IAEE Energy Forum

First Quarter 2016

International Association for Energy Economics

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Editor: David L. Williams

President's Message

Dear fellow members of IAEE,

It is such a great pleasure and honour to lead this organization. Our organization has grown to 4XXX members, a growth of Y% over the last five years. The family atmosphere of our Association is resulting from the rich social functions of our conferences and our next one is the 5th IAEE Asian Conference to be held on 14-17 February in Perth, Western Australia. I would like to thank past president Peter Hartley for the development of the Perth conference and for his excellent leadership. After Perth, we'll have the 9th NAEE/IAEE Conference on 24-26 April in Abuja, Nigeria, the 39th IAEE International Conference on 19-22 June in Bergen, Norway, and the 34th USAEE/IAEE Conference on 23-26 October in Tulsa, OK, USA. In addition to our standard set of international conferences, we're starting a new regional conference this year. The 1st IAEE Eurasian Conference will be held on 28-31 August in Baku, Azerbaijan. Please make sure that you attend at least one of our conferences this year. This is very important not only professionally but also socially for our organizational bonds to stick together. I am personally also engaged with business-and policy-oriented conferences on emerging issues of which I encourage you to become involved. The first one coming up elaborates on the new energy and business potential emerging in Iran after the embargo. Organized in collaboration with the Turkish Association for Energy Economics and the IRAEE, it will be held in January in Antalya, Turkey. The second one will elaborate on smart approaches in energy policy and on Slovenia's Energy Policy Manifesto. It will be held in March in Ljubljana, Slovenia. These conferences are organized under the umbrella of CECE, for more on which I invite you to visit the website www.cuttingedgeconferences.com.

We developed a number of strategic initiatives last year and are investing in the future of IAEE. Technology advances, so does our need to engage electronically with all of our members across the globe. Accordingly, we have developed our new website and will begin to carry electronic advertisements as well - if you are interested in advertising, please reach out to our Executive Director David Williams (iaee@iaee.org). Our Energy Data Links project is progressing very well - see our website on this at http://www.iaee.org/en/EnergyDataLinks/

Last year we established a new Affiliate in Slovenia. New affiliates now growing in Portugal, Greece and Ghana will be established very soon. IAEE hopes to foster the development of Affiliates in Croatia, Azerbaijan and Indonesia in 2016. If you are interested in developing an Affiliate in your location, please let us know.

Affiliates, if you desire an IAEE speaker to come to your meetings, please reach out to us. We have developed a Distinguished Lecturers Series - see website at http://www.iaee.org/en/resources/dls.aspx

As mentioned previously, the 1st IAEE Eurasian Conference will be held in Baku in August.

(continued on page 2)

Presidennt's Message (continued from page 1)

This will focus on energy economics emerging from the Caspian region. We are giving special importance to this new conference which is intended to be continued every other year. The plenary program covers the topics "Oil & Gas Price Dynamics and Expectations", "Regional Energy Security", "Regional Strategies to Alternative and Renewable Energy", and "Unlocking Caspian Energy Potential". An attractive technical program including oil & gas offshore platform tours and rich social activities await you in the city of winds, land of mud volcanoes. Come to beautiful Baku – it's a "must not miss" event.

A new service we started last year is the IAEE summer school. We had the first IAEE summer school in Istanbul and the second one in Harbin Chına. Both were most successful and we plan for IAEE summer schools in Istanbul and Bergen this year, and hope to have another one in China again. Make sure you register early enough as there is very high demand for our summer schools and capacity is limited.

I want to hear from you. IAEE is your organization and we actively work to develop the products and services that serve your needs. Please reach out to me (gurkank@boun.edu.tr) with your ideas and suggestions on how to better serve our member needs.

Finally, I would like to express my sincere thanks to all IAEE members for the vote of confidence that I lead the organization. It's an exciting time for IAEE and you will want to engage with our members, conferences and our products & servıces.

Gürkan Kumbaroĝlu

NEWSLETTER DISCLAIMER

IAEE is a 501(c)(6) corporation and neither takes any position on any political issue nor endorses any candidates, parties, or public policy proposals. IAEE officers, staff, and members may not represent that any policy position is supported by the IAEE nor claim to represent the IAEE in advocating any political objective. However, issues involving energy policy inherently involve questions of energy economics. Economic analysis of energy topics provides critical input to energy policy decisions. IAEE encourages its members to consider and explore the policy implications of their work as a means of maximizing the value of their work. IAEE is therefore pleased to offer its members a neutral and wholly non-partisan forum in its conferences and web-sites for its members to analyze such policy implications and to engage in dialogue about them, including advocacy by members of certain policies or positions, provided that such members do so with full respect of IAEE's need to maintain its own strict political neutrality. Any policy endorsed or advocated in any IAEE conference, document, publication, or web-site posting should therefore be understood to be the position of its individual author or authors, and not that of the IAEE nor its members as a group. Authors are requested to include in an speech or writing advocating a policy position a statement that it represents the author's own views and not necessarily those of the IAEE or any other members. Any member who willfully violates IAEE's political neutrality may be censured or removed from membership.

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

Editor's Notes

The response to our call for articles on the electricity market has been very gratifying. Indeed, the response was such that we'll be continuing the subject in the next issue. In the meantime, read on.

Peter Walsh and David Freeman write that in November of last year, the Province of Ontario, Canada sold 15% of Hydro One, the publicly-owned electricity distribution and transmission utility, in order to generate funds for infrastructure projects. The sale marked the first step in the eventual disposition of 60% of the utility. They present a financial evaluation of Hydro One which suggests the sale may have been underpriced and that perhaps an alternative source of infrastructure funding would have been a more reasonable solution

Mark Lively explains that many large consumers of electricity find it expedient to generate their own electricity instead of buying from the local electric utility. The hesitancy associated with long term contracts can be alleviated by pricing unscheduled deliveries using WOLF, a Walrasian tâtonnement for electricity, with prices changing at least every minute.

John Wolfram notes that utilities use *Economic Development Rates* to provide discounts to large firms to promote business attraction, expansion and retention. But do these rates really provide a public service, or do they create interclass subsidies? He describes how these rate structures can effectively support regional economic development when implemented properly.

Hari C. Mantripragada writes that a systems-wide techno-economic evaluation of a power plant is needed for making key decisions. He provides a broad overview of the factors affecting the performance and cost of a power plant, followed by illustrative case studies. The article uses the Integrated Environmental Control Model (IECM), a power plant modeling software tool developed at Carnegie Mellon University.

Erice Johnson and Matthew Oliver note that policies that encourage renewable energy development often seek to reduce electricity price risk for renewable energy investors.They show why renewables may actually reduce short-run price variability and, therefore, risk.

Gbadebo A. Oladosu reviews electricity sector reforms in Nigeria as an archetype for Sub-Saharan Africa. He highlights the requirements for success, and the crucial role of initiatives such as Power Africa.

Christian Skar, Ruud Egging and Asgeir Tomasgard discuss a model based analysis of the need for energy storage in a European power system with high shares of renewable energy for several scenarios with varying degree of transmission system reinforcements. In scenarios with high levels of transmission system investments the need for new energy storage capacity is found to be limited. The importance of energy storage is shown to increase substantially if the transmission system is not significantly developed.

Marten Ovaere posits that Network operators have been managing reliability of the power system using the deterministic N-1 reliability criterion. Increasing uncertainty due to renewable generation, combined with advances in communication and information technologies, induce network operators to introduce probabilistic methods in power system management. These methods incorporate probabilities and consequences of contingencies.

DLW

39th International Conference

19 - 22 JUNE 2016 | BERGEN | NORWAY

ENERGY: EXPECTATIONS AND UNCERTAINTY

CONFERENCE OVERVIEW

Energy: Expectations and uncertainty - Challenges for analysis, decisions and policy

Energy systems are becoming increasingly interdependent and integrated, raising the importance of changes in resources, markets, technology, policy, environment and climate. Methods, analyses and results that take explicit account of uncertainty and expectations from an economic and decision-making perspective will be highlighted.

The objectives of the Conference are to contribute to a better understanding of the role of expectations and uncertainty in energy, economic and environmental systems along these dimensions, and to place these topics within the broader themes of energy economics generally addressed by the Association.

CALL FOR PAPERS

PRESENTER ATTENDANCE AT THE CONFERENCE

At least one author of an accepted paper or poster must pay the registration fees and attend the conference to present the paper or poster. Authors will be notified by 2 March 2016 of the status of their presentation or poster. Final date for speaker registration fee, extended abstracts and full paper submission: 15 April 2016.

Multiple submissions by individuals or groups of authors are welcome, but the abstract selection process will seek to ensure as broad participation as possible. Each author may therefore present only one paper or one poster.

CONCURRENT SESSION ABSTRACT FORMAT

The abstract must be no more than two pages in length and must include an overview of the topic including its background and potential significance, methodology, results, conclusions and references (if any). All abstracts must conform to the format structure outlined in the template, and must be submitted online.

Abstract submission deadline:

Friday 15 January 2016

www.iaee2016nhh.no





HOSTED BY:

IAEE International Association *for* Energy Economics
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NAEE Norwegian Association *for* Energy Economics

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The 39th IAEE International Conference

ENERGY: EXPECTATIONS AND UNCERTAINTY - CHALLENGES FOR ANALYSIS, DECISIONS AND POLICY

PRELIMINARY PROGRAM

MONDAY 20 JUNE

9.00 am - 10.30 am: Opening Plenary Session

Energy and environmental policy formation in an uncertain world
Einar Hope, Professor, NHH (Presiding)
Confirmed speakers:
Yi Wang, Professor, Chinese Academy of Sciences, People`s Congress of China
Eldar Sætre, CEO, Statoil
Invited speaker:
Christiana Figueres, Executive Secretary of the UNFCCC

11.00 am - 12.30 pm: Dual Plenary Session

1. Energy and the economy: Sensitivity and expectations
Thomas Sterner, Professor, University of Gothenburg (Presiding)
2. Petroleum market fundamentals and risks
Klaus Mohn, Professor, University of Stavanger (Presiding)
Confirmed speakers:
Amrita Sen, Chief Oil Analyst, Energy Aspects
James L. Smith, Professor, Southern Methodist University

TUESDAY 21 JUNE

9.00 am - 10.30 am: Plenary Session

Technological change and energy in transport
Gunnar S. Eskeland, Professor, NHH (Presiding)
Confirmed speakers:
Elon Musk, CEO, Tesla Motors
Benjamin Schlesinger, President, BSA Energy

1.30 pm - 3.00 pm: Dual Plenary Session

1. Institutional investors and the energy sector
Espen Henriksen, Professor, UCLA Davis (Presiding)
2. Gas, Russia, and European markets
Arild Moe, SRF, Fridtjof Nansen Institute (Presiding)
Confirmed speakers:
Tatiana Mitrova, Head of Department, Russian Academy of Sciences
James Henderson, SRF, Oxford University
Klaus-Dieter Borchardt, Director, EU-Internal Energy Market

WEDNESDAY 22 JUNE

1.00 pm - 3.00 pm: Dual Plenary Session

1. Financial aspects of power markets
John Parsons, Professor, MIT (Presiding)
Confirmed speaker:
Norman C. Bay, Chairman of FERC
2. In the aftermath of Paris: What has happened, and what to expect
Gunnar S. Eskeland, Professor, NHH (Presiding)
Confirmed speakers:
Scott Barrett, Professor, Columbia University
Christoph Böhringer, Professor, University of Oldenburg
Ottmar Edenhofer, Professor, Potsdam University

3.30 pm - 5.00 pm: Closing Plenary Session

Strategies for the Energy Sector under Uncertainty: Round table discussion among business leaders
Karel Beckmann, Editor-in-Chief, Energy Post (Presiding)

PRE-CONFERENCE WORKSHOPS

- *Capacity markets and security of energy supply*
- *Future of utilities – utilities of the future*

Sunday 19 June

IAEE SUMMER SCHOOL

Financial Management of Energy Price Risk

Thursday 16 June - Saturday 18 June

PHD DAY

- *Special PhD session*
- *Enhancing academic presentation skills workshop*

Sunday 19 June

For more information, please visit

www.iaee2016nhh.no

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Remarks by John Kingston

IAEE 2015 Journalism Award Winner

Pittsburgh North American Conference, October 27, 2015

I went to my first IAEE meeting back in Orlando in 1999. Two things about that event have stuck with me ever since, and they say a lot about this organization.

The first is that Mike Lynch, whom I had known for several years and who at that time was President of the U.S. chapter, invited several of us to his suite one evening. As President, he got this gigantic suite. In fact, I think that the reason he's not here at this meeting is because he's still in that suite and refuses to leave.

That evening, the guests Mike brought up started talking about energy. I don't remember any of the specifics that we talked about, though I do remember that at that entire meeting, there had been a lot of talk about soaring oil prices, having come off their lows of earlier that year. By the time of the meeting in Orlando, they were all the way up to about $23.

I remember sitting in that room listening to all these brilliant people talking energy. And I felt flattered to have been invited by Mike to join in such a conversation, and it gave me my first real taste of just how many smart, engaged, people there were at IAEE meetings.

Later in that meeting, the lunch speaker was Bob Campbell, the CEO of Sunoco, which was a major oil refiner at the time. Bob goes through his speech about needing to change with economic trends and then he opens the floor up to questions. So one person in the room, maybe an academic with a futuristic view of the world, asked Bob: "Has your company done anything with carbon sequestration?" And Bob Campbell, a CEO of a very big oil processor replied: "We might, if I knew what the hell it was."

And I've thought about that exchange often, because there isn't a single person in the energy business today who doesn't know what carbon sequestration is. But back then, there was a CEO who didn't know what it was, and he ran into somebody at an IAEE meeting who did.

That said a lot about this organization and why it's important to journalists who cover the industry.

We always spend so much time focusing on the obvious stories. What's OPEC going to do? What's the breakeven price of shale? Is Keystone XL going to get approved?

And then you come to a meeting like this, you hear papers presented on perspectives that just leave you shaking your head in awe at the brainpower and the insight, and it makes you realize that there's just so much more out there to really understand where this industry, this sector, is going in the future.

So that's why I'm so honored to receive this award from a group that is so forward looking, so engaged and so visionary. And I receive it at a time when what is going on in energy is as intriguing as it ever has been.

Technological advances are upsetting every apple cart. The cost of generating a watt of electricity from solar panels or wind turbines is plummeting, only to run smack into a wave of natural gas generated by new technology that was never, ever planned when analysts would look out 10 years ago or so and figured by now, those alternate technologies would be able to stand on their own two feet in gaining market acceptance. And yet, it still hasn't happened.

The apple cart knew that U.S. production was going to decline and that U.S. was going to be importing lots of LNG and the last barrier that stood in the way of renewables' dominance was coal. And instead coal gets blindsided by a product that was supposed to soar in value.

And I think back to that gentleman in Orlando who asked Bob Campbell about carbon sequestration and I'd have to say to him: there's been a lot of technical advances. But some of them haven't really happened. So batteries aren't that much better. It's still virtually impossible to produce cellulosic ethanol competitively and commercially, and no, carbon sequestration really hasn't been the solution to reducing a carbon footprint.

But I have a feeling that if those things happen, they may very well happen with the involvement of somebody in this room, in this organization either nationally or internationally having some kind of role. Because it's a visionary group and that's the kind of thing they do. Sometimes they'll be wrong. And sometimes they'll be right. But I know they will never stop thinking about what lies ahead.

So I want to thank a few people by name. I want to thank some of my great Platts colleagues over the years: Joe Link, who has had as much impact on the course of Platts as anybody I worked with; the late Onnic Marashian, who also won this award, Margaret McQuaile and Neil Fleming, who also both won this award, and those other recipients who at one time or another had Platts on their resume. I also want to thank David Knapp and Maureen Lorenzetti, who may have thrown my name into this ring. And I want to thank Dave Williams for all the work he does putting on meeting after meeting all around the world.

I'm very honored to receive this award, and I thank all of you.

Robbing Peter to pay Paul? The Case of Ontario's Privatization of Hydro One

By Peter R. Walsh and David Feeman

Peter Walsh is Chair, Entrepreneurship and Strategy Department in the Ted Rogers School of Management at Ryerson University, Toronto, Ontario, Canada. **David Freemen** is a Graduarte Researcher at the school. Walsh may be reached at prwalsh@ryerson.ca

Since the late 1970s, there's been a notable increase in the private sector's management and financing of enterprises previously owned and operated by the state (Kikeri & Nellis, 2004). This trend is motivated, in part, by the desire to monetize valuable pubic assets as an alternative to raising public debt. The Government of Ontario (the Province) has a legitimate incentive to privatize public assets. The Province requires funds to invest in infrastructure projects, and divesting in existing assets could be an effective method to achieve these means. In November of this year, the Province sold 15% of Hydro One, the publicly-owned electricity distribution and transmission utility in order to generate funds for infrastructure projects in Ontario. In 2014, Hydro One had assets of approximately $23 billion (all $ figures in Canadian dollars) and an annual revenue exceeding $6 billion.

The Premier's Advisory Council on Government Assets led by Ed Clark (the Council), prepared a report proposing a model for the sale of Hydro One, which the Province has decided to adopt (Clark, Denison, Ecker, Jacob, & Lankin, 2015). The proposed model consisted of an initial IPO of a 15% equity stake in Hydro One, followed by 10% tranches up to a total of 60% of the company's equity. The remaining 40% of Hydro One's ownership will reside with the Province. Based on this model, private ownership of Hydro One will be limited to 10% per party, and the Province of Ontario will maintain veto rights on the Board of Directors. The projected amount of the sale is expected to raise $9 billion, of which $4 billion will be allocated to transit infrastructure projects and $5 billion to service the utility's debt (representing approximately 60% of the long term debt).

The issue that immediately comes to mind is whether the valuation of Hydro One put forth by the Province and used in the partial sale of the utility provides a net benefit to the people of Ontario or whether there was a better way for the Province to acquire funds to use for infrastructure projects. The Province's plan to privatize Hydro hasn't been without its critics. Stephen LeClair, Ontario's Financial Accountability Officer, has publicly claimed that the Province could have raised funds at a lower cost through issuing additional debt (FAO, 2015). In this article, a financial valuation is carried out using both the income approach and the market approach, each weighted in providing support for the final valuation. The valuations rely on secondary data obtained from stock exchanges, financial statements and electricity market data. The impact of the privatization on service quality, pricing for customers and management and operational implications of privatization is a discussion for another day.

Income Approach

Ontario's electricity demand was used as a proxy for projecting revenue growth as part of the income approach to valuation. Figure 1 shows Ontario's annual electricity demand from 1994 to 2014. Figure 1 shows steady growth in demand until a peak in 2005, at which time the trend begins to decrease. The loss of manufacturing and the impact of the recession of 2008 have contributed to the decreasing trend from 2005 to 2014. Based on these trends, three growth scenarios were determined representing worst-case (-1% negative growth), mid-case (0.1% growth) and best-case (1% growth) scenarios. These three scenarios were incorporated into an income valuation model that uses the company's future cash flows discounted (discount factor of 6.8% based on an estimation of Hydro One's weighted average cost of capital) to the present (DCF) under specific operating or market conditions.

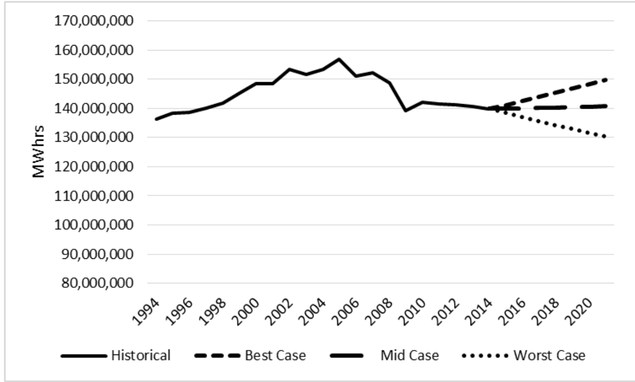

Figure 1. Ontario's annual electricity demand (1994-2014) and forecast scenarios.

In this case, operating cash flow for 20 years starting in 2015 was forecast using Hydro One's 2014 financial data representing the base year of the analysis and a terminal value (using a nominal growth rate of 4%) was added to provide a net present value for Hydro One. The results are presented in Table 1.

Scenario	DCF	Terminal Value	Valuation: 100% equity	Valuation: 60% equity
Worst-Case	$13 billion	$2 billion	$15 billion	$9 billion
Mid-Case	$21 billion	$18 billion	$39 billion	$23 billion
Best-Case	$28 billion	$37 billion	$65 billion	$39 billion

Table 1. Results from income valuation method using three growth rate scenarios ($CDN). Figures rounded.

Utility Name	Revenues ($US)	Sales (TWh)	Customers
Pacific Gas & Electric Co	$12.3 billion	76.4	5.4 million
DTE Electric Co	$5.0 billion	42.3	2.1 million
Consolidated Edison Co-NY	$4.8 billion	20.1	2.5 million
Wisconsin Electric Power Co	$2.9 billion	24.1	1.1 million
Hawaiian Electric Co	$2.1 billion	6.9	0.3 million
Hydro One ($CDN)	$6.6 billion	140.7	1.4 million

Table 2. Revenue, sales and number of customers for selected U.S. utilities and a comparison to Hydro One. 2013 data; figures rounded

Source: EIA (2015) and Hydro One

Utility Name	Symbol	Price ($US)	Number of shares (MM)	EPS ($US)	P/E
Pacific Gas & Electric Co	PCG	$51.12	480.0	2.62	19.5
DTE Electric Co	DTE	$77.51	177.0	4.8	16.2
Consolidated Edison Co-NY	ED	$60.81	292.9	3.74	16.3
Wisconsin Electric Power Co	WEC	$47.26	315.7	2.54	18.6
Hawaiian Electric Co	HE	3$0.45	107.4	1.5	20.3
Average					18.2
Hydro One Peer Evaluation Price	H	$17.09	595.0	0.94	

Table 3. Data for selected U.S. utilities (as at July 10th, 2015) and a comparable evaluation for Hydro One. Figures rounded.

Source: NASDAQ and TSX

Utility Name	EV ($US)	EBITDA ($US)	EV/ EBITDA
Pacific Gas & Electric Co	$39.8 billion	$4.9 billion	8.2
DTE Electric Company	$21.5 billion	$3.1 billion	7.0
Consolidated Edison Co-NY	$18.3 billion	$4.9 billion	3.7
Wisconsin Electric Power Co	$20.3 billion	$1.6 billion	12.5
Hawaiian Electric Co Inc	$5.0 billion	$0.3 billion	18.2
Average			9.9
Hydro One Peer Evaluation Price	$14.4 billion	$1.5 billion	

Table 4. A summary of EV and EBITDA for selected US utilities (fiscal 2014 results) and a comparable evaluation for Hydro One. Figures rounded.

Source: 2014 annual reports.

Market Approach

A market approach involves using market data of comparative utilities (peer companies) in terms of size of assets and revenues. Hydro One is one of North America's largest electrical utilities so the choice of peer companies was limited to certain larger U.S. electrical generation, transmission and distribution companies (Table 2). Two particular valuation methods using the market approach employ the use of market multiples such as Price to Earnings (P/E) and Enterprise Value (EV) to Earnings before Interest Income and Depreciation Allowance (EBITDA). Using the exchange data for Hydro One's peer companies presented in Table 3, P/E ratios for each peer company were determined by dividing price per share by earnings per share (EPS).

Hydro One's peer evaluation was determined by multiplying its EPS of $US 0.94 USD/share ($CDN:$US exchange = 0.75) by the average peer P/E ratio of 18.2. By multiplying this product by the common shares issued by Hydro One and converting the currency to $CDN, Hydro One's valuation was determined to be approximately $CDN 13.6 billion or $CDN 22.79 per sha re.

The EV values for each peer company were determined using data provided by their respective 2014 annual reports. EV/ EBITDA ratios for each peer company were determined and are presented in Table 4. The average peer EV/EBITDA ratio of 9.9 when multiplied by Hydro One's 2014 EBITDA of $US 1.5 billion, results in a valuation for Hydro One's EV of $US 14.4 billion or $CDN 19.2 billion after currency conversion.

Weighting Factors

Weighting factors were incorporated into the Hydro One valuation based on the nature of Hydro One's peer group, the industry and the methodology itself. Equity value multiples such as P/E are subject to accounting distortions and differences in capital structures of companies (Macabus, 2015). For example, earnings can be influenced by one-time expenses such as restructuring, which are not expected to be ongoing but reduce earnings nonetheless. Additionally, companies that are highly-levered will incur higher P/E multiples since the expected returns in the market are generally higher.

Enterprise value multiples including EV/EBITDA operate independently of capital structure and are suitable for capital-intensive industries, and reduce otherwise artificially high EV/EBIT ratios that are more appropriately used for non-capital intensive industries such as consulting firms. However, variability in sales based in the year selected for the valuation of both Hydro One and peer companies can impact the final valuation. Additionally, U.S. utilities that made up the peer group were combined generators, distributors and transmitters, therefore introducing discrepancies in regards to capital expenditure requirements and business models. Despite the inherent sensitivity to input variables, the income approach is widely considered the most objective valuation methodology and can provide the most intrinsic asset-based valuation. The market approaches offer higher degrees of variability as they are subject to external market perceptions. With all of this in mind Table 5 provides a summary of the weighted evaluation of Hydro One with the related weighting factors.

Conclusions

The privatization of any public utility asset should maximize the financial benefit for its owner and customers while ensuring the corporation operates in the best interest of the public. While the purpose of this article is not to explore the merits of privatization over crown-ownership models, an attempt has been made to objectively focus on the financial merits of the proposed transaction involving Hydro One as set forth by the Province. The privatization model was based on recommendations from the Premier's Advisory Council on Government Assets led by Ed Clark (the Council). The Council has admitted that: "the issue of lost income to the Province hasn't changed from our Initial Report – there will indeed be some lost income" (Clark et al., 2015, p.2).

In evaluating this model it is clear that the value of the interest being privatized (60%) would appear to be significantly greater than the expected value being put forth by the Province ($CDN 18 billion vs. $9 CDN billion). The political intent was to raise money in order to support infrastructure development in Ontario. However, it would seem reasonable to suggest that a more appropriate action would be for the Province to take on $CDN 4 billion in additional debt at an effective interest rate equal to their current borrowing rate of 4.29% (Ontario Ministry of Finance, 2015b) to build public assets, than to sell a public asset that has a positive NPV, discounted at 6.67%, that exceeds its book value by more than $CDN 4 billion. A view, as indicated earlier, shared by Ontario's Financial Accountability Officer. It leaves one wondering if, indeed, we are robbing Peter to pay Paul.

References

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CONFERENCE OVERVIEW

North America, if not the United States alone, is expected by many to soon be energy self-sufficient. Horizontal drilling, coupled with hydraulic fracturing, reversed the downward trend in production of both crude oil and natural gas. As a result, the lower-48 US will be exporting natural gas by the time we meet in Tulsa. The debate over crude oil exports from the US will likely still be raging, and is likely to be an element of the 2016 US Presidential election. The production turnaround has shaken world energy markets, and the operation of our energy markets produced substantial reductions in CO_2 emissions through economic substitution from coal to natural gas in power generation. When we add advances in renewables and the promise of industrial-capacity battery systems, the potential for North American energy self-sufficiency appears to be on the near horizon. So, the focus of the 34th USAEE/IAEE Conference will be to provide a constructive and collegial forum for extensive debate and discussion, based on solid research and evidence, to facilitate deeper and broader understanding of the implications of this transformation for North America and the rest of the world.

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

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

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

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

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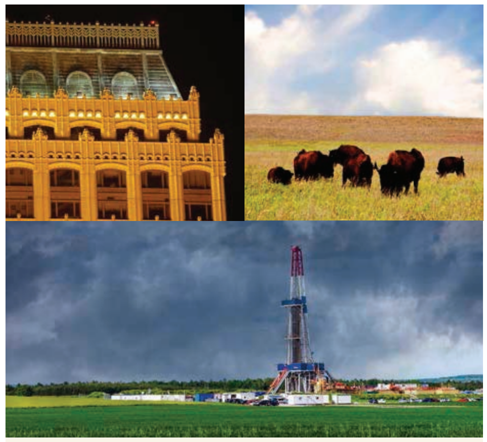

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The general topics below are indicative of the types of subject matter to be considered at the conference. A more detailed listing of topics and subtopics can be found by clicking here: http://www.usaee.org/usaee2016/topics.html

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We are pleased to announce the Call for Abstracts for the 34th USAEE/IAEE North American Conference, *Implications of North American Energy Self-Sufficiency*, to be held October 23-26, 2016, at the Hyatt Regency Tulsa, Tulsa, OK, USA.

CONCURRENT SESSIONS

There are two categories of concurrent sessions: 1) current academic-type energy economics research, and 2) practical case studies involving applied energy economics or commentary on current energy-related issues. This latter category aims to encourage participation not only from industry but also from the financial, analyst and media/commentator communities. In either instance, papers should be based on completed or near-completed work that has not been previously presented at or published by USAEE/IAEE or elsewhere. Presentations are intended to facilitate the sharing of both academic and professional experiences and lessons learned. It is unacceptable for a presentation to overtly advertise or promote proprietary products and/or services. Those who wish to distribute promotional literature and/or have exhibit space at the Conference are cordially invited to take advantage of sponsorship opportunities – please see www.usaee.org/usaee2016/sponsors.html Those interested in organizing a concurrent session should propose a top ic and possible speakers to Professor Ron Ripple, Concurrent Session Chair (ron-ripple@utulsa.edu) Please note that all speakers in organized concurrent sessions must pay speaker registration fees and submit abstracts.

CONCURRENT SESSION ABSTRACT FORMAT

Authors wishing to make concurrent session presentations must submit an abstract that briefly describes the research or case study to be presented.

The abstract must be no more than two pages in length and must include the following sections:

a. Overview of the topic including its background and potential significance
b. Methodology: how the matter was addressed, what techniques were used
c. Results: Key and ancillary findings
d. Conclusions: Lessons learned, implications, next steps
e. References (if any)

Please visit http://www.usaee.org/usaee2016/PaperAbstractTemplate.doc to download an abstract template. All abstracts must conform to the format structure outlined in the template. Abstracts must be submitted online by visiting http://www.usaee.org/usaee2016/submissions.aspx. Abstracts submitted by e-mail or in hard copy will not be processed.

Student Poster Session

The Student Poster Session is designed to enable students to present their current research or case studies directly to interested conference delegates in a specially designed open networking environment. Abstracts for the poster session must be submitted by the regular abstract deadline and must be relevant to the conference theme. The abstract format for the Poster Session is identical to that for papers; please visit http://www.usaee.org/usaee2016/PaperAbstractTemplate.doc to download an abstract template. Such an abstract should clearly indicate that it is intended for the Student Poster Session – alternatively that the author has no preference between a poster or regular concurrent session presentation. Abstracts must be submitted online by visiting http://www.usaee.org/usaee2016/submissions.aspx. Abstracts submitted by e-mail or in hard copy will not be processed. Poster presenters whose abstracts are accepted should submit a final version of the poster electronically (in pdf format) by August 19, 2016 for publication in the online conference proceedings. Posters for actual presentation at the conference must be brought directly to the conference venue on the day of presentation and must be in either ANSI E size (34in. x 44in.) or ISO A0 size (841mm x 1189mm) in portrait or landscape format.

Presenter Attendance at the Conference

At least one author of an accepted paper or poster must pay the registration fees and attend the conference to present the paper or poster. The corresponding author submitting the abstract must provide complete contact details—mailing address, phone, fax, e-mail, etc. Authors will be notified by July 7, 2016, of the status of their presentation or poster. Authors whose abstracts are accepted will have until August 19, 2016, to submit their final papers or posters for publication in the online conference proceedings. While multiple submissions by individuals or groups of authors are welcome, the abstract selection process will seek to ensure as broad participation as possible: each author may present only one paper or one poster in the conference. No author should submit more than one abstract as its single author. If multiple submissions are accepted, then a different author will be required to pay the registration fee and present each paper or poster. Otherwise, authors will be contacted and asked to drop one or more paper(s) or poster(s) for presentation.

The deadline for receipt of abstracts for both the Concurrent Sessions and the Student Poster Session is Thursday, **May 19, 2016**.

STUDENTS

In addition to the above opportunities, students may submit a paper for consideration in the Dennis J. O'Brien USAEE/IAEE Best Student Paper Award Competition (cash prizes plus waiver of conference registration fees). The paper submission has different requirements and a different deadline. The deadline for submitting a paper for the Student Paper Awards is June 21, 2016. Visit http://www.usaee.org/usaee2016/bestpapers.html for full details.

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CreatingaPeerRelationshipforElectricGeneration

By Mark B. Lively

Mark Lively is a Consulting Engineer with Utility Economic Engineers, Gaithersburg, MD, He may be reached at mbelively@aol.com or 301-428-3618.

See footnotes at end of text.

Some large industrial concerns believe they are financially better served by owning and operating their own electric generating plants instead of buying electricity from the local national utility. These captive power plants often operate independently of the local electricity utility, effectively forming their own micro-grid. However, occasionally the micro-grid will be able to reduce its costs by buying lower cost electricity from the local utility. Conversely, occasionally the local utility may find it convenient to buy electricity from the micro-grid. Such transactions need a mutually agreeable price, a price that reflects the concurrent operating conditions. An automated dynamic pricing mechanism can achieve such a mutually agreeable price when based on the concepts used by operating engineers.

Utility operating engineers increase and decrease the output of their generators based on whether system frequency is low or high versus the standard[1]. The same concept can be used to set real time prices on a dynamic basis. When the system frequency is high, the implication is that the nominal price is too high and the settlement price should be lowered. When system frequency is too low, then the implication is that the nominal price is too low and the settlement price should be raised. This dynamic pricing concept has be described in many articles under the title of Wide Open Load Following (WOLF).[2]

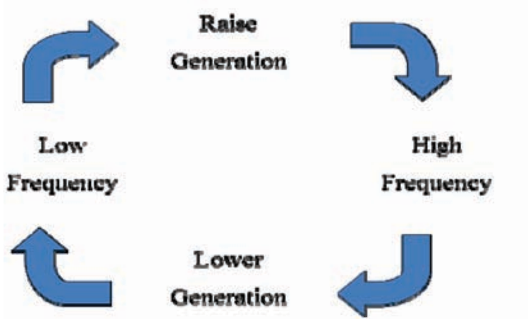

Figure 1.Control Theorgy for Operating Engineers.

Control Theory

Utility operators are always trying to balance supply and demand on a real time basis, generally by changing the output of the generators under their control, though occasionally by managing load. This utility operating protocol can be simplified into Figure 1. When system frequency is low as on the left side of Figure 1, utility operators send out control signals to increase generation. The increase in generation will lead to an increase in frequency. Conversely, when system frequency is high on the right side of Figure 1, the utility operators send out control signals to decrease generation.

Figure 2 converts the control protocol of Figure 1 into a supply and demand diagram. A shortage implies that demand exceeds supply, as is shown toward the bottom of Figure 2. Utility operators measure that shortage in terms of frequency error[3]. These calculations are performed every three or four seconds. As shown on Figure 2, demand exceeding supply means that the nominal price is below the equilibrium price. This creates pressure to increase the price toward the equilibrium price. The WOLF concept provides a formula to adjust the nominal price toward the equilibrium price, achieving some settlement price. With utilities calculating frequency error and/or ACE every three or four seconds, there could be a thousand different prices every hour.

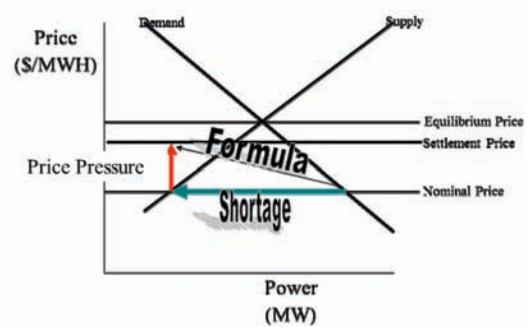

Figure 2. Wide Open Load Following Dynamic Economic Theory.

The operating protocol of Figure 1 can be converted into the WOLF pricing protocol of Figure 3 by changing physical control concepts to financial concepts. Thus, the low frequency on the left side of Figure 3 will lead the system to raise the settlement price above the nominal price, the dynamic that had been presented in Figure 2.

One option for the WOLF pricing protocol is shown in Figure 4. The solid heavy bottom line is the adjustment to move from the nominal price toward the equilibrium price. The adjustment is heavily dependent on the actual frequency at the time of the delivery. In this example the nominal price is assumed to be \$30/MWH. The WOLF settlement price is the dashed lighter upper line, \$30/MWH above the adjustment.

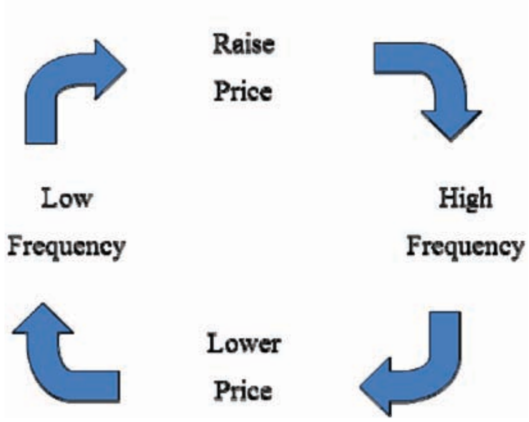

Figure 3. WOLF Pricing Control Theory.

Sometimes the nominal price is set poorly, or needs to be changed as circumstances change. In terms of Figure 2, demand consistently to the right of supply occurs when the nominal price is too low. This means

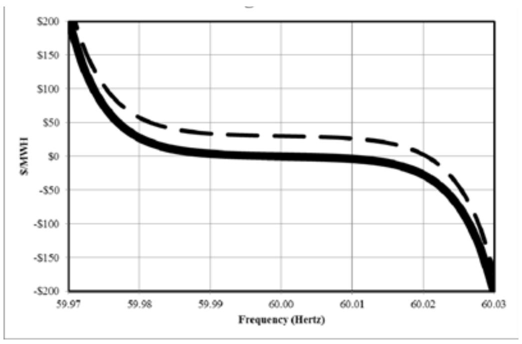

Figure 4. Pricing Curve.

there is a consistent upward price pressure. The consistent imbalance between supply and demand shows up as frequency consistently to the left on Figure 4.

A consistent low frequency will accumulate a negative time error, where synchronous[4] clocks are behind the GPS signal. Some systems have protocols to run their systems with a target frequency higher than standard to alleviate this time error. Figure 5 provides a WOLF protocol for dealing with this same issue. When clocks are slow, the nominal price is increased.

Wolf Eliminates Buyers Remorse

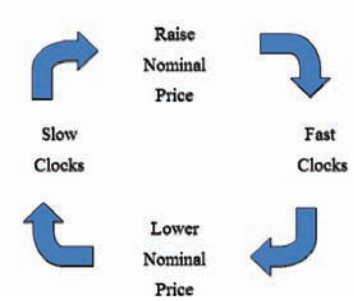

Figure 5. WOLF Pricing Control Theory for Persistent Error.

Buyer's remorse is a reference to the regret most people experience when making major purchases. The buyer might hear of a better deal in the form of a lower price from another company, or even that the seller had given a better deal to another buyer. The converse of seller's remorse is also true, in that a seller may hear of another deal in which the transaction price was higher for what might otherwise have been the same physical terms. The longer the deal, the more likely that buyer's remorse will occur. Buyer's remorse is especially endemic in contracts where one of the entities is part of the government which is subject to a change of the officials in charge.

WOLF pricing greatly reduces the potential for buyer's remorse. Changing the price a few times a minute means that the decision process is operational, how much electricity should the party generate. The actual transaction will be pure physics, the difference between generation and load will be delivered across the interchange between the utility and the industrial plant. Thus, under the concept that load is invariant, the utility (or the industrial plant) has to look at the operating decision as to how much generation to produce. Having prices change a few times a minute results in each transaction being for less energy and thus for less money. These small transactions greatly reduces the anxiety associated with the interconnection between the utility and the industrial facility.

Figure 6. Profit Associated with Setting Generation Marginal Cost at WOLF.

Utility operators have long minimized their operating costs through the concept of equalized lambda, or equalized marginal cost. The marginal cost of producing an additional unit of electricity will vary across the operating range of a generator. The marginal cost will also change with the input cost of fuel. Utility operators ramp up some units and ramp down other units until each unit has the same marginal cost. WOLF pricing for the electricity at the interconnection provides one mechanism for identifying marginal cost or system lambda.

Setting the operating level of each generator to achieve a marginal cost equal to the WOLF price will produce a level of generation that may be in surplus to the organization's load, or there could be a deficit. If there is a surplus, then the operator is making a slight profit on the delivery. The profit margin is the result of marginal cost being greater than incremental cost. This concept is demonstrated in Figure 6. The sloping line is the marginal production cost for one of the participants. The vertical line is the participants internal demand for electricity, which can be considered to be fixed. The horizontal line is the settlement price. The area within the triangle is the profit associated with increasing generation until the marginal cost of generation is equal to the settlement price.

Figure 6 is presented for the entity that is making the sale. Figure 6a presents a similar profit diagram for the entity that is buying power at the concurrent WOLF price.

Reliability issues will lead utility operators to operate at a level other than the WOLF price. Operators who are delivering electricity will tend to operate at a marginal cost level below the WOLF price, reducing the power being delivered off its system. This power reduction partially protects the utility from having to cope with a sudden loss of load should the interconnection fail. Conversely, operators who are receiving electricity will tend to operate at a marginal cost level above the WOLF price, again reducing the flow on the interconnection and reducing the power received from off system. In the import case, the protection is against having to cope with the sudden loss of supply should the interconnection fail.

Operating at a level different from the WOLF price can also provide the utility with a financial reward, whether the entity is long or short. The additional financial benefit is from the incremental revenue associated with the infra-marginal delivery or receipt. For the entity making the sale, a slight reduction in the amount of the sale will reduce the profit associated with the reduced volume, but will increase the profit associated with the remainder of the sale. This is illustrated in Figure 7.

Figure 7 shows the seller producing at slightly less than the a level that is the estimated WOLF settlement price. The slight reduction means that the seller forgoes a slight amount of profit at the far right end of the triangle. But the lower production level will result in a lower frequency and a higher WOLF price. The higher WOLF price produces the additional profit shown by the rectangle. Note that this gamesmanship is also available to the purchaser, which can increase generation beyond that which would be indicated by its internal marginal cost. This concept is shown in Figure 7a.

The buyer in Figure 7a produces more electricity than is indicated by equating generation marginal cost to the WOLF price. The buyer thus forgoes some of the profit associated with buying electricity at less than the buyer's marginal cost. The increased generation increases frequency and suppresses the WOLF price below the generation marginal cost. The profit on the infra-marginal purchase can be significantly more than the forgone profit on the reduced purchase.

The combined efforts of the buyer to reduce the WOLF price and of the seller to increase the WOLF price will be a dynamic dance, sometimes with the buyer benefiting, sometimes with the seller benefiting. The WOLF pricing mechanism produces a fair price independent of which party is trying to maximize its profitability.

Wolf Creates Reliability Payments

The references above to the marginal costs of the buyer and of the seller suggests that the buyer has additional capacity that it could use but chose not to use since the WOLF price is lower than the buyer's marginal cost. Such transactions have historically been called economy energy, where the buyer had capacity it could operate but that the cost of operation was greater than the transaction price.

In some situations, the buyer will not have additional generation and the transaction can be considered to be a capacity transaction. Under a traditional capacity transaction, the seller commits to deliver electricity out of its reserves and is paid for fuel and other operating costs plus a portion of the cost of owning and operating the reserves. WOLF prices depend on system frequency and receive no input from either party as to their reserve position. The WOLF price is simply from a formula with frequency as the input in Figure 3. Reserves matter only in regard to how much their owners decide to deploy them.

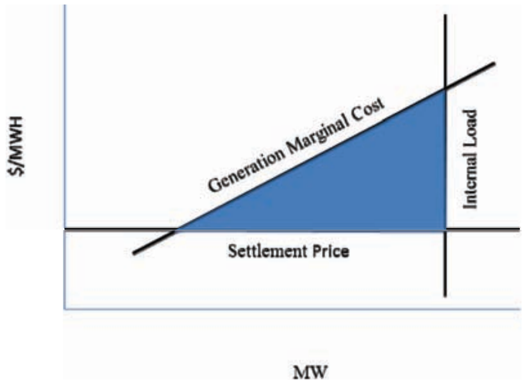

Figure 6a. Profit Associated with Setting Generation Marginal Cost at WOLF.

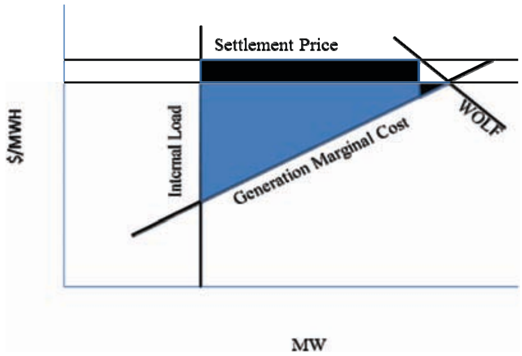

Figure 7. Profit Associated with Setting Generation Marginal Cost Below WOLF.

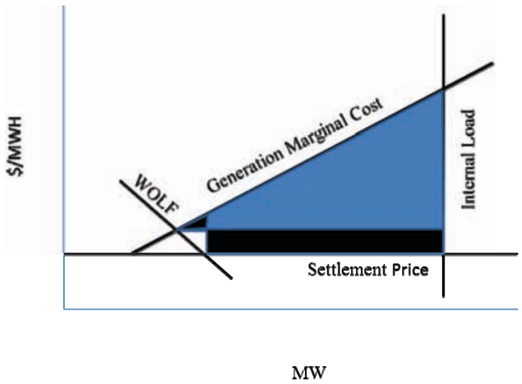

Figure 7a. Profit Associated with Setting Generation Marginal Cost Above WOLF.

Figure 7 showed how a seller could increase its profitability by a partial withholding of generation. The increased profitability can be considered to be a contribution to the fixed costs of the seller, a form of reliability payment.

Many utilities have implemented a concept called Demand Side Management. As mentioned above, utility operators usually dispatch their generators to achieve a balance between supply and demand. Sometimes utility operators have the ability to dispatch load, either on a contractual basis with some customers or using rotating blackouts to reduce load in wide areas. In essence, the WOLF pricing mechanism then is driven by the utility's demand curve instead of by its supply curve. The utility can either pay the high WOLF price or curtail load. Without the interconnection and the ability to buy electricity at the high WOLF price, the utility would have had to curtail some load in order to prevent a cascading blackout.

California has increasingly been warning about a shortage of ramping capacity. The concern is not that the utilities in California do not have enough capacity to meet the California peak but that the generators cannot move rapidly enough to meet swings in load. The example used by California is a spring afternoon with air conditioning ramping up as solar PV is ramping down. The dynamic WOLF pricing system handles this situation by continuing to use system frequency to set the price. Sometimes the dispatchable generators will ramp up too quickly and suppress the WOLF price. Sometimes the dispatchable generators will ramp up too slowly and the WOLF price will be very high.

WOLF pricing of unscheduled flows of electricity also provides the parties incentives to sign term contracts, specifying power delivery profiles and fixed prices, even though such term contracts can lead to buyer's remorse. WOLF pricing would be applicable to the difference between metered energy and the specified delivery profiles. In many respects, such term contracts can be considered to be hedges against future real time deliveries.

Conclusions

Some industrial facilities operate their own micro-grid, often in frustration from trying to negotiate what they consider to be economically fair contracts with the local national utility. Groups of utilities long ago realized the economic and reliability benefits associated with more generators connected together synchronously. A real time price for very short intervals of time changes the concept of buyer's remorse from a strategic issue to an operational issue. Each system operator attempts to optimize his generating level by matching the marginal cost of his generators against the WOLF transaction price. The very short intervals over which the WOLF price is applicable makes most such operating decisions have a very small individual effect. Further, a history of WOLF transaction prices may make some term contracts politically acceptable.

Footnotes

[1] The standard frequency in the U.S. is 60 Hertz or 60 cycles per second. The standard in Europe is 50 Hertz. Most of the rest of the world is split between these two frequencies.

[2] For instance, see Lively, Mark (1989) "Tie Riding Freeloaders--The True Impediment to Transmission Access," Public Utilities Fortnightly, 1989 December 21; Lively, Mark (1997), "Competition Versus the Good Old Boys' Club," Forum, IEEE Computer Applications In Power, January 1997; Lively, Mark (2005), "Creating an Automatic Market for Unscheduled Electricity Flows," The National Regulatory Research Institute, Volume 3, December 2005.

[3] Or in terms of Area Control Error (ACE) when the utility is part of a larger system

[4] Clocks plugged into an electrical outlet.

Economic Development Rates: Public Service or Piracy?

By John Wolfram

John Wolfram is the founder of Catalyst Consulting LLC, a consulting firm specializing in rate and regulatory matters for utilities. He may be reached at 502.599.1739 or by e-mail at johnwolfram@catalystcllc.com. See other articles at www.catalystcllc.com

See footnotes at end of text.

Economic Development Rates ("EDRs"), which provide electric rate incentives to large commercial and industrial customers to promote business attraction, expansion and retention, are experiencing a bit of a renaissance in North America. But do these rate structures provide a public service or constitute institutionalized piracy?

According to recent reports, economic development and site selection consultants believe the U.S. economy is already on a continuous growth track, which is reflected in the new facility and expansion plans of their clients.[1] Many utilities believe that if they adopt a creative economic development strategy, they can accelerate the success of such growth through regional attraction, retention, and expansion efforts. Such growth results in direct, indirect, and induced economic benefits for the region. Utilities have long relied upon EDRs as essential components of a comprehensive economic development strategy.

A general set of principles for the evaluation of EDRs has emerged from the broad body of regulatory deliberation spanning several decades. EDR tariff offerings may also be generally referred to as "discount rates" or "incentive rates." Properly designed and administered, discount rates can lead customers to make business decisions that are both financially attractive and economically efficient, providing advantages to the affected customer and other customers on the system.

EDRs Defined

Generally, EDRs act as a vehicle for the utility to provide an economic incentive to large commercial or industrial customers to locate or maintain a facility within the utility's service territory. The incentive is ordinarily provided in the form of a discount from the utility's standard tariff rates, terms or conditions.

Specifically, EDRs are rate structures aimed at persuading a customer to take or continue taking service from the utility when the customer is prepared to locate elsewhere or relocate for economic reasons. This applies both to customers considering relocation to another utility service territory and to those contemplating plant closure; the politics around each differ but the economics are largely the same. A rate discount lowers the operating costs of the business, which in theory should improve the customer's bottom line and thus help the utility to retain the load.

In the current economic climate, many utilities are focusing their attention on load retention and expansion more than attraction, in part because new projects are few and far between, but more so because almost all utilities have major commercial/industrial customers that provide a sizable revenue stream -- one that warrants additional protection in uncertain times.

Regulatory Criteria for EDRs

When a utility is considering an incentive rate offering, several factors warrant consideration. The following inquiries address the key regulatory criteria that are pertinent to an efficient and effective rate design:

Is the discount rate *necessary*?
Is the discount rate *sufficient*?
Does the discount rate *exceed the marginal cost* of providing service?
Does the discount rate *benefit all ratepayers*?

The discount must be necessary to secure the load. The question is, absent a discount, will the customer locate somewhere else or otherwise leave the system? In order to verify that this requirement is met for existing customers, many utilities and/or regulators require a sworn affidavit from the customer confirming that absent the rate discount, the customer load would leave the system. Alternatively, further evidence that demonstrates the need for a rate discount may also be considered, including documented customer communications with neighboring utilities, financial and accounting reports of the customer demonstrating financial distress, requests for proposals, or forecasts showing the extent of the customer's financial risk on a prospective basis. It is also important to note that compliance with this criterion must be demonstrated by the customer, not by the utility; only the customer is properly positioned to provide adequate evidence that a potential discount is necessary for the customer to remain on the system.

The discount must be sufficient to secure the load. The rate discount must be set so that the rate benefit to the customer is enough to offset any economic incentive for the customer to close its operations or to be served by another utility. A corollary to this requirement is that the discount be minimized; in other words, the discount must not be any larger than required to achieve the objective. Any discount beyond the minimum necessary to secure the load is a superfluous subsidy. Thus the discount must be sufficient -- but not *more* than sufficient. This can be a difficult criterion to meet because it is not formulaic and requires a subjective assessment. Regulators have recognized a balance between the need to offer a discount to retain the load and not offering a discount that is larger than necessary to prevent the loss of a major utility customer and regional employer.

The discounted rate must exceed the marginal cost of providing service. This is so because it is not efficient to charge less than marginal cost for marginal usage. Thus the utility that implements an incentive rate should incur lost revenues (i.e., the difference in revenues between the standard rate and the discounted rate) but should not incur negative margins by serving the load in question. This is an essential element of an efficient rate design.

The discounted rate must benefit all ratepayers. In many jurisdictions, there is a requirement that the discounted rate must benefit all ratepayers. There is no industry-wide consensus around this criterion. Some regulators require only that other rate classes are *made no worse off* by the offering of an incentive rate. Often, the requirement for "benefits" is interpreted to mean that the discounted rate should provide some contribution toward the utility's fixed costs -- an amount less than the contribution to fixed costs that is embedded in the standard tariff, but greater than zero. In this way, the other ratepayers benefit because this recovery of some utility fixed costs would not occur if the load were not served by the utility. Thus the discounted rate benefits other ratepayers by reducing the contributions required from them over time to cover the utility's fixed costs.

Other Regulatory Considerations

Incentive rates can benefit customers in a number of ways. Retention of a major customer through an incentive rate can keep a significant industry in the region, with direct, indirect, and induced economic effects that benefit the entire region. By retaining the load, the utility's costs are higher, but the revenues from the retained customer more than cover the added costs. As a result, the utility earnings are higher than they would otherwise have been (although not as high as if the customer were on the system under full standard rates).

An important feature of an EDR tariff is whether the tariff sufficiently protects against free riders. A free rider is a customer who receives the benefit of a rate discount but for whom the discount is not necessary. A generally available incentive rate, by itself, does not sufficiently protect against free riders. However, an EDR built into a *special contract*, subject to approval by the regulator, is a standard approach for protecting against free riders. This allows for the individual consideration of each application of an incentive rate, and permits an individual customer demonstration of the requirements outlined above (i.e., that the discounted rate is necessary, is sufficient, exceeds marginal costs, and benefits all ratepayers).

Some utilities design discount rates such that the incentive declines over time and is phased out by the end of a set period (e.g., a discount of 50% that declines by 10% each year so that after five years there is no discount). This design is more common for attraction than it is for expansion and retention rate offerings.

Finally, when the utility regulator evaluates the overall appropriateness of a load retention rate, it is not merely proper but imperative for the regulator to consider the effects of the potential loss of a significant business in the community. The possible impacts of the decision regarding a load retention rate have a legitimate and serious relevance to the public interest, so the regulator should give due consideration not only to ratemaking practice and precedent but also to the specific circumstances of the case. Many factors warrant review, including whether the customer is a major employer in the area, whether the business creates related employment and business opportunities for supporting industries in the region, whether the loss of the business leaves a void that cannot otherwise be filled, whether the business supports the community at large in other beneficial ways, and any other circumstances or facts unique to the particular proposal before the regulator. As long as the regulator evaluates the discount rate first by applying the proper criteria outlined in the framework provided here, all of these other factors should be given the appropriate weight by the regulator in its deliberations on the matter at large.

Ratemaking Considerations

The central ratemaking issue for approved load retention rates is whether the other ratepayers pay for the discount. In other words, during a rate proceeding, should the utility recover from other customers the difference in revenues between the discount rate and the standard tariff rate? Alternatively, for an investor-owned utility, will the regulator require the utility shareholders to absorb the "lost revenues" associated with the rate discount, by requiring that the utility impute revenues associated with the discount in the determination of the revenue requirement?

The answer varies by jurisdiction. Some regulators have required shareholders to absorb the discount from standard tariff rates. Other regulators have authorized a sharing of lost revenues between the utility customers and shareholders. Typically, the argument for sharing says that because serving the customer load offers economic advantages both to utility customers (via a contribution to the utility's fixed costs) and to utility shareholders (via a contribution to utility earnings), the revenue loss stemming from the discount should also be shared. Simply put, if the utility customers are better off with the load than without it, then the shareholders are similarly better off with the load than without it, and thus should share in the lost revenue burden. In this case, the utility must impute the discount in test period revenues in a rate case when establishing the revenue requirement -- effectively setting rates for other customers as if the incentive rate customer had paid a "full fare" and letting shareholders aborb the difference.

Regulators in other jurisdictions, however, allow utilities to allocate the lost revenues to other rate classes for ratemaking purposes. The basis for doing so is the regulatory compact, which essentially grants utilities the right to earn a reasonable rate of return on investment in return for providing energy services with its service territory. Regulated utilities in North America are entitled to a reasonable opportunity to recover their prudently-incurred costs,[2] and are also entitled to earn a fair and reasonable rate of return on their capital investments.[3] These are considered fundamental principles of utility regulation. At bottom, the question of whether a utility benefits from serving a particular load does not diminish the right of the utility to recover its prudently-incurred costs from customers and to earn a fair rate of return on its investment.

Continuing this argument, the only instance in which the utility shareholders would legitimately face exposure to lost revenues due to the implementation of an incentive rate is between rate cases. If an incentive rate is placed into effect between rate cases, the utility would be responsible for lost margins until the reduced revenues could be incorporated into base rates in the next rate case. This is no different from what would happen if a large customer were to close or curtail its operations; in that case, the prudently-incurred fixed costs that were formerly recovered from the departing customer could then be recovered from the remaining customers in the utility's next general rate case proceeding. This is consistent with standard ratemaking principles.

Conclusion

Utilities turn to EDRs as a ratemaking tool to help the utility participate more effectively in the site selection contest for attracting, maintaining, and expanding customer load. The EDRs help the utility to attract and retain major customers by providing those customers with a discount from the standard tariff rates.

Utility regulators typically expect EDRs to be necessary, to be sufficient, to exceed marginal costs, and to benefit all utility customers. Offering such discounts between rate cases can expose utility shareholders to lost revenues, but many utility regulators will allow the utility to recover the discounts from other customers in the next rate case if the incentive rate offering meets the aforementioned four criteria.

Utilities are revisiting EDRs now for a reason. Properly designed and administered EDRs can boost utility revenues, bolster public relations, promote job creation, and enhance the welfare of the community at large, without creating subsidization of large customers by other customer classes. Utilities will continue to thoroughly pursue the implementation of EDRs, as an element of a comprehensive economic development strategy, in order to advance these goals – especially in times when vigorous economic development is most urgently needed.

Footnotes

[1] Area Development Magazine, 11th Annual Consultants Survey: Consultants' Exhibit Confidence and Increasing Project Activity, Special Presentation (Q1 2015), at www.areadevelopment.com

[2] Federal Power Commission et al v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

[3] Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).

For Further Reading

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Techno-economic Evaluation of Fossil Fuel Electric Power Plants

By Hari C. Mantripragada

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Introduction

The function of a fossil fuel-fired power plant is to convert fuel, typically coal and natural gas, into electricity. A number of different factors affect the performance and cost of a power plant. For example, in a coal-fired power plant the choice of coal type, type of boiler, steam turbine, and pollution control technologies, and so on, directly or indirectly affect the performance and cost of the entire power plant. Thus, a systems-wide techno-economic evaluation of power plants is needed for making key decisions such as the technological choices to be made for building a new power plant, retrofitting an existing power plant with a new technology component, or for comparing different power plant options in the light of new market and regulatory factors. This article provides a broad overview of the factors affecting the performance and cost of a power plant, followed by illustrative case studies. The article also demonstrates the use of the Integrated Environmental Control Model (IECM), a power plant modeling software tool developed at Carnegie Mellon University [1].

Quantitative Metrics for Evaluation of Power Plants

A variety of quantitative metrics are needed for evaluating a power plant in general. These quantitative metrics usually relate to performance, emissions and ultimately, cost. A few of these are defined below.

Power Plant Performance

Typically, a power plant is designed to generate a desired quantity of net electrical output. All the other choices are centered on that. In a pulverized coal (PC) power plant, coal is combusted in a boiler which generates steam. Depending on the boiler design, the steam could be sub-critical, super-critical or ultra super-critical. The steam runs a steam turbine which generates electricity. Similarly, in a natural gas combined cycle (NGCC) power plant, product gases from natural gas combustion run a gas turbine to generate electricity. The hot exhaust gas from the gas turbine is used to generate steam which in turn runs a steam turbine, generating more electricity.

Plant Thermal Efficiency

The amount of fuel needed to generate the desired quantity of electricity is an indication of the performance of the power plant. Consequently, the most widely used performance metrics for a power plant are its thermal efficiency and plant heat rate. Thermal efficiency of a plant indicates how much output can be obtained from a given amount of input and conversely, heat rate indicates the amount of input needed to generate a unit of output. Output here means the electrical energy and input is the fuel energy. Thermal efficiency is typically expressed as percentage and heat rate is expressed as BTU/kWh or kJ/kWh.

Both of these parameters can be evaluated on either a "gross" power basis or a "net" power basis. The electricity generated by the turbine generator is called the "gross" power output. Some of this electricity is utilized within the power plant in order to meet some auxiliary loads (fans, blowers, pumps etc). Most modern power plants are also equipped with various pollution control technologies, in order to limit harmful emissions into the atmosphere. These emission control technologies also consume a part of the plant's gross electrical output. The resulting power output is the "net" electricity which is sold to the grid. By definition, gross plant thermal efficiency is always higher than the net thermal efficiency. Conversely, the net plant heat rate is always higher than the gross plant heat rate.

Power Plant Emissions

In general, power plants need to meet different emissions standards, like the new source performance standard (NSPS) or its equivalent. Emissions control technologies include electrostatic precipitator (ESP) or fabric filter for particulate removal; wet or dry flue gas desulfurization (FGD) for SOx removal; selective catalytic reduction (SCR) for NOx control; and possibly carbon dioxide capture and storage (CCS) for CO_2 control.

Emissions can be quantified on an absolute basis (mass flow rate). However, emissions normalized over unit input or output energy is often used in comparative analysis (e.g., kg/BTU fuel input or kg/kWh output). Many regulations are specified in normalized units. For instance, the new source performance standards regulate SO_2 emissions from fossil-fired power plants to 0.258 mg/kJ of fuel input. On the other hand, the EPA's final rule on greenhouse gas emissions for coal-fired boilers limits the CO_2 emissions to 1,305 lb/MWh (0.653 kg/kWh) of net power [2].

While meeting the emissions standards, the plant with a higher net thermal efficiency (or lower net heat rate) is considered to have a better performance than a plant with lower net thermal efficiency (or higher heat rate).

Power Plant Costs

Costs associated with power plants are key parameters in decision-making. Some of the most commonly used metrics are the plant's capital cost ($), operational and maintenance (O&M) cost ($/year) and the cost of electricity ($/MWh). Capital cost mainly depends on the sizes of different equipment which are generally a function of the flow rates. O&M costs can be divided further into fixed O&M (FOM), variable O&M (VOM) and fuel cost (FC). Sometimes fuel costs are included within the VOM costs. The cost of electricity (COE) or levelized COE (LCOE) is the cost of generating a unit of electricity. LCOE depends on both capital and O&M costs as well as the financial structure of the project (e.g., interest rate, plant life, etc.) and its capacity factor. LCOE, expressed in the equation below, effectively embeds all the performance and cost parameters of the plant.

$$LCOE\left(\frac{\$}{MWh}\right) = \frac{TCR\,(\$) \times FCF\left(\frac{1}{year}\right) + FOM\left(\frac{\$}{year}\right)}{8766\left(\frac{hr}{year}\right) \times CF \times MW_{net}} + \frac{VOM\left(\frac{\$}{year}\right)}{8766\left(\frac{hr}{year}\right) \times MW_{net}} + FC\left(\frac{\$}{BTU}\right) \times \frac{HR\left(\frac{BTU}{kWh}\right)}{1000}$$

TCR is the total capital requirement of the plant which includes direct costs of equipment, indirect costs such as contingencies (which depend on factors such as the technological maturity of the process) and sometimes owner's costs. FCF is the fixed charge factor (also called capital charge factor) used to annualize capital costs over the lifetime of the power plant. FCF depends on the plant life and financial variables such as discount rate. CF is the capacity factor which indicates the effective fraction of time the power plant operates at full capacity in a year.

Thus it is clear that a variety of technological and financial parameters affect the LCOE.

Two additional cost metrics can be used to evaluate the cost effectiveness of a CO_2 capture technology. One is called cost of CO_2 captured and the other is the cost of CO_2 avoided. Cost of CO_2 captured denotes the cost of capturing a tonne of CO_2, compared to a reference plant without CO_2 capture, while still providing a unit of electricity. This does not include the cost of CO_2 transport and storage. This measure is used to compare the economic feasibility of a CO_2 capture system compared to a market price of CO_2 (for example, for enhanced oil recovery).

$$Cost\ of\ CO_2\ captured\left(\frac{\$}{tonne}\right) = \frac{LCOE_{CCS}\left(\frac{\$}{MWh}\right) - LCOE_{ref}\left(\frac{\$}{MWh}\right)}{\left(\frac{tCO_2}{MWh}\right)_{captured}}$$

On the oth ... $)_2$ compared to a reference plant without CCS. This includes the cost of transport and storage, since CO_2 is avoided only when it is sequestered. This metric is used to assess the feasibility of CO_2 capture in general. For instance, this is the CO_2 tax ($/tonne of CO_2 emitted) beyond which CO_2 capture would become more economical for the reference plant.

$$Cost\ of\ CO_2\ avoided\left(\frac{\$}{tonne}\right) = \frac{LCOE_{CCS}\left(\frac{\$}{MWh}\right) - LCOE_{ref}\left(\frac{\$}{MWh}\right)}{\left(\frac{tCO_2}{MWh}\right)_{ref} - \left(\frac{tCO_2}{MWh}\right)_{CCS}}$$

It must be ... O_2 captured and avoided. More details about techno-economic evaluation of power plants are available in Rubin et al (2013) [3].

Ideally, a power plant should give the best performance at the lowest cost.

Illustrative Case Studies

To illustrate the effect of different technological and financial variables on the performance and cost of a power plant, a few case studies are presented here. PC and NGCC power plants without CO_2 capture are used as the base cases. To illustrate the effect of coal type, two types of coal are used – Appalachian medium sulfur coal and Wyoming Powder River Basin (PRB) coal. The former is a higher quality coal (bituminous) but with relatively high sulfur content while the latter is a lower quality coal (sub-bituminous) but with much lower sulfur content. The lower sulfur coal would require a smaller FGD unit, leading to possible cost savings. Sensitivity analyses are also conducted to understand the effect of key variables on the performance and cost of different plants. The effect of CO_2 capture on a PC power plant has also been illustrated. The Integrated Environmental Control Model (IECM), developed at Carnegie Mellon University, has been used for performing these case studies.

Integrated Environmental Control Model (IECM)

The Integrated Environmental Control Model (IECM), developed at Carnegie Mellon University, is a freely and publicly available power plant modeling computer tool which evaluates the performance and costs of several types of fossil fuel power plants, including pulverized coal (PC), coal-fired integrated gasification combined cycle (IGCC) and natural gas combined cycle (NGCC) power plants. Based on fundamental mass and energy balances, together with empirical data, the IECM calculates plant-level performance and material flows, including environmental emissions, for current and advanced power plant designs whose configuration and parameters are specified by the user. Each power plant configuration can be designed with a variety of emission control options, including CO_2 capture and storage. The IECM also provides the capability to quantify uncertainties in model input parameters and express results as probability distribution functions as well as deterministic values. Comparative analyses of different system designs also can be performed easily. The following sections provide some illustrative case studies of techno-economic evaluation of power plants using the latest version of IECM (v 9.0.2).

Case Study Results

All the plants in the case study are designed to generate 580 MW of net electrical output. A fixed charge factor or 0.113 and a base case capacity factor of 75% are assumed.

Table 1 compares the performance and cost characteristics for the PC and NGCC power plants considered here. Most of the performance and cost metrics described before are illustrated in the table. It can be seen from the table that the NGCC plant has a much better performance (net plant efficiency of 50%) compared to the PC plants (net plant efficiencies in the range of 36-39%). Coal plants emit more than twice the CO_2 compared to NGCC. Within the PC plants, the bituminous coal plant has a higher net thermal efficiency than that of the sub-bituminous coal plant. Because sub-bituminous coal is of lower quality, a much higher quantity is needed to produce the same amount of electricity. The higher flow rates also lead to higher capital costs, as shown in the table. In general NGCC plants cost much less to build. The table also shows the LCOE results for the three power plants. It can be seen that NGCC generates electricity at a much lower cost ($34/MWh) compared to the PC plants. Among the PC plants, the sub-bituminous coal plant has a lower LCOE ($52/MWh) compared to the bituminous coal plant ($60/MWh), even though the capital cost of the sub-bituminous coal plant is about 5% higher and the fuel flow rate is almost 70% higher compared to the bituminous coal plant. This difference can be directly attributed to the much lower price of sub-bituminous coal ($9.6/tonne, compared to $49.9/tonne of bituminous coal). The table also shows the contribution of capital cost element to the LCOE for the three plants. In coal plants, more than half the LCOE can be attributed to plant capital cost, the rest being the O&M costs. On the other hand, LCOE of NGCC plants is dominated by O&M costs. It may be noted that a significant fraction of O&M costs comes from the fuel costs.

Sensitivity Analysis

The performance and cost results presented so far are specific to the input assumptions made for different plants. Changing the input assumptions will affect the outputs as well. The IECM is used to perform sensitivity analyses to understand the variation in LCOE when key input parameters are changed. As we have seen earlier, fuel price is a key variable in determining the cost of electricity generation. Figure 1 shows the effect of varying fuel price on the LCOE for the three plant designs. It is clear that LCOE is very sensitive to variation in fuel price, with NGCC being more sensitive than PC plants. The economic viability of NGCC plants relative to coal plants thus depends on the price of natural gas. Historically, coal prices have been relatively more stable compared to natural gas prices. The graph shows that, for fixed coal prices, NGCC becomes more costly (in terms of LCOE) than sub-bituminous coal and bituminous coal plants if the natural gas prices were over about $180/mscm ($4.7/GJ) and $230/mscm ($6/GJ), respectively.

Another important variable affecting the LCOE is the plant's capacity factor, which is an indication of the amount of time a power plant operates in a year. Capacity factor depends on the maintenance schedule of the power plant as well as the electricity demand in that region. Base load plants generally have higher capacity factors compared to peaking plants. Figure 2 shows the effect of variation in the capacity

Inputs			
	PC-b	PC-sb	NGCC
Fuel	Coal		Natural gas
Quality	Bituminous	Sub-bituminous	-
Higher heating value (MJ/kg)	30.8	19.4	52.3
Sulfur content (wt%, as-received)	2.1	0.37	-
Fuel price	\$49.9/tonne (\$1.62/GJ)	\$9.6/tonne (\$0.50/GJ)	\$91.8/mscm (\$2.42/GJ)
Boiler/Turbine technology	Supercritical boiler		GE 7FB gas turbine
Results			
Gross power out (MW)	620	630	595
Fuel input	175 tonnes/hr (5,380 GJ/hr)	295 tonnes/hr (5,700 GJ/hr)	80 tonnes/hr (4,180 GJ/hr)
CO_2 emissions (kg/kWh)	0.82	0.90	0.36
Gross thermal efficiency (% HHV)	41.6	39.7	51.3
Gross plant heat rate (kJ/kWh)	8,660	9,060	7,010
Net thermal efficiency (% HHV)	38.9	36.7	50.0
Net plant heat rate (kJ/kWh)	9,260	9,820	7,200
Total capital cost (\$/kW-net)	1,960	2,060	774
LCOE (\$/MWh)	60.4	51.8	33.6
Capital cost contribution to LCOE	56%	68%	39%

Table 1. Performance and cost results of the case study power plants (PC-b – PC plant with bituminous coal; PC-sb – PC plant with sub-bituminous coal; NGCC – natural gas combined cycle power plant). All plants generate 580 MW of net electrical output. A capacity factor of 75% and a fixed charge factor of 0.113 are assumed.

factor on the plant's LCOE for the bituminous coal plant and NGCC plant. For the NGCC plant, two natural gas price scenarios are shown – low price (\$91.8/mscm or \$2.4/GJ) and high-price (\$268/mscm or \$7/GJ). It can be seen that the higher the plant's capacity factor, the lower is its LCOE. For the low natural gas price case, NGCC is always cheaper than the bituminous coal plant (in terms of LCOE). However, for the high natural gas price case, NGCC becomes costlier than the PC plant at capacity factors greater than about 55%. In general, PC plants have been used as base load plants (i.e., have higher capacity factor) and NGCC plants have been used as peak load plants. This shows that the relative economic feasibility of PC and NGCC plants depends simultaneously on multiple factors.

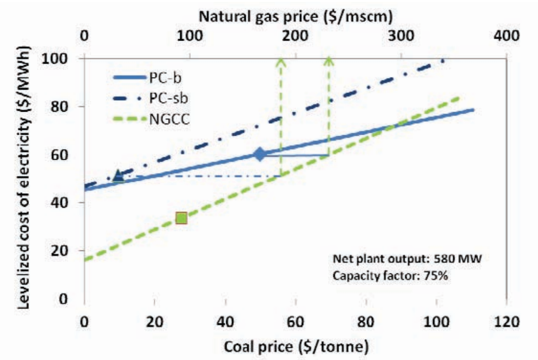

Figure 1. Sensitivity of LCOE of the three power plants to fuel price. Markers show the fuel prices assumed for base cases (results shown in Table 1).

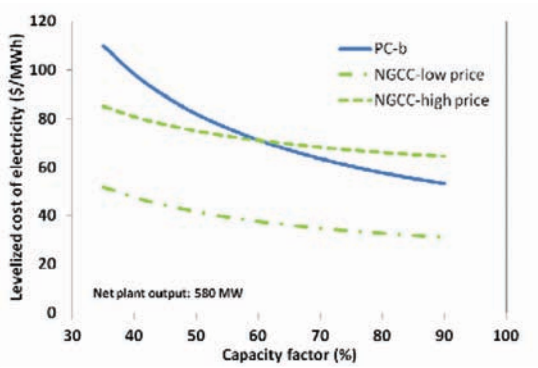

Figure 2. Sensitivity of LCOE to capacity factor.

Effect of CO_2 Capture

The IECM can be used to evaluate the effect of different CO_2 capture options on a power plant performance and cost. A bituminous coal PC plant, generating net electricity of 580 MW and equipped with an amine-based CO_2 capture system that captures 90% of CO_2 emissions, has a net thermal efficiency of 28% (heat rate of 12,840 kJ/kWh). Capital cost of the plant increases to \$3,430/kW-net and LCOE increases to \$104/MWh, about 70% higher than the plant without CO_2 capture. When the plant without CO_2 capture is used as the reference plant, the cost of CO_2 captured is \$38/tonne and the cost of CO_2 avoided is \$62/tonne. This means that the captured CO_2 should be sold (for example, for enhanced oil recovery) for at least \$38/tonne or the CO_2 tax should be at least \$62/tonne, for CCS to become economically viable for this plant. In this way, techno-economic models like the IECM can be used to make informed decisions and policies.

Conclusion

This article demonstrated that a systems-level techno-economic evaluation of power plants is very important for decision-making. The Integrated Environmental Control Model (IECM), developed at Carnegie Mellon University, was used for the case studies, analyzing the effect of various technical, operational and financial parameters on a plant's performance and cost. Three different power plants were considered for case studies – PC power plants using bituminous and sub-bituminous coals; and NGCC power plant. It was also shown that the relative economic feasibility of power plants depends simultaneously on multiple factors.

For more details about the IECM and exploring its analysis capabilities, the readers are encouraged to visit the model's website (www.iecm-online.com).

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[1] Integrated Environmental Control Model (IECM), Carnegie Mellon University, www.iecm-online.com

[2] US Environmental Protection Agency, Clean Power Plan Final Rule, 2015. www.epa.gov

[3] Rubin E.S., et al, 2013. A proposed methodology for CO_2 capture and storage cost estimates. International Journal of Greenhouse Gas Control, 17, 488-503.

Renewable Energy and Wholesale Electricity Price Variability

By Eric Paul Johnson and Matthew E. Oliver

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See footnotes at end of text.

It is well understood that wholesale price variability is a fundamental feature of deregulated electricity markets. Around the world, nearly all advanced economies have made the move toward deregulation, and have correspondingly seen an increase in the variability of wholesale electricity prices. This variation stems from an array of factors, including (but not limited to) fuel price shocks, availability of generation capacity, unexpected outages, demand inelasticity, exogenous demand variations, and transmission constraints (Benini et al., 2002).

At the same time, non-hydro renewable energy (RES-E) – led by technologies such as wind, solar, tidal, and geothermal power – continues to penetrate the market for generation in a significant way. According to International Energy Agency (IEA) statistics, these sources accounted for 0.37 percent of OECD total electricity supply in 1990, compared to 5.36 percent in 2013 (see Table 1). In absolute terms the increase has been equally remarkable. Meanwhile, the share of total generation from conventional fossil fuels (specifically oil and coal) has declined precipitously.[1] Moreover, the increase in the share of RES-E technologies in total generation varies widely across countries, in large part due to varying levels of political and economic support for RES-E investment. In the United States, RES-E accounted for 0.61 percent of total generation in 1990, compared to 4.66 percent in 2013. In Germany, these technologies produced barely 0.01 percent of total supply in 1990, but by 2013 had increased their share considerably to approximately 13.13 percent. Given continuously increasing public concern about the potentially disastrous climate effects of carbon emissions, many scholars would argue the transition toward RES-E generation is only just beginning to take off at a global level.

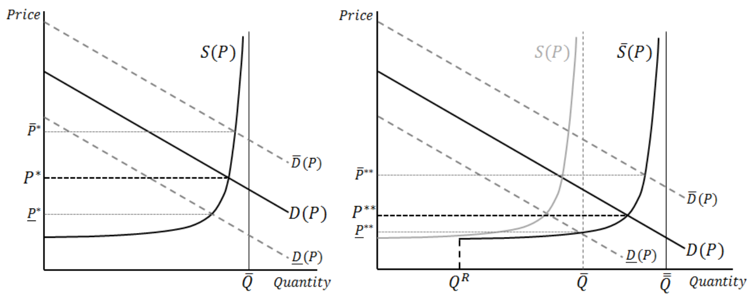
Source	1990	2000	2013
Wind	3,844	28,534	435,854
Solar PV/ thermal	681	1,244	111,136
Geothermal	23,190	25,752	33,973
Tidal/ocean	529	539	959
Total non-hydro RES-E	28,244	56,069	581,922
Pct. of total generation	0.37	0.57	5.36

Table 1. RES-E generation: 1990 versus 2013, OECD total (GWh).
Source: IEA (2014a,b).

Traditionally, economists and policy-makers have cited revenue risk from price variation (in conjunction with the high levelized cost per kWh of RES-E compared to conventional fuels) as the primary inhibitor of investment in RES-E generation. Indeed, shielding investors from risk has been a key feature of most RES-E support policies—feed-in tariffs or renewable portfolio standards, for example (Schmalensee, 2012). However, we argue that as RES-E continues to penetrate countries' total generation portfolios, the short-run variation in wholesale electricity prices is likely to decline.

The key to understanding this effect is that these technologies enter at the base of the generation mix, and not at the margin. To see why, consider Joskow's (2011) clear distinction between dispatchable and intermittent electricity generation technologies. He defines dispatchable technologies as those that "can be controlled by the system operator and can be turned on and off based primarily on their economic attractiveness at every point in time,"—e.g., coal, natural gas, or nuclear. By contrast, intermittent technologies like wind and solar depend on exogenous weather characteristics, and thus typically cannot be dispatched by the system operator to balance supply and demand at any given point in time. In other words, intermittent generation cannot be used as a marginal supply source. Additionally, because most RES-E technologies have a marginal cost of generation near zero, when these generators are able to operate, they enter at the base of the total electricity supply curve. Given the amount of RES-E generation, system operators then balance residual demand with supply by dispatching conventional power sources at the margin.

To see the underlying microeconomic intuition for why increased RES-E generation should be expected to reduce short-run wholesale price variation, consider the simple graphical model of an electricity market presented in Figure 1. Panel (a) depicts the market with zero RES-E generation. The short-run supply curve for conventional generation is $S(P)$ where P is the wholesale electricity price. Define maximum capacity as Q. Consistent with conventional wisdom, we assume the electricity supply curve remains relatively flat over most of its range, but rises sharply as output approaches the capacity constraint. The expected demand curve for electric power is $D(P)$, which stochastically shifts up and down in the short run as a result of random, exogenous demand shocks.[2] The expected equilibrium price is



(a) Withoug RES-E (b) With RES-E

Figure 1. Simple Model of an Electricity Market.

P^*. For simplicity, let the upper bound for a positive demand shock be $\overline{D}(P)$ and the lower bound for a negative shock be $\underline{D}(P)$. The equilibrium price thus varies stochastically in the short run between its upper and lower bounds of $\overline{P}^*$ and $\underline{P}^*$.

Panel (b) depicts the market with RES-E output of Q^R. Because Q^R enters at the base of the generation mix, this shifts the short-run conventional electricity supply curve to the right by Q^R units to $S(P)$, and maximum output for the market is now $Q = \overline{Q} + Q^R$. Given the same expected demand curve and range of variation from demand shocks, the equilibrium price fluctuates between $\overline{P}^*$ and $\underline{P}^{**}$, which is clearly a tighter range of short-run variation than was the case without RES-E. In addition, the expected equilibrium price, P^{**}, is lower.[3] Note that the same intuition applies even when Q^R is stochastic.

The economic implications of this effect are straightforward. Reduced variability in wholesale electricity prices would reduce revenue risk for RES-E investors, which may alleviate (at least in part) the need for transfers associated with RES-E support schemes. Lower price risk is likely to provide additional benefits as well—first, to utility service providers, by way of reduced resources devoted to costly risk management strategies; and second, through lower risk premiums passed on to electricity consumers.

To our knowledge, these effects have yet to be fully explored in the literature. We are currently engaged in a cross-country empirical analysis using wholesale electricity price and generation data; early results support the theory that greater RES-E penetration reduces the variation in wholesale electricity prices. Ultimately, we seek to quantify the effect for different RES-E support schemes, which will aid policy makers seeking to implement such schemes in order to increase the share of RES-E in total generation and meet CO_2 emission reduction goals.

Footnotes

[1] Much of this decline has been offset by an increase in generation from natural gas, biofuels, and renewable waste.

[2] Demand also follows predictable hourly and seasonal patterns.

[3] Sáenz de Meira et al. (2008) have found empirical support for this prediction. In the case of wind generation in Spain, the increase in electricity production from wind power led to a reduction in wholesale electricity prices.

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Electricity Market Reform in Sub-Saharan Africa and the Power Africa Initiative: The Nigerian Case

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Introduction

Electricity is an important modern energy source for human development (Alstone, et al, 2015; Pasternak, 2000). Thus, socio-economic development in Sub-Saharan Africa faces a daunting barrier given that the region has the lowest electricity generation capacity in the world. Rosnes and Shkaratan (2011) estimated that infrastructure weaknesses in Sub-Saharan Africa, with electricity been the most critical, reduce per capita economic growth by an average of 2%. This paper focuses on the Nigerian electricity sector as an archetype of the Sub-Saharan Africa region. At a current population of about 180 million persons or 1 in 5 of Sub-Saharan Africa's population in 2014 the Nigerian electricity market is potentially large. The 2015 World Population Prospects (United Nations, 2015) suggests that half a billion persons will live in Nigeria by 2050. The economy is currently the largest in Africa and 22nd largest in the world with a nominal GDP of about \$570 billion in 2015. A 2011 Citigroup report identified Nigeria as one of the 11 top global growth generators (Weisenthal, 2011). Figure 1 shows data on population, gross domestic product and electricity generation capacity for Nigeria and ten comparable countries in the global GDP ranking (5 above and below), as well as for five other African countries. Apart from Kenya, Nigeria has the lowest generation capacity among all 16 countries, as well as generation capacity per capita and per dollar of the GDP. Total public electricity generation capacity is only 6 GW or less than one-third of the minimum requirement for a medium level of human development in a country with the same population. To make up for the shortfall in electricity supply, Nigerians spend nearly \$500 million annually to import electric generating sets, with half of these on 1.6 million small spark ignition engines (see Figure 2) in 2013 (COMTRADE, 2015). The total number of generators in Nigeria has been estimated at about 60 million (Adeyemo, 2012). The issues underlying the parlous state of the Sub-Saharan electricity sector have been highlighted by many studies (see Rosnes and Shkaratan, 2011; Iwayemi, 2008; Adenikinju, 2003; Makwe et. al., 2012). The rest of this paper describes the state of reform efforts in the Nigeria electricity sector, discusses the requirements for success, and highlights the crucial role of international initiatives such as the United States' Power Africa.

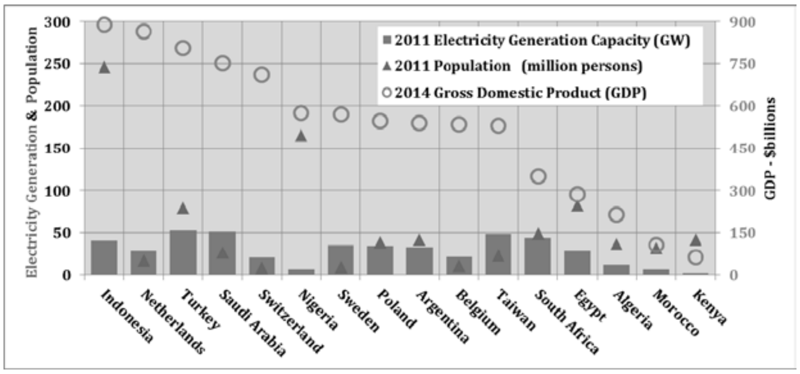

Figure 1. Electricity generation capacity, population and GDP in Nigeria and peer economies.

The State of Electricity Sector Reforms in Nigeria

After his inauguration in 1999 the president of Nigeria's new democratic republic stated that "We cannot be talking about creating a conducive environment for foreign investments if the performance of our transport, telecommunications and energy sectors remains dismal and epileptic."(Ndukwe, 2005; italics mine). However, efforts to reform the electricity sector lagged until 2005 when the Electric Power Sector Reform Act (EPSRA) was enacted. The National Electric Power Authority (NEPA) was replaced by the Power Holding Company of Nigeria (PHCN) under the Bureau of Public Enterprises as an initial phase towards privatizing the sector. Manitoba Hydro International (MHI) was engaged as a management contractor for the public Transmission Company (TCN) of Nigeria in 2012, and 6 generation and 11 distribution companies were privatized in 2013. The interface between the generation and distribution companies is to be managed by the Nigerian Electricity Bulk Trader (NBET). Figure 3 shows the 11 private distribution companies and their coverage areas.

Figure 2. Generating sets in Lagos Nigeria (Source: Adeyemo, 2012).

Expenditures by the government in the electricity sector since 1999 have been estimated at \$16-\$32 billion (Eboh, 2013). Although the total installed capacity has changed little, the operating capacity now peaks at more than 4.5 GW compared with less than 2 GW in 1999. Thus, most of the expenditures since 1999 were on repairing and replacing obsolete generation, transmission and distribution system components dating back to the 1970s. The operable capacity and transmission system continue to be subject to inefficiencies and outright system collapse, but there are signs of improvements. According to a recent statement the TCN, in partnership with its management contractor, has "achieved a wheeling capacity of 5,300 MW and reduced system losses from over 12 percent to approximately eight percent. In addition, system collapses have reduced significantly, from 22 in 2013 to 9 in 2014, while the duration of collapses has reduced from more than 2.5 hours to approximately 30 minutes" (Alike, 2015).

A major aspect of the electricity reform effort is the Multi-Year Tariff Order (MYTO), designed to raise tariffs gradually over four years starting in July 2009 with the aim of reaching cost-reflective tariffs in 2011 (Ajayi, et al., 2013; Tallapragada, 2009). However, this was based on a number of assumptions, including raising the generation capacity to 10 GW (by 2010) and reducing technical, non-technical and revenue collection losses from 45% to 30%. The MYTO also includes a 15-year forward view of tariffs to provide stability for investors in the electricity sector. Although progress has been made in system efficiency, the inability to raise generation capacity to 10 GW, five years past the due date, means that the objectives of the MYTO could not be met. Moreover, revenue collection remains highly inefficient. Under the reforms, the government is providing subsidies, managed by the NBET, to cover the difference between costs and revenues until the full cost of electricity supply can be passed on to consumers.

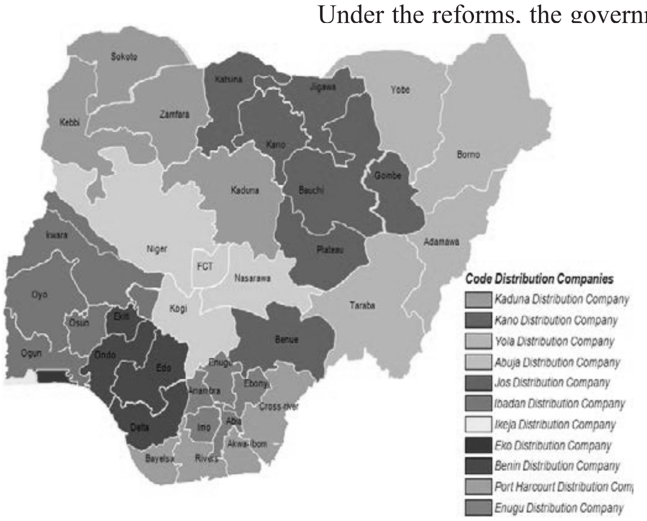

Figure 3. Privatized distribution utilities in Nigeria and coverage areas (Source: Ajayi, et al., 2013).

The Power Africa Initiative

The above makes clear that electricity sector reforms in Nigeria since 1999 have been slow, and has met with limited success. In this context, the "Power Africa" initiative of the United States government appears to be a much needed intervention. The Power Africa program was launched by President Obama in 2013, and has the goals of adding more than 30 GW of cleaner, more efficient electricity generation capacity, and 60 million new home and business connections across sub-Saharan Africa (The White House, 2015). The program involves 12 agencies of the United States government, the World Bank, African Development Bank (ADB), African governments, the government of Sweden and private sector partners. The United States government has committed \$7 billion to provide financial and technical support, and loan guarantees under the Power Africa initiative. The Power Africa initiative has helped to support transactions and commitments for nearly 7.5 GW of generation capacity in its six focus countries of Ethiopia, Ghana, Kenya, Liberia, Nigeria and Tanzania, involving nearly \$20 billion from the private sector. Some of Power Africa's activities in Nigeria include financial and technical support for the privatization of the generation and distribution components of the electricity system, including the provision of \$1 billion in long term capital expenditure support for 10 distribution companies. Other contributions include technical support on the power purchase agreement for a new 450 MW power plant (USAID, 2015). On the eve of President Obama's recent visit to Africa a number of commentators appraised the two years of the Power Africa initiative. In a New York Times article Ron Nixon (2015) stated that "Two years later…the reality of Power Africa's promise bears little resemblance to the president's soaring words. It has yet to deliver any electricity." While conceding that many of the deals under the Power Africa initiative were achieved because they were already in the works, officials in charge of the initiative have appropriately noted that "the program was intended to provide incentives and support to help foster private investment, rather than to function simply as an aid program". The questions then are: Are the objectives of Power Africa in line with the requirements for a successful reform of the Nigerian and Sub-Saharan electricity sector? If so, how can the Power Africa initiative help to accelerate these reforms?

Requirements for Success in Reforming the Nigerian Electricity Sector

Of the three critical sectors identified for reform by the Nigerian president in 1999, only the telecommunications sector can be judged to have been successful. The National Telecom Policy of 2000 sought to increase telephone lines from less than 600,000 in 1999 to 9 million by 2005. Although there are many remaining issues in the industry, total connections exceeded the target by more than 2 million lines by 2005, and currently stand at more than 110 million lines (Mawoli, 2009). Cumulative private investment in the Nigerian telecommunications industry since 2001 has been estimated at $32 billion (Adepetun, 2014). The success of telecommunications reform in Nigeria offers lessons for the electricity sector. On the positive side, similarities between the pre-reform conditions of the two sectors imply that electricity sector reforms can be successful. Similarly, the continued flow of investments into the Nigerian telecommunications sector means that private investments will also flow into the electricity sector, if requisite conditions can be met. Lastly, as with telecommunications, a successful reform of the electricity sector will likely exceed projections. On the negative side, the slow pace of reforms in the electricity sector reflects a far more complex supply chain relative to the telecommunications sector, and the extent of the required reform. In addition, the disposition of the government to public ownership of critical sectors of the economy has changed little despite the long-standing history of technical inefficiency, weak management, and corruption. Rosnes and Shkaratan (2011) identified success factors for independent power plants, which provide an outline of requirements for successful electricity sector reform in Sub-Saharan Africa, including policy reforms, a competent and experienced regulator, timely and competitive bidding and procurement process, good transaction advice, a financially viable off-taker, a solid power-purchase agreement, appropriate credit and security arrangements, availability of low-cost and competitively priced fuel, and development-minded project sponsors. In the Nigerian case these factors recommend the following areas for immediate action:

- Firm Commitment to a Private Sector-led Electricity Sector: The government of Nigeria would need to re-commit to private sector led growth, not only in the electricity sector, but throughout the economy. Nigeria's potentially large electricity market meets a primary condition for creating a successful private electricity market. The privatization of generation and distribution companies is laudable. However, the new president has already been urged to reverse the privatization process or at least take 59% ownership, instead of 49%, in these companies in order to "have control in the running of such power assets across the country" (Okpara, 2015). Also, the management contractor for the TCN recently threatened to pull out of its contract over disputes about revenue management procedures and non-payment of its fees (Abdulhamid, et al, 2015). These indicators raise the danger that the newly privatized system may fall victim to political meddling and corruption. Needless to say, any fraud in the privatization process should be corrected, but this should be done with a view to minimizing uncertainties that would result from a wholesale reversal or re-acquisition of privatized assets. This could be debilitating to the entire sector in the short- and long-term. Collier and Cust (2015) have outlined in some detail options for increasing private financing for infrastructure in Africa. The government's role and funding would be to help de-risk the market and support private investment, rather than as direct investors in the market. Used this way the government's expenditure of $16-$32 billion in the electricity sector since 1999 could have geared up private investments many times greater and increased electricity generation significantly. This approach is also appropriate given that the economy is potentially facing a long period of low oil prices and needs to prevent the dependence on sovereign debts that were responsible for the devastating debt overhang of the 1980s and 1990s.
- Technically Sound Regulatory Agency with Political Authority: As a natural monopoly the electricity sector is vulnerable to rent-seeking behavior. Thus, the role of a market regulator is indispensable in the formation and day-to-day running of a private electricity market. The regulator serves the triple role of implementing the government's market de-risking programs, monitoring performance, and protecting consumers against exploitation. Although the brief of the Nigerian regulatory agency, NERC, includes promoting competition and private sector participation, its main effort so far has been to administer the MYTO, which consumers have described as producing "crazy bills". The fixed electricity charge in the MYTO is particularly vexing to consumers because it must be paid even when consumers do not receive any electricity. Thus, the charge is essentially a perpetual "electricity connection tax" that consumers not only see as unfair, but has the real consequences of increasing payment defaults, electricity stealing, and discouraging connections. No doubt there is a critical need to reform the distribution, revenue collection and end-use parts of the system, including a re-design of the MYTO that balances the interests of electricity suppliers and buyers. For this purpose, the technical capabilities of the Nigerian electricity regulator would need to be greatly enhanced, hand in hand with its authority, to oversee the industry. The regulator would need to develop analytical capabilities, including identification

of risks to investment, implementation of de-risking programs, and monitoring of developments in the sector through the development of databases on technologies, resources and system performance. The regulator would also play a crucial role in identifying the manpower requirements of the electricity sector, and designing training programs and certifications. With the regulator adequately equipped and empowered the need for the government to re-insert itself into the electricity market as a direct investor would be eliminated.

- Recognition of the Crucial Role of Technologies: The role of technology in reforming the Nigerian electricity supply chain will be crucial. Perhaps, the single most important reason for the success of telecommunications reforms in Nigeria was the maturity of the GSM 2G protocol (Global System for Mobile Communications) which enabled operators to by-pass the moribund publicly controlled land-lines and inefficient mobile systems. As a result, while the telecommunications policy envisaged 5 million fixed and 4 million mobile lines, the outcome of the reforms produced only 1 million fixed lines and 11 million mobile lines by 2005. Although electricity systems that can by-pass the current land-tied transmission and distribution used today are many decades away, the immature state of the current Nigerian electricity system offers opportunities to integrate more efficient technologies as it develops. Distributed generation technologies in particular have the advantage of less capital intensity and faster deployment that could help accelerate the increase in generation capacity (Alstone et al., 2015). Given the lack of the required domestic technical capacities, much of these technologies would need to be obtained through private investments and other international arrangements. However, minimum domestic competencies would be needed to operate the technologies and adapt them to the unique geographical and cultural environment for electricity supply and demand in Nigeria.
- Innovative Approach to Infrastructure Security: Stakeholders in the Nigerian electricity industry agree that the disruption of fuel supply, particularly natural gas, to power plants is a critical impediment to successful reforms (Bala-Gbogbo, 2015; USDOS, 2013). A recent compilation of stories related to the vandalism of energy infrastructure in Nigeria shows that it bears a significant responsibility for the wide fluctuation in available generation capacity (The Nation Newspaper, 2015). The issue of infrastructure vandalism is tied with broader conflicts in the management of natural resources in Nigeria. As such, efforts to reduce tensions in the affected regions will contribute to the assurance of energy supplies. In addition, the government and regulators would need to enforce infrastructure security procedures, and industry stakeholders would need to employ innovative technologies for protecting the electricity infrastructure. Diversification options can help minimize fuel supply disruption risks and should be a basic design criterion in electricity supply plans in Nigeria, making the case for distributed generation even stronger.

What Role for the Power Africa Initiative in Sub-Saharan Electricity Sector Reforms?

The objectives and the modalities of the Power Africa initiative appear to fit well with the requirements for successful electricity reforms in Nigeria as outlined above. The Power Africa program is aimed at providing risk-insurance, credit enhancements, grants, technical assistance and investment promotion, which are needed, but are areas of critical weakness, in Sub-Saharan Africa's quest for private investments in electricity supply. In addition, the Power Africa program seeks to promote electricity access through small-scale energy solutions (USDOE, 2015), which also falls in line with the significant role that distributed generation technologies could play to increase electricity supply. Comments on the lack of visible impacts two years into the program reflect the enormous challenges of electricity sector reforms, as well as the fact that electricity infrastructure is capital intensive and evolves slowly. The catalyst role of the initiative has increased the chance that existing plans will succeed. Thus, the Power Africa program, building on these short-term achievements, would help to accelerate the increase in electricity supply in the region. The Power Africa, and similar initiatives, could also help advance electricity sector reforms by providing support for the technical capabilities of the regulatory agency and the domestic manpower needed for industry operations.

Conclusions

With the lowest regional generation capacity in the world improvements in electricity supply is critical to socio-economic development in Sub-Saharan Africa. On the one hand, Nigeria, with its potentially large electricity market, provides an archetype of the parlous state of the sector in Sub-Saharan Africa. On the other hand, successful electricity reform in Nigeria can be the nucleus for powering surrounding nations with smaller markets. The electricity sector in Nigeria had been dominated by technically inefficient and weakly administered public utilities, but the government has taken a number of laudable, if belated, steps to build a private-led electricity supply system. These reform efforts would need to be sustained and enhanced, including the empowerment of a technically sound regulatory agency. The support of international initiatives, typified by the United States' Power Africa would be crucial to gearing up private investment and developing the required technical capabilities for industry operation. With these components the prospects for successful electricity reforms in Nigerian and Sub-Saharan Africa are good, and can be the crucial linchpin to putting the region on the path of sustainable development. Private investors and Nigerian citizens stand to benefit from the resulting competitive returns to investments and improvements in socio-economic activities.

Contact author for references.

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Slovenian Affiliate Holds First Meeting

Held on the 26th of November the main topic of the meeting was: How to help the Slovenian energy industry to grow? Mr. Martinec, Executive Director of Energy Industry Chamber of Slovenia, compared the financial results of companies from the energy sector with results of companies from other industries. The presentation was well received by all 21 participants at the meeting. It raised an interesting debate about global and internal causes for these effects and a decision was made to develop a document, named Manifesto of Energy Economics by the SAEE. The decision was inspired by the Industrial policy manifesto, made by the Chamber of Commerce and Industry of Slovenia and presented in October 2015. The document's intent was to search for key solutions for achieving the optimal development of industry by the year 2020/2030 and presented concrete proposals. Following the example, the Manifesto of Energy Economics would also search for optimum solutions for achieving growth in energy sector of Slovenia. The Manifesto of Energy Economics will be developed by the Executive Committee of SAEE, once the members are elected.

In this regard it should be pointed out that the meeting included discussion and decisions regarding the future conduct of the SAEE.

On the basis of the results of an internet opinion survey, conducted between 23rd July and 23rd November, proposed operating rules of the SAEE were presented and approved. The operating rules focus on the scope of work of the SAEE, its means of operating, the means of executing its scientific research and the means of collaboration with related organizations. We are proud to announce that already, the SAEE has gained support of the following organizations: Slovene district energy association (Slovensko društvo za daljinsko energetiko), Association of economists in electrical power industry and coal industry (Društvo ekonomistov elektrogospodarstva in premogovništva) and Slovenia National Committee of the World Energy Council (SNK WEC).

With the aim of forming an active core of the Slovenian organization, three new committees have been formed: Executive Committee, Academic Committee and Committee for Education. At this point, elections for 3 elected members for each committee has been launched. The elections are planned to conclude in December or in the beginning of January 2016.

All these decisions are meant to form a solid ground on which SAEE can function and prosper for years to come. And the fact, that all the decisions were passed unanimously by over a half of all members with voting rights present, can surely be seen to hold out the prospect of productive and active functioning of SAEE. Additionally, at the meeting, the Program of work for the coming year was formed, where the main focus is on meetings and a possible conference with IAEE in March 2016. Further, the possibility of hosting the IAEE European Energy Conference in 2019 was discussed.

As the year is ending, SAEE is not resting, the elections for the members of committees are in full swing as also are the preparations for the upcoming meeting with the IAEE.

Tina Strukelj
General Secretary

Attendees at the first SAEE meeting

SAEE Officers

A Presentation

The Role of Transmission and Energy Storage for Integrating Large Shares of Renewables in Europe

By Christian Skar, Ruud Egging and Asgeir Tomasgard

Christian Skar, Ruud Egging and Asgeir Tomasgard are with the Norwegian University of Science and Technology. Skar may be reached at christian.skar@ntnu.no

See footnotes at end of text.

Ambitious goals for decarbonizing our energy supply necessitates a large-scale deployment of renewable energy (RES) power generation. The most prominent RES technologies, wind power and solar power, are intermittent and non-dispatchable by nature, which impose new challenges to power system planning. Significant shares of our power generation will be as reliable as the weather. An important consideration in power systems is balancing, preserving a match between generation and load at all times while safely operating the grid by not overloading its components. With large shares of fluctuating and non-dispatchable power generation throughout the system, the ability to transfer power from where it is produced to where it is used will become increasingly complex. Emerging technologies on the demand side, such as utility grade batteries and smart grid technology provide new opportunities by offering services which have previously been of limited availability to the electricity sector, energy storage and demand side management. While the grid provides the system with spatial balancing of supply and demand, energy storage allows for temporal balancing. However, these balancing services interact. In particular, in a system with much renewables and a weak grid the possibility of sharing generation resources is low, but energy storage can help alleviate local shortage situations. With a strong grid the need for energy storage for balancing can potentially be much lower.[1]

In order to shed light on the interacting roles of transmission and energy storage as means to integrate renewables in Europe we present a brief analysis of a few selected scenarios using the EMPIRE[2] model [1]. This model is a dynamic capacity expansion model for the European power system based on stochastic programming. Using projections for demand development, fuel prices and power generation technology development EMPIRE computes the least-cost investment plan, with five-year increments, for generation capacities, cross-border transmission corridor capacities and energy storage (power and energy) capacities. Embedded in the model is an economic dispatch optimization for the European system, which drives the economic valuation of the investment options. The geographical detail level in EMPIRE is national (covering 31 countries).

The scenarios analyzed (Table 1) have three levels of transmission reinforcement strategies represented: high, limited and no expansion. In the limited transmission scenario expansion of cross-border capacities between countries is constrained to 10 % of the 2010 capacity plus 300 MW for every five year investment step. For the high transmission scenario a 200 % increase of the 2010 capacity plus 1 GW is allowed for each connection every fifth year. The rationale behind these constraints is to form a conservative infrastructure plan while still not limiting development of weak connections too extensively. The scenarios either allow for energy storage to be deployed or not. Four energy storage technologies are available, two technologies where power and energy capacity are individually decided (each with individual costs) and two large-scale battery technologies[3] in which only the energy component is assumed to have a cost. An initial installed capacity of 44 GW/2.6 TWh pumped storage (power and energy capacity) is assumed installed in the European system in 2010.

A common assumption for all the scenarios investigated is that the direct emissions from the power sector should be linearly reduced to 90% below 2010 levels by 2050. Low carbon technologies other than renewables are assumed to play an insignificant role in decarbonizing the European power sector. Nuclear power is constrained to remain close to current levels, and carbon capture and storage is assumed not to be commercially available. Assumptions regarding fuel price and electricity demand development are based on the 2013 EU reference scenario published by the European Commission [2]. Parameters and cost assumptions for generation technologies implemented in EMPIRE coincide with the data sets published in [3].

In this analysis we focus on a few selected metrics to understand the effect of transmission and energy storage options on integration of intermittent renewables (iRES). These metrics are the optimal iRES share in the 2050 generation mix, curtailed generation and the deployment of energy storage capacity in the system. Table 2 shows that a 90 % emission reduction will require a significant share of wind and solar in the EU generation mix, 54-63 %. Scenarios 5 and 6 show that if this increase in intermittent generation is not accompanied by massive expansion of cross-border transmission capacity the total cost to the electricity sector will be high, potentially in the hundreds of billions euros. Energy storage can be seen to be an important technology if the transmission system is not strengthened. In scenario 6, where

	Transmission		
Energy storage	High	Limited	No expansion
Available	Scenario 1	Scenario 3	Scenario 5
Not available	Scenario 2	Scenario 4	Scenario 6

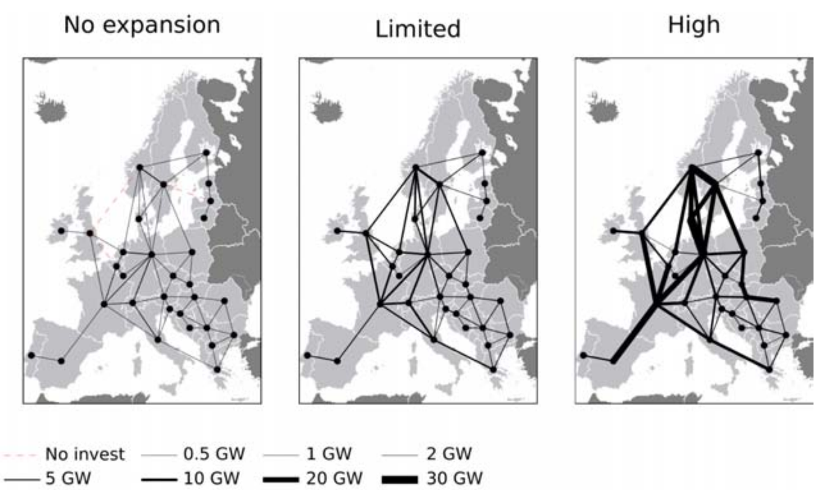
Table 1: Scenarios analyzed with the EMPIRE model.

	Δ cost (compared to scenario 1)	iRES generation share in 2050	Curtailed energy 2050		Added transmission by 2050	Added energy storage by 2050	
			Wind	Solar		Power	Energy
	[bn€$_{2010}$]	[%]	[TWh]	[TWh]	[GW]	[GW]	[GWh]
Scenario 1		56	8	7	466	20	1
Scenario 2	1	56	11	7	470		
Scenario 3	63	54	15	6	192	33	90
Scenario 4	64	54	28	8	192		
Scenario 5	182	56	169	43		133	2046
Scenario 6	274	63	490	153			

Table 2: Selected results from the analysis

neither new transmission capacity nor energy storage is allowed, there is a significant increase in the renewable generation share over the other scenarios. The reason is simple, when there is limited potential to transfer or store electricity in a system with high renewable generation shares, capacities have to be scaled such that local generation can make a significant contribution to cover the local load peaks. Unless the peak generation for the renewables is highly correlated with the peak demand this strategy will result in capacity which under-utilized at times when generation is high and the load is low. The amount of curtailed energy from renewables, i.e., the generation lost due to the system's inability to absorb it, is 643 TWh in scenario 6. To put this number into perspective, in 2014 the total generation from wind power in EU-28 was in 247 TWh [4]. By enabling energy storage to be deployed in scenario 5, there is a much better utilization of the intermittent resources, and the curtailed generation see a three-fold reduction.

The amount of increased transmission capacity found optimal by EMPIRE is largely unaffected by the availability of energy storage. In the 'limited transmission' scenarios, 3 and 4, the total new capacity by 2050 is 192 GW. In the 'high transmission' scenarios, 1 and 2, the optimal transmission more than twice that of the limited case, 466 GW with energy storage investment allowed, and 470 GW in the scenario without. In both the limited and high transmission reinforcement scenarios the infrastructure investments are substantial compared to the total transmission capacity in 2010, which was 67 GW. Figure 1 shows how the transmission corridors in Europe are developed in each scenario with energy storage.



The main conclusion we can draw from this analysis is that in terms of renewable integration at levels above 50 % in Europe, energy storage is an expensive alternative solution to grid reinforcement. However, even the limited transmission expansion scenario considered here entails increasing the capacity to a level close to four times the capacity in the current system. Although these infrastructure investments are part of the cost-efficient solution, we cannot be guaranteed that they will in fact materialize. Should the infrastructure development fall behind, energy storage can be used as a recourse option.

Footnotes

[1] Other services from energy storage such as energy arbitrage and ancillary service provision can still have significant value to the system but is out of the scope of this discussion.

[2] European Model for Power System Investments with (high shares) of Renewable Energy

[3] Using published cost and technical parameters for Tesla's Powerpack battery and the Eos Aurora 1000|4000 grid-scale energy storage system. See https://www.teslamotors.com/powerwall and http://www.eosenergystorage.com/technology-and-products/ for more information.

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Electricity Transmission Reliability Management

By Marten Ovaere

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Electricity is the backbone of modern society: we want electricity to be available at all times. However, uncertain generation and consumption; adverse weather; unplanned outages of lines, transformers, generation plants and large loads; loop flows; and forecast errors could cause major interruption for electricity consumers or a widespread network collapse. To prevent this, network operators (Transmission System Operator, Regional Transmission Operator or Independent System Operator) make decisions at different time horizons to apply different costly actions:

- System expansion: construction, upgrading, replacement, retrofitting or decommissioning of assets like AC or DC high-voltage transmission lines, substations, shunt reactors, phase-shifting transformers, etc.
- Asset management: monitoring the health status of network components, planning maintenance activities, repairing the components in case of failure, etc.
- Operational planning: congestion management, system protection, reserve provision, preventive actions, voltage control, decisions on outage executions, etc.
- Real-time operation: corrective actions, activation of reserves, reliability assessment, etc.

The ultimate goal of these actions is to ensure a reliable transmission system. Unfortunately, a completely reliable electricity supply comes at an infinite cost. Therefore, network operators need to determine an acceptable reliability level, by balancing the costs and benefits. A transmission network has an acceptable reliability level if with a high probability the voltage and frequency remain within an acceptable range.

A reliability criterion is a guiding principle for network operators to reach such an acceptable system reliability level. The above TSO management decisions should satisfy the reliability criterion at minimum socio-economic costs in the different time horizons.

N-1 Reliability Criteria

The N-1 criterion states that a system that is able to withstand at all times an unexpected failure or outage of a single system component, has an acceptable reliability level. This implies that some simultaneous failures could lead to local or widespread electricity interruptions. However, the N-1 criterion has achieved acceptable results over the past decades.

Variations of the N-1 criterion exist in multiple countries: N-0 during maintenance, considering double-line failures during adverse weather, stronger reliability criteria for cities or certain business districts, etc. (GARPUR, 2014). Likewise, the Dutch regulator has changed the reliability criterion to “N-1 during maintenance, unless the costs exceed the benefits” (de Nooij, 2010).

Reliability assessment generally consists of power flow analysis on a network model. For each contingency, the voltage level, voltage angle and power flow should be between certain limits. With the N-1 reliability criterion, the contingency list consists of failures of single lines, transformers, generation plants, large loads, etc.

Transmission reliability criteria were mostly developed in the 1950s and have been carried over essentially unchanged from the old regime of regulated vertically integrated monopolies (Joskow, 2006). However, these reliability criteria may be inefficient in the future system characterized by more decentralized decision makers, more uncertainty and variability, and more interconnected networks. Several aspects of the N-1 criterion are criticized.

1. It weights each component outage equally, irrespective of the probability of outage.
2. The rule lacks transparency about the reliability level of the system.
3. It does not take into account the cost of consumer interruptions.
4. The cost of attaining an “N-1 reliable electricity network” is not considered.
5. It lacks flexibility to react to changing network conditions: adverse weather, planned outages, etc.

In summary, the N-1 criterion lacks transparency and flexibility, and ignores the economic trade-off between costs and benefits. Hence, scholars are developing reliability criteria that respond to these criticisms. These reliability criteria are generally referred to as “probabilistic reliability criteria”.

Probabilistic Reliability Criteria

Probabilistic reliability criteria explicitly incorporate costs and benefits of reliability decisions and

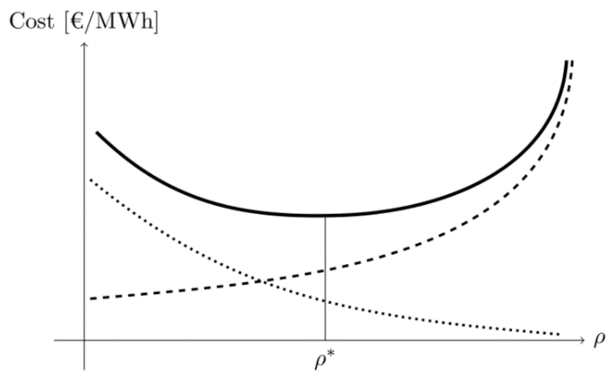

Figure 1 Total costs (solid line), interruption costs (dotted line) and all other electricity market costs (dashed line) as a function of the reliability level ρ.

allow to quantify the reliability level. Figure 1 plots expected total costs (solid line) of the electricity market as a function of the reliability level ρ. The dotted line represents expected interruption costs, decreasing with the reliability level, while the dashed line represents the sum of all other expected electricity market costs, increasing with the reliability level.

The goal of probabilistic reliability management is then to determine and execute these actions that minimize total socio-economic costs. This is at the point where the marginal decrease of interruption costs equals the marginal increase of all other electricity market costs. This yields a certain optimal reliability level ρ*.

The expected interruption cost [$/h] is the product of the probability, the extent and the consequences of interruptions:

Expected interruption cost = probability*extent*consequences

That is, the TSO has to calculate the probability of a certain interruption [%], how much load is interrupted [MW], and the cost of interrupted load [$/MWh]. That is, probabilistic criteria take into account the consequences of an interruption and the probabilities of failure, instead of only considering single outages and treating all interruptions uniformly, as under N-1. They thus acknowledge the possibility of high-intensity low probability (HILP) events. The cost of interrupted load is generally represented by the Value of Lost Load (VOLL). The VOLL depends on the type of interrupted consumer, the duration and region of interruption, the time of occurrence, etc., but is usually assumed to be constant.

Deterministic vs. Probabilistic Reliability Criteria

Table 1 summarizes the main differences between the deterministic N-1 criterion and probabilistic criteria.

Despite the obvious advantages of probabilistic criteria over deterministic criteria, the N-1 criterion, or a variation of it, is still used by all network operators, because it is a straightforward and easily comprehensible decision rule. Network operators are starting to be aware of the economic inefficiencies of the N-1 criterion but the complexity, the huge amount of required stochastic input data, accurate VOLL estimates (CEER, 2010), and the computing power required are major barriers for probabilistic criteria.

	Deterministic N-1 criterion	**Probabilistic criterion**
Contingency list	Single outages	-All contingencies up to N-k system states -All contingencies up to a certain cumulative probability of occurrence
Probabilities	Not considered	Failure probability for each component
Consequences	Not considered	Interruptions are valued at VOLL

Table 1 Comparison of the deterministic N-1 criterion and probabilistic criteria

Towards Probabilistic Reliability Management

The necessary detailed data – failure rates, forecast errors, wind and solar data, demand data, maintenance planning, repair time, temperature and weather data (9 out of the 10 most risky days in 2010-2014 in the North American bulk power system were caused by adverse weather (NERC, 2015)) – are not yet available. However, advances in communication and information technologies facilitate gathering this data. For example, generation (since 2004), transmission (since 2008) and demand response (since 2011) availability data is already collected in the North American bulk power system (NERC, 2012).

With more data available, network operators can gradually introduce probabilistic methods into reliability management in the different time horizons. A starting point is to expand the contingency list to include high risk simultaneous failures. In addition, explicitly incorporating the cost of interruptions in reliability management clarifies the trade-off between the costs and benefits of reliability decisions.

We have a lot more to learn about reliability. The good news is that advances in communication and information technologies enable using the grid more efficiently, increasing reliability while lowering the costs, and accommodating an increasing share of renewable generation.

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(Note: All conferences are presented in English unless otherwise noted)

Date	Event, Event Title and Language	Location	Supporting Organization(s)	Contact
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February 14-17	5th IAEE Asian Conference *Meeting Asia's Energy Challenges*	Perth, Australia	OAEE/IAEE	Peter Hartley *hartley@rice.edu*
April 24-26	9th NAEE/IAEE International Conference *Energizing Emerging Economies: Role of Natural Gas & Renewables for a Sustainable Energy Market and Economic Development*	Abuja, Nigeria	NAEE NAEE/IAEE	Wumi Iledare *wumi.iledare@yahoo.com*
June 19-22	39th IAEE International Conference *Energy: Expectations and Uncertainty Challenges for Analysis, Decisions and Policy*	Bergen, Norway	NAEE	Olvar Bergland *olvar.bergland@umb.no*
August 28-31	1st IAEE Eurasian Conference *Energy Economics Emerging from the Caspian Region: Challenges and Opportunities*	Baku, Azerbaijan	TRAEE	Gurkan Kumbaroglu *gurkank@boun.edu.tr*
September 21-22	11th BIEE Academic Conference *Theme to be Announced*	Oxford, UK	BIEE	BIEE Administration *conference @biee.org*
October 23-26	34th USAEE/IAEE North American Conference *Implications of North American Energy Self-Sufficiency:*	Tulsa, OK, USA	USAEE	David Williams *usaee@usaee.org*
2017				
June 18-21	40th IAEE International Conference *Meeting the Energy Demands of Emerging Economic Powers: Implications for Energy And Environmental Markets*	Singapore	OAEE/IAEE	Tony Owen *esiado@nus.edu.sg*
September 3-6	15th IAEE European Conference *Heading Towards Sustainability Energy Systems: by Evolution or Revolution?*	Vienna, Austria	AAEE/IAEE	Reinhard Haas *haas@eeg.tuwien.ac.at*
2018				
June 10-13	41st IAEE International Conference *Security of Supply, Sustainability and Affordability: Assessing the Trade-offs Of Energy Policy*	Groningen, The Netherlands	BAEE/IAEE	Machiel Mulder *machiel.mulder@rug.nl*
September 19-21	12th BIEE Academic Conference *Theme to be Announced*	Oxford, UK	BIEE	BIEE Administration *conference @biee.org*
2019				
May 26-29	42nd IAEE International Conference Local Energy, Global Markets	Montreal, Canada	CAEE/IAEE	Pierre-Olivier Pineau *pierre-olivier.pineau@hec.ca*
August 25-28	16th IAEE European Conference *Energy Challenges for the Next Decade: The Way Ahead Towards a Competitive, Secure and Sustainable Energy System*	Ljubljana, Slovenia	SAEE/IAEE	Nevenka Hrovatin *nevenka.hrovatin@ef.uni-lj.si*

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01-03 February 2016, Solar Finance & Investment at Grange City Hotel, 8-14 Cooper's Row, London, EC3N 2BQ, United Kingdom. Contact: Jason Andrews, Solar Media Limited, 2 America Square, London, EC3N 2LU, United Kingdom. Phone: +4402078710122, Email: jandrews@solarmedia.co.uk, URL: http://atnd.it/37976-1

02-02 February 2016, International Academic Symposium "Energy and Environmental Policy" at Parc Científic de Barcelona - Auditorio Baldiri i Reixac Street, 4-8, Barcelona, Spain. Contact: Xavier Massa, Research Assitant, Chair of Energy Sustainability University of Barcelona, John M. Keynes, 1-11, (Spain), Barcelona, Barcelona, 08034, Spain. Phone: +34 934034729, Email: chairenergysustainability@ub.edu, URL:http://www.ieb.ub.edu/es/vmchk/categorias-de-actos/international-academic-symposium-energy-and-environmental-policy#.VjcvRNIvfIV

03-04 February 2016, 8th Annual Onshore Wind O&M Forum Europe 2016 at Sofitel Alter Wall Hamburg, Alter Wall 40, Hamburg 20457, Germany. Contact: Victoria, Auckland, Wind Energy Update, Germany. Phone: +44 (0)207 375 7164, Email: vauckland@fc-bi.com, URL: http://atnd.it/40206-0

08-11 February 2016, Investing in African Mining Indaba at Cape Town at the Cape Town International Convention Centre (CTICC), Convention Square, Cape Town 8001, South Africa. Contact: Phillip, Lofaso, Mining Indaba, USA. Phone: +1-212-224-3546, Email: phillip.lofaso@miningindaba.com, URL:http://atnd.it/35296-0

08-09 February 2016, European Steam Turbine Users Conference 2016 at Birmingham, United Kingdom. Contact: Luba Jersova, Marketing manager, T.A.Cook Consultants Ltd, McLaren Building, 46 The Priory Queensway, Birmingham, West Midlands, B4 7LR, United Kingdom. Phone: +441212003810, Email:l.jersova@tacook.com, URL: http://goo.gl/Yu3bxl

09-10 February 2016, 29th Annual Power and Gas M and A Symposium at Ritz-Carlton Battery Park, Two West Street, New York, 10004, United States. Contact: Customer Service, SNL Financial, One SNL Plaza , Charlottesville, VA, 22902, USA. Phone: 8889917786, Email: info@snlcenter.com, URL: http://atnd.it/34579-0

09-11 February 2016, International Petroleum (IP) Week 2016 at Intercontinental Park Lane, 1 Hamilton Place, London, W1J 7QY, United Kingdom. Contact: Sheetal Ruparelia, Energy Institute, 61 New Cavendish Street, London, W1G 7AR, United Kingdom. Phone: +4402074677116, Email: sheetal@energyinst.org, URL:http://atnd.it/38134-1

09-09 February 2016, Fuel Cells for Stationary Power Applications at Institution of Mechanical Engineers, 1 Birdcage Walk, Westminster, London, SW1H 9JJ, United Kingdom. Contact: Knowledge Transfer Department, Institution of Mechanical Engineers, 1 Birdcage Walk, Westminster, London, SW1H 9JJ, United Kingdom. Phone: 0207 973 1258, Email: events@imeche.org, URL: http://atnd.it/41884-0

17-19 February 2016, Master Class Underground Gas Storage at Groningen, The Netherlands. Contact: Thiska Portena, Course Manager, Energy Delta Institute, Groningen, Netherlands. Phone: +31 (0) 88 1166827, Fax: +31 (0) 88 1166899, Email: portena@energydelta.nl, URL:http://www.energydelta.org/mainmenu/executive-education/specific-programmes/underground-gas-storage-course

18-19 February 2016, Platts 15th Annual Liquefied Natural Gas Conference at The Westin Galleria Houston, 5060 West Alabama Street, Houston, 77056, United States. Contact: Christine, Benners, Platts, 2 Pennsylvania Plaza, New York, 10121, USA. Phone: 857-383-5733, Email: christine.benners@platts.com, URL:http://atnd.it/39634-0

22-24 February 2016, Operational Excellence Oil and Gas Roundtables Roadshow at IQPC Aberdeen, Union street, Aberdeen, AB10 6BM, United Kingdom. Contact: PEX , Network, PEX Network, 128 Wilton Rd, London, SW1V 1JZ, United Kingdom. Phone: +44 (0) 207 368 9300, Email: enquire@iqpc.co.uk, URL:http://atnd.it/39860-0

22-26 February 2016, 35th IHS CERAWeek at The Hilton Americas, Houston, Texas, USA. Contact: CERAWeek Information, 0. Email: ceraweek@ihs.com, URL: www.ceraweek.com

23-23 February 2016, Uk Shale Gas: The Engineers Summit at Institution of Mechanical Engineers, 1 Birdcage Walk, Westminster, London SW1H 9JJ, United Kingdom. Contact: Knowledge, Transfer, Institution of Mechanical Engineers, United Kingdom. Phone: 0207 973 1258, Email: eventenquiries@imeche.org, URL:http://atnd.it/41999-0

23-25 February 2016, International Conference on Ocean Energy (ICOE) 2016 at EICC, The Exchange, Edinburgh, EH3 8EE, United Kingdom. Contact: Aparna Chopde, RenewableUK, Greencoat House, Francis Street, London, SW1P 1DH, United Kingdom. Phone: +4402079013000, Email:aparna.chopde@renewableuk.com, URL: http://atnd.it/41192-0

01-04 March 2016, ASIA 2016: Water Resources and Hydropower Development in Asia at National Convention Centre, Road 13, Vientiane, Laos. Contact: Melanie Ganz, Aqua Media International, Wallington, SM6 6AN, United Kingdom. Phone: 02087737251, Email: sales@hydropower-dams.com, URL:http://atnd.it/28498-0

02-04 March 2016, Platts 5th Annual North American Crude Oil Summit at Hyatt Regency Houston Galleria, 2626 Sage Road, Houston, 77056, United States. Contact: Christine Benners, Platts, USA. Phone: 857-383-5733, Email: christine.benners@platts.com, URL: http://atnd.it/37861-0

03-04 March 2016, Platts 3rd Annual Petrochemicals Conference at Hilton Amsterdam Hotel, Apollolaan 138, Amsterdam, 1077 BG, Netherlands. Contact: Baron Kootstra, Platts, 20 Canada Square, 9th Floor, London, E14 5LH, United Kingdom. Phone: +4402071766300, Email: conf_registrations@platts.com, URL:http://atnd

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