THE ICER CHRONICLE

A FOCUS ON INTERNATIONAL ENERGY REGULATION

EDITION 2, JULY 2014

The ICER Chronicle

Edition 2, July 2014
www.icer-regulators.net

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I. Foreword

This is the second edition of the ICER Chronicle. Already it has proved to be a very popular publication among its target audience of energy regulators.

I am pleased to see that the number articles proposed for this edition was substantial and the standard set – and met by many – is very high. The articles chosen by the Editorial Board for this edition reflect the high standards achieved by their authors.

The Chronicle is the only publication aimed at the world's electricity and gas regulators. Through its pages we aim to share good practices, leading edge thinking, and promote an awareness of the current difficult issues faced by energy regulators everywhere.

The International Confederation of Energy Regulators (ICER) was launched in Athens in 2009 at the fourth World Forum on Energy Regulation (WFER). ICER aims to enhance collaboration between energy regulators on issues affecting energy regulation globally. It also seeks to enhance the understanding of policy makers in governments on the role of energy regulation in respect of broader energy policy. ICER is a truly international organisation and depends on the commitment and contributions of energy regulators internationally, and on a number of other bodies where the public interest issues of energy policy play a significant role. The ICER Chronicle, for example, is produced by Working Group 4: Regulatory Best Practices led by NARUC, the U.S. state-level regulatory association.

ICER is organised with a very light operational structure. It has four working groups which operate virtually – using electronic communication tools to organise and deliver a three yearly work programme which provides a link between each World Forum on Energy Regulation.

- Working Group 1: Opening & Integration of Regional Markets
- Working Group 2: Technology Change
- Working Group 3: Consumers
- Working Group 4: Regulatory Best Practices

WFER VI will take place in Istanbul in May 2015 (www.wfer2015.org) and ICER will present the outcome of its current work programme there. Critical deliverables include reports in regional market integration; regulation and investments in new technologies; and consumer protection and empowerment. Two ICER Distinguished Scholar Awards will be made in Istanbul at WFER VI to those candidates (including at least one from developing markets) who demonstrate leading thinking in a key area of interest for regulators. In this and other ways ICER works to foster new approaches and to develop good practices from which all regulators (and ultimately energy consumers) can benefit. A further example is the ICER Women in Energy (WIE) initiative which aims to unlock the full potential of women in energy regulation.

If you have any feedback on the ICER Chronicle, suggestions on how future edition might be improved, or have an original article you think would be of interest to energy regulator, please send your comments or proposal to chronicle@icer-regulators.net.

Lord Mogg
ICER Chairman

II. Welcome from the Editorial Board Chair

On behalf of ICER Working Group 4: Regulatory Best Practices, I am excited to share Edition 2 of the ICER Chronicle. The inaugural issue was well received by the international regulatory community as a means to further promote ICER's goals of enhanced exchange of regulatory research and expertise. If you missed it, please check out the first edition:
http://www.icer-regulators.net/portal/page/portal/ICER_HOME/publications_press/ICER_Chronicle

The Chronicle is published biannually in order to share information among international energy regulatory agencies and beyond. If you haven't received this subscription directly, you can join our list-serve by emailing chronicle@icer-regulators.net.

The ICER Chronicle is open to submissions from regulators, academia, industry, consultants and others (such as consumer groups). This ensures a variety of perspectives and increases the exchange of information and messages among the various groups. Submissions will be collected on a rolling basis, in addition to formal Calls for Articles. You are invited to send your article to chronicle@icer-regulators.net. The deadline for consideration for inclusion in the third edition of the Chronicle is October 15, 2014.

Finally, I would like to thank the dedicated members of our Editorial Board. They thoughtfully reviewed all submissions and assessed those that are particularly interesting and timely to the global regulatory community.

Sincerely,

Vice Chairman John W. Betkoski, III
Chairman of the Editorial Board
Connecticut Public Utilities Regulatory Authority, United States
Chair, ICER Virtual Working Group 4: Regulatory Best Practices

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Ms. Natalie McCoy, Secretary General

National Association of Regulatory Utility Commissioners (NARUC), United States
Commissioner Eric Callisto, Wisconsin Public Service Commission
Mr. Charles Gray, Executive Director
Ms. Erin Hammel, Director of International Programs

Many thanks to the following support staff who contributed to the design and development of the Chronicle:

Ms. Erin Hammel, Director of International Programs
Ms. Umida Hashimova, Senior Program Officer, International Programs, NARUC
Mr. Jerome M. McLennon, Manger, Internet & Information Technology, NARUC
Ms. Una Shortall, Deputy Secretary General, CEER
Ms. Francesca Pia Vantaggiato, ICER Secretariat

III. Women in Energy (WIE) Story-telling

WIE Women in Energy
The ICER International Network

Interested in joining Women in Energy – the ICER International Network?

Free to join, the ICER WIE network is open to all staff and commissioners (men and women) of ICER's energy regulatory authorities. To join, visit http://bit.ly/ICERWomenInEnergy
The WIE section of the ICER website contains more inspiring stories (including video interviews), infographics and information on how to submit a story to the ICER Chronicle.

Welcome to the Women in Energy story-telling section of the Chronicle!

In this 2 minute video, ICER Chair, Lord Mogg talks about how resource-constrained organisations can get the most out of their staff. NARUC President, Colette Honorable, reveals the secret of her successful career.
Watch the video and share it .

Read the latest inspiring women in energy stories from Austria and learn how women in leadership thrive at the Arizona Corporation Commission.

Una Shortall
Chair of the ICER Women in Energy Steering Group

Women in Energy
The ICER International Network

Women in Energy Story Telling: from Austria

Andrea Lenauer

Andrea Lenauer, born as Brandstätter, has more than 10 years of experience in pioneering international projects, teams and institutions, mostly within and for the Austrian regulator.

She currently works as coordinator directly for the management of E-Control and regularly evaluates its performance on the basis of international regulatory rankings.

In her spare time she advises young women in (future) leadership positions as a life and social coach and acts as co-trainer in communication seminars.

So it’s my first day back in the office after my 12-month maternity leave, and there is an article sitting on my desk which argues that women are not, in fact, better leaders than men. So I start thinking. What is that, a leader, an executive, a boss? For most of my professional life, my superiors have been male. No wonder. Energy is such a male business.
But as a woman in energy, and as mother of a one-year-old man, my message to other women (and to him) is a different one.

Hard Work Leads to New Opportunities

A good measure of courage, confidence and trust in myself. Much owing to my boss’ trust in me, who had wisely chosen to rely on his staff instead of performing rigorous checks and controls, that’s what I had packed when three energy regulation pioneers from Italy, Portugal and Austria sent me to Brussels. As a seconded national expert, my challenges were (a) to act in an environment where the native French speakers had a great deal of trouble pronouncing my last name (try saying *Brandstätter* quickly three times in a row) and (b) to set up the CEER secretariat, together with Sergio Ascari and Una Shortall, as a platform through which meetings could be organised to exchange national experience in energy regulation. That was, frankly, a first.

I first came to E-Control after a business contact of mine had told me over lunch that his executive, Walter Boltz, was planning to establish this Brussels office. So I owe this career turn to my flexibility and my gut feeling: I was hungry, for food and for international experience, and I knew that **you have to work with people you get along with.** So I went off to work for the regulator.

Probably I also got this chance to “go to Brussels” because I **speak a couple of foreign languages**, because I am **always open for new perspectives**, and because I am a pretty straightforward person. And let’s not forget: **I had a vision!** As a woman in energy regulation in Brussels, I wanted to do something ground-breaking. I wanted to contribute some of my own to Europe, to European energy policy, by getting all of the then 15 – later 25, then 27, now 28! – together to make our common point to the Commission. Participation in our groups kept growing, and soon the Balkan countries joined in as well. This was when my **obstinacy and perseverance**, character treats one of my mentors at DG Telcoms, Paul Timmers, had diagnosed me with early on, paid off: the heads of regulatory authorities whose countries had fiercely fought each other until not so long ago sat down at the same table together with me, and later on also with others, to make some progress with the market in south-east Europe. (What I experienced at these tables is enough material for a story on its own.) Sure, it took two or three meetings (i.e. about six months, with the rhythm of meetings we had going) until all the regulators had accepted that I was there, but the entire thing was a breakthrough nonetheless.

Best Advice

While we're on it: I also learned how to greet people everywhere in Europe. (Do you kiss one or two cheeks? Or maybe left-right-left? In the Balkans, be aware of when and how to shake hands. So yes, there are many things to find out.) I guess people were also lenient because I was **young**, so I had enough time to get used to these diplomatic (and sometimes pragmatic) intricacies. Only some years later it dawned on me that it is not always good to understand such conventions quite so quickly. Like Jean Cocteau, I didn't know it was impossible, so I did it. Generally, women **think way too much** about everything. Even though we can always use some healthy self-reflection. So let's see:

Stamina and confidence are two essentials for your personality if you want to get somewhere in today's male-dominated energy business. Then proceed with your international energy mix and add this: **Be convinced of what you are doing, and be content with yourself (and others).** If you've got these things lined up, it is ever more likely that communication will work and that you'll succeed with your goals (if they're not completely out of reach). Success is not about finding the right answers, but about asking the right questions.

"Regulating energy should follow the same principles as regulating a river: with a firm hand but a light touch. Time is our ally, smoothing away the rough edges of overregulation."

Visualise your goal. I often think of a surfer braving the waves. That's how I want to tackle challenges. I like this picture, even though I don't surf myself. Well, I do surf the Internet. And then I sometimes come across one of these to-the-point pieces about the complex EU decision-making process. (Lobbying still seems very much driven by national interests.) I recommend exercising **patience** when it comes to harmonising EU rules, and today I'll also add: **be down-to-earth** (something that comes with time). Above all, it's a can-do attitude that is needed. So do something, even if you might make a mistake (I have this feeling that men are somehow less afraid of that).

Networking, international relations – empty shells of words? Absolutely not. Make sure you build your relationships and your network. But always take care to keep it a give and take. I have chosen Roman Braun for my coach and mentor, who in one of his publications he theorises that our world consists of our encounters. He's right. I'm **inspired by people**.

The Value of Mentors

As a woman, **don't be too polite** towards men or you risk being misunderstood. A well-known Austrian businesswoman recently shared some advice her mentor gave when she was merely starting out: never ever make coffee for your male colleagues. I wouldn't say it quite that way, but there's something to it. I prefer not so much doing something for men but rather doing something for life. The conditions at your workplace should enable you to start a family. Being a mom, I can now guide my son's development, which is another way for me to contribute to what Europe will look like in 2020 and beyond. Learning and **education**.

As a woman in energy, I've always been grateful for my **strong communication skills**, which I've honed and polished in training programmes offered by E-Control, again making me more eligible for higher positions. Any organisation should make use of its male and female employees' strengths, possibly pry them out by internal coaching, and combine them with principles such as **valuing your staff's work**. Communication and personality training should take a prominent role.

My Success

It is not a sign of weakness to **accept assistance**. I used to do most things on my own, and maybe I could have come "further" if there had been a mentoring programme, but perhaps I would have missed out on some of my lessons. The WIE network did not exist then, or maybe I wasn't aware of it; I'm sure I would have liked it.

Today I'm proud to look back on my energising international years, with many opportunities used to build energy relations across borders. So here goes my message – to all you women and to my son Fabian: **be yourself**. Other people will acknowledge that and you'll never lack for energy. Transform your energy into success, and get energy out of it.

Hopefully this account of my experience on the international energy stage has made for some entertaining reading for you, if nothing else. But now, I have to hurry home, my son and my husband will be waiting for me. And until tomorrow morning, I'm all theirs.

WIE Women in Energy
The ICER International Network

Women in Energy Story Telling: from Arizona, USA

Rebecca Wilder

Rebecca Wilder proudly serves as the Director of Communications for the Arizona Corporation Commission, seeking to raise public awareness of the Commission and its role in utility regulation. She is a veteran public relations specialist, with more than a decade of experience in Washington D.C. as a senior staffer for Members of the U.S. House and Senate, and the U.S. Chamber of Commerce.

Women in Leadership Thrive at the Arizona Corporation Commission

The State of Arizona has long been a place where women are accepted and, in fact, thrive in leadership roles. Born with a frontier spirit, Arizona has fostered an environment where, when a job needs to be done, it needs to be done by whoever is willing and is best suited for the job. And history bears out that in Arizona, the job is quite often filled by a woman.

The Arizona Corporation Commission (ACC), the state's independent utility regulatory agency, mirrors this same spirit as a place that nurtures female leaders. Of the five statewide elected Commissioners, two are currently women—Brenda Burns and Susan Bitter Smith. The agency is headed by Jodi Jerich, its Executive Director. Five of the Commission's nine divisions are headed by women, and three of the five Commissioners have women as their policy advisors.

Commissioner **Brenda Burns**, elected in 2010, came to the Commission after having previously served as the first female President of the Arizona State Senate, and first woman House Majority Leader before that. Commissioner **Susan Bitter Smith** was elected in 2012 and was the first woman to serve as President of the Central Arizona Project Board, one of Arizona's primary water sources and the state's largest power consumer.

Commissioner Burns was happy to welcome a female colleague to the ACC. "Not only is it great to serve with another woman at the Commission, but Susan is a leader when it comes to water expertise. She has grasped all of the issues, very quickly, and is an asset when we are tackling tough decisions."

Challenges

Both women have faced challenges in their careers, given their leadership roles in organizations that are traditionally led by males. "When I first came to the Arizona Corporation Commission, Commissioner Brenda Burns was a great teacher and mentor," said Commissioner Bitter Smith. "Before I was even sworn in, Brenda provided opportunities to listen and learn on issues, so that I was better prepared to hit the ground running as a new Commissioner."

Describing the role of the Commission, particularly in the arena of energy regulation is a challenge, as most people in Arizona are not clear about what the Corporation Commission does. Typically, they will describe the Commission as the "most important governmental body that no one has ever heard about," but Commissioners Burns and Bitter Smith enjoy any opportunity they have to educate the public on how the Commission regulates the state's utilities to ensure that customers have quality, reliable energy service. Arizona's Constitutional provisions mandate that Commissioners keep a balance between maintaining healthy utilities and setting appropriate consumer rates.

Both Commissioner Burns and Bitter Smith have made it a priority to make the Commission more publicly accessible and easier to understand. The ACC website is continually updated to be more user-friendly--with more capabilities allowing the public to stream Commission meetings--and both women have encouraged the Commission to hold more meetings throughout the state to give ratepayers greater access to the Commission process.

Hard Work Leads to New Opportunities

But the story of the Commissioners is only a part of the example that the Arizona Corporation Commission can set for other organizations. The Commission's staff further exemplifies the spirit of leadership by women.

Jodi Jerich was appointed as the first female Executive Director of the Commission in December 2012 after having served over three years as Director of the Arizona Residential Utility Consumer Office (RUCO), an agency charged with representing the interests of residential utility ratepayers in cases before the Commission. Prior to being appointed by Governor Brewer to head up RUCO, she served as Chief of Staff of the Arizona House of Representatives. Jodi Jerich also has prior direct experience with the Arizona Corporation Commission, having served as Policy Advisor to former Commissioner Mike Gleason from 2002-2004.

One of the most telling stories of the Arizona Corporation Commission is not only the caliber of women who work there, but how long many of the women have served and how high they've advanced during their tenure.

Janice Alward joined the Commission nearly 30 years ago. In 2008, she was appointed the Commission's Chief Counsel--the first woman to hold the position--after having served as Assistant Chief Counsel for several years. As a Commission attorney, Janice has represented the Commission in many and varied rate proceedings, administrative proceedings before federal agencies, and at all levels of state and federal courts. She says that even though she has been at the Commission for nearly 30 years, it is amazing how there is always some new challenge and something new to learn.

Lyn Farmer is the Chief Administrative Law Judge for the ACC and has served there for over twenty-two years. She was the Hearing Examiner for the Kansas Corporation Commission for four years. Ms. Farmer has served as Chair of the NARUC Staff Subcommittee on Administrative Law Judges and is a member of the National Association of Administrative Law Judiciary.

Patricia Barfield is the Director of the Corporations Division of the Arizona Corporation Commission. She joined the Corporations Division in 2008 as its part-time attorney, and then served as the Division's Deputy Director for two and a half years before being appointed Director in 2011.

Kim Battista began her career in utilities with the Oklahoma Corporation Commission as an Administrative Secretary. In 2003, she moved to Arizona and continued her career at the ACC, working her way up as a supervisor and manager, to current position as the Director of Administrative Services.

Letty Butner, IT Division Director/CIO, took leadership of the Information Technology Division in December 2013. Prior to joining the Commission, she most recently served as the Director of Project Management at the Arizona Superior Court, the 4th largest judicial system in the United States. She also worked at Arizona State University as a Project Manager and also as a Lecturer. Her private sector experience includes management positions at Intel.

The Commissioners' policy advisors are equally as impressive.

Laurie Woodall came to the ACC with a great deal of experience in the utility regulatory arena. She currently serves as policy advisor to Commissioner Susan Bitter Smith. She served seven years as Chairman of the Arizona Power Plant and Transmission Line Siting Committee as an appointment from the Attorney General and had also received appointments by the Governor to serve on the Board of Technical Registration, the Water Quality Appeals Board, and the Governor's Solar Advisory Task Force.

Amanda Ho is Chairman Bob Stump's policy advisor. She first joined the ACC in 2007 as former Commissioner Jeff Hatch-Miller's policy advisor. She then worked in the Legal Division as a staff attorney until joining Chairman Stump in 2009.

Angela Kebric Paton serves as the policy advisor to Commissioner Bob Burns. Prior to working at the ACC, she served as an Assistant Attorney General, representing the State of Arizona in numerous written appeals as well as in oral argument before the Arizona Court of Appeals and Arizona Supreme Court.

None of these talented women were hired to fill a quota, but were brought to the Commission because of their skill, knowledge, and expertise; and they represent only the tip of the iceberg of talented women employed at the Arizona Commission.

Best Advice

Executive Director Jodi Jerich offers her advice "not to focus on how to succeed *as a woman* in a career in energy but on how to succeed--period. Focus on your individual achievement by working hard, working smart, and making yourself an indispensable asset to the organization. Regardless of whether you are a man or a woman, you will encounter challenges both professionally and personally. A strong character and a solid work ethic will allow you to rise to these challenges and set you apart as a valuable asset to your company."

The Value of Mentors

Commissioner Bitter Smith counsels that "young women interested in looking at career opportunities in energy should take advantage of networking opportunities and internships in order to establish connections with women already in the field. Women can be great supporters and should not be overlooked as career mentors. Having access to other women in leadership positions through groups such as Women in Energy (WIE)-the International Network is a great resource for continued idea sharing, support, and encouragement." Commissioner Bitter Smith notes that she has found great resources in other female Commissioners within the NARUC organization and WIE has the opportunity to expand that network globally.

From engineers to attorneys, from policy experts and accountants to judges, the Arizona Corporation Commission provides an atmosphere of respect and encouragement and shines as an example of female leadership in energy.

IV. How to Increase Cyber-Security in the Power Sector: A Project Report from the Austrian

By Walter Boltz and Philipp Irschik

Executive Summary

Protecting a nation's power system and ensuring reliable supply of energy are top priorities for regulators and governments all around the world. As the risks of cyber-attacks grow especially in the energy sector, and the costs of such attacks are mounting, cyber-security moves up the political agenda.

To drive cyber-capabilities and resilience collectively a private-public partnership under the leadership of E-Control was carried out for the Austrian power sector in 2013 to systematically understand which assets need to be protected and define efficient and adequate defense mechanisms. The project goal was to identify and mitigate cyber-risks at organizational and system level and provide decision makers with simple actionable steps to improve cyber-resilience.

Based on well-established risk management standards and international frameworks, the year-long project identified 73 individual risks of varying priority in five (5) risk clusters for which baseline cyber-security and safety standards were developed.

The applied methodology together with the lessons learned can serve as a guidance that regulators can use for assessing, identifying and applying appropriate cyber-security requirements.

Introduction

Digital technology touches virtually every aspect of our daily lives. At the same time our dependence on 24/7 connectivity is growing swiftly. As the importance of information technology (IT) and telecommunications infrastructure in our power systems increases, new interdependencies and vulnerabilities are emerging and overall complexity is rising. Previous standalone systems with proprietary protocols and completely isolated operations are transformed into interconnected, heavily computerized networks with an increasing number of entry-points. Systems, once built on custom based soft- and hardware, are replaced by off-the shelf solutions while operating know-how is outsourced to third parties. In the light of these developments the traditional notion of security through isolation ("air gap approach") seems quaint and ever more difficult to ensure. In the meantime, company's cyber-risk management capabilities often remain in a nascent and developing stage as C-level awareness for the issue has only lately gained traction.

In 2010 the Stuxnet computer worm which infected the software of at least 14 industrial sites in Iran raised the bar on cyber-attacks as it was deliberately intended to disable critical infrastructure. Two years later, in 2012, the Flame malware, an extensive, highly complex and sophisticated code aimed at gathering and deleting vast amounts of information, was discovered. Like it or not, cyber threats are as numerous as they are complex. They heavily depend on the specific sector in question and can have a wide range of potential impacts, ranging from distributed denial of service attacks (DDoS) over data exposure to disinformation and reputational damage. Accepted risk frameworks usually distinguish between five (5) major, mutually not exclusive, categories: hacktivism, criminal, government-driven, terrorism and corporate espionage.

As the risk of falling prey to sophisticated and complex cyber-attacks becomes more prevalent, the protection of safety-critical control and processing systems, which are essential for electricity production and distribution, demands the adaption of new policies and regulations. Supported by regulators, providers of critical infrastructure need to acquire a clear understanding of the threats against their own network and systems, as well as of their interdependencies with other market players and third parties. Put differently, cyber-resilience demands a collective approach as the disruption to one can have a rapid and escalating effect on others or even society at large. Given this situation, regulators are in a unique position to serve as a convener to bring different parties together as well as facilitate and coordinate actions among stakeholders.

In the case of Austria, the federal government has indicated that it is not keen on legislating cyber -security measures and standards in detail and instead prefers to work directly together with sectors and industries to raise awareness and share best practices.

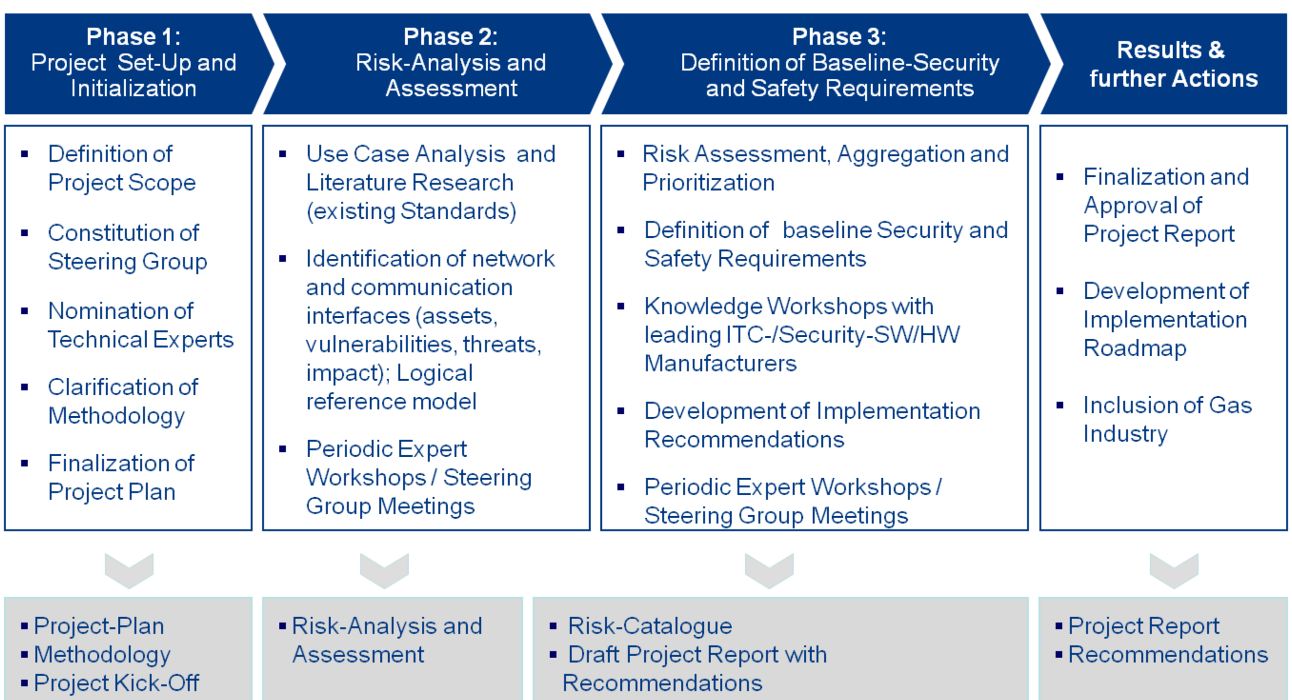
Unsatisfied with the status quo E-Control initiated a public-private partnership in 2013 in order to raise the profile of cyber-risks, harmonize actions and policies, promote better information sharing and improve institutional capabilities within the power sector.

In a first step a unique sector-specific project organization, comprising all relevant Austrian public and private sector institutions relevant for cyber security under the leadership of E-Control was set-up. On the part of the Austrian power industry, the country's main power generators, distribution system operators (DSOs) as well as the transmission system operator (TSO) took part in the project. On the part of public authorities, the (cyber) security-relevant federal ministries as well as the federal chancellery participated in the project.

On a strategic level, a steering committee with key stakeholders of all organizations, tasked with the periodic review of the process and project activities was established. On an operational and technical level a working group with leading IT and risk-management experts with day-to-day operational responsibility from all organizations was set-up to carry out the risk assessment and develop baseline security and safety standards.

Developing a Clear Set of Action Areas

A structured, well-established risk-management process in accordance with ISO 31.000, ONR 49.002-1-3 and ÖNORM S2410 standards was chosen to carry out the project. The project was divided into four (4) main phases – project set-up and organization, risk-analysis and assessment,



Tangible project deliverables in the form of a final project report and implementation plan were namely,

- a risk assessment of the entire value chain in the Austrian power industry and,
- the development of effective and adequate baseline cyber-security and safety standards.
- Intangible project deliverables were primarily,
- the augmentation of sensibility and awareness for existing vulnerabilities and threats and,
- an increase in trust and interoperability between private and public stakeholders.

In a first step, a thorough analysis of use cases and literature research was carried out to avoid the duplication of effort and align the initiative with past and ongoing national and international initiatives. In particular four (4) cyber-risk frameworks were selected and used as guidance for the further process of carrying out the risk-assessment:

- US National Institute of Standards and Technology (NIST) Cyber-Security Framework,
- US National Electric Sector Cybersecurity Organization Resource (NESCOR) Guide to Penetration Testing for Electrical Utilities,
- Swiss ICT-Risk Analysis,
- German Federal Office for Information Security (BSI) Act

In a next step, a comprehensive domain model for the Austrian power sector, comprising all eight (8) domains – bulk generation, trading/markets, operations, transmission, distribution, customer premises, service providers and regulatory authority – was developed. For each of these domains a high-level view of the various actors needed to transmit, store, edit, and process information among each other and along the value chain was created. Each domain was thus broken into more granular detail without yet defining any interface specifications and data types. In total 58 relevant actors were identified during this exercise.

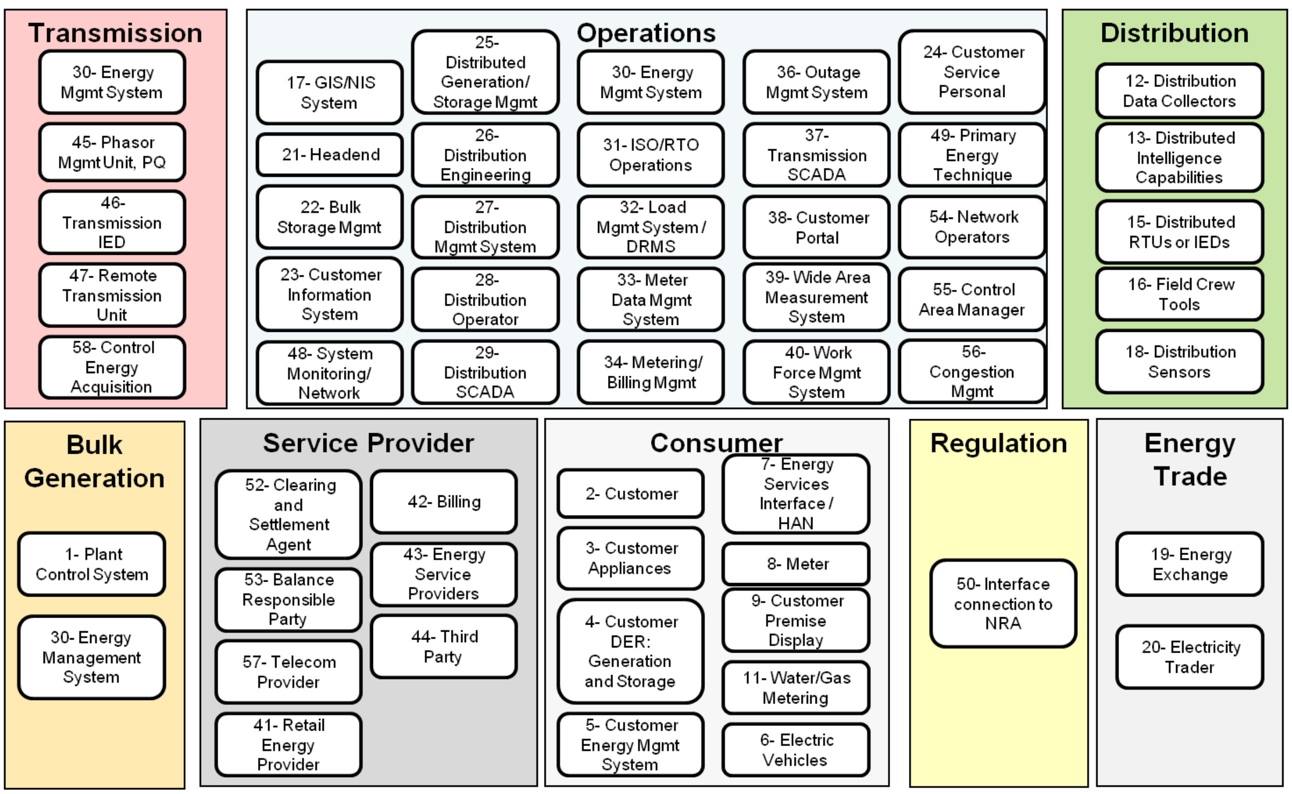


Figure 2. Domain Model Austria

In order to arrive at a logical reference model, existing individual interface connections were added to the analysis. These interfaces were then assigned to one of 15 logical interface categories on the basis of shared or similar security-related characteristics. The main objective behind this categorization was to facilitate the identification, organization and prioritization of potential vulnerabilities and communicate necessary security requirements and security-related responsibilities of actors. Listed below are the 15 identified logical interface categories:

- Machine-to-Machine (M2M) Communication
- SCADA and Control Systems within the organization
- SCADA and Control Systems between organizations
- Back-office Systems
- Intra-Organizational Communication
- Interfaces between Control/Non-Control Systems
- Service and Maintenance
- Sensor and Sensor Networks
- Advanced Metering Infrastructure (AMI)
- Interfaces with Customer Side Networks
- Interfaces on Metering Equipment
- Operations Support Systems
- Engineering and Maintenance
- Security Networks / System Management
- Home Area Network (HAN) / Body Area Networks (BAN) / Neighborhood Area Network (NAN)

Findings: Understanding Cyber-Risks and Response Readiness

On the basis of this clustering into 15 logical interface categories, a preliminary risk analysis was carried out which identified a total of 114 technical vulnerabilities, natural hazards and intentional threats. Besides deliberate attacks, inadvertent compromises of the information infrastructure resulting from user errors, equipment failures, and natural disasters were considered and included in the list. The initial list of vulnerabilities was developed using information from several existing documents such as the NIST Guidelines for Smart Grid Cyber-Security, Vol.1.

In a next step a holistic approach to analyze risk was developed in order to systematically document and prioritize vulnerabilities as well as their potential consequences. Risk (R) was defined as the potential for an unwanted outcome resulting from internal or external factors, as determined from the feasibility of the occurrence (F), the probability of the occurrence (PQ) and the associated impact (I).

Risk (R) = Feasibility of Occurrence (F) x Probability of Occurrence (PQ) x Impact (I)

For the assessment of the feasibility of occurrence (F) financial, organizational, technical, and temporal exigencies were taken into consideration. The probability of the occurrence (PQ) was measured for intentional threats, natural hazards and technical errors on a five-stage scale from unlikely (incident occurs once every 50 years) to frequent (incident occurs at least once a year). The impact (I) of an occurrence was measured as a combination of either the number of affected connections in percentage in combination with the time of the outage in minutes or the percentage of affected peak/system load in percentage. Regarding the affected peak/system load, a scale from 1% to above 10% was chosen. For the number of affected connections in a supply area, a scale ranging from 1% to above 50% was selected. The time of outage was measured on a scale from 30 minutes to above 12 hours.
In a next step the risk assessment was conducted and each of the initial 114 vulnerabilities was assessed on the basis of the predefined criteria. During this process some of the previously identified vulnerabilities were deemed non-critical to the functioning of the power supply and thus dismissed from the set. In total 73 individual risks with the potential of endangering cyber-resilience and disrupting the Austrian power supply were identified as a result of the risk assessment. In addition to a worst-case scenario, which formed the basis for the final

development of a visual 5x5 risk matrix, a risk assessment was carried out for a best-case and a most-likely case scenario. For all three (3) scenarios a 5x5 risk matrix was created with impact (low – catastrophic) and the probability of occurrence (unlikely – frequent) as the two axes.

To improve visibility and facilitate the further process of devising effective and adequate baseline cyber-security and safety standards, the 73 individual risks were aggregated, on the basis of similar security-related characteristics into 19 aggregated risks. As depicted in the figure below eight (8) aggregated risk factors were considered to be of high criticality and thus given priority one status (red risk area). Seven (7) aggregated risk factors were given priority two status (yellow area) whereas five (5) aggregated risk factors were considered to be of lesser importance (priority status three, green area).

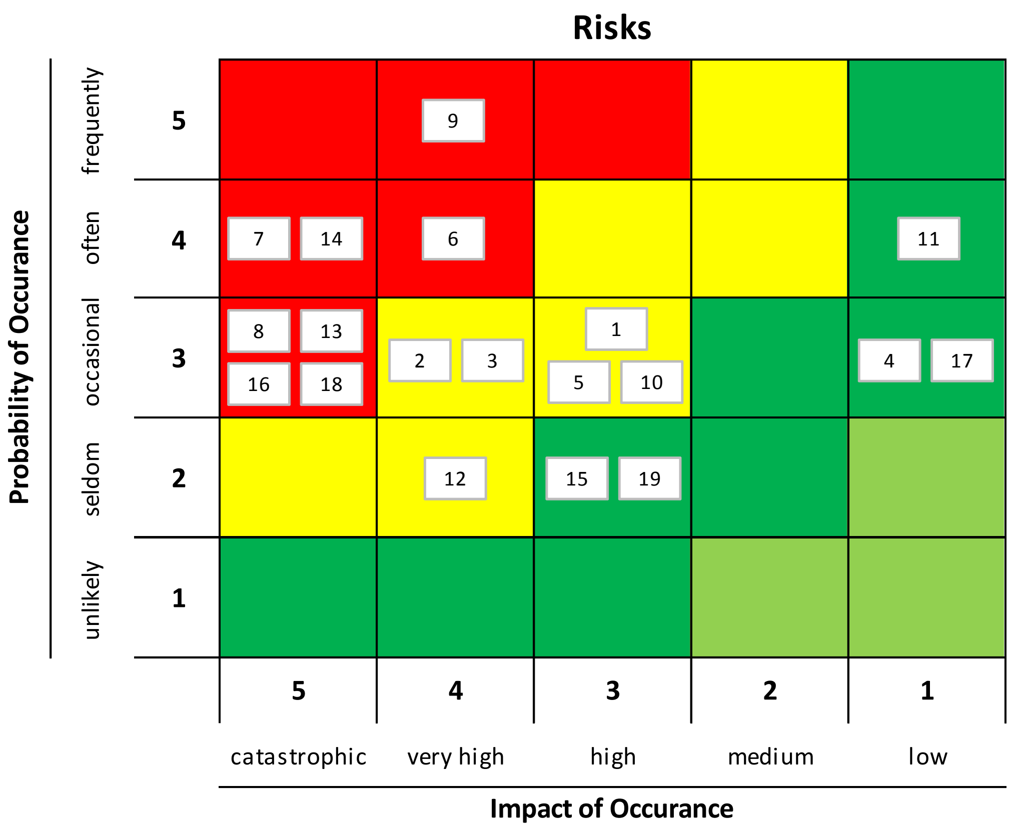


Figure 3. 5x5 Risk Matrix

Risks given priority one (1) and two (2) statuses relate primarily to the following six (6) risk clusters:

- Communication Structures and Escalation Hierarchies
- Design and Architecture
- Human Factor
- Hard- and Software
- Standardizations and Legal Aspects
- Access Controls and Cryptography

Pathway to a Cyber-Resilient Power Sector

Following the risk assessment, a risk-mitigation plan with detailed actions and implementing steps for each of the 73 previously identified individual risks was developed. For each individual risk a dedicated process owner from one of the participating public or private organizations was named and given the responsibility to implement the envisaged measures within a scheduled timeframe. Implementing measures range from baseline cyber-security standards in the form of ISO and ISMS certifications over the facilitation of sector-specific cyber-exercises to the improvement of communication and escalation hierarchies. In order to ensure the effectiveness and adequateness of measures, special attention was given to the varying size and capabilities of market players as well as the associated financial costs.

Accountability was introduced through the voluntary adoption of the recommended standards and norms by the participating market players in the form of a final project report and a collectively agreed risk-mitigation plan.

To secure progress and spur cooperation among public and private stakeholders, a dedicated process of periodic reviews was established on a technical and executive level.

Conclusion

As with any realistic assessment and analysis, a periodic review of potential vulnerabilities is of utmost importance as no static and universal set of actions can address the rapidly evolving environment of cyber-risks. Public-private partnerships can serve as platforms to foster collaboration, overcome information asymmetries, gradually build trust and improve cyber-resilience to match an ever evolving set of cyber-threats. The Austrian experience has shown that regulators are in a unique position to drive sectorial approaches to tackle systemic cyber-risks by enabling effective collaboration processes between public and private partners.

Acknowledgements

An extensive number of executives, experts and policy makers participated in the projects' workshops and expert interviews throughout 2013. We are deeply indebted to all of those who have provided their valuable insights, though-leadership and expertise to this public-private partnership.

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Philipp Irschik is Executive Assistant to the Board of Directors at the Austrian National Regulatory Authority E-Control. Previous to his position at E-Control he worked as a senior strategy consultant at an international consultancy. He holds a master degree in International Business Administration from the Vienna University of Economics and Business and a master degree in International Management from the Global Alliance in Management Education (CEMS). Currently he is participating in the annual training program for energy regulation at the Florence School of Regulation (FSR).

V. Getting it Right: Defining and Fighting Energy Poverty in Austria

By Walter Boltz and Florian Pichler

Abstract

Recent publications in European media, especially Germany, portray energy poverty as a rapidly growing phenomenon among the low-income population of Western Europe. While hardly any official definitions exist, lively debates across Europe alert the public about the social consequences of rising end-user energy prices and have stakeholders propose a variety of measures to fight energy poverty. From a regulatory point of view, NRAs should engage in these discussions to avoid overburdening of the energy sector by any premature stakeholder requests, for instance, price regulation or free energy. To better inform policy, E-Control then proposes a definition and conducts an empirical study which explores the magnitude of energy poverty and examines the characteristics of such households in Austria. Results indicate that energy poor households are predominantly found in rural Austria, and many older single-occupying women in social housing have to pay high energy bills on low disposable income. Yet, many are not sufficiently aware of their high energy consumption. To combat energy poverty, investments in energy efficiency promise huge success. Energy counseling, replacement of older appliances and thermal renovation of buildings offer great opportunities to improve the life of energy poor household without jeopardizing the capacities of both energy policy and social welfare.

Background

Energy poverty has recently become an often debated but rarely specified phenomenon in the Austrian public and elsewhere in Europe. Despite a lack of reliable data, NGOs, politicians and energy companies alike propose ideas how to combat energy poverty, ranging from more generous social benefits to free energy for the poor. These developments offer opportunities to regulators to respond to public and political claims. Yet, without a clear definition and measurement of energy poverty the danger persists to overburden both the existing welfare state and the energy sector since it cannot be guaranteed that new policy instruments target the real causes of energy poverty. While energy policy should not be designed to replace social policy, it could relieve customers from strain caused by inappropriately high needs for consumption and where energy use is inefficient. Hence, E-Control Austria investigates in detail the prevalence of energy poverty to better inform future public discourses and actions to efficiently combat energy poverty.

A Definition of Energy Poverty

Whereas a global definition of energy poverty often comprises households without access to the electricity grid, in the context of advanced economies energy (or fuel) poverty often encapsulates low-income households which cannot afford enough energy to cover their basic needs. Existing definitions often equate with energy poverty a "difficulty", "impossibility" or "incapability" of a household to ensure adequate heating at "correct", "appropriate" or "affordable" prices (e.g. European Economic and Social Committee 2010; European Fuel and Energy Efficiency Project 2006). In Britain, a legally binding view on energy poverty focuses on households which "need to spend more than 10% of their income on all fuel use and to heat the home to an adequate standard of warmth" (Department for Industry and Energy 2001:6). Only recently, however, a UK government review defines: *"households are considered fuel poor if a) they have required fuel costs that are above the median level; and b) were they to spend that amount they would be left with a residual income below the official poverty line"* (Hills 2012).

The existing attempts to define energy poverty can be criticized for a number of reasons. General definitions such as the one form the European Economic and Social Committee fail to specify what, for instance, "a difficulty to ensure adequate energy" actually means. Likewise, what are "correct or appropriate prices"? Foregoing a specification of an income/expenditure threshold such as in the (former) UK definition may otherwise lead to energy poverty despite very high incomes. Generally speaking, estimating required fuel costs is of little practical relevance since this also involves normative decisions on “what is required by whom” and, importantly, a rather costly assessment procedure in individual cases – both debates are better embedded in social policy.

Following these criticisms, E-Control proposed the following definition of energy poverty. *A household is energy poor if its disposable income is below the at-risk-of-poverty threshold and, at the same time, it has to cover above-average energy costs*. Disposable income is net income (including all income sources and benefits) after housing costs and accounts for the size of the household (equivalisation). The at-risk-of-poverty threshold is set at 60% of the median of the disposable income, following existing EU practice. In the same vein, above-average energy costs are set at 140% or more of the median energy costs to clearly mark energy costs as a driving factor of energy poverty.

This definition satisfies a number of important conditions relevant to energy policy. First, it maintains a clear separation between energy poverty and poverty “as a whole”. Only households with relatively low disposable incomes and high energy costs may be energy poor, otherwise households may be “just poor.” This is crucial to many national contexts especially since policies to combat energy poverty cannot substitute general social policy. Second, thresholds of comparably low income or comparably high energy costs nip normative debates about “appropriate standards” in the bud. Third, the role and importance of energy is emphasized in such a definition while recognizing a priority of housing costs in general, which debt counselors are eager to point out. Finally, this definition offers opportunities to cut costs by decreasing consumption and increasing energy efficiency.

Measuring Energy Poverty

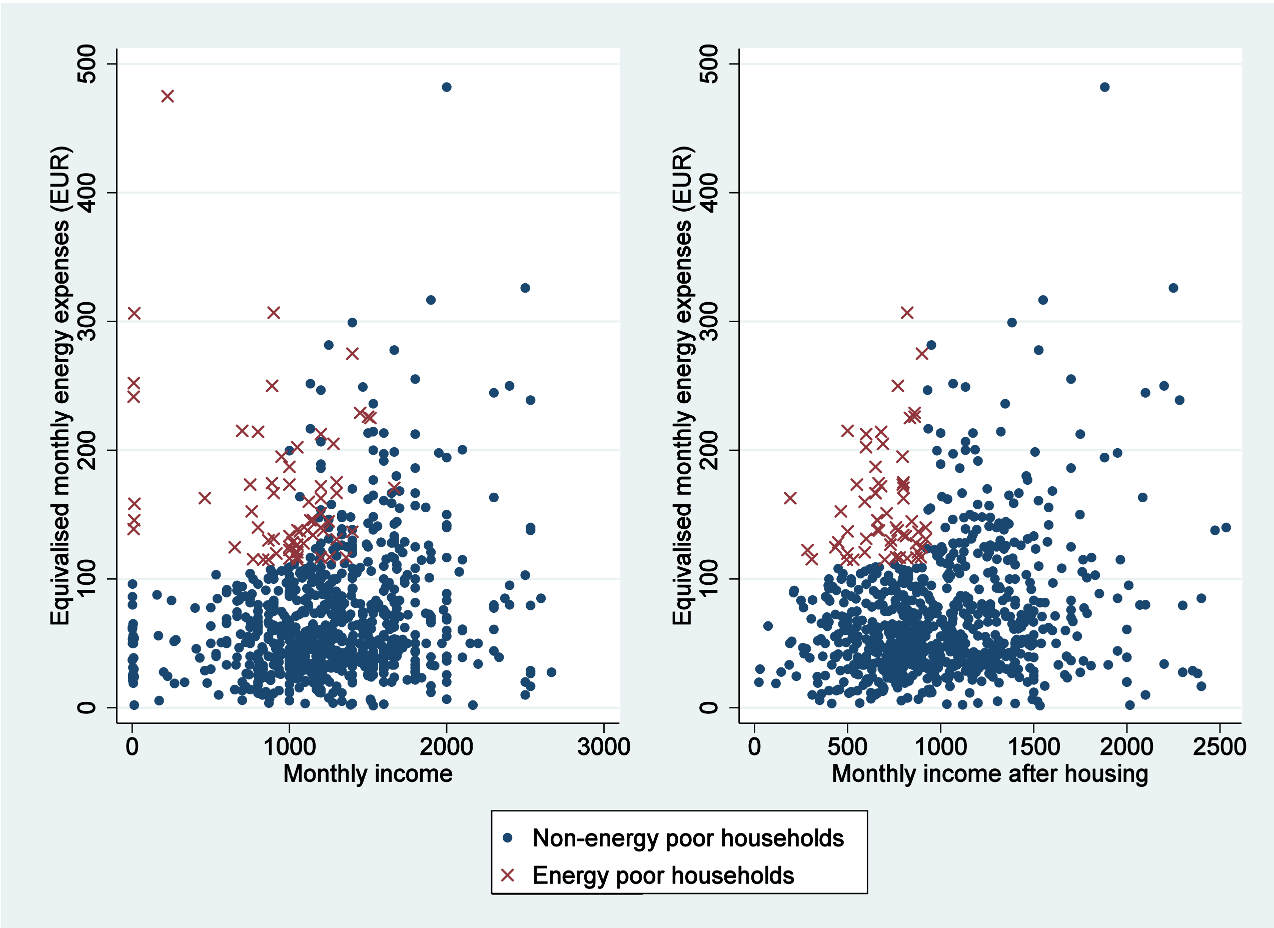
The proposed definition suggests collecting information on household income and size, housing costs and (actual and foregone) energy expenses to measure the magnitude and distribution of energy poverty. Nonetheless, commonly used alternative measures may provide valuable insights into energy poverty in Austria. For instance, households may be asked whether they can afford to keep their homes adequately warm such as it is the case in the EU-wide Survey on Income and Living Conditions (EU-SILC), or whether they feel burdened by their energy costs. These additional indicators provide contrast and help assess the validity of the proposed definition by adding subjective experiences of energy customers to what can be rather seen as a definition on objective and comprehensible grounds.

To provide reliable data, E-Control commissioned the first quantitative survey on energy poverty in Austria. 931 low-income households have been personally interviewed in a representative random sample of households, covering approximately the lower third of the income distribution. The survey tests several approaches to energy poverty, including numerous indicators to contrast a more objective expenditure approach such as identified in the proposed definition of energy poverty by E-Control and a more subjective or consensual approach as in EU-SILC (cf. Prize et al. 2012). Importantly, the survey investigates energy expenses, important socio-demographics of energy-poor households inasmuch as their (reported) behavior with respect to energy efficiency.

Findings

Figure 1 juxtaposes monthly income and energy expenses of energy poor and non-energy poor households. According to the definition, energy poor households can be found in the upper-left corner of each chart where low incomes match high energy expenses. The left-hand chart also shows that some energy poor households have incomes significantly above the official at-risk-of-poverty line in Austria (EUR 1066 or more). In addition, some households below the at-risk-of-poverty line are not identified as energy poor when their housing expenses are not considered. Yet, energy poor households are a minority among low-income households and after deducting housing costs (right-hand chart), all households with high energy expenses in combination with low disposable incomes can be clearly identified as energy poor. These households account for approximately 2.5 percent of the total Austrian population.

Figure 1. Equivalised monthly household income and energy expenses of energy poor and other households in Austria (in EUR).



Source: E-Control Energy Poverty Survey 2013.

To find out about key characteristics of energy poor households, we contrasts a series of properties of households responding to three distinct markers of energy affordability. First, we examine households who claim to be unable to afford adequately warm homes. Second, we portray households who say that they feel strongly or very strongly burdened with energy expenses. And third, we describe energy poor households according to the E-Control definition. Strikingly, the correlation between subjective measure and the expenditure approach to energy poverty is small. Only about 17 percent of the energy poor mention that they cannot afford to keep their homes adequately warm, and only 53 percent feel burdened by their high energy costs.

Table 1 then illustrates income, expenses, housing arrangements, behaviors, attitudes and key socio-demographics referring to different groups of households in energy poverty. By and large, all three groups of households dispose of the same amount of money, roughly EUR 1000. A big difference, however, are their monthly energy expenses. People who claim to be unable to afford adequate warmth pay EUR 56 per month, whereas energy poor households pay EUR 142, which is also a substantially higher share of their incomes (13%).

Table 1. Selected properties, behaviors and attitudes of energy poor households in Austria.

		EU-SILC	Burdened	Energy poor
Share of population (%)		2.44	5.30	2.48
Monthly disposible household income (EUR)		950	1000	1050
Housing expenses (EUR)		267	267	385
Energy expenses				
	EUR	56	78	142
	% household income	6	8	13
Living space (m^2)		74	86	97
Housing form (%)				
	House ownership	19	32	25
	Flat ownership	3	6	8
	Social housing	19	16	30
	Rent	35	37	28
	Subletting	17	8	3
Main heating system (%)				
	District heating	22	20	12
	Central heating	48	54	43
	Gas heating	17	12	38
In arreas with bills/installments (%)		48	31	13
Actively saving energy (%)		40	24	10
Open windows in winter (%)		14	15	13
Lower temperature overnight (%)		59	72	55
Warm enough for T-Shirt (%)		5	22	20
Living in Vienna (%)		46	27	12
Female respondent (%)		44	52	67
Age of respondent		44	48	54
Single parent (%)		10	7	12
Citizenship (%)		84	92	92
Highest level of education of respondent (%)				
	Primary school	44	33	25
	Apprenticeship	27	39	43
	High School	19	20	23
Employment status of respondent (%)				
	Full-time	33	36	28
	Part-time	6	6	2
	Unemployed	22	18	7
	Retired	25	27	50

Notes: **EU-SILC** population report to be unable to afford to heat their homes adequately warm; **Burden** population feels (very) strongly burdened by their energy expenses; **Energy poor** population is energy poor according to E-Control definition.
Monetary values refer to the median of the subpopulation.
Source: E-Control Energy Poverty Survey 2013.

In terms of home equipment, energy poor households inhabit spacious homes (97 square meters), are most often in social housing (30%) and mainly heat with gas (38%). Despite a high financial burden, only few energy poor households report to be in arrears with payment. Moreover, these households are surprisingly little aware of energy efficient behavior. Only ten percent say that they save energy actively and in every fifth energy poor household it is still warm enough for a T-shirt in winter. Some of these findings might, however, be explained by the demographic structure of energy poor households. The typical energy poor person is female, older, retired and living in rural areas in either their own house or in social housing, which may explain their higher consumption. Even more so, spending a lot of money on energy might nevertheless appear as “normal” to some people since there is little overlap with subjective feelings of un-affordability.

5. Policy Implications

A growing number of stakeholders outline energy poverty as an emerging social issue with a strong link to energy policy across Europe. Yet, there is no common understanding of energy poverty and little progress has been made to empirically measure it. To avoid an overburdening of both the social security system and the energy sector, energy poverty should be clearly differentiated from other forms of poverty. Otherwise the danger remains that premature policies fail to combat the true causes of energy poverty. Since energy policy cannot replace social policy benefits, energy poverty should only be identified where energy expenses pose a significant financial challenge to low-income households. Therefore, any long-term benefits in the energy sector should be designed in a way to cut consumption of households rather than making energy cheaper or providing it even for free. Furthermore, increasing energy efficiency is an attractive solution in the light of widely anticipated higher energy prices in the near future. In a related and recently published document, the European Commission proposes a series of such energy efficiency measures to support vulnerable consumers across the European Union (European Commission 2013).

The findings of the first E-Control Energy Poverty Survey also support the idea to combat energy poverty with energy efficiency measures. After having defined and measured energy poverty along a combination of low income and high energy expenses, statistical analysis underlines the potential of investments into energy efficiency. First, increasing awareness among energy poor households helps reduce energy consumption and costs by sometimes quite small and simple behavioral and attitudinal adaptations. According to our survey, a significant share of energy poor people remains unaware of their own powers to decrease their bills – often because of older age, lower education or "long-term or outdated habits". With professional energy counselling and other measures, many households may quickly benefit without cutting back on their standard of living.

While changing behavior is a necessary step to reduce costs, much higher savings may be realized by replacing old and inefficient household equipment and heating systems – both can be found more frequently in low-income households. Replacing larger appliances such as refrigerators, deep freezers or washing machines may target an important source of high consumption and already pay off in a few years.

Most importantly, however, improving the thermal properties of buildings is key to cutting consumption of energy. Yet, low-income households rarely dispose of additional financial means to invest in their homes. As our survey has shown, many of the energy poor households live in social housing which further curtails their possibilities to improve the insulation of the building. Since state authorities own such buildings, they might find it more cost-efficient to direct funds into their infrastructure since such long-term investment is by far more promising than annual allowances to households.

Conclusions

To conclude, the concept of energy poverty is of growing public interest. In a first quantitative study, E-Control Austria proposes to define it as a combination of low disposable income and high energy expenses to be able to fight the causes of energy poverty. In this respect, energy efficiency measures promise long-term aid to households in energy poverty without distorting the market or overburdening the social security system. While regulated energy prices or free energy come at the expense of all households, various energy efficiency schemes for low-income households represent a fair and market-oriented instrument since they have been available for more affluent households for years in many European countries.

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Florian Pichler works at the department of consumer affairs at E-Control Austria. He holds a PhD in sociology from the University of Aberdeen, Scotland. He has gained expertise in survey research on, amongst other things, poverty, social exclusion and customer satisfaction. He is currently coordinating the first comprehensive quantitative study on energy poverty in Austria, in which a wide range of aspects of energy poverty, including its definition, empirical assessment and measures to combat it are explored and discussed with numerous other stakeholders and affected households.

VI. Integrating Variable Renewable Energy in Electricity Markets: Best Practices from International Experience

By Jaquelin Cochran, Lori Bird, Jenny Heeter and Doug Arent

Introduction

Economic, environmental, and security concerns associated with conventional fuel supplies have strengthened support for clean energy technologies among governments and the private sector on a global scale; yet questions persist about how to effectively integrate large amounts of variable renewable electricity generation (Variable renewable energy is defined as renewable energy that cannot be stored prior to electricity generation; it includes primarily wind and solar PV but also technologies such as tidal power and run-of-river hydropower). Renewable energy (RE) accounted for nearly half the estimated 194 gigawatts of new capacity in 2010—an investment equal to $211 billion (REN21 2011). Variable renewables, in particular, have achieved significant penetration in many countries, and issues associated with grid integration are increasingly gaining attention among a broad range of stakeholders.

The depth of experience in various countries—situated in diverse geographical and market contexts—provides insights for decision makers interested in increasing the penetration of variable RE into the power sector. This paper documents the diverse approaches to effective integration among six countries, and summarizes policy best practices that energy ministers and regulators can pursue now to ensure that electricity markets and power systems can effectively coevolve with increasing penetrations of variable RE.

Many countries—reflecting very different geographies, markets, and institutional structures—are already demonstrating success in managing high levels of variable RE on the grid, such as from wind and solar. The cases examined in this paper—Australia (South Australia), Denmark, Germany, Ireland, Spain, and the United States (Colorado and Texas)—all have relatively high penetrations of RE but reflect different system and market characteristics. Analysis of the results from these case studies reveals a wide range of mechanisms that can be used to accommodate high penetrations of variable RE (e.g., from new market designs to centralized planning).

Nevertheless, the myriad approaches collectively suggest that governments can best enable variable RE integration by implementing best practices in the following areas of intervention:

- Lead public engagement, particularly for new transmission
- Develop rules for market evolution that enable system flexibility
- Expand access to diverse resources and geographic footprint of operations
- Improve system operations.

For each of the four areas of intervention, we summarize the rationale for action and best practices for implementation. Text boxes highlight the diversity of approaches as revealed through the case studies. Additional details on the case studies and best practices associated with these areas can be found in Cochran et al. (2012). (This paper is derived from a longer report published by the NREL Joint Institute for Strategic Energy Analysis.)

Lead Public Engagement, Particularly for New Transmission

High penetrations of variable RE may require expanded transmission capacity—to accommodate diverse RE locations and locations far from load, to enlarge balancing areas, to reduce nodes of transmission congestion, and to fully access flexible resources (generation, storage, and demand response). Installing this transmission, however, is a challenge; stakeholders may express concerns over land use changes, environmental damage, decreased property values, or health concerns. Negotiating the balance between new transmission and public unease requires political leadership.

Best Practices

1. Involve from the outset of planning public stakeholders that reflect many perspectives; engage them throughout the process
2. Use a transparent process for developing routing options
3. Explain the objectives for grid expansion, especially as it relates to public concerns (e.g., reliability, electricity prices, RE goals, employment)
4. Clearly describe the types and distribution of costs and benefits, as well as costs of inaction or suboptimal actions (REALISEGRID 2011)
5. Create a publically approved, transparent process for evaluating property values and compensation
6. Create a regulatory approach that is accessible to the public and minimizes burdens on applicants

Text Box 1. Approaches to Public Engagement

Texas: New transmission lines designed to serve 18.5 gigawatts of new capacity at remote and varied wind sites were key to integration. Line construction, often resisted, was successful due to extensive and varied opportunities for public feedback.

Germany: to facilitate new transmission, uses legislation that 1) gives priority to extra-high voltage transmission projects that reduce north/ south congestion and 2) shortens planning and permission process by consolidating responsibilities at the federal level.

Denmark: to address public concerns about aesthetics, plans to bury its entire high-voltage grid by 2030.

Develop Rules for Market Evolution that Enable System Flexibility

Rationale

Markets help minimize power system costs, and for systems using variable RE in particular, they can facilitate access to a range of options that increase system flexibility. Higher penetrations of variable RE require increased flexibility from the power system to manage the variability and uncertainty of the generation. Flexibility can be achieved through changes in market operations, increased transmission, or the addition of flexible resources to the system, such as more flexible generating units, storage, and demand response. While flexibility is of high value to the system and can reduce the need for new capacity, it may come at a cost to power suppliers. Increased ramping of units that are not adequately designed for cycling can result in maintenance issues or reduce the lifetime of units. Also, conventional generators may experience profit margins that are insufficient to maintain their long-term financial viability if variable generators depress wholesale market prices and generators are only compensated for energy production. Therefore, market rules and operations may need to be modified over time to achieve operational efficiency in systems with increasing penetrations of variable RE.

Best Practices

Use markets to support the most cost-effective solution to increasing flexibility, which could include:

1. Flexible generation
   - Encourage sub-hourly scheduling and dispatch intervals (5- or 15-minute) and shorter gate closure periods to improve system efficiency (EWIS 2010)
   - Use zonal or nodal pricing to help manage congestion on the system and encourage development of resources where needed
   - Develop equitable rules for curtailment of variable generators during periods of excess generation on the system (NERC 2011)
   - Design imbalance payment rules so that they do not unduly penalize variable generators
   - Require flexibility in resource planning or provide financial incentives to ensure new capacity is as flexible as possible

2. Flexible storage

- Ensure optimal use of storage, for example, supporting entire system rather than dedicated to a single generator (NERC 2010)
- Allow ancillary markets to raise the value of fast-discharge storage thereby increasing its cost-competiveness (NERC 2010, Delille et al. 2010)
- Consider non-electric demand, such as combined heat and power for sources of flexibility (Kiviluaoma and Meibom 2010)

3. Flexibility of load through demand response and smart grid

- Support short-term balancing; reduce ramping and curtailments (IPCC 2011, Ensure adequate communication infrastructure between system operators and load (IPCC 2011)

Text Box 2. Approaches to Markets and System Flexibility

Denmark:

- A large power pool provides greater flexibility, e.g., Norway's hydropower is critical to accommodating Denmark's wind.
- A regulating (real-time) power market operates up to 15 minutes before delivery.
- Negative pricing provides an economically efficient way to reduce output during excess generation.
- Combined heat and power is required to participate in the spot power market.

Australia: Sub-hourly (5 min.) dispatch intervals reduce the need for ramping and improve forecast accuracy. Nodal and negative pricing encourage market efficient location strategies.

Germany has implemented mechanisms to encourage energy storage. There is a €200 million ($261 million) budget for storage research and development up to 2014, and new storage facilities are exempt from grid charges and the levy required by the German renewable energy act in 2000.

Texas: Demand response for frequency regulation has been important for an isolated system like Texas. Participating load moves up and down automatically to maintain frequency at 60 HZ; participates in non-standard reserves by being able to ramp load in 30 minutes; and is able to respond within 10 minutes to provide "spinning" (responsive) reserves. In February 2008, when anticipated wind and traditional generation fell short, and demand ramped up more quickly than anticipated; 1,108 megawatts (MW) of demand response were activated in 10 minutes.

Expand Access to Diverse Resources and Geographic Footprint of Operations

One of the concerns about integrating variable RE is vulnerability of the power system to weather events. Integration studies have consistently found that expanding access to diverse resources reduces this vulnerability. This can be achieved in two ways: enlarging effective balancing areas and diversifying the location and types of RE generation.

By enlarging balancing areas, the relative variability and uncertainty in both the load and RE generation will be lowered, smoothing out differences among individual loads and generators. This in turn reduces the need for reserves and lowers overall integration costs. Larger balancing areas may also provide access to a greater amount of flexible generation.

Greater geographic distribution of renewable resources reduces the variability of RE because weather patterns are less correlated across large geographies, reducing the relative magnitude of output changes. Greater diversity of technologies similarly reduces the correlation among generators and thus has an effect that is similar to that of increasing geographic diversity.

Best Practices

1. Create larger balancing areas to help integrate higher penetrations of variable RE generation on the system (NERC 2011), for example, the Nordic system's balancing area allows flexible hydropower in Norway and elsewhere to accommodate the variability of wind in Denmark
2. Interconnect isolated, small systems with neighbors to be able to access generation sources

from larger grids

3. For areas without organized markets and with small balancing areas, hybrid market solutions could help achieve balancing area cooperation and reserve sharing; which can result in cost savings from sharing reserves without the need to create a fully organized market
4. Because transmission access often influences where RE generators are located, renewable energy zone planning can help identify diverse areas of RE resources and encourage transmission planning to those resources (e.g., Texas and the western United States)
5. Include an assessment of the location of the resource and its potential impact on the system in project bid evaluations, thereby encouraging a mix of resources on the system. Economic incentives could be provided to encourage renewables to be sited in locations that minimize system overall system cost.

Text Box 3. Approaches to Diverse Resources

Ireland has twice sought both to reduce its vulnerability to weather variability and to strengthen its power system through expanding regional integration:

- Single Electricity Market with Northern Ireland: required for all electricity >10 MW sold and bought in Ireland; no bilateral transactions permitted
- 500 MW East-west interconnector to U.K.

The **U.S. West** largely lacks an organized wholesale electric market, but an energy imbalance market has been proposed to allow balancing areas to share reserves and—through this broader diversity—reduce the system-wide variability of RE.

Improve System Operations

Beyond market and institutional changes to system operations described in earlier sections (e.g., faster scheduling, enlarged balancing areas), system operations can be improved by adopting advanced forecasting techniques and changes to grid codes.

Using advanced forecasting techniques helps reduce the amount of system flexibility needed to integrate variable RE generation. Renewable energy generation can be variable, changing with the time of day and weather patterns, and uncertain because of the inability to predict the weather with perfect accuracy. Using forecasts in grid operations can help predict the amount of wind energy available and reduce the uncertainty in the amount of generation that will be available to the system.

Revising grid codes to address issues related to variable generation (e.g., concerns about frequency control and other disruptions to network stability) both allows hardware and procurement agreements to be designed in advance to support the power system and reduces the financial burdens of retroactive requirements. Creating a model grid code can serve as a guide for each system to evaluate what changes are needed.

Best Practices

1. Advanced forecasting

- Integrate forecasts into fast market operations, the control room, and other standard operating practices of the system operator or market operator. Using forecasts to determine unit commitment and reserve requirements can minimize movements on fossil plants and the need for reserves—a cost savings (NREL 2010).
- Ensure RE plants continually provide updated data to improve the accuracy of the forecasts they use
- Continue to evaluate and improve forecasting methods to facilitate more efficient operations (Holttinen et al. 2009)

2. Grid codes

- Create a roadmap of system reliability requirements based on an integrated review of needs and capabilities

- Require fault ride-through capabilities and turbines to provide reactive power, and, in some cases, voltage and frequency control (Holttinen et al. 2011, IPCC 2011)
- Distinguish what needs to be addressed at the project level and generator level

Text Box 4. Approaches to System Operations

Spain

- The Control Centre for Renewable Energies monitors RE installations real-time.
- Wind farms with capacities greater than10 MW and solar photovoltaic installations with capacities greater than 2 MW provide reactive power support
- Most wind farms (97.5%) have fault-ride through capability.
- New operational procedures have been proposed to maintain optimal voltage control.

Australia: Market operators use a forecasting model that integrates forecasts from a variety of sources.

Denmark: The system operator uses multiple and advanced forecasts in planning, congestion management, dispatch, and to assess the need for regulating power.

Conclusion

The cases reviewed for this analysis illustrate considerable diversity, not only of the electricity systems—and their supporting markets, institutions, and renewable resources—but in the actions each country has taken to effectively integrate high penetrations of variable RE. The cases reveal that there is no one-size-fits-all approach; each country has crafted its own combination of policies, market designs, and system operations to achieve the system reliability and flexibility needed to successfully integrate RE.

The best practices associated with the strategic areas of intervention benefit all power systems, not just those with high penetrations of variable RE. Yet these strategies are particularly instrumental in accommodating variable renewables where they minimize the impact of RE's variability and allow more options to cost-effectively strengthen the ability of a power system to respond to change. Advancements in energy efficiency and smart grids, when conjoined with higher RE integration, further strengthen the efficacy of any power system.

Any country's ability to successfully integrate variable RE depends on a wide array of factors—technical requirements, resource options, planning processes, market rules, policies and regulations, institutional and human capacity, and what is happening in neighboring countries. The more diverse and robust the experience base from which a country can draw, the more likely that it will be able to implement an appropriate, optimized, and system-wide approach. This is as true for countries in the early stages of RE integration as it is for countries that have already had significant success. Going forward, successful RE integration will thus depend upon the ability to maintain a broad ecosystem perspective, to organize and make available the wealth of experiences, and to ensure that there is always a clear path from analysis to enactment.

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Jaquelin Cochran is a Senior Energy Analyst with the National Renewable Energy Laboratory, where she analyzes policies and market designs that create an enabling framework for emerging energy technologies (renewable energy, demand response, distributed generation). Dr. Cochran has published on many topics related to integration of renewable electricity, including policy best practices, coal cycling, curtailment, variability analysis, integration studies, system flexibility, and market designs. Dr. Cochran also recently led an analysis on business opportunities that build from synergies between natural gas and renewable energy. Prior to NREL, Dr. Cochran was an Assistant Professor of Natural Resource Management with KIMEP University in Almaty. She also served as a Peace Corps Volunteer for two years with the Polish Foundation for Energy Efficiency (FEWE) in Krakow. She holds a Ph.D. and M.A. from the Energy & Resources Group at the University of California at Berkeley.

Lori Bird is a senior energy analyst with the National Renewable Energy Laboratory in Golden, Colorado, specializing in the area of renewable energy policy, markets, and integrating variable generation into electric grids. She recently contributed to reports on mitigation options and international best practices for renewable energy grid integration. She has published nearly 100 articles and reports on renewable energy issues. Before joining NREL, she worked for DOE's Office of Energy Efficiency and Renewable Energy in Denver and Hagler Bailly Consulting in Boulder, Colorado. She holds a master's degree in Environmental Studies from Yale University's School of Forestry and Environmental Studies.

Jenny Heeter is a renewable energy analyst at the National Renewable Energy Laboratory (NREL) in Golden, Colorado. She focuses her research on renewable energy certificate markets, renewable portfolio standards, the voluntary renewable energy market, and issues related to high penetrations of renewables on the grid. Prior to joining NREL, she worked for the Indiana Office of Utility Consumer Counselor, representing ratepayer interests in renewable energy and energy efficiency cases brought by utilities before the Indiana Utility Regulatory Commission. She holds an M.P.A. in environmental policy from Indiana University-Bloomington's School of Public and Environmental Affairs.

Doug Arent is Executive Director of the Joint Institute for Strategic Energy Analysis at the National Renewable Energy Laboratory (NREL). He specializes in strategic planning and financial analysis competencies; clean energy technologies and energy and water issues; and international and governmental policies. In addition to his NREL responsibilities, Arent is Senior Visiting Fellow at the Center for Strategic and International Studies. Arent was appointed as a Coordinating Lead Author for a chapter of the 5th Assessment Report of the Nobel Prize-winning Intergovernmental Panel on Climate Change (IPCC) and serves on the National Research Council Committee to Advise the U.S. Global Change Research Program. He is a member of the Policy Subcommittee of the National Petroleum Council Study on Prudent Development of North America Natural Gas and Oil Resources, and the American Academy of Arts and Sciences Steering Committee on Social Science and the Alternative Energy Future. Arent is a Member of the Keystone Energy Board and serves on the Advisory Council of the Smart Cities Council. Prior to coming to his current position, Arent was Director of the Strategic Energy Analysis Center at NREL from 2006-1010. Prior to joining NREL, he was a management consultant to clean energy companies, providing strategy, development, and market counsel. Dr. Arent has a Ph.D. from Princeton University, an MBA from Regis University, and a Bachelor of Science from Harvey Mudd College in California.

VII. The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources

By Michael W. Howard

The successful integration of distributed energy resources (DER) such as small natural gas-fueled generators, combined heat and power plants, electricity storage, and solar photovoltaics (PV) on rooftops depends on the transformation of the existing electric power grid. That grid, especially its distribution systems, was not designed to accommodate a high penetration of DER while sustaining high levels of electric quality and reliability. The technical characteristics of certain types of DER, such as variability and intermittency, are quite different from central power stations. To realize the full value of DER and maintain established standards of quality and reliability, the need has arisen to integrate DER in the planning and operation of the electricity grid and to expand its scope to include DER operation – what EPRI is calling the *Integrated Grid*.

To better understand the costs and opportunities of different technological and policy pathways, the EPRI has initiated a project aimed at charting the transformation to the integrated grid. Analysis of the integrated grid, as outlined here, should not favor any particular energy technology, power system configuration or power market structure. Instead, it should make it possible for stakeholders to identify optimal architectures and the most promising configurations – recognizing that the best solutions vary with local circumstances, goals, and interconnections.

The Changing Power System

Today's power system was designed to connect large generation plants with relatively small consumers. The U.S. power system, for example, is anchored by ~1,000 gigawatts (GW) of central generation on one end, and consumers on the other end that generally do not produce or store energy [1,2].

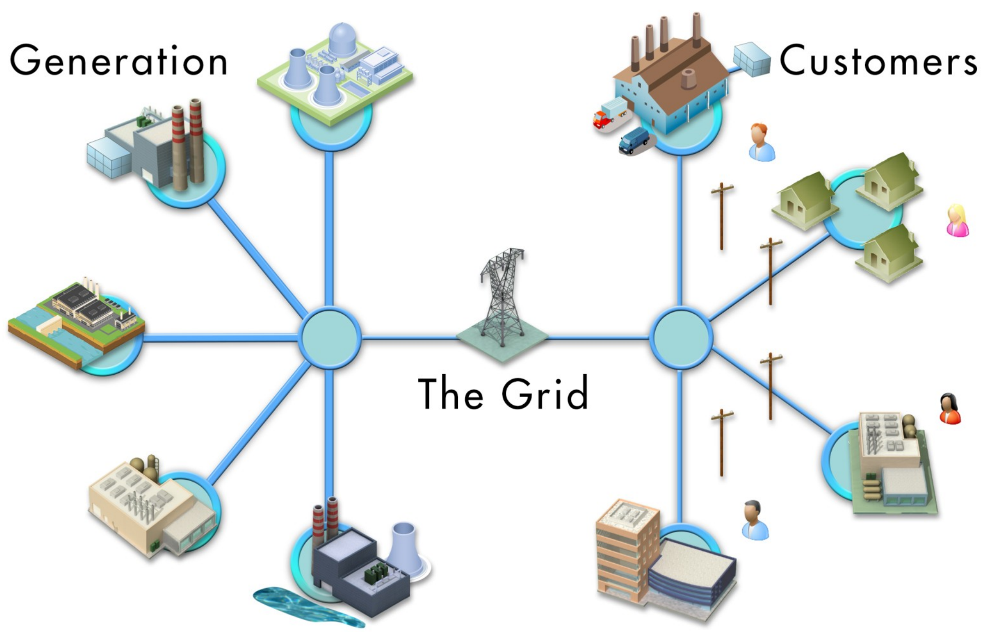

Figure 1. Today's Power System Characterized by Central Generation of Electricity, Transmission, and Distribution to End-Use Consumers.

Electricity flows in one direction, from power plants to substations to consumers (Figure 1).

The classic vision of electric power grids with one-way flow may now be changing. Consumers, energy suppliers, and developers increasingly are adopting DER to supplement or supplant grid-provided electricity. In most cases, grid-connected DER benefit from the electrical support, flexibility and reliability that the grid provides, but they are not integrated with the grid's operation. Consequently, the full value of DER is not realized in providing support for grid reliability, voltage, frequency and reactive power.

For example, the grid serves as a reliable source of high-quality power to compensate for the variable output of DER. With PV, the variability is not only diurnal but, as shown in Figure 2, can fluctuate during the day due to overcast conditions or fast-moving clouds. The grid serves as a crucial balancing resource available for whatever period—from seconds to hours to days and seasons—to offset variable and uncertain output from distributed resources.

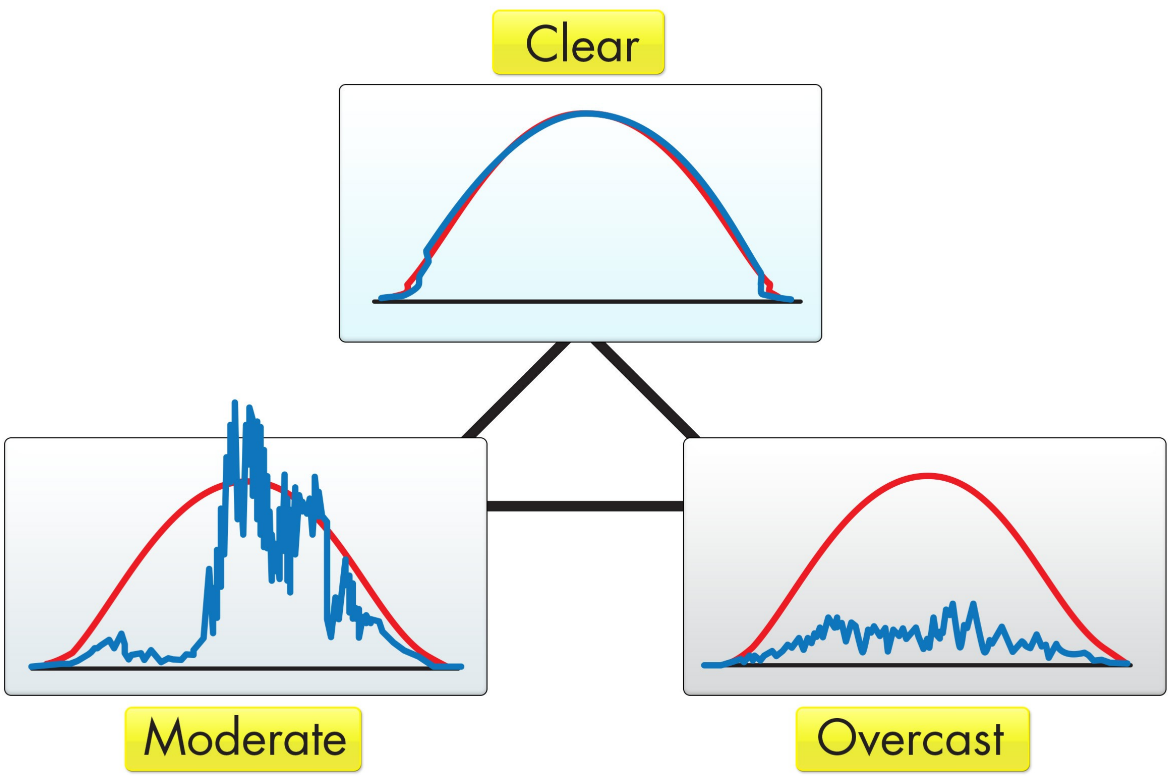

Figure 2. The Output of PV is Highly Variable and Dependent on Local Weather

The grid also provides the instantaneous reactive power for devices that require a strong current flow ("in-rush" current) when starting up, such as compressors, air conditioners, transformers, and welders. Without grid connectivity or other supporting technologies (supporting technologies include variable-frequency drive (VFD) systems, which are able to start motors without the in-rush current common in "across-the-line" starting [24]) , a conventional central air conditioning compressor relying only on a PV system may not start at all unless the PV system is oversized to handle the in-rush current.

Figure 3 illustrates the instantaneous power required to start a residential air conditioner. The peak current measured during this interval is six to eight times the standard operating current [3]. While the customer's PV array could satisfy the real power requirements of the heating, ventilating and air conditioning unit during normal operation, the customer's grid connection supplies the majority of the required starting power.

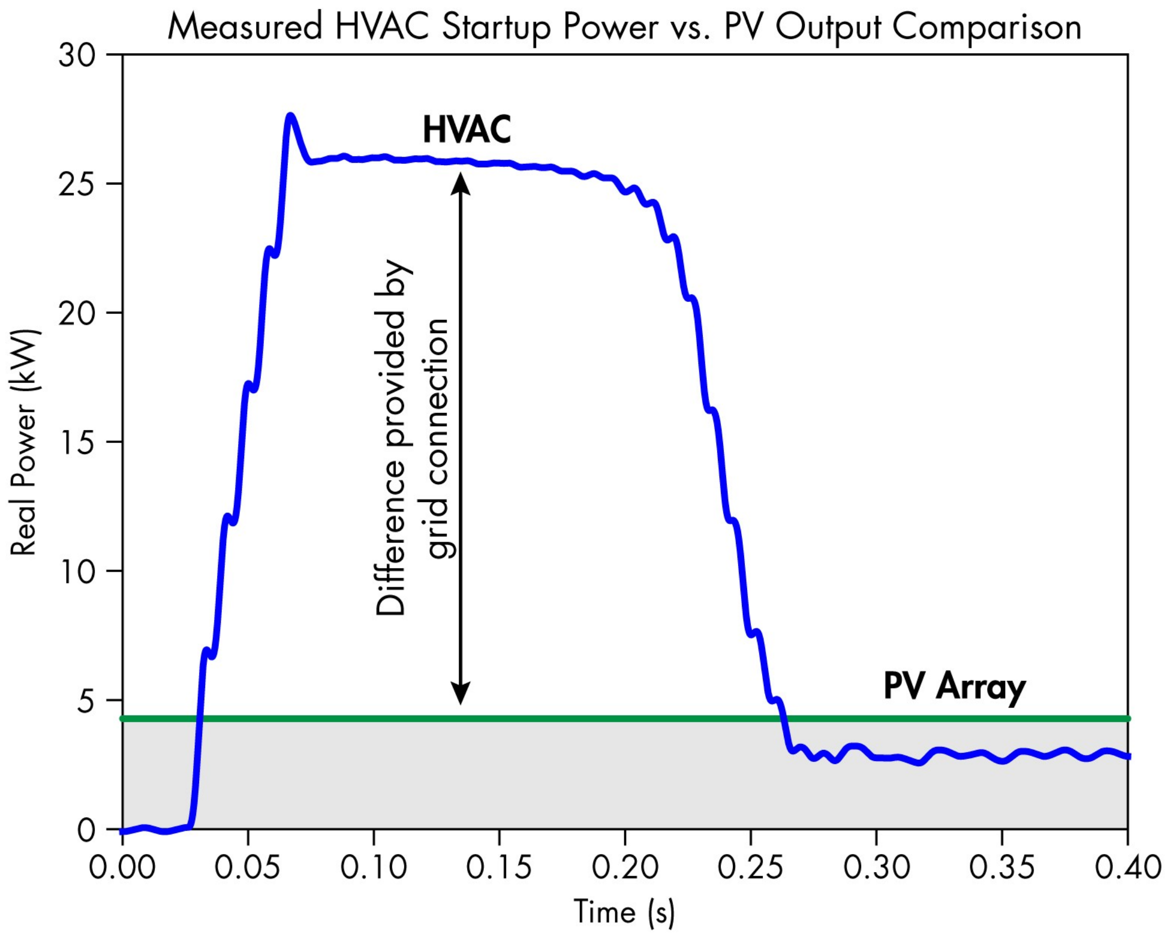

Figure 3 . The Grid Provides In-Rush Current Support for Starting Large Motors which may be Difficult to Replicate with a Distributed Generator

Cost of Grid Service: Energy and Capacity Costs

For residential customers, the costs for generation and transmission and distribution components can be broken down into costs related to serving the customer with energy (kWh) and costs related to serving the customer with capacity that delivers the energy and grid-related services. Based on the U.S. Department of Energy's Annual Energy Outlook 2012, an average customer consumes 982 kWh per month, paying an average $110 per month, with $70 for electricity generation. That leaves $30 for distribution system and $10 for transmission [4], known together as "T&D."

The next step is to allocate these costs (generation and T&D) into fractions that are relevant for analyzing how the grid works with DER. In this analysis we focus on capacity and grid-related services because they are what enable robust service even for customers with DER. Indeed, consumers with distributed generation may not consume any net energy (kWh) from the grid, yet they benefit from the same grid services as consumers without distributed generation.

Figure 4 shows that most costs associated with T&D are related to capacity, except for a small fraction representing system losses – estimated to be $3 per month per customer from recent studies in California [5]. Based on PJM data [6] regarding the cost of energy, capacity, and ancillary services, about 80% of the cost of generation is energy related, leaving the rest for capacity and grid services.

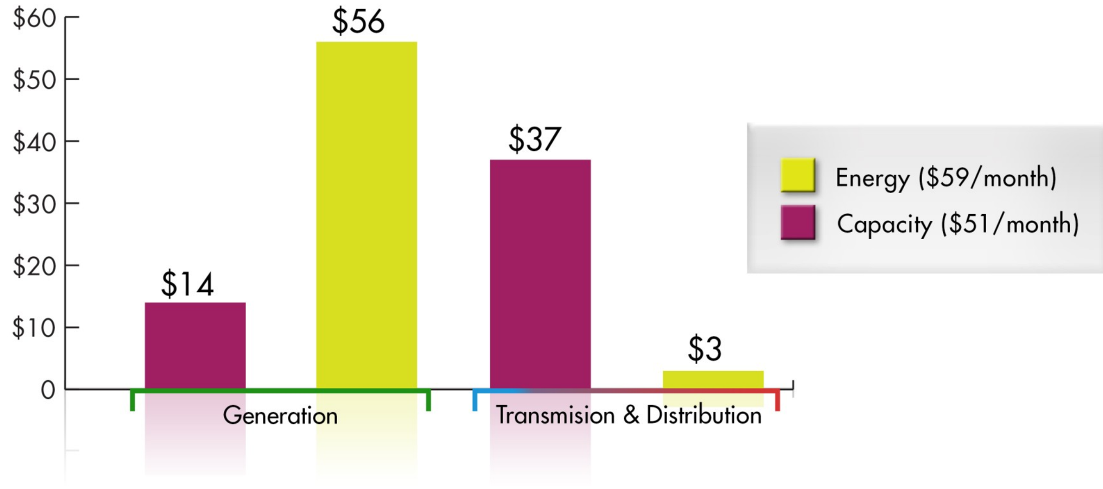

Figure 4. In Considering the Value of the Integrated Grid, Costs of Generation, Transmission and Distribution can be Further Determined for Energy and Capacity

As illustrated, capacity-related costs average $51/month while energy costs average $59/month. These costs vary widely across regions and among consumers, and also will vary with changes in generation profile and the deployment of new technologies such as energy storage, demand response-supplied capacity, and central generation. The values illustrate that capacity and energy are important elements of cost and should be recovered from customers who use both capacity and energy resources (that is, "conventional" electricity consumers). Customers with distributed generation may offset the energy cost by producing their own energy, but they still utilize the non-energy services that grid connectivity provides.

Technologies are available that enable consumers to self-generate and disconnect from the grid. Reinforcing the system for an off-grid PV application would require the following upgrades:

- Additional PV modules beyond the requirements for offsetting annual energy consumption in order to survive periods of poor weather;
- Multi-day battery storage with dedicated inverter capable of operating in an off-grid capacity;
- Backup generator on the premises designed to operate for 100 hours per year; and
- Additional operating costs including inverter replacement and generator maintenance.

In simulation, the cost to re-create grid-level service without a grid connection is $275-$430 per month *above* that of the original array. Expected decreases in the cost of battery and PV module technology could reduce this to $165-$262 per month within a decade. Costs for systems based on other technologies, or larger deployments such as campus-scale microgrids, could be relatively lower, based on economies of scale. However, even if amortized capital costs are comparable to grid services, such isolated grids will result in deteriorating standards of reliability and quality of electricity service and could require extensive use of backup generators whose emissions negatively impact local air quality.

Realizing the Value of DER through Integration

With increasing penetration of variable generation, capacity- and ancillary service-related costs will become an increasing portion of the overall cost of electricity [7]. However, with an integrated grid (Figure 5), DER could more efficiently contribute to the capacity and ancillary services needed to operate the grid.

- **Delivery Capacity** – The extent to which DER reduce system delivery capacity depends on the expected output during peak loading of the local distribution feeder, which typically varies from the aggregate system peak. If local PV output is high during system peak demand, it will do nothing to reduce distribution feeder capacity requirements if its output during system peak occurs after the sun sets, as in the case with some residential feeders. However, when coupled with energy storage resources dedicated to smoothing the intermittent nature of the resources, such resources could significantly reduce capacity need. Similarly, a smart inverter integrated with a distribution management system may be able to provide distributed reactive power services to maintain voltage quality.

- **Supply Capacity** – The extent to which DER reduce system supply capacity depends on the output expected during high-risk periods when the margin between available supply from other resources and system demand is relatively small. If local PV production reduces high system loads during summer months but drops significantly in late evening prior to the system peak, it may do little to reduce system capacity requirements. Conversely, even if PV production drops prior to evening system peaks, it may still reduce supply capacity requirements if it contributes significantly during other high-risk periods such as shoulder months when large blocks of conventional generation are unavailable due to maintenance. Determining the contribution of DER to system supply capacity requires detailed analysis of local energy resources relative to system load and conventional generation availability across all periods of the year and all years of the planning horizon.

- **System Flexibility** – Capacity requirements are defined by the character of the demand they serve. Distributed resources such as PV alter electricity demand, changing the distributed load profile. PV is subject to a predictable diurnal pattern that reduces the net load to be served by the remaining system. At high levels, PV can alter the net load shape, creating additional periods when central generation must “ramp” up and down to serve load. Examples are early in the day when the sun rises and PV production increases and later, as the sun sets, when PV output drops, increasing net load. The net load shape also becomes characterized by abrupt changes during the day, as when cloud conditions change significantly.

- **Grid Planning** – Adequacy of delivery and supply capacity are ensured through detailed system planning studies to understand system needs for meeting projected loads. For DER to contribute to meeting capacity needs in the future, DER deployment must be included in the associated planning models. Also, because DER are located in the distribution system, certain aspects of distribution, transmission, and system reliability planning have to be more integrated.

- **DER Availability and Sustainability over Planning Horizon** – For either delivery or supply capacity, the extent to which DER can be relied upon to provide capacity service and reduce the need for new T&D and central generation infrastructure depends on planners’ confidence that the resource will be available when needed across the planning horizon. To the extent that DER may be compensated for providing capacity and be unable or unwilling to perform when called upon, penalties may apply for non-performance.

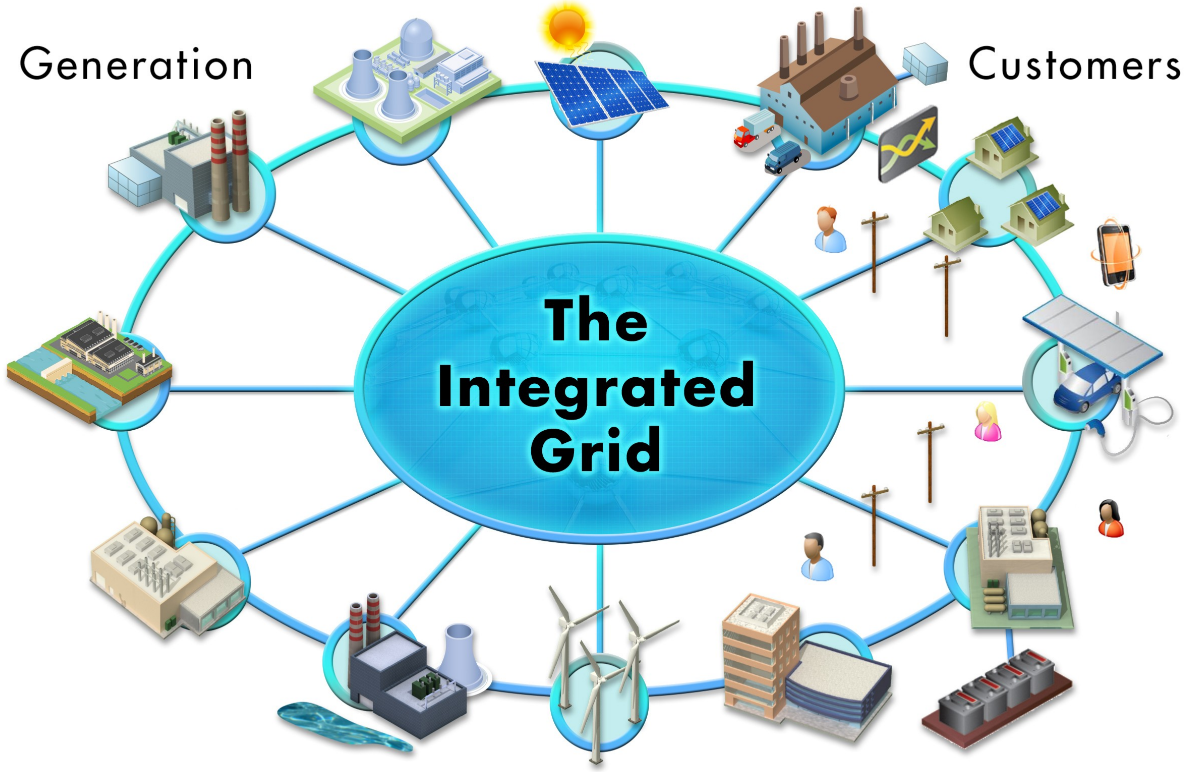

Figure 5. The Integrated Grid Could Link Residences, Campuses, and Commercial Buildings Using a Multi-Level Controller

Enabling Policy and Regulation

A policy and regulatory framework will be needed to encourage the effective, efficient, and equitable allocation and recovery of costs incurred to transform to an integrated grid. New market frameworks will have to evolve in assessing potential contributions of distributed and central resources to system capacity and energy costs. Such innovations will need to be anchored in principles of equitable cost allocation, cost-effective and socially beneficial investment, and service that provides universal access and avoidance of bypass.

As discussed, the cost of supply and delivery capacity can account for almost 50% of the overall cost of electricity for an average residential customer. Traditionally, residential rate structures are based on metered energy usage. With no separate charge for capacity costs, the energy charge has traditionally been set to recover both costs. This mixing of fixed and variable cost recovery is feasible when electricity is generated from central stations, delivered through a conventional T&D system, and with an electromechanical meter that measures energy use only by a single entity [8,9].

Most residential (and some commercial) rate designs follow this philosophy, but the philosophy has not been crisply articulated nor reliably implemented for DER. Consequently, consumers that use distributed resources to reduce their grid-provided energy consumption significantly, but remain connected to the grid, may pay significantly less than the costs incurred by the utility to provide capacity and grid connectivity. In effect, the burden of paying for that capacity can potentially shift to consumers without DER [10].

As DER deploys more widely, policy makers will need to look closely at clearly separating how customers pay for actual energy and how they pay for capacity and related grid services. EPRI believes that an integrated grid that optimizes the power system while providing safe, reliable, affordable, and environmentally responsible electricity will require focused collaboration in four key areas:

1. Interconnection Rules and Communications Technologies and Standards

- Interconnection rules that preserve voltage support and grid management
- Situational awareness in operations and long-term planning, including rules-of-the-road for installing and operating distributed generation and storage devices
- Robust information and communication technologies, including high-speed data processing, to allow for seamless interconnection while assuring high levels of cyber security
- A standard language and a common information model to enable interoperability among DER of different types, from different manufacturers, and with different energy management systems

2. Assessment and Deployment of Advanced Distribution and Reliability Technologies:

- Smart inverters that enable DER to provide voltage and frequency support and to communicate with energy management systems [11]
- Distribution management systems and ubiquitous sensors through which operators can reliably integrate distributed generation, storage and end-use devices while also interconnecting those systems with transmission resources in real time [12]
- Distributed energy storage and demand response, integrated with the energy management system [13]

3. Strategies for Integrating DER with Grid Planning and Operation

- Distribution planning and operational processes that incorporate DER;
- Frameworks for data exchange and coordination among DER owners, distribution system operators (DSOs), and organizations responsible for transmission planning and operations
- Flexibility to redefine roles and responsibilities of DSOs and independent system operators (ISOs)

4. Enabling Policy and Regulation

- Capacity-related costs must become a distinct element of the cost of grid-supplied electricity to ensure long-term system reliability
- Power market rules that ensure long term adequacy of both energy and capacity
- Policy and regulatory framework to ensure costs incurred to transform to an integrated grid are allocated and recovered responsibly, efficiently, and equitably
- New market frameworks using economics and engineering to equip investors and other stakeholders in assessing potential contributions of distributed resources to system capacity and energy costs

EPRI has initiated a three-phase effort to assess the costs and opportunities of different technologies and policy pathways to fully integrate DER into the electric power system. Phase I resulted in a concept paper outlining the main issues; Phase II will develop a framework of analytical tools and procedures to inform the development of an integrated grid; and Phase III will involve global demonstrations and modeling to provide the data needed for stakeholders to cost-effectively implement integrated grid technologies.

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Dr. Michael Howard is the President and CEO at the Electric Power Research Institute (EPRI). Howard has over 30 years of results-driven, multi-faceted leadership experience in organizations ranging from entrepreneurial start-ups to large public companies with increasing responsibilities in operations, finance, sales and marketing, product development, and strategic planning. Most of his experience is in providing technical consulting services and products to both U.S. and international electric utility companies.

Prior to his current appointment, Dr. Howard served as Senior Vice President, Research and Development, and President and Chief Executive Officer of EPRI Solutions, Inc., a wholly-owned subsidiary of EPRI. EPRI Solutions was created by the merger of three companies, one of which was the EPRI Power Electronics Application Center (PEAC) Corporation where he served as President and Chief Executive Officer. Previously, Dr. Howard was President of the Tennessee Center for Research and Development (TCRD) located in Knoxville, Tennessee and President of Beta Development Corporation (BDC), an early-stage venture capital firm focused on providing equity investment in technology-based companies.

Dr. Howard began his career in 1980 with Westinghouse Electric Corporation as an applications engineer for the fossil and nuclear digital control systems group.

Howard holds a Bachelor of Science in electrical engineering from the University of Tennessee, a Master of Science in business and engineering management from the University of Pittsburgh, and a doctorate in engineering science from the University of Tennessee. He has also completed the MIT Reactor Technology Course.

VIII. Energy Efficiency Potential in the U.S.: 2012 through 2035

By Sara Mullen-Trento, Chris Holmes and Omar Siddiqui

Abstract

Electricity plays an integral role in supporting living standards by enabling end-use applications such as air conditioning, lighting, refrigeration, and motive power to provide comfort, convenience, health and safety, security, and productivity. Moreover, the computational and communications infrastructure associated with our digital economy depends on electricity – from powering data centers to charging ever-proliferating mobile electronic devices.

Although substantial energy savings have been achieved through codes and standards and existing energy efficiency programs, substantial savings opportunities remain in several end use categories across the residential, commercial and industrial sectors. While the Energy Information Administration's 2012 Annual Energy Outlook projects electricity consumption growth at 0.7% annually from 2012 to 2035, new energy efficiency programs could reduce annual growth to 0.4%.

Index Terms—Energy Efficiency, Demand-side Management (DSM), Energy Efficiency Potential, Forecasting

Introduction

The challenge to provide affordable, reliable and environmentally responsible electricity encourages providers to understand all resources available to meet demand. Utilities and policymakers continue to look to energy efficiency as a cost-effective resource to enable reliable and affordable electric service while reducing carbon emissions.

In 2009, the Electric Power Research Institute (EPRI) commissioned a study to assess the potential energy savings achievable through energy efficiency and demand response programs in the U.S. from 2010 through 2030 [1]. This study updates that 2009 assessment with several modifications to the modeling engine, treatment of end-uses, and an enhancement to reflect the U.S. Energy Information Administration's 2012 Annual Energy Outlook (*AEO2012*) baseline [2]. The majority of the effort focused on the identification of cost-effective energy efficiency options and an assessment of the achievable potential resulting from application of cost-effective efficiency measures beginning in 2013 through 2035, where 2013 is the first year where efficient technologies are applied as equipment stock retires.

The "achievable potential" represents an estimated range of savings attainable through programs that encourage adoption of energy-efficient technologies, taking into consideration technical, economic, and market constraints. The study's objective is to provide a technically grounded estimate of the potential for electricity energy savings and peak demand reduction from energy efficiency programs through 2035 to help inform utilities, electric system operators and planners, policymakers, and other electricity sector industry stakeholders in their efforts to develop actionable savings estimates for end-use energy efficiency programs.

Approach

This study implemented an analysis approach consistent with the methods described in EPRI's Energy Efficiency Planning Guidebook (as depicted in steps 1 through 5 of Fig. 1), and the National Action Plan for Energy Efficiency (NAPEE) Guide for Conducting Energy Efficiency Potential Studies [3],[4].

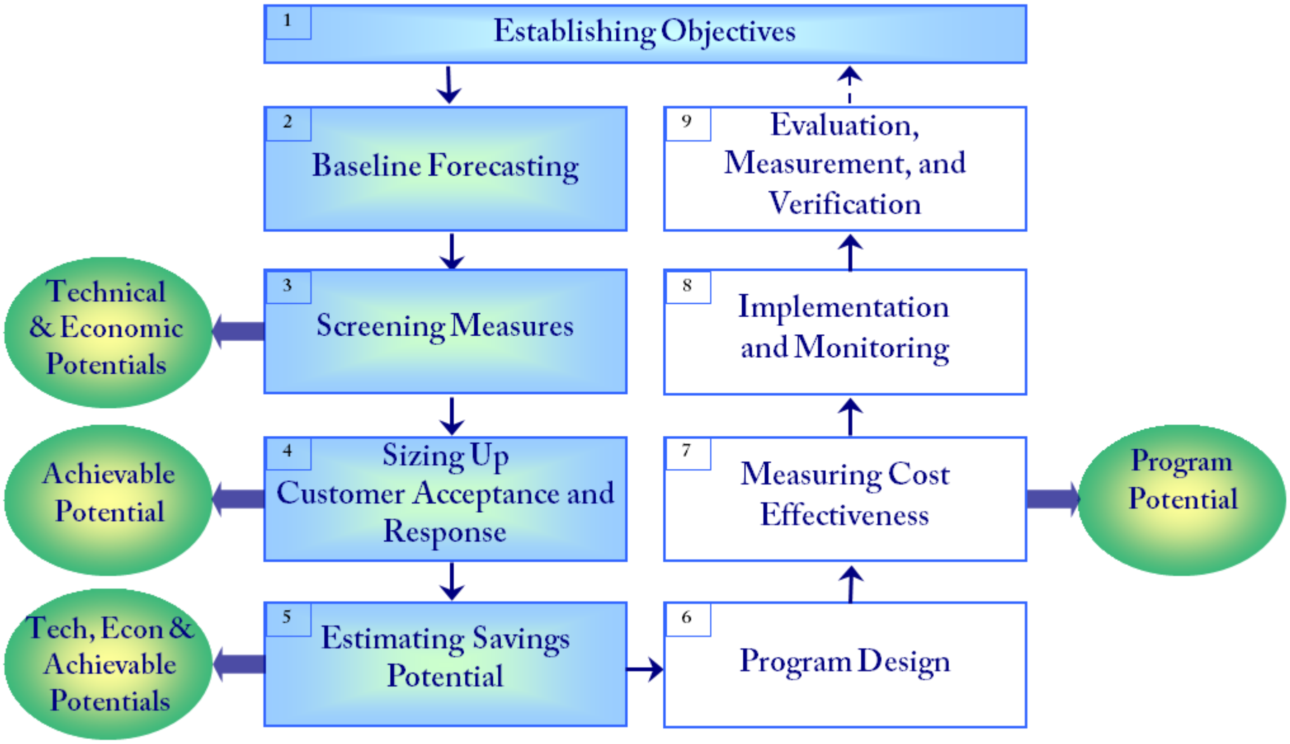

Figure 1. General Energy Efficiency Analysis Framework

The approach for deriving achievable potential is predicated on first establishing the theoretical constructs of technical potential and economic potential and then discounting them to reflect market and institutional constraints. This study assumes that new equipment does not replace existing equipment instantaneously or prematurely, but is "phased-in" over time as existing equipment reaches the end of its useful life.

Potential is defined in this study using several terms, as described below.

a. Technical Potential

The technical potential represents the savings due to energy efficiency and programs that would result if all homes and businesses adopted the most efficient, commercially available technologies and measures, regardless of cost. Technical potential does not take into account the cost-effectiveness of the measures, or any market barriers.

b. Economic Potential

The economic potential represents the savings due to programs that would result if all homes and businesses adopted the most energy-efficient, *cost-effective,* commercially available measures. With the efficiency measure inputs and avoided costs, the Total Resource Cost test (TRC) is calculated over the life of the measure. This benefit-cost ratio compares the present worth of the avoided power supply costs to the incremental measure cost plus the energy efficiency program administration cost.

If several measures have a TRC greater than or equal to 1.0, the most efficient measure (greatest energy savings) is adopted. Measures are screened for cost-effectiveness in each forecast year to capture effects of changing costs, rates and technology evolution.

c. High Achievable Potential

The high achievable potential takes into account those barriers that limit customer participation, including perceived or real quality differences, aesthetics, customer inertia, or customer preferences for product attributes other than energy efficiency.
Market acceptance ratios (MARs) are scaling factors that capture the effects of market barriers, including transactional, informational, behavioral, and financial barriers. The MARs are applied to

the economic potential measure savings over the forecast period, and change over time (maximum of 100%) to reflect that market barriers are likely to decrease over time. MARs represent what exemplary energy efficiency programs have achieved, assuming that they have overcome market barriers to some extent.

d. Achievable Potential

Achievable potential represents a forecast of *likely* consumer adoption. It takes into account existing market delivery, financial, political and regulatory barriers that can limit the savings achieved through energy-efficiency programs. For example, utilities do not have unlimited budgets for program implementation. There can be regional differences in attitudes toward energy efficiency and its value as a resource. Achievable potential is calculated by applying program implementation factors (PIFs) to the high achievable potential for each measure over the forecast period, and are assumed to increase over time as programs mature. The PIFs were developed by taking into account recent utility experience with such programs and their reported savings.

Baseline

a. The Starting Point: Base-Year Electricity Use by Sector and End Use

Based on the *AEO2012* baseline, annual electricity use for the residential, commercial and industrial sectors in the U.S. in 2012 is estimated at 3,722 TWh. The allocation of electricity use across sectors is fairly even: the residential sector accounts for 38%, the commercial sector for 36%, and the industrial sector for 26%. The complete breakout of 2012 consumption in each sector by end use is shown in Fig. 2.

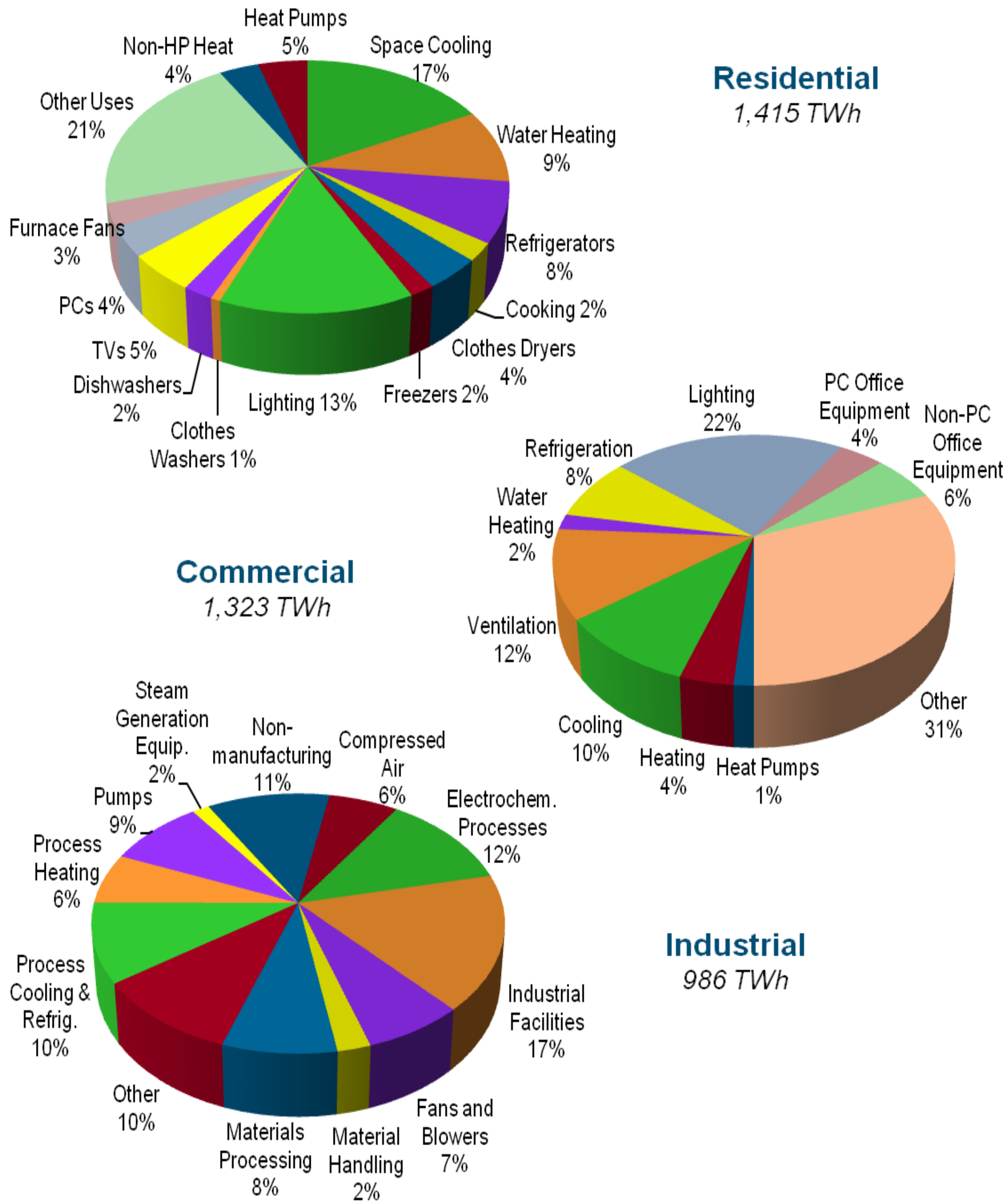

Figure 2. 2012 U.S. Electricity Consumption by Sector and End Use

b. The Baseline Forecast

U.S. electricity use is expected to increase by 18% between 2012 and 2035, according to the *AEO2012* Reference case baseline [2]. The annual growth rate for the residential, commercial and industrial sectors is forecast to be 0.7% between 2012 and 2035, as illustrated in Fig. 3. Although steady growth is predicted, the AEO forecast of growth in electricity consumption has been declining year over year accounting for shifts in the economy, energy prices, and technology innovation among other things.

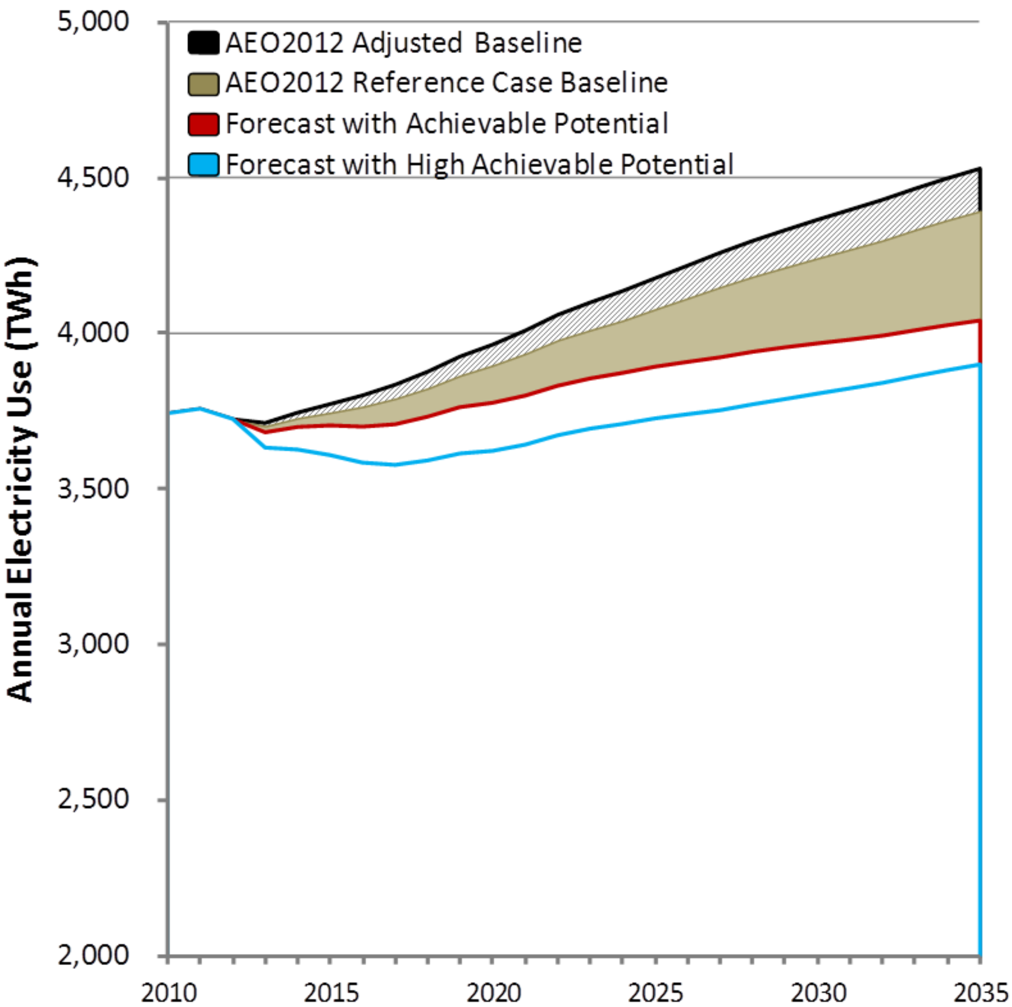

Figure 3. AEO2012 Reference Case Electricity Consumption Forecast

This Reference case forecast already includes expected savings from several efficiency drivers, including codes and standards, market-driven efficiency, and implicit efficiency programs. The baseline forecast does not assume any expected savings from future federal or state appliance and equipment standards or building codes not currently enacted. Finally, the baseline embodies the *AEO2012* price forecast, which is relatively flat in real terms over the forecast horizon.

The analysis of potential savings from utility programs began with a list of energy efficiency measures. This list includes high-efficiency appliances and equipment for most end uses, many of which have numerous efficiency levels, devices, controls, maintenance actions, and enabling technologies such as programmable thermostats. Table I and Table II summarize the residential and commercial energy-efficiency measure categories included in the analysis.

No measures are applied per se in the industrial sector due to the diversity of equipment installations and applications. Instead, the savings are applied top-down to process-level consumption within each manufacturing segment (by three-digit NAICS code).

Table I. Summary of Residential Efficiency Measure Categories

Residential Sector Measure Categories
Efficient air conditioning (central, room)
Efficient space heating and cooling (heat pumps)
Efficient water heating (e.g. heat pump water heaters & solar water heating)
Efficient appliances (refrigerators, freezers, washers, dryers)
Efficient lighting (CFL, LED, linear fluorescent)
Efficient power supplies for Information Technology and consumer electronic appliances
Air conditioning and heat pump maintenance
Duct repair and insulation
Infiltration control
Whole-house and ceiling fans
Reflective roof, storm doors, external shades
Roof, wall and foundation insulation
High-efficiency windows
Faucet aerators and low-flow showerheads
Pipe insulation
Programmable thermostats
In-home energy displays

Table II. Summary of Commercial Efficiency Measure Categories

Commercial Sector Measure Categories
Efficient cooling equipment (chillers, central AC)
Efficient space heating and cooling equipment (heat pumps)
Efficient water heating equipment
Efficient refrigeration equipment & controls
Efficient lighting (interior and exterior)
Efficient power supplies for Information Technology and electronic office equipment
Water temperature reset
Efficient air handling and pumps
Economizers and energy management systems (EMS)
Programmable thermostats
Duct insulation

Results

The *AEO2012* Reference case baseline forecast for U.S. electricity consumption between 2012 and 2035 (0.7% growth per year) is significantly lower than actual consumption growth over the past 30 years (1.9% per year). The *AEO2012* Reference case is predicated on a relatively flat electricity price forecast in real dollars between 2012 and 2035, suggesting slow growth in demand in the electric sector. Despite this lower load growth outlook, this study shows that energy efficiency remains a significant resource.

The savings impact of energy efficiency programs “embedded” in the AEO2012 Reference case was estimated and removed from the *AEO2012* Reference case, resulting in a higher adjusted baseline forecast. This adjusted baseline forecasts annual growth of 0.85% from 2012 to 2035. For this adjusted baseline, EPRI estimates that energy efficiency programs have the potential to reduce electricity consumption in 2035 by 488 to 630 billion kWh. The 488 billion kWh represents a “moderate case” achievable potential of 11%, while the 630 billion kWh represents a “high case” achievable potential of 14%.

Relative to the *AEO2012* Reference case, which implicitly assumes some level of energy efficiency program impact, this study identifies between 352 and 494 billion kWh of additional cost -effective savings potential from energy efficiency programs. Therefore, energy efficiency programs have the potential to reduce the 0.7% annual growth rate in electricity consumption forecasted in *AEO2012* by 51% to 72%, reducing the annual growth rate to 0.2% to 0.4%.

Table III presents energy efficiency potential estimates for the U.S. in 2025 and 2035, and Fig. 4 illustrates the achievable energy savings potential relative to both the Reference case and the adjusted *AEO2012* baselines.

Table III. Energy Efficiency Potential Forecasts for the U.S.

	Forecast (TWh)			**Compound Annual Growth Rate (2012-2035)**
	2012	**2025**	**2035**	
Baseline Forecast	3,722	4,177	4,529	0.9%
***AEO2012* Reference Case**	3,724	4,078	4,393	0.7%
Achievable Potential	3,724	3,893	4,041	0.4%
High Achievable Potential	3,724	3,725	3,898	0.2%

89 GW,

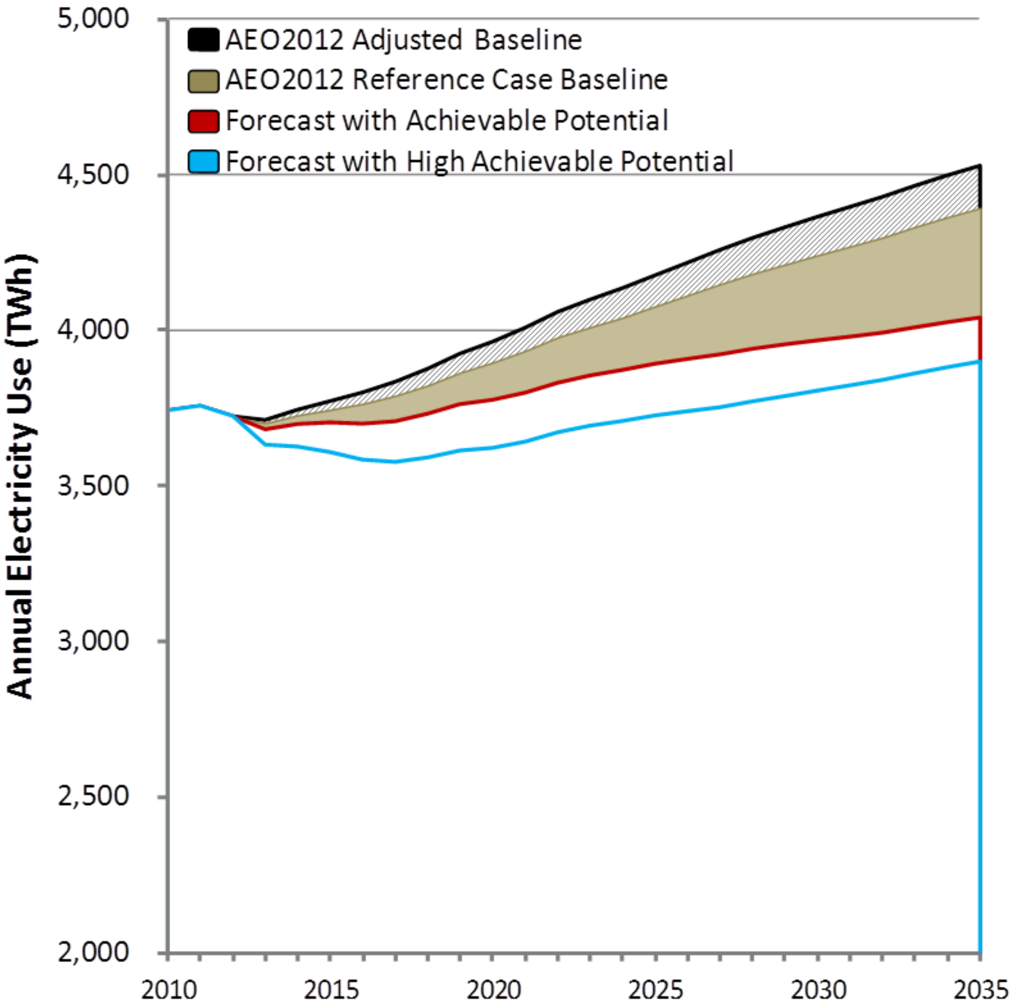

Figure 4. U.S. Energy Efficiency Achievable Potential

These estimated levels of electricity savings are achievable through voluntary energy efficiency programs implemented by utilities or similar entities. The analysis does not assume the enactment of new energy codes and efficiency standards beyond what is already in law.

a. Peak Demand

Along with energy savings, application of efficient technologies impacts the demand that coincides with the utility system's peak demand. Depending on the technology these may be summer or winter demand reductions and in some cases efficient technologies will result in both summer *and* winter coincident peak demand reductions.

Summer coincident peak demand in the U.S. is projected to be 595 GW in 2012, and is expected to increase to 714 GW by 2035, reflecting 0.8% compound annual growth.

Energy efficiency programs have the potential to reduce coincident summer peak demand by 79 to 117 GW, representing an achievable potential reduction in 2035 summer peak demand of 11% to 16%. This can also be expressed as a 65% to 98% reduction in the forecasted annual growth rate of summer peak demand through 2035.

Winter coincident peak demand in the U.S. is projected to be 495 GW in 2012, and is expected to increase to 628 GW by 2035, reflecting 1% compound annual growth. Winter peak demand is expected to grow at a faster annual rate than electricity use due partly to the expected growth in the share of electric water heating.

Energy efficiency programs have the potential to reduce coincident winter peak demand by 64 to representing an achievable potential reduction in winter peak demand in 2035 of 10% to 14%. This can also be expressed as a 45% to 65% reduction in the forecasted annual growth rate of winter peak demand through 2035.

b. Energy Efficiency by Sector and Measure

Fig. 5 depicts presents the highest saving end uses for each sector. Commercial indoor lighting presents significant opportunities for energy savings, more than the sum of the remaining end uses, and 38% of the total achievable 2035 energy savings. Note that the heading of industrial facilities includes HVAC, water heating and lighting for the industrial sector.

LED technologies replacing both screw-in lamps and linear fluorescents account for the lighting savings in the residential and commercial sectors in most cases. In a few cases where LEDs are not cost-effective, dimmable CFLs and dimmable T-5 linear fluorescents provide savings. Induction lighting technologies present opportunities for savings in commercial high-intensity discharge (HID) applications.

Space cooling is in the top three for both residential and commercial, where more efficient central air conditioners, room air conditioners and chillers present cost-effective energy savings above and beyond what is mandated by codes and standards. The following technologies provide opportunities for savings in residential and commercial HVAC:

- Residential:
  - Central AC – SEER 16 to20 in Texas, Florida, and South Atlantic
  - Air-source heat pumps – SEER 21+ in California, Pacific Northwest, Mountain North
  - Ground source heat pumps – COP 3.0 in Texas, Central Plains, Southwest, Florida
  - Ductless heat pumps – SEER 25
  - HVAC maintenance & re-commissioning
  - Programmable thermostats
  - Envelope (insulation, windows, roofs, etc.)
- Commercial
  - Air-source heat pumps (COP 3.4 or greater)
  - Chillers with energy management controls
  - Variable speed ventilation

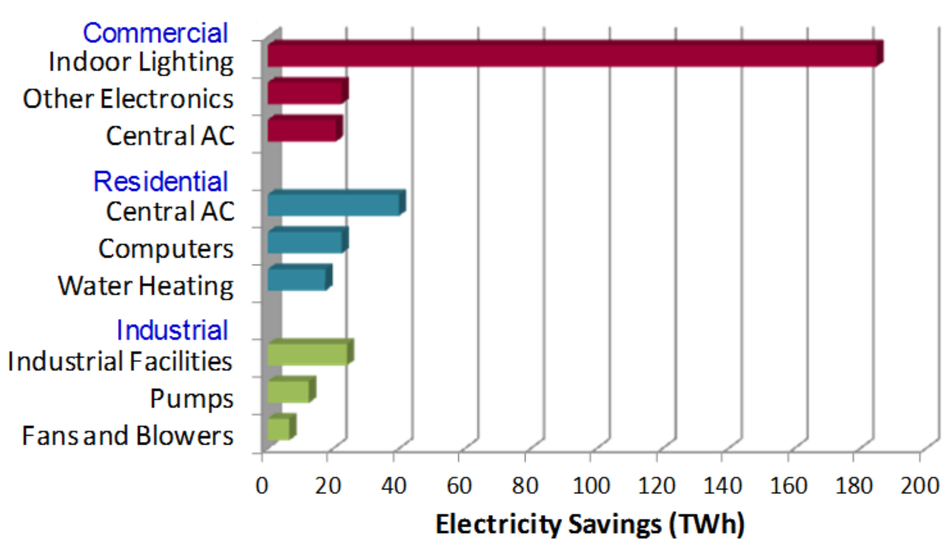

Figure 5. Top Three End Uses for Achievable Energy Savings, 2035

Heat pump water heaters could provide significant savings in the residential sector for smaller units, with capacity less than 55 gallons.

In addition, advanced power supplies and displays contribute to savings in electronics in both the commercial and residential sectors. Efficient servers, storage, and other equipment; improved thermal management; and emerging techniques provide opportunities for savings in commercial data centers.

The remaining high savings categories have several common threads that will provide new opportunities for energy savings beyond what we expect to see today:

- Advanced motor technologies,
- New materials in batteries and electronics
- Advanced power management.

Within the residential sector, single family homes have the highest potential for energy savings, representing 70% of U.S. energy savings in 2035. Within the commercial sector, retail space has the highest potential for energy savings, representing 17% of projected U.S. energy savings in 2035, primarily via savings in lighting, HVAC and office equipment.

C. Energy Efficiency Savings Potential by U.S. Census Region

Estimates of baseline consumption and demand, as well as forecasts of measure-based savings potentials, were developed for the U.S. as a whole, using U.S. census divisions and several individual states, as shown in Fig. 6.

The analysis included eight census divisions: New England, Middle Atlantic, East North Central, West North Central, South Atlantic, East South Central, West South Central, and Pacific. The ninth census division, Mountain, was broken out into Mountain North and Mountain South. Moreover, to achieve better granularity, California, Florida and Texas were broken out from their respective census divisions of Pacific, South Atlantic and West South Central.

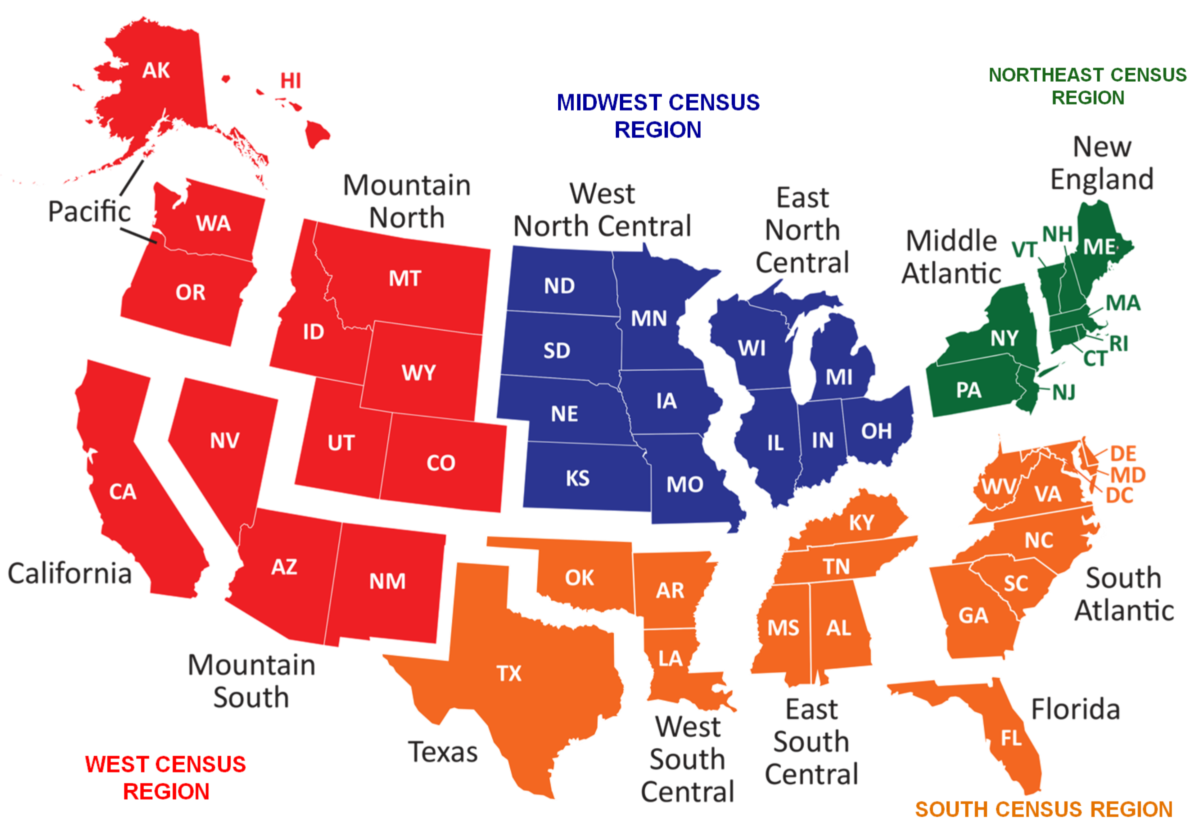

Figure 7. illustrates how the total U.S. 2035 achievable potential of 488 TWh is broken out among the divisions.

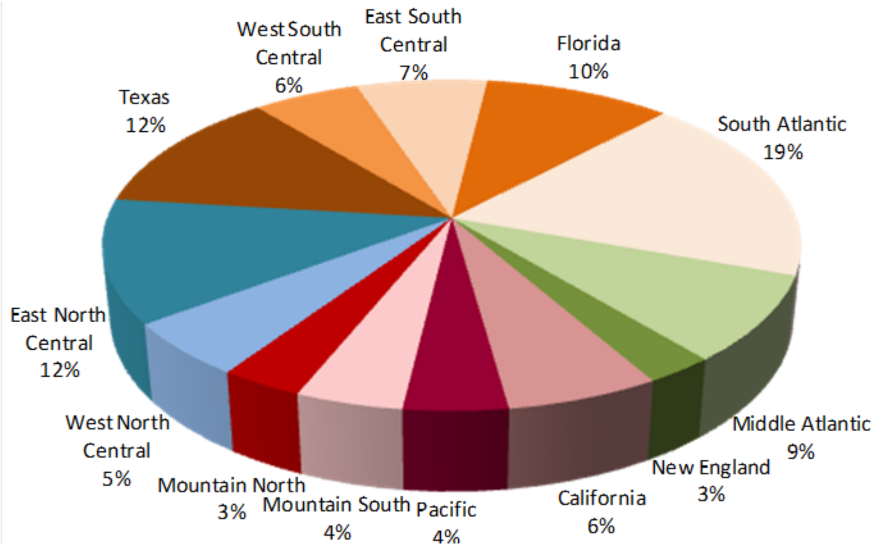

Figure 7. Division Shares of 2035 Achievable Potential

Conclusion

The results presented in this study give insight into the end uses with the greatest opportunities for energy savings through energy efficiency, as well as the geographic regions where these savings are most applicable.

Several technologies are expected to play a significant role in energy efficiency offering new opportunities for customer flexibility, including:

- Advanced motor technologies,
- Advanced thermal technologies such as heat pumps with expanded market potential in colder climates,
- More efficient electronics incorporating advanced materials, batteries and power management,
- Emerging electric end-use categories such as smart phones and tablets, and electric transportation.

Moreover, as end-uses emerge, new opportunities for energy savings will be created, and the realm of cost-effective efficiency measures will expand.

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Dr. Sara Mullen-Trento is a Project Manager/Technical Lead at the Electric Power Research Institute (EPRI). Dr. Mullen-Trento joined EPRI in September of 2009, and currently manages projects focused on assessment of efficient technologies for cost-effectiveness and customer value and the resulting potential for energy and emissions impacts. In addition, she works with the Electric Transportation group with a focus on energy transfer from plug-in electric vehicles back to the power grid. The work draws on her background in power systems operations and controls.

Dr. Mullen-Trento received the Bachelor of Computer Engineering degree, and Master's and doctoral degrees in Electrical Engineering from the University of Minnesota, Twin Cities in 2003, 2006, and 2009, respectively. Her doctoral dissertation focused on the use of distributed storage to support grid reliability and is titled Plug-In Hybrid Electric Vehicles as a Source of Distributed Frequency Regulation.

Christopher J. Holmes is a Principle Technical Leader at the Electric Power Research Institute (EPRI). His position focuses on analytical frameworks and how to quantify the benefits to energy consumers from energy efficiency, demand response, and efficient rate design. Mr. Holmes has spent over thirty years in the electric power industry, with the Tennessee Valley Authority (TVA), Aquila, Cinergy, and the Salt River Project. He was involved in a diverse set of management and technical capacities including rates, finance, marketing, EE&DR planning, strategic and resource planning.

Mr. Holmes has coordinated the development of time-based pricing programs, designed demand response products and has evaluated the economics of advanced metering initiatives. Mr. Holmes was also involved in program designs for energy efficiency and demand response programs including developing program implementation plans, M&V guidelines and a diverse set of activities designed to ensure utility success with their implementation efforts. Mr. Holmes has conducted marginal and embedded cost-of-service studies and has testified as an expert witness on rate design and class cost of service recovery. He has also been involved in the planning and implementation of statistical samples for load studies for use by utilities in revenue allocations and rate design.

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Omar Siddiqui is Senior Technical Executive at the Electric Power Research Institute (EPRI). He leads strategy, marketing, business development, and cross-cutting technical content for EPRI's Energy Utilization RD&D portfolio, which spans the disciplines of energy efficiency, demand response, electric transportation, electrification, distributed generation, energy storage, power quality, and customer behavior. Mr. Siddiqui provides leadership to help EPRI RD&D accelerate the advancement of technologies that enable cost-effective and environmentally sustainable use of energy. He consults with power company executives and government officials worldwide on energy utilization.

Mr. Siddiqui previously served for three years as Director of EPRI's energy efficiency, customer behavior, and power quality research area. He has managed prominent studies of national and regional potential for energy efficiency, peak demand reduction, and carbon reduction from end-use technologies, smart grid applications, and "end-to-end" efficiency strategies. He is a frequent speaker on energy utilization at industry and media events.

Before joining EPRI, Mr. Siddiqui worked at Global Energy Partners, leading business development and project management in energy efficiency engagements with utilities and government clients. His background also includes financial, mergers and acquisitions, and management consulting experience with such firms as J.P. Morgan, Kaiser Permanente, and A.T. Kearney.

Mr. Siddiqui holds a Bachelor of Science degree in Chemical Engineering from Stanford University and an MBA from the Anderson School of Management at the University of California, Los Angeles (UCLA). He also earned a certificate for an executive legal program from the Vermont Law School.

IX. Thinking Outside the Box: New Perspectives from the Paper Industry on Demand-side Flexibility

By Nicola Rega

Introduction

With the growing share of so-called non-programmable renewable energy sources (NP RES) in electricity systems, demand-side programmes have suddenly re-gained interest in the public debate in Europe. Most of the discussions revolve around experience gained from demand-side programmes for industry, how to better promote these programmes to capture the "untapped potential", and the future households' role in developing new programmes.

This paper argues that although experience gained with industry is important and valuable, it shouldn't be overestimated, as those programmes were properly designed to address a specific problem: excess of electricity demand. However, if the problem is excess of electricity supply, the recipe would have to be adjusted.

The paper therefore starts with an analysis of the experience gained with traditional demand-side programmes, and an assessment of their limits. It then focuses on industry's potential in managing NP RES, the barriers preventing this from happening, and some concrete proposals on the way forward.

The European pulp and paper industry has started to concretely investigate this aspect. That is why this article uses this sector as a starting point to stimulate a wider debate among energy-related stakeholders on how to properly re-adjust regulation in a way that combines energy-climate objectives (and challenges) with the promotion of industrial competitiveness.

Traditional Demand-side Programmes: Experience from the Pulp and Paper Industry

Demand-side programmes are not new to the industry. For instance, the pulp and paper industry has already engaged, where possible, in demand-side programmes.

Mechanical pulping, an electro-intensive process, can be used for "peak shaving" programmes. It can react at reasonably short notice, ranging from as short as 15 minutes up to one hour, depending on the frequency and schedule of interruptions. However, these are indicative figures, which need to be carefully assessed at mill level. Specifically, they will vary depending on the trade-offs between benefits from balancing the electricity system, the need to meet paper demand, and the overall economic impact that balancing the grid would have on the production process.

In some countries, paper production also participates in "valley filling" programmes: the whole industrial process is shifted to the night or to the weekends to optimise baseload electricity production. Examples of this can be found in Austria or Belgium. In Norway there are also provisions for flexibility markets where industry can participate. In this case, the transmission operator asks for bids.

Limits of Traditional Demand-side Programmes

The way traditional demand-side programmes operate is well known to industry. However, the potentials for further exploring "peak shaving" or "valley filling" programmes are however limited due to both the specificities of industrial processes as well as the need for production optimisation.

In the paper making process, for instance, beside auxiliary processes, the flexibility margin is very small when it comes to demand-reduction programmes. Moreover, most of the energy required from the sector (steam and electricity) is generated on-site, therefore mostly off the grid.

More generally, demand-side programmes for industry were primarily designed as a way to react to network congestions due to peak in electricity demand. However, one of the main criticalities of the electricity system is how to properly integrate electricity generated from "variable", or "non-programmable" renewable energy sources, like wind and solar, at a time of low or no demand.

Therefore, the traditional demand-side programmes are still important in addressing peak in electricity demand and should definitely be pursued. But they appear rather inadequate in coping with the challenge from NP RES: reducing demand at a time of excess in electricity supply would only worsen the problem.

Industry's Potential in Managing Non-programmable Renewable Energy Sources (NP RES)

At the moment, coping with excess of NP RES supply requires the network operator to curtail electricity generation. In general, curtailing is not really a cost-effective solution. And specifically for NP RES, curtailing is particularly inefficient, as these technologies produce at zero marginal prices.

While most R&D programmes focus on energy storage and on demand-side programmes for households, the pulp and paper industry is in a rather unique position to potentially provide solutions to

- efficiently absorb excess of electricity supply,
- <u>while</u> creating value for the EU economy.

Most importantly, all this could be already delivered with current technologies.

To explain how this would be possible, a few words on the pulp and paper industry are necessary.

CEPI, the Confederation of European Pulp and Paper Industries, represents 959 mills located in 18 European countries. According to CEPI latest figures, in 2011 the European pulp and paper industry consumed 111 TWh of electricity, of which 57 TWh (52%) produced on-site via co-generation units. In 2011 the sector also consumed 557 TJ, or 155 TWh-equivalent, of heat, all on-site generated ("2012 European Paper Industry Statistics", available at http://www.cepi.org/topics/statistics/pressreleases/2012keystatistics).

Combining the two figures for on-site generation, the sector generated and consumed about 212 TWh of energy in 2011. This is all energy sitting outside the boundaries of the electricity system. To put these figures into context, it is worth noticing that in 2011 total European electricity production from wind and solar was about 223 TWh.

What would happen if, at a time of excess of electricity supply, the sector ramps up electricity demand by ad-hoc moving from "off" to "on" the grid? It would absorb the peak of cheap electricity supply while maintaining the industrial output unchanged. Meaning more value per kWh, less primary energy consumption, less carbon emissions. In one word: a more competitive industry.
In most cases technology is already available and deployable. For instance, in some cases it would be sufficient to install an extra, highly-efficient electric boiler. With the support of additional Research Development and Innovation (RDI) projects, more options could be envisaged in the near future, whereby electro-technologies could be progressively introduced in the drying process.

The geographical distribution of mills in Europe allows for cost-effective absorption of excess electricity produced by decentralised energy sources, substantially reducing the need for costly investments in grid extensions.

Last but not least, this cost-effective measure will also be beneficial in reducing the need for additional costs to remunerate unused thermal capacity for electricity generation (so-called Capacity Remuneration Mechanisms – CRM), as the impact of NP RES on the running hours of conventional power plants will be largely mitigated.

Regulatory barriers are the main reason for not making this a reality. Without addressing this aspect first, it will be impossible for any mill operator to start any cost-benefit analysis to assess how to adapt a mill operation in a way that would deliver on-site financial benefits.

Barriers to New Demand-side Programmes – and the Way Forward

The idea of industry cost-effectively absorbing excess of electricity supplied by NP RES will remain just on paper, as long as European and national regulation do not address the main barriers preventing this from happening. Specifically:

Regulatory barriers

This is the key barrier for demand-side flexibility in absorbing excess electricity supply from NP RES.

Currently, network tariffs and network charges (including levies and taxes) are set in a way that discourages industries from accessing the grid.

This approach is in principle correct, as it tends to promote stable and predictable demand from big energy users.

However, in this context, the network operator needs a service to balance the network. A service the industry is ready to provide. But here is the paradox: instead of being remunerated for such a service, industry would have to pay for offering it, to the benefit of the network operator.

In Germany, for instance, should a paper mill decide to import electricity from the grid, it would face additional costs of at least 70 €/MWh.

Moreover, a mill has a very flat power consumption profile, like i.e. 7000 (or 7500 or 8000) full load hours a year. On this basis, it enjoys a reduced grid fee, i.e. in Germany it pays only 20% (or 15% or 10%) of the normal fee. Normal grid fee depends on local grid operator and could range between 5 to 11 €/MWh. When taking additional load from the grid, the profile will no longer be flat and the 7000 hours threshold might not be reached anymore. As a consequence, the mill would have to pay the remaining 80 to 90% of the grid fee.

A proper regulatory framework should incentivise both the “off-the-grid” baseload demand, and the flexibility to bring “on-the-grid” ad hoc electricity demand to help matching the excess of electricity generation from NP RES.

To our knowledge, the only exception is Norway. There, already since 1999, the government promoted the installation of electric boilers on industrial sites (although other incentives were already earlier in place). The rationale was to absorb seasonal excess of hydro electricity generated. The boilers are activated in remote by the network operators.

In exchange for this flexibility, industrial operators receive a significant reduction in grid charges. While the usual tariff for the Norwegian transmission grid (Statnett) is 170 NOK/kW (about 20 €/kW) in 2013, the tariff for flexibility load is 43 NOK/kW (about 5 €/kW). In addition there are distribution charge and taxes. Since 2010 the flexibility grid fee is open for all that can offers to decouple the load either by remote control or at 15 minutes or 2 hour notice.

For customers with remote control, the grid operator can move the load from day to night. The grid operators are very satisfied with this system. The possibility to decouple load has proven to save the grid from collapse. The use of flexible load in periods with excess of electricity stabilizes the grid.

We strongly encourage national regulators to urgently use the Norwegian example as a best practice case for promoting and valuing flexibility markets in their own countries.

Market barriers

Balancing NP RES is clearly not an intrinsic element of industrial processes. Industry can be part of the solution, and is willing to do so, provided there is a business case supporting it.
However, industry lacks crucial information to build a proper business case. There should be some kind of guarantee on the minimum yearly number of hours one should reasonably expect to be called for providing services to balance the market.

This minimum number of hours should be provided by the regulator and/or network operator and should be the founding element of any contractual agreement.

Moreover, commodity prices will have to be extremely low (or even negative) to compensate for the loss of revenues from CHP/green certificates or other support schemes. In fact, if commodity prices were on the level of the fuel used normally, that would mean equal costs for steam generation, but no compensation for lost electricity generation.

Energy supply contracts may also need to be adapted to incorporate this additional flexibility.

Legislative barriers

In many cases, the industry is subject to stringent energy efficiency targets. In case of demand side flexibility, deliberately stopping CHP units would negatively impact the industry performance.

In order to promote energy efficiency programmes while incentivising demand-side flexibility (DSF), the legislation should clearly state that importing electricity from the grid would be done to absorb the load from NP RES, such as wind and solar. Therefore the electricity imported should be counted as 100% energy efficient.

Concluding Remarks

Industry has a clear role to play in promoting cost-effective integration of non-programmable renewable energy sources into the energy systems. New type of demand-side programmes could be instrumental in coupling energy-climate objectives with industrial competitiveness.
However, this possibility will not materialise by itself. Regulators should work to ensure that the following minimum preconditions are met:

- Removal of regulatory barriers to create extra demand for electricity at a time of need: no extra costs (tariffs, levies, taxes) when participating in DSF programmes;
- Maintain current incentives for on-site generation;
- DSF to be compatible with energy efficiency targets: 100% energy efficiency for electricity taken from the grid when participating in DSF programmes;
- Regulators/network operators to guarantee a minimum yearly amount of hours a paper mill should reasonably expect to be called when participating in DSF programmes.

Last, but not least, participation in DSF programmes would require significant changes in the way industry operates, both from a technological and industrial processes perspective. Support for Research, Development and Innovation would be needed.

Nicola joined CEPI in January 2013 as Energy & Innovation Manager His field of expertise covers Climate Change, Energy and Innovation policies, both at EU and international level.

Nicola moved to Brussels in February 2013. Since then, he has built a thorough understanding of EU-related policies by working in a wide range of stakeholders (industry associations, European Commission, NGOs, governmental institutes, consultancies).

Nicola holds a Master's Degree in Law from the University of Turin, an Advanced Master's in Political and Social European Integration from the VUB, and a Master of Laws in Energy and Environmental Law from the K.U.Leuven.

X. Market-led Development of Transmission Networks: an Australian Case Study

By Stuart Slack

Introduction

The Australian Energy Market Commission is investigating a new model for generator access to the wholesale electricity market. It would provide a form of financial compensation to generators that are unable to be dispatched because of network congestion. The development of transmission networks would be driven (in part) by the purchase of these firm access rights [1].

Linking transmission capacity to access rights would extend the commercial and market drivers of generation investment to the transmission system. Doing so may promote more efficient investment in both generation and transmission – particularly if there is significant change in the future from established patterns of generation and demand.

Existing Wholesale Market and Transmission Arrangements

The National Electricity Market (NEM) is eastern Australia's wholesale market, serving six states and territories [2]. The market was created as a mechanism to facilitate interconnection and trade between pre-existing state-based electricity supply industries.

The NEM is based on a regional design. There are five state-based regions, each with its own transmission network. They are linked together by cross-border interconnectors.

Wholesale electricity from large-scale power stations is traded through the NEM. On the basis of generators' offers, the Australian Energy Market Operator determines the combination of generation to meet demand in the most cost-efficient way and dispatches the generators accordingly. Within a region, generators receive and retailers pay a uniform spot price – the "regional reference price". The regional reference price is based on the local clearing price at a regional reference node, located in each state's major load centre [3].

Generators and retailers contract with each other to manage the risk of spot price variability [4]. The use of a uniform regional spot price allows market participants to write contracts that are referenced to this common price, promoting contract market liquidity.

Historically, transmission networks within each region were quite strong but interconnections between regions were weak. Therefore the NEM design established congestion prices between regions as a risk management tool, but not within regions. Spot prices between regions diverge when the interconnector between them becomes congested.

The transmission network in the NEM is operated on the basis of open access. Generators, subject to the appropriate regulatory approvals and payment of relevant charges, are able to access the network on a non-discriminatory basis.

However, generators are paid only when dispatched [5]. Transmission network congestion within a region can limit the ability of some generators to sell their electricity, even if their offer is below the regional reference price: they are "constrained off". Generators that are constrained off receive reduced or no revenue. Unlike most market designs with regional pricing, there is no compensation paid to such generators. When the NEM was designed, the costs of establishing such a regime were considered likely to outweigh the benefits.

Generators do not pay for using the shared transmission network. They pay only a "shallow" connection charge. The shared network is paid for entirely by end-users.

Transmission businesses have statutory obligations to maintain reliability of supply to end-users. They are subject to ex ante incentive-based regulation and undertake an economic cost-benefit test in deciding what investments to make. These measures encourage the businesses to plan and operate their networks to meet their reliability obligations at least cost.

Transmission businesses are also permitted, but not obliged, to undertake capital expenditure to reduce congestion - within their own region or between two regions - where this passes a cost-benefit test. However, they have no obligation to provide any particular service level to individual generators.

Concerns with Current Arrangements

Australia's National Electricity Market is experiencing a period of change. Climate change policies and technological developments have affected the use of the transmission system by generators. Changes to the structure of the Australian economy and the response by consumers to rising electricity prices have resulted in changes to patterns of demand. These factors may have a significant impact on future investment in these sectors.

Against this background, there is a concern that the current arrangements will not deliver the combination of generation and transmission investment that minimises the total system costs faced by consumers. The different investment-making processes for generation and transmission have the potential to result in a lack of coordination:

- Generation investment decisions are market driven. In deciding whether to invest in new generation capacity, competitive businesses take into account price signals from the wholesale electricity market and retailers' willingness to enter into contracts to hedge against future price risk [6].

- Because they only pay a "shallow" connection charge, generators do not face clear locational signals with regard to transmission costs or existing spare capacity [7]. A generator may locate closer to a fuel source (or where the wind quality is better) without taking into account the implications for the transmission system. Trade-offs may exist between proximity to a fuel source and transmission costs that would result in a lower total system cost if they were taken into account.

- In seeking the least-cost investments to meet reliability needs, transmission businesses forecast where and when generation investment is likely to occur. It becomes increasingly difficult to do so if the patterns of network flows are changing and the forecasts of future needs are uncertain.

- Regulated decision-making may fail to deliver an efficient level of transmission investment. Generators benefit from transmission investment where it reduces congestion, allowing them to be dispatched and so to earn revenue. They may value the benefit of additional transmission investment more than it would cost. However, there is no means for them to fund additional investment and secure a right to the additional market access that is created.

While there is limited firm evidence that the current arrangements have caused significant coordination issues to date, these issues are more likely to arise if the future brings significant change.

New Model for Transmission Access and Planning

The Australian Energy Market Commission [8] has developed an alternative transmission model called *optional firm access*. The model creates the ability for generators to "insure" against the risk of congestion. It would transform the way generators access the market during times of congestion and the way that transmission investment decisions are made:

- Generators would have the option of buying firm access rights to manage congestion risk. These financial rights would take the form of compensation payments funded by generators without such rights, and would be underpinned by the provision of transmission capacity.

- Generators, rather than planners, would drive some part of the decision-making about future transmission development. In choosing to acquire firm access, generators would fund and guide the development of new transmission to underpin their access rights.

The optional firm access model is an integrated package of market reforms that touches on most of the significant interfaces between generation and transmission: how generators access the wholesale market via the transmission system, the way in which transmission congestion is managed, what transmission charges generators face and how transmission businesses plan and operate their networks.

Firm Access Rights

The optional firm access model gives generators the option of obtaining firm access to their regional reference price. Even when they were not dispatched because of congestion within their region, firm generators would still receive some payment.

Generators would have the option of purchasing a quantity of firm access from their local transmission business, which might be for all or part of their output. Purchase of firm access would confer a financial access right. It would confer no physical rights – to preferential dispatch for example – so it is not like a capacity right on a gas pipeline. Instead, the firm access right would be analogous to financial transmission rights in other electricity markets [9].

Generators that did not procure firm access would receive non-firm access.

Where the dispatch of non-firm generators contributed to congestion they would compensate firm generators for any loss of dispatch. Generally the compensation payment afforded by the firm access right would represent the margin that a generator would have earned by being dispatched, so would provide the constrained-off firm generator with a hedge against congestion risk.

Generators that were required to pay compensation would nevertheless always earn at least their offer price on each unit of energy for which they were dispatched. Therefore a generator should never regret being dispatched.

The firm access product would only have value during times of network congestion [10].

Transmission Planning and Operation

A new firm access standard would require transmission businesses to plan and operate their networks to provide the level of capacity necessary to meet the agreed quantities of firm access. Transmission businesses would not be required to plan or operate their networks to provide non-firm access.

The firm access standard would be a real-time standard. In every settlement period under normal operating conditions, transmission businesses would be required to provide enough network capacity for firm generators to be dispatched [11]. Actual network capacity would reflect both transmission business planning (what capacity has been built) and operational decisions (how much of that capacity is delivered in a moment of time).

Access Pricing and Procurement

Generators would pay their local transmission business to obtain firm access. The procurement process would be regulated. There would be no charge for non-firm access.

A request for additional firm access by a generator would increase the network capacity that the transmission business is required to provide over time, imposing new costs on the network provider. Access pricing would estimate what these costs are. The firm generator would pay an amount to the transmission business that covered these estimated incremental costs [12].

Commercial Drivers on Transmission Development and Operation

The optional firm access model has the potential to deliver better long-term outcomes by introducing more commercial drivers on transmission businesses and more commercial financing of transmission infrastructure. It may help to deliver the most efficient development path for both generation and transmission over time.

- *Generation and transmission location.* If generators face the full cost of transmission, in the form of an access charge, they will factor this into their location decision. They have incentives through competition to minimise the combined lifetime cost of generation and transmission, and of other energy networks - such as gas pipelines - where they use them.

- *Efficient levels of transmission development.* In choosing whether to acquire firm access, generators would trade off the cost of transmission (in the form of the access charge) against the avoided cost of congestion (the payout on the firm access right). The result should be a more efficient level of transmission development.

- *Risk for consumers from investment decisions.* The owners of generation businesses would bear the costs of transmission development undertaken to support their access decision. Competition is likely to limit their ability to pass through the costs of inefficient decisions to consumers.

- *Operation of transmission networks.* The arrangements would result in a measurable outcome from transmission businesses' network operations. Incentives would be placed on them to maximise the availability of their network when it is most valuable to the market.

An issue in all energy markets is how to provide and manage scarce transmission capacity. Linking the purchase of access rights to the provision of transmission capacity is an attractive solution for liberalised energy markets that wish to extend the commercial and market drivers of generation investment to investment in the transmission system.

It is not a new idea: it is the basis on which many gas transmission pipelines are provided [13]. The analogy in other electricity markets employing nodal pricing would be guiding and funding the expansion of transmission through the sale of financial transmission rights.

An important difference of our model from other electricity markets employing financial transmission rights is its optionality: generators choose their access amount (and so whether or not they pay for access); transmission businesses develop their networks accordingly. In this choice, the transmission investment decision is - at least partially - decentralised.

Such a model raises some important questions. How will transmission businesses maintain the reliability of supply to end users when generators are driving part of the investment decision?

Will generators estimate sufficient private benefit from purchasing firm access to drive the optimal amount of transmission investment? Does there need to be a mechanism to correct this potential market failure?

In the next stage of our investigation, we will assess the significance of these issues and seek solutions if we find problems are likely to arise. We will assess the potential benefits of decentralised investment decision-making – and other impacts of the optional firm access model. If we find that the model is likely to promote the long-term interests of electricity consumers, we will recommend its implementation.

References

[1] The author gratefully acknowledges the assistance of Dave Smith from Creative Energy Consulting in the preparation of this article.

[2] Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania.

[3] We understand that the NEM is unique in setting its regional prices this way, rather than calculating an average across all nodes.

[4] By international standards, the NEM has high spot price variability. The market price cap is currently $13,100 per MWh. The market floor price is -$1,000 per MWh.

[5] The NEM is an "energy only" market. There are no capacity payments to generators.

[6] Recently, climate change policies have also been an important driver of generation investment.

[7] Transmission losses, congestion and inter-regional price variation do provide a degree of incentive for efficient generator location. However, these factors do not signal the long-term costs of transmission or the likelihood of future congestion.

[8] The Australian Energy Market Commission is the rule maker and developer for Australian energy markets. As a national, independent body we make and amend the national electricity, gas and energy retail rules. We conduct independent reviews of energy markets for Australia's governments.

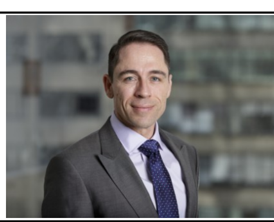
[9] With some important differences related to the model's objectives and the NEM's design. For instance, the access right would be linked to a particular power station, unlike other nodal pricing arrangements where non-physical parties can trade the hedging product. All firm access rights within a region would be referenced to the regional reference price, reflecting the market's regional pricing design.

[10] The firm access right would entitle the holder to the difference between its local nodal price and the regional reference price. When there is no congestion, these prices are the same.

[11] The firm generators may not be dispatched themselves: non-firm generators may be dispatched instead if they appear cheaper to the dispatch system. But there needs to be network capacity equal to the firm generators' aggregate access amounts such that dispatch of non-firm generators will create the pool of funds that is used to compensate constrained-off firm generators.

[12] The access price would reflect both the immediate and future costs of network expansions to give effect to the access, and so would differ from a "deep connection" charge. The access charge would be fixed for the life of the access agreement and so will not perfectly capture the actual incremental costs that the network business incurs.

[13] The access right in this case is usually a physical capacity right, guaranteeing the user of a gas pipeline the ability to ship its gas.



Stuart Slack is a Senior Economist at the Australian Energy Market Commission. He has assisted with the development of energy markets in various consulting and policy roles. He holds an Honours degree from the University of Cambridge.

XI. Revealing Flexibility Value

By Stephen Woodhouse

The EU is pressing for completion of the 'internal electricity market'. A central element of the posed market is termed the 'Target Model' for electricity trading between markets. It is intended to be largely in place by end-2014. It will be codified in legally binding 'Network Codes' and 'Guidelines'.

In summary the arrangements include provisions for creating price zones, forward allocation of inter-zone capacity, a single process of day ahead price coupling across Europe, continuous intra -day markets including between price zones, and cross border balancing with cost reflective imbalance pricing for all participants. This set of arrangements is intended to deal with the increasing levels of non-programmable renewable generation (mainly wind and solar) in European markets while maximising the value of trading between markets.

Background

European electricity markets will increasingly be dominated by variable renewable generation. This will require flexibility from all market players, which must be rewarded. This summary document [1] outlines ways in which flexibility can be valued in electricity markets.

The work has been sponsored by a group of 20 clients [2], and has benefited from dialogue with a wide range of stakeholders and policy makers from across Europe.

The winds of change have overturned the status quo

The growth of renewables brings new risks for thermal generation and new challenges for balancing supply and demand. The need for flexibility is growing, and trading must move closer to real time in response to forecast error. Market players now face a potent combination of price and volume risk which cannot easily be hedged with standard traded products. For example, 'spark spread' assumes a generation profile which has barely been seen by a CCGT in Europe in the last five years.

The EU Target Model for electricity, due for introduction by the end of this year, embraces these trends. However, there are other steps which must be taken to allow a transition to the low carbon economy.

New market designs will continue to undervalue flexibility

In response to the new circumstances, many EU countries are planning to introduce Capacity Remuneration Mechanisms ('CRMs') which could lower risks for generators and other market players.

However, many proposed CRM schemes are simplistic and run the risk of:

- replacing market risk with regulatory risk;
- damping peak prices;
- undervaluing flexibility; and
- distorting cross-border trading and demand management incentives.

Generally, CRMs are expected to reduce the volatility of energy prices (particularly close to real time). This reduces the value of flexibility that can be captured from the market and increases the importance of the (often) regulated revenue stream.

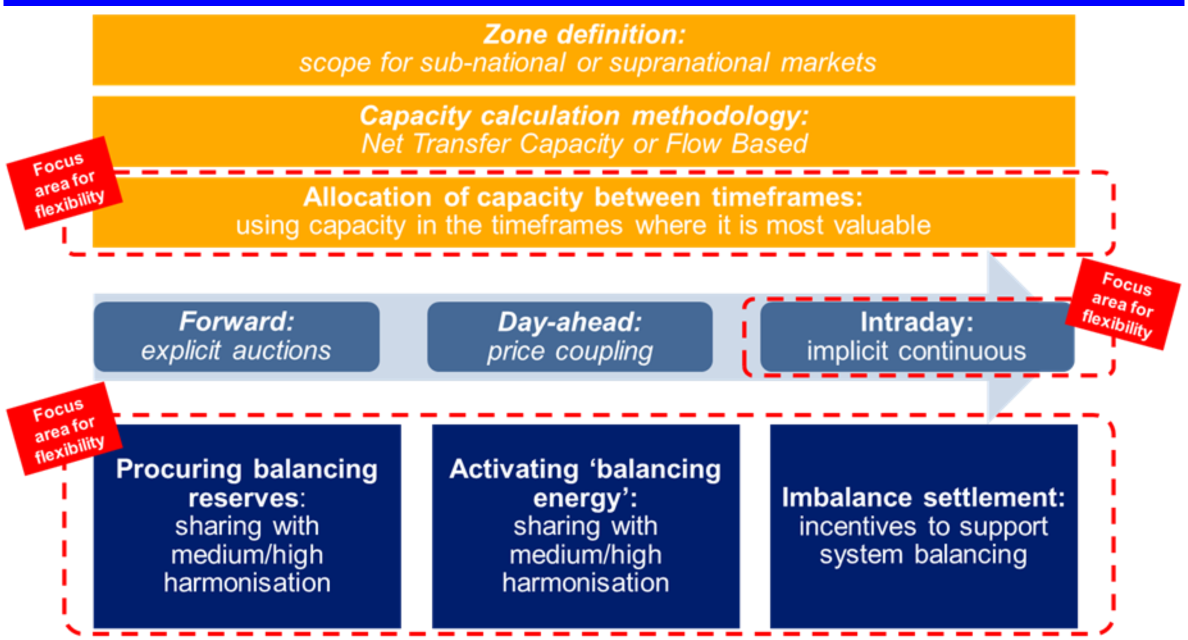
Capacity gives the option to deliver energy. However, the value of any capacity relates to its capability to respond when needed, e.g. in terms of the speed of response and also the price for delivery. Most CRM designs assume a static definition of 'capacity' which will not adapt to future system needs, e.g. as forecast accuracy changes, generation mix changes and smart metering changes demand patterns.

A mechanism which delivers capacity to meet system peak (in MW terms) without consideration of flexibility may not be adequate to meet actual system needs, and is therefore a necessary but not sufficient condition for system reliability. In such a case, a further payment stream may be needed [3]. Conversely, **a mechanism which delivers the capability to meet system needs over all relevant timeframes and notice periods should also deliver generation adequacy in simple MW terms.**

The EU Target Model should reward flexibility but implementation is flawed

The core elements of the EU Target Model are intended to be implemented by end-2015, with further elements completed in the following years. Figure 1 summarises the building blocks of the Target Model.

Figure 1. High-level building blocks of the European Electricity Target Model



By its design, the Target Model should make a clear step towards integrating renewable generation because it:

- **Places increased responsibility on market participants for trading energy up to as close as possible to real-time** with balance responsibility for all market participants and imbalance charges which reflect the full marginal cost of balancing;
- **Emphasises the use of intraday trading by participants** (including between markets and price zones), reducing the role of TSOs for within-day balancing; and
- **Fosters greater integration of national electricity markets** through trading and allocation of cross-zonal capacity across timeframes, covering forward, Day-Ahead, intraday and balancing to increase the sharing of resources across Europe.

However, in implementation (as presently intended) [4], emphasis is given to Day-Ahead at the expense of intraday. The price for intraday capacity on interconnectors is effectively zero, which could block new interconnection (especially to the Nordic region which has a surplus of both energy and capability).

Some areas of the Target Model are well advanced, particularly in forward and Day-Ahead timeframes. Intraday markets and arrangements to permit cross-border balancing are less well developed. Crucially, it is in these less-developed markets that flexibility should find its true value. Under these market arrangements, flexibility will continue to be undervalued, and cannot easily be traded between countries.

Is there a better approach?

We have worked to create market-based ways of valuing capability, which could support the integration of renewables into the market while allowing all market players to manage their risks. Wherever possible, investment and allocation decisions should be based on the actions of market players. The commercial influence of regulation and of single buyer TSOs on market outcomes should be kept to a minimum.

Our proposals are based on the principle that capability has a value which can be traded in the market in the form of energy options. Energy options can:

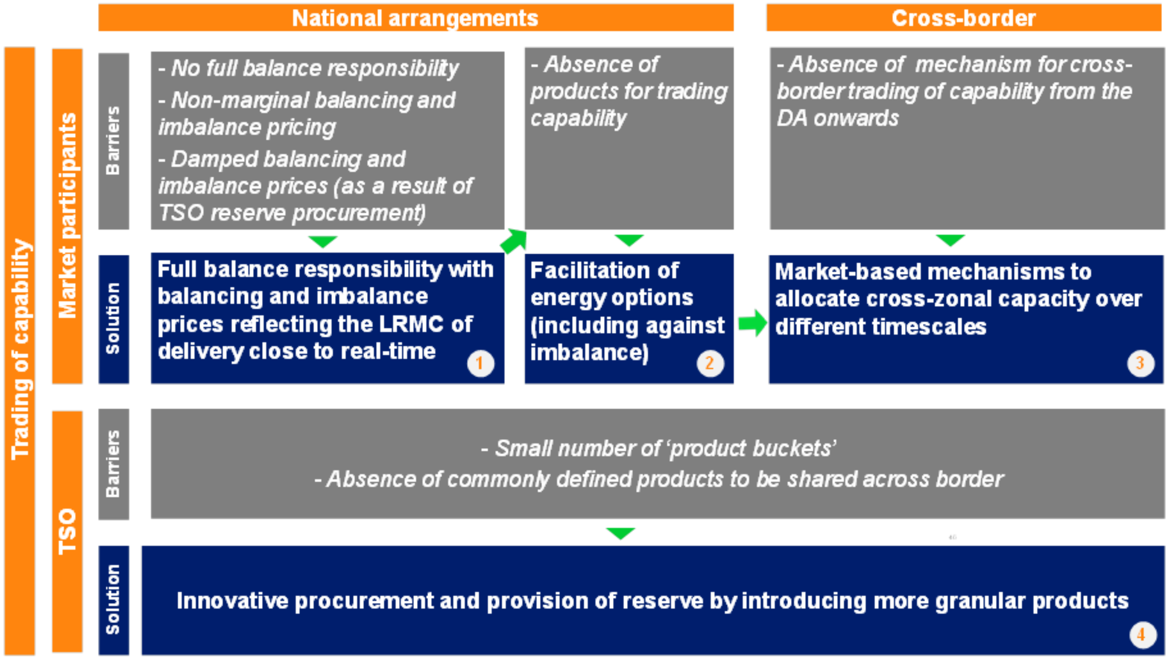
- hedge against price and volume risk;
- reward flexibility in ways which adapt to system needs over time; and
- promote investment in the right types of capacity.

Our proposals

Our vision for future electricity market arrangements can be achieved through the following four steps:

- Imbalance should not be sheltered:
    - all market participants should be balance responsible; and
    - imbalance prices should reflect the full long-run marginal cost of balancing the system, including reserve costs.
- Market designs should support trading of energy options between market participants (including as insurance against imbalance).
- Market coupling rules should allocate cross-zonal capacity across timeframes based on market values not *a priori* reservations, and should provide a way of pricing intraday capacity.
- Balancing services should be defined in ways which promote innovation and avoid forcing all providers to fit predefined characteristics.

Figure 2 summarises our vision for the future trading of flexibility and the four steps necessary to make this vision a reality.



The value of flexibility will be enhanced by assigning full balance responsibility to each participant and exposing it to full marginal balancing and imbalance prices [5]. To allow participants to manage imbalance risks we advocate trading of energy options for delivery intraday, including balancing timeframes. Such options could be traded before Day-Ahead. This would allow more predictable revenues for peaking and mid-merit generators and other providers of flexibility, as a market (rather than a mechanism) which will value capability.

Cross-zonal capacity should be made available in all forward timeframes. A mechanism should be included in the Day-Ahead coupling process which permits capacity to be allocated against energy options for use later (i.e. intra-day or balancing). This can be achieved through both implicit energy option market coupling and explicit transmission rights to support trading of energy options.

We also outline a way which would permit TSOs to exchange more granular balancing products, in a way which supports innovation by service providers and by the TSOs in their procurement.

Recommendations

Proposal 1: full balance responsibility

If all market participants face full balance responsibility, they will seek access to replacement energy to resolve forecast errors. This will directly lead to a value for flexibility which could be revealed in the intraday markets.

The intention of marginal balancing and imbalance pricing embodied in the Target Model appears sound, but we advocate strengthening the principles. The distorting impact of reserve contracting on balancing and imbalance prices should be removed. Imbalance prices should fully reflect the long-run marginal cost of balancing the system (without price caps or other distortions).

Different measures could be used to reflect the full cost of balancing actions in the price while excluding the impact of non-energy actions. While they need further definition they could include combinations of:

- a 'tagging' process to exclude non-energy balancing actions;
- an appropriate 'adder' for distributing the upfront reservation fees for contracted reserve capacity procured by the TSO in the balancing prices based on expected utilisation [6];

- changing the nature of TSO-procured reserve to avoid fixing the activation price;
- a reserve scarcity (VoLL/LOLP) function for pricing reserve (when used to balance the system); and/or
- an Ex-Post Unconstrained Schedule ('EPUS') for revealing an unconstrained merit-order (this could remove some actions by the TSO and add some others).

Proposal 2: trading of energy options

The move towards 'sharper' imbalance prices will reveal the need for appropriate risk management tools. These tools should take the form of energy options. **Energy options are market-based products for managing both price and volume risk which mitigate the risks of volatility.**

Energy markets reveal at any time a single 'best guess' of the value of energy for a particular delivery period. Trading energy options would permit traders to reveal their view of the volatility around this 'best guess'.

This market-derived view of the value of volatility should be a powerful way of determining how the capacity of networks and generation should best be committed in different timeframes. Traded options have a rich set of dimensions, including the notice period (how flexible) and at what strike price (how much risk is transferred from buyer to seller).

Effectively, options allow the holder to transfer responsibility for volume (and price) risk to the provider of the option, in exchange for an upfront option fee. This fee allows the sellers (providers of capability over different timescales) to swap a volatile income for a more stable one (in lieu of a regulated CRM).

The concept of options can be extended to allow exercise after intraday Gate Closure. 'Balancing resource options' (BROs) would allow participants to hedge against imbalance risk. With single marginal pricing for energy balancing and imbalance (and if balancing offers are always called if their price is better than the marginal price), then BROs could take the form of purely financial contracts between the participants. If balancing and imbalance prices could diverge (or if balancing offers are not called in strict merit order); then the imbalance arrangements would need adaptation to allow the risks to be effectively insured.

Critically, the revenue deriving from the sale of energy options is not expected to be a diversion of a portion of the overall value of energy. It is rather a replacement of a volatile (delivery-based) for a more stable (capability-based) revenue stream, retaining the full value of energy and scarcity within the spot markets. Energy market volatility should continue to govern cross-zonal trading (through market coupling) and should also deliver efficient spot prices to producers and consumers.

Effective markets for energy delivery close to real time should support forward markets for capability. An options market could provide appropriate rewards for different capability, and these values could adapt to appropriately reflect changing system conditions through market adjustments. Such an approach may have less regulatory risk than more centralised solutions such as CRMs.

Proposal 3: cross-border trading of capability

So far the report has described changes that could encourage market participants to trade products more actively within markets, until close to real time. The Target Model is designed to allow effective trading between markets, defined in terms of price zones.

The Target Model requires **appropriate allocation of capacity across all timeframes** but the emphasis of its implementation has so far only been on the Day-Ahead market.

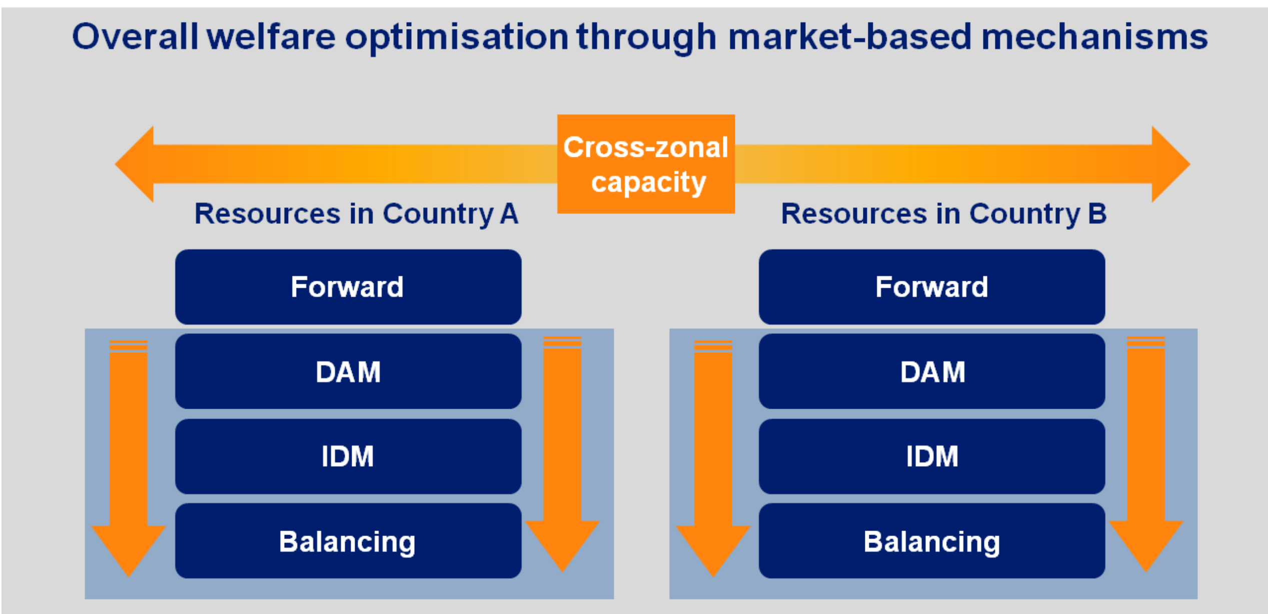
Increasing importance of wind and solar generation will raise the significance of intraday. The optimal allocation of capacity between timeframes will be dependent on system conditions on the day, and in practice any allocation between timeframes which is fixed in advance is likely to be suboptimal [7]. Allocating (i.e. reserving) the entirety of cross-zonal capacity primarily to the Day-Ahead market may not deliver the optimal social welfare in all market circumstances, since it forecloses the opportunity value of flexibility for use in shorter market timeframes.

A major challenge for effective cross-zonal trading is that the Target Model implementation does not include a market-based mechanism to compare the value of using network capacity in different timescales.

In line with the philosophy of allocating capacity between balancing and energy delivery, we advocate efficient allocation of cross-zonal capacity across different timeframes. Prices should be offered (or derived from option prices) for cross-zonal capacity for use intraday, ahead of the intraday market. This should deliver market-based values which can then be used to allocate cross-zonal capacity across timeframes. Such an approach should better respond to system conditions on the day compared to just "reserving" all available capacity at Day-Ahead and deliver more efficient use of resources between bidding zones across different timeframes. This is visualised in Figure 3.

So a long-term vision is to create **effective competition in cross-zonal capacity between timeframes by using energy options**. At any point, this would confer a choice between committing now and retaining the option to commit later. It should be supported by long-term transmission rights that allow for trading cross-zonal capacity over the full range of timescales (including forward).

Figure 3. Optimisation across different timeframes and bidding zones



Proposal 4:

The Target Model envisages that balancing services are exchanged in the form of 'standard balancing products'. This assumes that TSOs will accept that balancing services can be defined in terms of a small number of standardised products. We believe that balancing services are based on a sophisticated set of characteristics, and that oversimplification will lead to higher cost outcomes and exclude innovation and non-standard providers.

In the main report we outline a way which would permit TSOs to exchange more granular balancing products, in a way which supports innovation by service providers and by the TSOs in their procurement. This is designed to address the expectation that the existing plan to create a liquid cross-border trade of a small number of Standard Balancing Products may face difficulties in further design and implementation.

Timing is important

Electricity markets in Europe are reeling from recession and rapid growth of renewable generation. Today, there is no real shortage of capacity, and the value of flexibility would be low in many markets even if our recommendations are followed.

However, the need to act is urgent, in terms of both institutional arrangements and also infrastructure. The rules for market coupling will be defined in the coming weeks and months, and plans for national capacity schemes are advanced. Decisions on generation closures are being taken now, and infrastructure plans are being delayed by the prospect of CRMs.

We believe that our proposals are in line with the spirit and the letter of the Target Model proposals but that more could be done to ensure that the ideas are taken forward across Europe.

We aim at influencing the direction of the integrated European market, and seek to ensure that the final Target Model (in the form of Network Codes) supports – or at least does not block – proposals for appropriately valuing flexibility.

Next steps

Further work is needed to persuade more policy makers of the merits of the proposals, to prove the value in different circumstances and to set up pilot arrangements. We will work with our existing group of supporting clients and with other stakeholders to take these ideas forward.

References

[1] A public summary report is at https://www.tinyurl.com/poyryflexibility. Study members received a more detailed report. This short version is adapted from the public summary.
[2] The sponsors include regulators, network operators, power exchanges, manufacturers, generators and vertically integrated utilities.

[3] For example, the BDEW proposals for a decentralised CRM notes that if flexibility is not delivered , and additional instrument may be required (Design of a decentralised capacity market, Position Paper, BDEW, 18 September 2013)

[4] https://www.epexspot.com/document/25834/2014-02-04_NWE_Go-Live_Communication_NWE_PCR_SWE.pdf

[5] The arrangements should explicitly avoid imbalance prices from being distorted by TSO procurement of reserve, and we propose ways of achieving this.

[6] CfDs would be taken at a fixed activation price to avoid double payments for contracted reserve

[7] The 2012 RAP advisory note on the Balancing Framework Guidelines states "*With a generation mix that contains a high level of intermittent renewable generation, the optimum allocation of interconnector capacity will be highly dependent on weather conditions and therefore difficult to identify accurately much in advance of real time*." (RAP, Advisory Note: Balancing Framework Guidelines to Promote an Integrated, Low-Carbon, European Electricity Market, June 8, 2012)

Stephen Woodhouse is a Director with Pöyry Management Consulting. He heads Pöyry's Market Design group which deals with all aspects of energy market policy regulation and design, for private and public-sector clients. Stephen is an expert in market reform, from high-level policy design through to the implementation of systems and processes for market participants. He specialises in the economics of transmission and interconnection; market regulatory policy across Europe and the UK and Irish electricity and gas markets.

Stephen is responsible for Pöyry's multi-client projects addressing Future Market Design, Valuing Flexibility and also a series of projects analysing intermittency in Northern Europe.

Stephen leads Pöyry's business development in the inter-related areas of intermittency, smart grids and market design, and continues to contribute to the debate on appropriate models for reward for generation capacity, transmission charging and access.

Prior to joining Pöyry, he was an Economic Modeller for Ofgem. Stephen has an MA in economics from the University of Cambridge.

XII. ICER PUBLICATIONS

Reports

ICER's Virtual Working Groups draft reports on an on-going basis and in accordance with three year work plan cycles. The following reports were prepared during the 2009-2012 period:

- Role of Energy Regulators in Guaranteeing Reliability and Security of Supply: The National, Regional and Global Dimensions (March 2012) http://bit.ly/1bY3aLg
- Experiences on the Regulatory Approaches to the Implementation of Smart Meters (April 2012) http://bit.ly/18Uc4bz
- Renewable Energy and Distributed Generation: International Case Studies on Technical and Economic Considerations (February 2012) http://bit.ly/18x7XUT
- Examples of Methodologies Utilized to Manage Competitiveness and Affordability Issues Related to the Introduction of Renewable Forms of Electricity Generation and New Technologies: An Overview Report of a Compilation of Four Case Studies (April 2012) http://bit.ly/19aWbQs
- A Description of Current Regulatory Practices for the Promotion of Energy Efficiency (June 2010) http://bit.ly/1bNctsR
- Response to the European Commission Public Consultation on the External Dimension of the EU Energy Policy (February 2011) http://bit.ly/18UcvCC

ICER Chronicle 1st edition http://bit.ly/1hMXskK

The first edition of the ICER Chronicle was released in December 2013. It comprises 9 articles, selected by a distinguished Editorial Board made from experts from various fields nominated by the Regional Regulatory Associations that are members of ICER. Submissions were received from a wide range of authors and on a variety of topics related to regulation of energy markets and the challenges regulators face in them. The Chronicle is an electronic publication only, publicly available on the ICER website.

Distinguished Scholar Award http://bit.ly/1dKx58q

ICER established its Distinguished Scholar Awards with a view to contributing to an increased reflection on energy regulation policy issues. These Awards acknowledge important contributions made to enhance electricity and gas regulation around the world. Two recipients are selected each cycle, in the categories of Impact on Developing Countries and Next Practices. The Awards are now held every three years in conjunction with the World Forum on Energy Regulation (WFER).

- **2015 Theme: Creating and Managing Regional Energy Markets (deadline April 1, 2014)** http://bit.ly/1uc8nog

- **2012 Theme: Integrating New Technologies into the Grid**
  2012 Winners
  - **Category: Impact on Developing Countries**

    Development of New Infrastructure and Integration of New Technologies in Guatemala's Electricity Sector: Practical Lessons Learned by a Regulator in a Developing Country, prepared by Carlos Colom, President, Comisión Nacional de Energia Eléctrica (CNEE), Guatemala http://bit.ly/1dKzFeI

  - **Category: Next Practices**

    Changing The Regulation for Regulating the Change: innovation-driven Regulatory Developments in Italy: Smart Grids, Smart Metering and E-mobility, prepared by Luca Lo Schiavo, Maurizio Delfanti, Elena Fumagalli and Valeria Olivieri, Italy http://bit.ly/ISUfQl

- **2010 Theme: The Impact of Renewables on Energy Regulation**
  2010 Winners
  - **Category: Impact on Developing Countries**

    Effects of the Introduction of Successful Mechanisms to Promote Energy Efficiency in Non-EU Countries prepared by the MEDREG Ad Hoc Group on Environment, RES and Energy Efficiency http://bit.ly/1emp3XT

  - **Category: Next Practices**

    Pricing of Ancillary Services and the Impact of Wind Generation on the Capability of the Transmission Network prepared by Mr. Darryl Biggar (Economist, Australian Energy Regulator (AER) and the Australian Competition and Consumer Commission (ACCC)) http://bit.ly/1bcpz35

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