use the resulting coefficients to estimate the cumulative effect of changes in the three explanatory factors from 2008 to 2016 on annual average market prices for each nuclear generator. In addition, the locations of the nuclear plants span from the mid-Atlantic states in the east to Illinois in the west. I take advantage of this fact to explore geographic variation in the effects of each explanatory variable.

I find that a roughly 3.5 percent decline in electricity demand across the PJM and MISO electricity markets from 2008 to 2016 is responsible for a statistically significant but modest decline in electricity prices at all 19 nuclear plants in PJM. The cumulative effect of changes in demand over this period is on the

Jesse D. Jenkins

order of a 1.5 to 4.0 percent decline in the average prices earned by these plants. Declining demand has a greater impact on electricity prices at plants in the east (closer to major population centers) than those in the western portion of PJM. In other words, it is fair to say that electricity prices earned by nuclear plants in PJM would have been a few percentage points higher had demand in PJM and MISO remained steady at 2008 levels. Prices would have been higher still had demand continued to grow at over 1 percent per year, as projected by many analysts prior to the Great Recession.

Annual average wind energy generation in MISO and PJM grew more than five-fold since 2008 to supply 4.4 percent of electricity demand in the two market regions in 2016. This growth had a modest and statistically significant effect on electricity market prices only at nuclear plants in the western portion of PJM (e.g., in Illinois, Michigan, and Ohio). For these plants, the cumulative impact of growing wind generation was of a similar magnitude as the effect of declining electricity demand—a roughly 1 to 6 percent decline in average prices. For all other nuclear plants in PJM, growth in wind generation does not appear to have had a statistically significant effect on electricity prices.

Finally, due to surging domestic production of gas unlocked by hydraulic fracturing and horizontal drilling techniques, market prices for natural gas declined 72 percent from 2008 to 2016. Across a variety of specifications presented in this paper, the drop in the price of natural gas appears responsible for the majority of observed declines in electricity prices across the 19 PJM nuclear plants over this period—e.g., 50 to 86 percent of observed changes in the primary specification.

The methods employed here produce a less precise estimate of the effect of natural gas than for the other variables. Point estimates for the cumulative effect of changes in gas prices from 2008 to 2016 range from a roughly 20 to 85 percent decline in electricity prices depending on the location of the plant and which model specification is used. Furthermore, 95 percent confidence intervals span plus or minus 8 to 29 percentage points around these point estimates across plants and specifications.

Despite this variance in estimated effects, one can confidently conclude that the impact of declining gas prices on nuclear plant revenues in PJM is an order of magnitude greater than the impact of either declining electricity demand or the growth in wind energy generation over this time period. Changes in gas prices also appear to have had a greater impact on prices earned by nuclear plants in the eastern portion of PJM, although effects are large and statistically significant for all plants in the PJM footprint.

In short, cheap natural gas appears to be killing the profitability of nuclear power producers in the PJM Interconnection. That said, stagnant electricity demand and expectations of future growth in wind generation going forward may be accomplices.

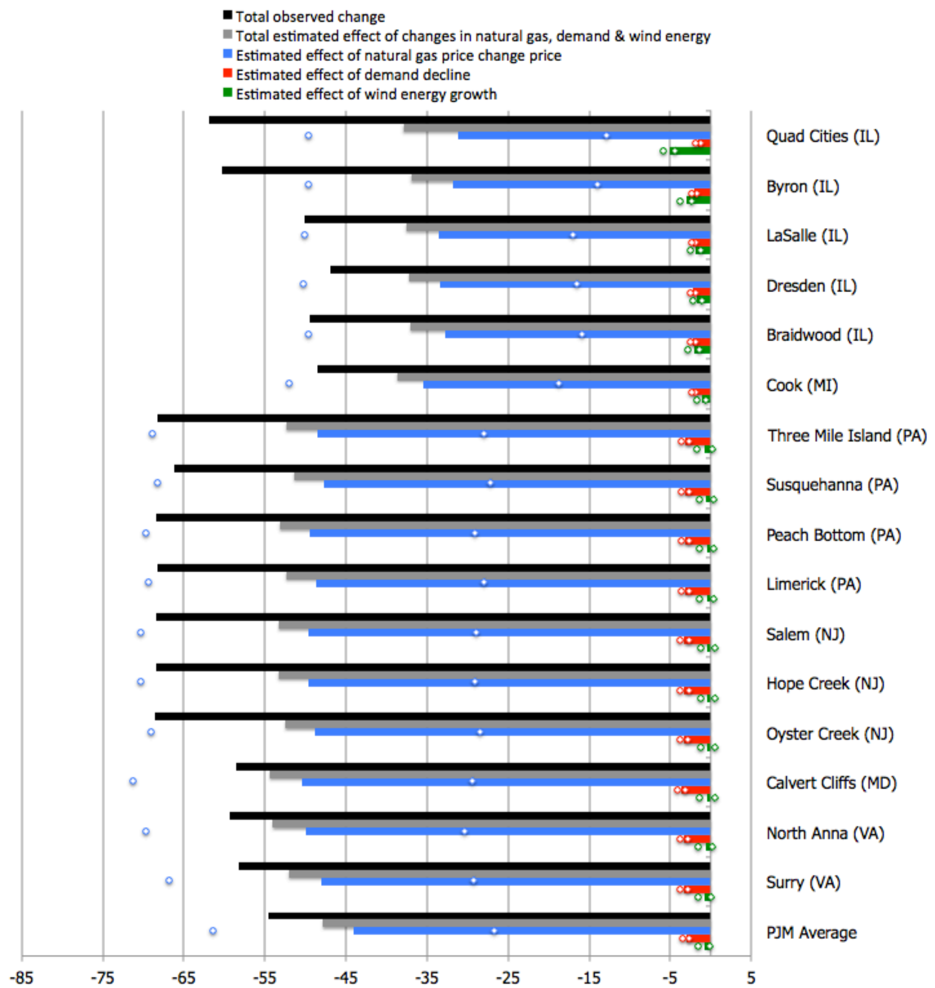


Figure 2: Estimated effect of cumulative observed changes in average demand, wind generation, and natural gas prices from 2008 to 2016 on annual average day-ahead electricity market prices for 16 nuclear generators in PJM (Estimates for Davis Besse, Perry, and Beaver Valley plants are excluded as the data series for these plants begins in 2011). Circles depict 95 percent confidence intervals for each estimate (using Newey-West HAC standard errors). Estimates are based on counterfactual 2016 predictions adjusting actual 2016 daily observations to reflect the percent change between annual average 2008 values and annual average 2016 values for each time series. Total observed change in annual average prices from 2008 to 2016 presented for comparison.

[1] Jesse D. Jenkins (2018), "What's Killing Nuclear Power in US Electricity Markets?" *CEEPR WP-2018-001*, MIT, January 2018.

Reforming Electricity Markets for the Transition: Emerging Lessons from the UK's Bold Experiment

by: Michael Grubb and David Newbery

Michael Grubb

Until 1990, the UK - like many other countries - had an electricity system that was centralized, state-owned, and dominated almost entirely by coal and nuclear power generation. The privatization of the system that year with the creation of a competitive electricity market attracted global interest, helping to set a path which many have followed.

Two decades later, however, the UK government embarked on a radical reform which some critics described as a return to central planning. The UK's Electricity Market Reform (EMR), enacted in 2013, has been a topic of intense debate, and global interest in the motivations, components, and consequences.

A new Working Paper[1] summarizes the evolution of UK electricity policy since 1990 and explains the EMR in context: its origins, rationales, characteristics, and results to date. We explain why the EMR is a consequence of fundamental and growing problems with the form of liberalization adopted, particularly after 2000, combined with the growing imperative to maintain system security and cut CO_2 emissions, whilst delivering affordable electricity prices.

The fifteen years after privatization, coinciding with the era of low fossil fuel prices, had seen mostly falling electricity bills; from about 2004 they started to rise sharply, for multiple reasons including increasing fossil fuel prices, the need for new investment in both generation and transmission, and inefficient ways of promoting renewable energy.

The EMR comprises four instruments: fixed-price contracts for zero-carbon sources (defined as contracts-for-difference on the electricity price, lasting 15 years for renewables); a whole-system capacity market (paying a fixed £/kW/yr for firm power); a minimum or top-up price on CO_2 emissions; and an emissions performance standard which in effect bans new coal plants. The first two are implemented through competitive auctions, for amounts defined,

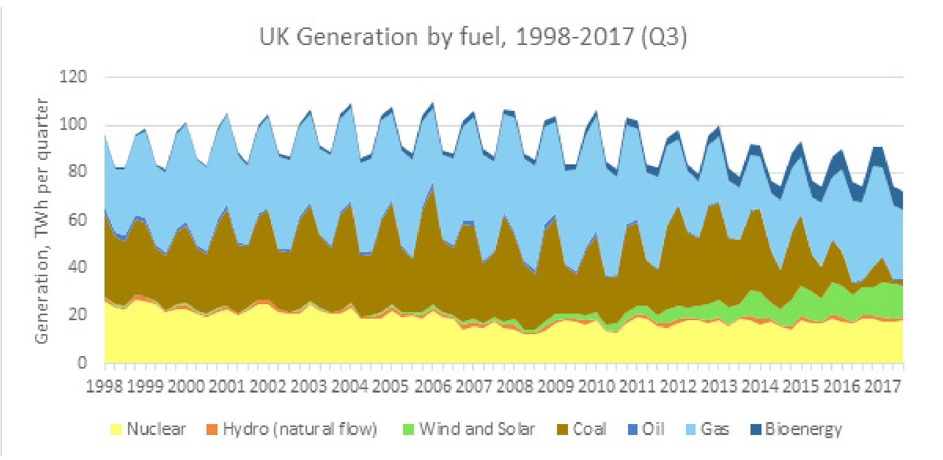


Figure 3: UK Quarterly Electricity Generation by Fuel Type, 1998-2017 (Q3) Source: Energy Trends

David Newbery

respectively, by targets for renewable energy (for the CfDs) and the estimated capacity needed to ensure system security (for capacity market volumes).

These four instruments have indeed combined to revolutionize the sector; they have also both drawn on, and helped to spur, a period of unprecedented technological and structural change. Competitive auctions for both firm capacity and renewable energy have seen prices far lower than predicted. The fixed-price contracts for renewables are estimated to have reduced financing costs to little over 3%/yr, which would save over £2bn/yr on the cost of financing the projected renewables investments, compared to the previous support system; the most recent auction saw contracted prices even for offshore wind tumbling to less than £60/MWh.

Rather than the expected new combined cycle gas plants, smaller scale decentralized generation - and most recently storage - has been the main beneficiary of the Capacity market, though this has highlighted complexities in design and pricing elsewhere in the system.

The minimum carbon price has brought cleaner gas to the fore, displacing coal to the margin. Electricity prices may have peaked from 2015, with energy efficiency helping to lower overall consumer bills.

New forms of generation have expanded rapidly at all scales of the system. Renewable electricity in particular has grown from under 5% of generation in 2010, to almost 25% by 2016, and is projected to reach over 30% by 2020 despite a political de-facto ban on the cheapest bulk renewable, of onshore wind energy. The environmental consequences overall have been dramatic: coal generation has shrunk from about 2/3rd of generation in 1990, to 35% in 2000, to 10% in 2016, halving CO_2 emissions from power generation over the quarter century.

Neither the technological nor regulatory transitions are complete, and the results to date highlight other challenges. Pushing coal to the price-setting margin cuts emissions but initially exacerbates the impact of carbon prices on electricity prices; revenues are returned to internationally exposed major industrial consumers, and the impact will decline as coal retreats (and coal is due to be phased out entirely by 2025). The Capacity mechanism has proved ill-suited to encouraging demand-side response, at least initially, and in combination with the growing share of renewables, has underlined problems in transmission pricing. As the share of variable renewables grows further, the associated contracts will require reform to improve siting efficiency and avoid adverse impacts on the wholesale market.

Thus the results to date show that EMR is a step forwards, not backwards; but it is not the end of the story.

[1]Michael Grubb and David Newbery (2018), "UK Electricity Market Reform and the Energy Transition: Emerging Lessons." *CEEPR WP-2018-004*, MIT, February 2018.

Restructuring Revisited: Competition and Coordination in Electricity Distribution Systems

by: Scott P. Burger, Jesse D. Jenkins, Carlos Batlle, Ignacio Pérez-Arriaga

The emergence of distributed energy resources (DERs), digital technologies, and innovations in power electronics and network technologies are creating new options for the delivery of electricity services and the potential for more affordable and resilient power systems. However, these developments are also placing new strains on electric power industry structures that were established in a time of static distribution networks and relatively inelastic demand. DERs and digital technologies dramatically expand the number of potential investors in and operators of power system infrastructure, challenging traditional means of planning and coordinating the construction of generation, storage, and network assets. Distribution-connected resources have historically not participated in traditional means of executing least cost, security-constrained dispatch of generation and typically face regulated tariffs as opposed to market-determined prices. Thus, the emergence of DERs is challenging the structures historically used to coordinate investments in power system infrastructure and to coordinate supply and demand to ensure reliable operations of power systems in real time.

During the restructuring that swept through the electricity industry in the 1980s, 1990s, and 2000s, regulators grappled with a set of questions over how to assign the roles of transmission system ownership and operation, generation ownership, market operation, and retailing to power system actors in order to ensure the development of an affordable mix of network and generation assets.

Today, the emergence of DERs has spurred regulators to engage in analogous debates over which actors should perform which roles within the distribution system. Regulators are interested in ensuring the efficient utilization of and investment in both DERs and the system's conventional suite of network, generation, demand, and storage resources. In addition, regulators are interested in maintaining or enhancing competition in the horizontal segments of the power sector (e.g., generation and retailing) where it exists, while potentially fostering more competitive provision of "non-wires" or operational alternatives to investment in conventional network assets.

Existing industry structures do not adequately achieve these goals, prompting a need to revisit the challenge of industry structure once again. In power systems where actors remain vertically integrated across generation, transmission, distribution, and retail, coordinating system investments and operations requires a set of internal planning and operating decisions and appropriate price signals, incentives, and/or communications with electricity users. In systems with competition in generation and/or retail, this coordination requires multilateral arrangements between monopoly network providers and market actors and market-facilitated price signals and contracts for energy, capacity, and ancillary services. In light of the decentralization of the power sector, regulators and policymakers must carefully consider how distribution industry structure impacts the ability of power sector stakeholders actors to efficiently plan, coordinate, and operate distribution networks and connected devices.

To facilitate this critical task, a recent CEEPR Working Paper[1] defines and

In light of the decentralization of the power sector, this paper carefully considers how industry structure regulations impact competition, market development, and the efficiency of investments in and operations of network infrastructure and connected resources.

reviews the core activities and economic characteristics of six key industry roles: distribution network ownership (DNO); distribution system operation (DSO); DER ownership; distribution-level markets; aggregation of demand and DERs; and data management. We assess the implications of different structures for competition in DER ownership and aggregation. We analyze the arrangements needed to coordinate actions between distribution network owners and operators, DER owners, electricity consumers, and any aggregators serving these consumers. Our analysis focuses primarily on whether a given structure is likely to lead to the least-cost mix of network and generation resources in the short and the long run.

This paper addresses five questions that are currently being debated by regulators and policymakers globally.

1. Should distribution system operations be separated from distribution network ownership in order to ensure the neutrality of the DSO role?
2. Should DNOs be allowed to own and operate DERs, or should DER ownership be left exclusively to competitive actors?
3. Does the emergence of DERs necessitate a reconsideration of the role of competition in the provision of aggregation services such as retailing?
4. What is the role of the distribution system operator (DSO) – independent or otherwise – in future power system operations?
5. What, if any, market mechanisms might be needed under different institutional arrangements to coordinate efficient investment and operational decisions across various actors?

We find that separating distribution system operations and network ownership would likely result in a decrease in system efficiency relative to a system in which the DNO and DSO are a single entity. However, a combined DNO and DSO must be sufficiently separated from any competitive activities, given the increasingly central role that DSOs will play in system planning and operation. We note that price signals at the distribution level play a new role in coordinating investment in and operation of DERs. As a result, these signals must be dramatically improved to ensure that DERs improve the power system as a whole, rather than for any one network user at the expense of others. This will require significant improvements in electricity tariff design, as well as the creation of new market mechanisms such as auctions for procuring non-wires alternatives.

[1] Scott P. Burger, Jesse D. Jenkins, Carlos Batlle, and Ignacio Pérez-Arriaga (2018), "Restructuring Revisited: Competition and Coordination in Electricity Distribution Systems." *CEEPR WP-2018-007*, MIT, March 2018.

Scott P. Burger

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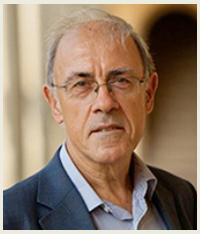
Carlos Batlle



I. Pérez-Arriaga

Power Sector Reform and Corruption: Evidence from Sub-Saharan Africa

by: Mahmud I. Imam, Tooraj Jamasb, and Manuel Llorca

The literature supports the notion that corruption can, through various transmission channels, constrain economic development of countries. Defined as the "abuse of entrusted power for private gain" (Kaufmann and Siegelbaum, 1997), corruption imposes corrosive effects on the economy through higher transaction costs and uncertainty (Murphy et al., 1991), inefficient investments (Mauro, 1995; Shleifer and Vishny, 1993), reduced human capital development (Reinikka and Svensson, 2005), and misallocation of resources (Rose-Ackerman, 1999).

This study[1] examines these important but much less explored channels at the sector-level. We focus on the reform of electricity systems in developing countries (Wren-Lewis, 2015; Estache et al., 2009; Dal Bó, 2006; Bergara et al., 1998). Corruption can cripple economic development by inhibiting the performance of the electricity sector. It can also reduce labor productivity (Wren-Lewis, 2015; Dal Bó, 2006), increase the networks' energy losses, and constrain the efforts to increase access to electricity services (Estache et al., 2009).

Electricity reforms and in particular introducing independent regulation and private sector participation were, together with the unbundling of the vertically integrated functions of this industry, aimed to improve the efficiency of the sector (Joskow, 2006). However, the experiences of reforms around the world have shown the difficulty of creating an economically efficient electricity sector underpinned by genuine competitive markets that benefit consumers through reliable service, low tariffs, and choice of alternative sources (IEA, 2014).

Also in Sub-Saharan Africa the reform experience has lagged behind the anticipated outcomes and has led to extensive political backlash against reforms. Higher electricity prices have been an obvious source of political resistance in many countries, especially for groups that are accustomed to paying near nothing for electricity services (Victor, 2005). This resistance was further reinforced by the awareness that elections can be won or lost because of electricity prices (UNDP and World Bank, 2005).

Therefore, the appropriateness of the standard reform model for developing countries has been questioned as it often resulted in higher prices, loss of employment, unreliable services, and concentration of services to profitable areas since the private firms did not have incentives to extend the service to poor areas (Transnational Institute, 2002; Victor, 2005).

We examine whether the reforms in Sub-Saharan Africa have been successful. We estimate a set of econometric models of the performance of electricity reforms in terms of their effect on efficiency, welfare, and economic development in 47 countries in the region for the 2002-2013 period. The paper shows that corruption has an adverse and statistically significant effect on three performance indicators of electricity reform - i.e. technical efficiency, access rates, and economic performance. This finding adds to the large body of evidence that stress the detrimental impacts of corruption on electricity sector performance.

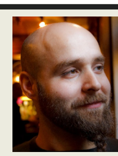
We find that the creation of independent regulation and private sector participation not only has the potential to enhance the utilities' performance but also has wider economic benefits. Specifically, we find that independent regulation has the potential to increase social welfare directly and indirectly by reducing the association between corruption and electricity access rates. We also show that private sector participation is associated with improved technical efficiency and increased economic performance, while we find privatization policies have no statistically significant impact on access rates.

More importantly, we analyze how corruption interacts with the two reform policies and how these interactions impact the three indicators of performance. The creation of independent regulators has substantially reduced the adverse association between corruption and access rates, while it has not mitigated the often-cited negative association between corruption and income levels, nor the association between corruption and technical efficiency. However, private participation has offset the adverse effects of corruption on technical efficiency and income, without impacting on the association between corruption and access rates.

Therefore, implementation of electricity reforms in developing countries can not only enhance the performance of the electricity sector, but would also boost economic performance, since improvements in technical efficiency can be translated into increased access rates and income growth.

[1] Mahmud I. Imam, Tooraj Jamasb, and Manuel Llorca (2018), "Power Sector Reforms and Corruption: Evidence from Sub-Saharan Africa." *CEEPR WP-2018-006*, MIT, March 2018.





From left to right:

Mahmud I. Imam
Tooraj Jamasb
Manuel Llorca

Evaluating the Energy Efficiency Gap & Measuring Savings from Fault Detection and Diagnostics

by: Danielle Dahan

Data analytics will play a major role in advancing energy efficiency and high performance building goals nationally and globally. As the fault detection and diagnostics industry emerges and unlocks numerous energy efficiency savings opportunities in buildings, it is crucial that we also advance our methodologies for evaluating these systems and quantifying the energy impact.

Energy efficiency programs account for 72% of global greenhouse gas abatement strategies (IEA), and utility spending on energy efficiency more than doubled in the United States from 2007 to 2011 (Cooper and Wood). With an increased focus on high performance, sustainable buildings in the United States and around the world, and as improvements in data analytics continue to develop, a new field of building fault detection and diagnostics (FDD) has emerged. FDD systems can continually monitor heating, ventilation, and air conditioning (HVAC) systems in buildings and identify numerous faults as they occur, rather than these faults going unnoticed for years or even decades and causing significant energy waste. For example, hot water and chilled water valves can fail after only a few years and cause energy waste, but these relatively small components of an HVAC system are often hidden above ceilings or in mechanical rooms and can easily go unnoticed without a closely monitored FDD system. However, there is very little research evaluating FDD systems in real buildings to identify the actual energy impact of these faults.

Through this research initiative[1], I tested a modeling approach using novel machine learning algorithms to estimate counterfactual energy usage in real buildings and calculate the energy efficiency savings associated with an existing FDD system. We took advantage of high-frequency 15-minute interval electricity, chilled water, and steam energy usage data over several years in four campus buildings. We then compare the accuracy of these models applied to brand-new data using three different machine learning modeling techniques, the Lasso Model, Ridge Regression, and an Elastic Net Model and numerous interacted variables, such as hour of the day, day of the week, month, time, temperature, and humidity. Finally, I applied these models to 8 time periods in which the existing FDD system identified a fault, thus isolating the energy impact of the fault. With this approach, I found that each of the three modeling techniques outperformed the other two techniques in at least one of the models, indicating that there is likely a benefit from using three approaches in building energy modeling. Further, I found that the models are likely able to isolate the energy increase associated with these faults, with some models yielding a higher confidence level than others. In addition to the overall average increase in energy, the faults showed consistent results in the daily load profile shifts after the fault occurred.

This methodology could therefore be used in more buildings and with different types of FDD systems to better evaluate the benefits of FDD software across applications. By using this method more extensively, we can better inform policy that can in turn aim to reduce the energy efficiency gap in commercial buildings. There are currently very few building code requirements that specify FDD systems, but this is likely to change as the FDD market rapidly expands. As building codes begin to specify FDD software, this research methodology could help regulators identify how and which type of FDD applications should be required. Additionally, this methodology could be developed further to run alongside an FDD system to help identify and estimate the energy impact of faults as they occur in real time.

[1] Danielle Dahan (2018), "Evaluating the Energy Efficiency Gap & Measuring Savings from Fault Detection and Diagnostics." *CEEPR WP-2018-009*, MIT, May 2018.

Danielle Dahan

Electricity Market Design with Renewables: A Comparison of Europe and the United States

by: Audun Botterud and Hans Auer

The installed capacity of renewable energy technologies, in particular wind and solar, has increased rapidly in Europe and the United States in the last decade. At the end of 2015, Europe was generating 28.8% of its electricity from renewables, about twice as much as in the United States. Since 2005, most of the growth in renewables in both regions came from increased wind and solar, with hydropower generation remaining roughly constant.

Several factors have led to the rapid development of these renewable technologies. In Europe, the main support mechanism has been feed-in-tariffs, which provides a fixed payment per kWh of generation from selected technologies. However, there has been a recent trend towards governments conducting auctions to achieve renewable generation targets in a more cost-effective manner. In the United States, the main policy instruments have been federal tax credits and state-level renewable portfolio standards. In both the United States and Europe, tariff structures such as net metering, where customers with local generation are compensated at the full retail rate, provide indirect support for renewables. Finally, a focus on distributed generation, microgrid solutions, and a growing interest in purchasing wind and solar from different consumer groups (households, communities, corporations) that are willing to pay a premium for green products all have contributed to the demand for wind and solar.

The rapid growth in renewable energy is starting to make an impact on the prices in the electricity markets. Wind and solar energy have very low operating costs, which may even be negative when policy support schemes are considered. Hence, these resources displace generation from technologies with higher operating costs, which tends to reduce electricity market prices, as observed particularly in some European markets. In addition, constraints on the system combined with excess wind and solar generation is leading to a significant increase of negative prices in electricity markets on both continents. Of course, other factors also influence prices in the electricity market. In the United States, several studies show that reductions in the cost of natural gas is the primary reason for the low electricity prices in recent years.

In principle, the revenues from the markets for energy and operating reserves should be sufficient to provide incentives for adequate investments in generation capacity. This is the premise for the so-called energy-only market design. However, the reductions in electricity market prices are making it harder for existing generators to make a profit. This has led to renewed discussions about the need for capacity mechanisms, which are additional compensation schemes designed to provide incentives for generation investments and system reliability. Figure 4 categorizes capacity mechanisms into price-based and quantity-based mechanisms. Both categories exist in Europe, where some countries have relied on capacity payments or strategic reserves for a long time, and other countries have recently introduced capacity markets or obligations. However, many countries in Europe still rely on the "energy-only" market design. In the United States, four electricity markets rely on centralized capacity markets, two on capacity obligations, whereas the market in Texas (ERCOT) is the only energy-only market. The current status clearly illustrates that no consensus exists on the best approach to maintain reliability.

Independent of the choice of capacity mechanism, we argue that the most important challenge in electricity market design is to achieve a good price formation in the short-term markets. A sharper price formation will provide better incentives for system flexibility from supply, demand, and energy storage resources. This can be obtained through increased demand response to market prices so that they better reflect consumers' preferences and willingness to pay for electricity. A particularly important issue is what happens to prices when supplies are short, as scarcity rents are critical for capital cost recovery. Improved scarcity pricing can be achieved through demand participation as well as administrative

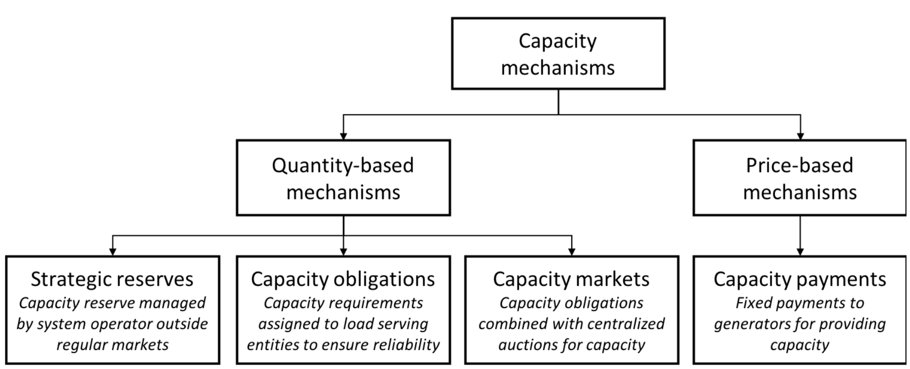


Figure 4: Overview of the main capacity mechanisms.

mechanisms, such as using demand curves for operating reserves rather than fixed requirements to calculate the price for operating reserves. It would also be beneficial to move from technology specific incentive schemes for renewable technologies towards adequate pricing of carbon emissions, as it would have the effect of increasing the cost of emitting technologies rather than depressing wholesale electricity prices. We argue that these general recommendations, which apply to Europe as well as the United States, would foster a more market-compatible integration of wind and solar energy, better functioning energy-only markets, and less reliance on capacity mechanisms.[1]

We also find that certain market design challenges differ in Europe and the United States. For instance, in Europe there is a need for improved representations of the transmission network in market clearing algorithms to obtain locational prices that better reflect congestion patterns. In addition, substantial benefits would be achieved from moving towards shorter time intervals in real-time balancing markets and from introducing integrated markets for energy and operating reserves, as is already done in some US markets. In the United States, electricity markets should follow the European approach of using intraday markets to enable a more market-based balancing of system deviations between the day-ahead and real-time markets. Overall, as electricity markets continue the transition towards a low-carbon future on both continents, lessons can and should be learned in both directions.

[1] Audun Botterud and Hans Auer (2018), "Resource Adequacy with Increasing Shares of Wind and Solar Power: A Comparison of European and U.S. Electricity Market Designs." *CEEPR WP-2018-008*, MIT, April 2018.

Audun Botterud

Hans Auer

E2e Project Update: Examining the Effects of Behavioral Responses on Energy Efficiency Decisions

by: Leila Safavi

E2e recently released two new working papers[1] whose results were directly affected by human socioeconomic conditions and behavioral responses. They demonstrate a need for better accounting of potential human behavior and decision making in engineering models and policymaking.

The first paper is written by affiliates Lucas Davis, Sebastian Martinez and Bibiana Taboada. The paper evaluates the costs and benefits of an energy-efficiency program in Mexico, in which over 450 new homes were provided with insulation and other energy-efficiency upgrades. The authors find that households which received these upgrades did not use less electricity or experience greater thermal comfort than households that did not. These results fall short of engineering estimates which predicted that insulation would lead to a 26% decrease in electricity use, a stark difference that is echoed in other recent E2e working papers on energy-efficiency programs (Burlig et al. 2017 and Allcott & Greenstone 2017).

The upgrades were studied in a field experiment studying a large housing-complex in the Mexican state of Nuevo Leon. Buyers selected the style and location of the home they wanted and energy-efficiency upgrades were installed as homes were under construction in a quasi-random pattern. Importantly, neither the buyers nor the sales team knew which homes would feature the upgrades. The authors partly attribute the lack of energy savings to the fact that air conditioning ownership is less common in the housing-development than was assumed by the engineering estimates (13% vs 36% of

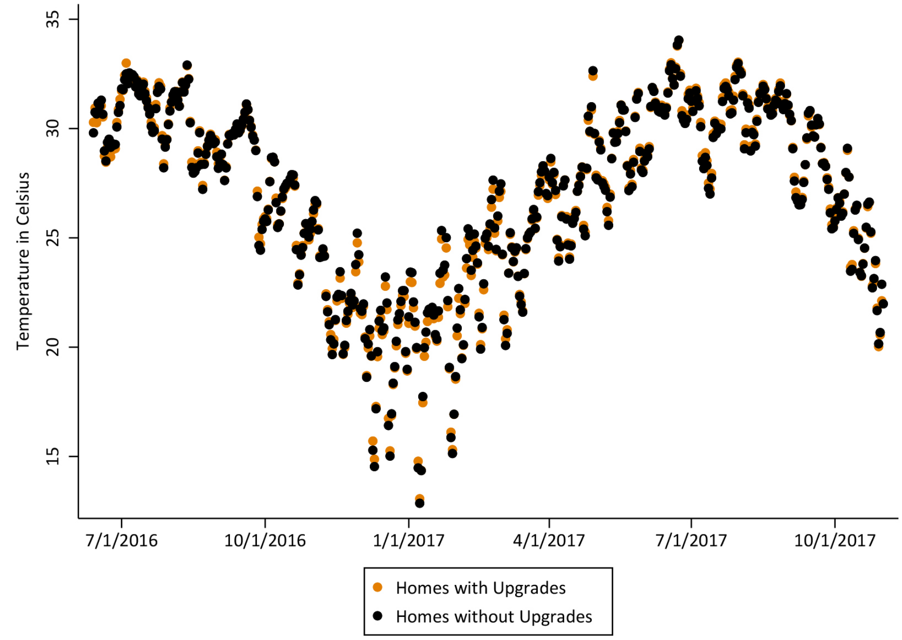
Leila Safavi

homes). This mismatch is critical since energy savings in the engineering model derive from reduced air conditioning using. Furthermore, the lack of air conditioning meant that more homes relied on passive cooling, which generates less cool air inside the home. This technology, coupled with households' propensity to keep windows open, may also be responsible for the lack of effect on thermal comfort.

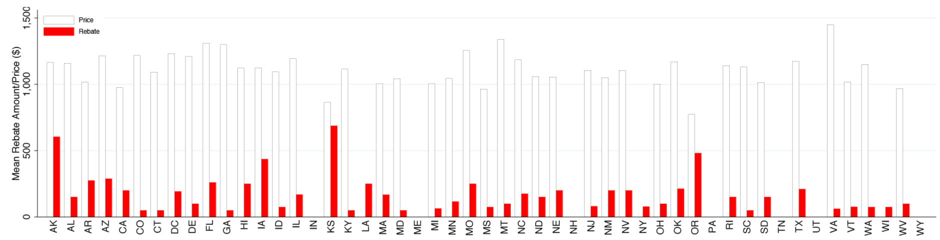
E2e's second working paper of 2018 comes from affiliates Sébastien Houde and Joseph Aldy. This paper studies how the complicated mix of taxes and subsidies used to promote energy-efficiency investments can have varying effects on different types of consumers. Consider a consumer who is interested in purchasing a refrigerator. They may be eligible for a state rebate if they purchase a particularly energy efficient model, but also may be interested in a product with an ENERGY STAR designation. Their purchase is also subject to sales tax, which can vary on the efficiency of the model they purchase.

Aldy and Houde study the refrigerator market from 2008 to 2012 in order to understand how consumers reacted to the variety of fiscal instruments used to promote energy efficient purchases at that time. They find that lower income households respond better to rebates, while higher income households are more likely to change their purchasing behavior in response to taxes. The authors explain that the value of a rebate is higher for lower-income households, which may drive their popularity. Meanwhile, economy-wide policies such as increases in sales or income taxes may affect high-income households more if these consumers are less credit constrained or more likely to plan for the future. The findings of this research point to the need for legislators and regulators to consider how various energy policies operate together and differently impact consumers.

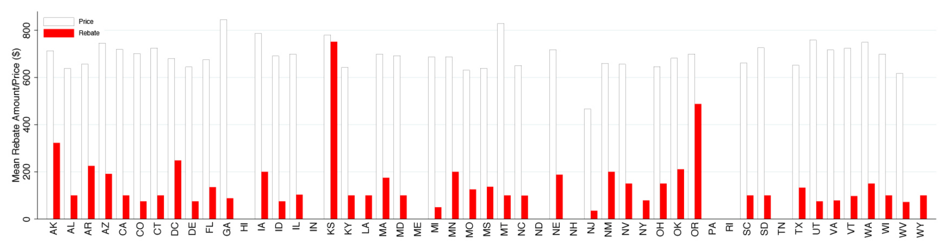
[1] For the full papers, please visit http://e2e.mit.edu/ to learn more about this project.



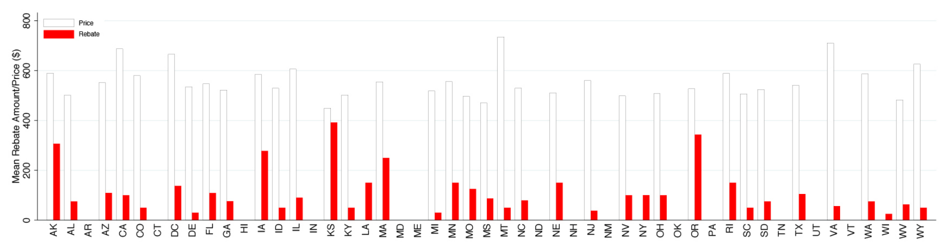
This figure plots the mean daily outcomes from a field experiment in a large housing complex in Nuevo Leon. The results show that households that did receive energy-efficiency upgrades experienced nearly identical indoor temperatures to households that did not receive the upgrades.



(a) Refrigerators



(b) Clothes Washers

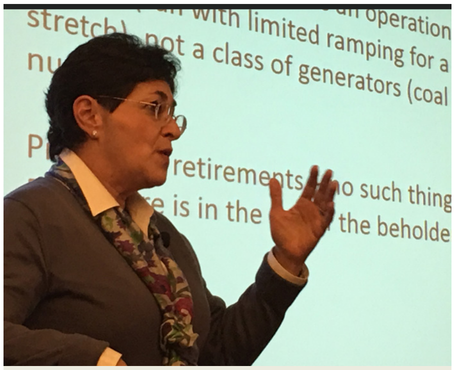


(c) Dishwashers

Figure 5. Average Price vs. Rebate Amount

Each panel shows the average price of the appliance purchased (in white) and the average rebate amount claimed (in red). States with no average price but a positive rebate amount are states where program managers did not collect price information. States where both price and rebate information are missing did not offer rebates for this particular appliance.

2017 Fall Research Workshop and 40th Anniversary



Alison Silverstein speaks during a session on baseload power and grid reliability.

On November 16-17, 2017, the MIT Center for Energy and Environmental Policy Research (CEEPR) held its annual Fall Research Workshop in Cambridge, Mass. In keeping with tradition, topics on the agenda spanned all areas of the energy sector, touching upon cross-cutting issues such as innovation and digitization, and diving more deeply into specific sectors, such as transportation and electricity markets. But as CEEPR Director Christopher R. Knittel also pointed out during his opening remarks, this particular workshop also marked a special moment for CEEPR, commemorating its 40th anniversary.

A highlight of the event, therefore, was a roundtable bringing together the current and four past directors of CEEPR to share thoughts and anecdotes about the origins, impacts, and intellectual legacy of CEEPR, as well as to venture a glimpse into future research topics and priorities. Moderated by Christopher R. Knittel, his predecessors Richard S. Eckaus, Henry D. Jacoby, Paul L. Joskow, and Richard L. Schmalensee drew on their vast experience to trace key trends of energy and environmental policymaking over the last four decades, an eventful and often tumultuous trajectory in which each played a pioneering role.

To kick off the first session, moderator Randall Field reminded the audience why research on transportation is so important: policies in the sector are often inefficient, yet at the same time, the availability of rich data and opportunities for experimental research make it uniquely suited to identify improved solutions. Both presenters drew heavily on work with large datasets: Christopher Knittel shared insights from recent research on attribute substitution in household vehicle portfolios, showing how consumer decisions to purchase a second car are influenced by the type and attributes of the first car. Ashley Langer of the University of Arizona followed with a discussion of the potential for infrastructure investment and new communication technologies to reduce both fuel consumption and travel time.

A technology trend that is rapidly redefining entire areas of the energy sector is digitization. Joining remotely from the UN climate conference in Bonn, David Turk provided a good framing for the next session by presenting a report on digitization and energy that his organization, the International Energy Agency, had released only days earlier. Christian Catalini of the MIT Cryptoeconomics Lab then provided an overview of one particular phenomenon in the digital realm, blockchain or distributed ledger technology, and its potential applications to energy. He was followed by Peter Fox-Penner of Boston University, who offered a practical perspective by describing his work with several technology startup companies harnessing digital technologies to better understand and monetize all steps in the energy value chain.

With unprecedented cuts announced in federal funding for energy research, innovation and how to stimulate it with targeted policies and incentives has attracted growing attention. Derek Lemoine of the University of Arizona discussed the role of innovation in driving energy transitions, using a model of directed technical change to infer an optimal pricing strategy for climate change mitigation. David C. Popp of Syracuse University summarized key lessons from research on policy and innovation, focusing on the role of different policy instruments and their effects on private and public sector innovation.

During dinner, Melanie Kenderdine of the Energy Futures Initiative and Former Director of the Office of Energy Policy and Systems Analysis at the Department of Energy (DoE) delivered the keynote address. Her remarks focused on energy security and the growing concern about electricity reliability, including the policy responses available to address threats to cybersecurity, presaging the themes of the next day's first session. In that session, dedicated to baseload power and grid reliability, Alison Silverstein, author of a widely-discussed DoE Staff Report on Electricity Markets and Reliability, described the report and its main outcomes, as well as the process preceding its adoption. John Parsons of the MIT Sloan School of Management and MIT's Center for Advanced Nuclear Energy Systems (CANES) followed with an update on technology developments in nuclear energy, how these affect the cost of nuclear, and their viability in competitive electricity markets.

The closing session addressed ratemaking at the distribution edge. Scott P. Burger of MIT's Institute for Data, Systems, and Society (IDSS) discussed how current tariff designs are not well-suited to a rapidly evolving power sector. Drawing on a set of economic principles, he set out criteria for a comprehensive and efficient system of prices and charges for electricity services that puts all resources on a level playing field and achieves efficient operation and planning. Fereidoon Sioshansi of Menlo Energy Economics concluded the workshop with a number of examples of technological disruption in the electricity system, and how a proliferation of options is leading to increased customer stratification with implications for electricity ratemaking.

UPCOMING WORKSHOPS

July 2-3 2018, Berlin, Germany
November 15-16, 2018, Cambridge, MA

Notable Changes

In April, CEEPR welcomed Dr. Audun Botterud as a new MIT affiliate. Audun is a Principal Research Scientist at the MIT Laboratory for Information and Decision Systems and at MIT IDSS. The main goal of his research is to improve the understanding of the complex interactions between engineering, economics, and policy in electricity markets, and ultimately enable the transition towards a cost efficient and reliable low-carbon energy system. He is particularly interested in the integration of renewable energy and energy storage into a smarter electricity grid. Towards this end, he uses analytical methods from operations research and decision science combined with fundamental principles of electrical power engineering and energy economics.

In addition, CEEPR and MITEI are jointly supporting Benny Ng as a new graduate research assistant. Benny's current research focuses on improving the efficiency of dynamic electricity pricing schemes, using readily available historical electricity pricing data, and applying regression techniques, to determine the effectiveness of different electricity pricing schemes based on economic efficiency.

Benny Ng,
Graduate Research Assistant

Recent Working Papers

WP-2018-009
Evaluating the Energy Efficiency Gap & Measuring Savings from Fault Detection and Diagnostics
Danielle Dahan, May 2018

WP-2018-008
Resource Adequacy with Increasing Shares of Wind and Solar Power: A Comparison of European and US Electricity Market Designs
Audun Botterud and Hans Auer, April 2018

WP-2018-007
Restructuring Revisited: Competition and Coordination in Electricity Distribution Systems
Scott P. Burger, Jesse D. Jenkins, Carlos Batlle, and Ignacio J. Pérez-Arriaga, March 2018

WP-2018-006
Power Sector Reform and Corruption: Evidence from Sub-Saharan Africa
Mahmud I. Imam, Tooraj Jamasb, and Manuel Llorca, March 2018

WP-2018-005
The Economics of Ride-Hailing: Driver Revnue, Expenses, and Taxes
Stephen Zoepf, Stella Chen, Paa Adu, and Gonzalo Pozo, February 2018

WP-2018-004
UK Electricity Market Reform and the Energy Transition: Emerging Lessons
Michael Grubb and David Newbery, February 2018

WP-2018-003
Subsidizing Fuel Efficient Cars: Evidence from China's Automobile Industry
Chia-Wen Chen, Wei-Min Hu, and Christopher R. Knittel, January 2018

WP-2018-002
The Use of Regression Statistics to Analyze Imperfect Pricing Policies
Mark R. Jacobsen, Christopher R. Knittel, James M. Sallee, and Arthur A. van Benthem, January 2018

WP-2018-001
What's Killing Nuclear Power in US Electricity Markets? Drivers of Wholesale Price Declines at Nuclear Generators in the PJM Interconnection
Jesse D. Jenkins, January 2018

WP-2017-023
Learning, Adaptation, and Climate Uncertainty: Evidence from Indian Agriculture
Namrata Kala, December 2017

WP-2017-022
Finding Itself in the Post-Paris World: Russia in the New Global Energy Landscape
Igor Makarov, Henry Chen, and Sergey Paltsev, December 2017

All listed and referenced working papers in this newsletter are available on our website at ceepr.mit.edu/publications/working-papers

MIT CEEPR

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During the Fall 2017 Workshop, CEEPR convened a panel to commemorate its 40th anniversary and reflect on the changing energy landscape since its inception. Former CEEPR directors Paul Joskow, Henry Jacoby, Richard Schmalensee, and Richard Eckaus (left to right) discuss their experiences and offer insights for the future in a session moderated by current CEEPR Director Christopher Knittel (far right).