2014 ENERGY POLICY FORUM

Responding to Trends in the U.S. Electricity Sector



Sue Tierney, Chair
Dave Grossman, Rapporteur

THE ASPEN INSTITUTE
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Energy and Environment Program

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For additional copies of this report, please contact:

The Aspen Institute
Publications Office
109 Houghton Lab Lane
P.O. Box 222
Queenstown, MD 21658
Phone: (410) 820-5326
Fax: (410) 827-9174
E-mail: publications@aspeninstitute.org
Web: www.aspeninstitute.org/eee

For all other inquiries, please contact:

The Aspen Institute
Energy and Environment Program
One Dupont Circle, NW
Suite 700
Washington, DC 20036-1193
Phone: (202) 736-2907
Fax: (202) 467-0790

The Aspen Institute
One Dupont Circle, NW
Suite 700
Washington, DC 20036-1193

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Table of Contents

Foreword

The Aspen Institute's second annual Energy Policy Forum, held in the summer of 1978, focused on natural gas and concluded, "the natural and supplemental sources of gas energy are potentially plentiful and should continue to play a significant part in America's energy mix."

The third annual Forum in 1979 considered "Decentralized Electricity and Cogeneration Options," concluding that "decentralized systems will come into increasing use" and that "public policy should be altered to permit this competition."

The thirteenth annual Forum, in the summer of 1989, discussed global climate change and concluded, "enough is known now to set in motion certain steps (to) reduce emissions of CO_2 and/or other greenhouse gases."

It is unlikely that many of the participants in those forums could foresee how long it would take for their conclusions and recommendations to take effect, but in 2014 the 38th annual Forum, "Responding to Trends in the Electricity Sector," revisited all of these issues. The Environmental Protection Agency's proposed rule on CO_2 emissions from existing electric power plants poses a challenge to utilities just as they are dealing with, among other challenges, the impact of surging production of cheap gas and virtually flat demand and revenue, due in part to distributed energy resources.

The Forum used brief introductory presentations and moderated dialogue among a diverse and knowledgeable group of energy experts to consider a range of public policy and business choices facing the electricity sector. The Forum's rule against quoting anyone by name or affiliation, honored in this report, encouraged a candid and spirited discussion.

Sue Tierney, Managing Principal of The Analysis Group and former Assistant Secretary of Energy for Policy, chaired the Forum. Her deep and varied experience with the industry was helpful in developing the Forum agenda. Her moderating skill, her understanding of the issues, and her good nature enabled her to manage effectively a potentially contentious dialogue.

Highly qualified and informative speakers provided a wealth of information and a variety of perspectives, and the diverse expertise of the participants contributed substantially to the richness of the dialogue.

The Aspen Institute acknowledges and thanks the following Forum sponsors for their financial support. The majority have been participants and supporters for many years. Without their generosity and belief in the value of our work, the Forum could not have taken place.

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David Grossman again wrote the Forum report. No written report can capture all the depth and nuance of a multi-day conversation among participants with various views and areas of expertise, but he has captured the key points of a fast-moving conversation and distilled them into this admirable summary.

Avonique DeVignes handled the logistics of the Forum and responded to the needs of participants, hiding the challenges she faced behind an unfailingly cheerful demeanor. She was ably assisted by Timothy Olson, who preceded her in this role for several years. I am grateful for their dedication and support.

This report is issued under the auspices of the Aspen Institute. The chairs, speakers, participants, and sponsors are not responsible for its contents. It is an attempt to represent ideas and information presented during the Forum, but not all views could be included, the views expressed were not unanimous, and participants were not asked to agree to the wording of the report.

John A. (Jack) Riggs
Senior Fellow
Energy and Environment Program

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David Grossman
Rapporteur

Executive Summary

New federal regulations, changes in fuel prices and trends, the expansion of distributed energy resources, declines in U.S. electricity consumption, and advances in technology are all spurring utilities and regulators to respond and adapt. Discussions of the challenges and opportunities these forces present for the U.S. electricity sector – as well as how the industry and its regulators are adapting – formed the heart of the 2014 Aspen Institute Energy Policy Forum. This report summarizes and organizes some of the key insights from those discussions.

Among the newest and highest-profile of the forces the sector is dealing with is the U.S. Environmental Protection Agency's proposed rule for carbon dioxide emissions from existing fossil-fuel fired power plants, issued under section 111(d) of the Clean Air Act. The rule proposes to set long-term, rate-based carbon intensity goals for each state and then give the states enormous flexibility to meet them. If implemented, the rule, which is designed to follow where the energy world is already heading, is likely to spur improved efficiency at coal-fired power plants, greater use of natural gas-fired power plants, increased deployment of renewable energy and perhaps nuclear power, and increased demand-side energy efficiency. The rule is only a draft, and there are many issues that still need to be clarified and on which the agency is seeking comments. Even in its draft form, though, the rule has spurred conversations in and across states about clean energy, fuel switching, emission reductions, and compliance approaches. Further guidance or meetings may be needed to foster collaboration and coordination among the wide range of affected actors before the rule gets finalized.

If the 111(d) rule is following where the energy industry is already heading, it has to account for the numerous cross-currents in the industry that are affecting existing facilities and future fuel choices. Due to the shale revolution, the United States has rather suddenly developed an abundance of inexpensive natural gas that is steadily gaining market share in power generation. That market share is largely coming at the expense of coal, and it is expected that a large amount of coal-fired generation will be retired over the next decade – and that pretty much no new coal plants will get built. The heavy reliance on gas carries some risks, but gas's central role in the U.S. power system of the 21st century is a near certainty. That power system will also depend heavily on renewable energy sources, which have combined with gas to account for virtually all new U.S. generation capacity in recent years. Gas can support renewables with nimble and fast ramping capability, and the two sources have many potential synergies over the near- and long-term. The future of nuclear power is very uncertain, though, as this zero-carbon source suffers economically in a low-gas-price environment and has an aging fleet. Energy efficiency, however, is cheap, abundant, and low-risk, and efficiency technologies continue to make great strides. Energy efficiency is considered by many to be the first "fuel" to choose.

At the same time, expectations of what the grid can and should deliver are changing, with emerging interest in environmental sustainability, resilience, flexibility, and customer control. It is in this context that distributed energy resources such as demand response, solar photovoltaics, advanced metering infrastructure, microgrids, and energy storage are increasingly being deployed. Those utilizing distributed energy resources generally still rely on the grid for backup. As these resources expand, there will be a need to figure out how to value energy, capacity, and grid services separately, how to integrate distributed resources into the grid, and how to ensure the grid continues to provide the reliability and convenience customers want. There are a variety of models and principles being discussed for how best to accomplish these goals, how to structure the broader distribution market platform, and what role utilities should play in that system.

Utility strategies have evolved continually over the years in response to what was going on in the world. Many of the past and present pressures on the industry, including the federal 111(d) rule, have not fundamentally altered the underlying business of utilities, but slowing retail electricity sales growth and increased competition from technology do pose potentially fundamental threats to the utility business model. Utilities now need to understand and respond to customer choice, which is a challenge for an industry that has limited experience in that area. Utilities can choose to play defense in the face of these pressures, making incremental changes, or they can play offense and pursue new revenue streams, new business models, and new products and services.

Utilities generally cannot create new business models on their own, however. Regulators also play a critical role in facilitating new models, as well as in promoting conversations about the regulatory compact, the changing grid, and the evolving suite of energy resources. Many times, regulators and the regulatory process act as obstacles to change, but regulators have an opportunity now to adapt to changing circumstances and pursue specific detailed efforts that can help create the right incentives for new business models and broader system efficiency. Regulators can also lead the way by pursuing fundamental redesigns of the entire electricity regulatory system, such as the pioneering effort getting underway in New York that may be every bit as important and impactful as the federal 111(d) rule.

EPA's Clean Air Act Rules for Carbon Emissions from Power Plants

In early June 2014, the U.S. Environmental Protection Agency (EPA) released its proposed rule for carbon dioxide (CO_2) emissions from existing fossil-fuel fired power plants, issued under section 111(d) of the Clean Air Act (CAA). Driven by President Obama's desire to take action on climate change and his recognition that Congress will not do so, the EPA's draft 111(d) rule – dubbed the Clean Power Plan – represents a creative but mission-driven effort to reduce carbon pollution. It will be finalized on June 2, 2015, following a lengthy comment period, which will condense the time the EPA has to address the comments and make changes (so the earlier comments are submitted to the EPA, the better).

The rule builds on the tremendous gains made since the CAA's bipartisan enactment in 1970 and bipartisan amendment in 1990. By 2012, the United States. had achieved 60-80% reductions from 1970 levels for the six main pollutants (PM10, PM2.5, SO_2, CO, VOC, and NOx) while growing the economy and keeping retail energy prices stable. These are successes we do not celebrate nearly enough – and that we can now begin to replicate with CO_2.

Approach of the 111(d) Rule

The proposed rule is the embodiment of cooperative federalism, with the EPA setting state goals and then giving states maximum flexibility to meet them. The rule was designed to follow where the energy world is already heading, not to drive an energy transition. It is designed to be a practical and affordable Clean Air Act rule, not an energy policy. There are some who contend that the EPA should have pushed farther, given that the agency has legal authority, Congress will not act, we need very significant reductions to address climate change, and the EPA will be criticized for killing jobs and coal no matter what the rule actually contains. The EPA, however, designed the rule to stay within the confines of the CAA, achieve cost-effective and substantial CO_2 reductions, and put us on a path that could achieve significantly more.

The 111(d) rule is not cap-and-trade, and it is not aimed at a particular goal (despite the fact that the cumulative reductions states would achieve under the proposed rule – roughly 30% below 2005 levels by 2030 – were calculated and announced). Rather, the state goals were established from the bottom up, by looking at how the energy world works and applying the "best system of emission reduction" (BSER) in a practical way to each state's energy situation, based on what is already being done in the state, what technology is readily available and practical, and what the state says it is planning to do.

The EPA determined that BSER consisted of 4 "building blocks": (1) improving plants' heat rate, (2) shifting dispatch from coal-, oil-, and natural gas-fired steam generation to natural gas combined cycle (NGCC) generation, (3) increasing renewable energy and nuclear generation and avoiding retirement of some existing nuclear units, and (4) increasing demand-side energy efficiency. The EPA thus did not limit the scope of its proposed rule to "inside the fenceline" actions (i.e., actions at the power plant itself), as the emission reductions achievable are much greater and more cost-effective when one also includes "outside the fenceline" measures (i.e., actions taken beyond the power plant that have the effect of reducing required emissions from the power plant).

The proposed rule would set an individualized rate-based carbon intensity goal (pounds of CO_2 per MWh) for each state to reach in 2030, thereby giving states the opportunity to think more long-term and to factor carbon emissions into the existing trends in the energy world. The rule would also set an interim goal for each state that represents the 10-year average emissions rate from 2020-2029, which would drive states to make decisions and reductions earlier and give them check-in points to make sure they will meet the 2030 goals.

While the BSER building blocks were used to come up with each state's goal, states do not need to use the building blocks in the way the EPA calculated – or even use them at all – in putting together their implementation plans. Since resources, options, and costs will vary from state to state, the rule proposes to give states enormous flexibility to chart their own destinies. Efforts underway in states to remake the grid could be part of state plans, as they drive changes in managing demand and achieving reductions. The EPA will also put something out soon that recognizes some biomass feedstocks as compliance options under the rule. In addition, the proposed rule recognizes nuclear power as part of the zero-carbon energy generation mix and calls attention to the fact that some plants are aging and non-competitive, which means if those plants end up getting retired, states will have a lot of zero-carbon ground to make up.

The EPA made clear in the draft rule that states could pursue regional opportunities to achieve compliance, which could be easier and cheaper for some states. However, states are not limited simply to a Regional Greenhouse Gas Initiative (RGGI) type of model; they could do any regional arrangement that makes sense for them (e.g., just renewables). States get extra time to submit plans if the states need new legislation or regulations or are pursuing multi-state programs.

The EPA's approach is somewhat modeled on the strategy of adaptive management used in the natural resources arena – namely, states have a goal they are trying to achieve, they can try things to reach it, and if those do not work, they can try something else. The rule does not try to set everything in stone through 2030. For instance, given that smart technologies are infusing themselves into the energy sector at an increasingly fast pace, states will need to be able to update their plans to reflect the latest technologies. States have the ability to change course and pursue new opportunities, as long as they provide an analytical basis showing achievement of at least the same level of reductions.

States really are in the driver's seat, but whatever they choose to submit in their compliance plans, and as much flexibility as they have to figure out the path forward, the draft rule proposes to have those efforts be federally enforceable under the Clean Air Act.

The EPA makes clear in the proposed rule that it welcomes comment on a wide range of topics, from fundamental principles about the overall framework to the data used in calculating each state's goal.

Confusion and Concerns about the Rule

The proposed rule has triggered a fair amount of confusion and concern. For instance:

- Some leading states complain that the EPA did not recognize their leadership in reducing emissions, though the EPA tried to give states credit for existing action and leadership.
- Some states are expressing concern about fuel diversity, though the EPA tried to factor that into the targets and enable states to make the choices they think make the most sense.
- Some readers of the rule are getting confused in thinking that the "building blocks" that make up BSER are requirements for the states. There are also concerns that some of the building blocks' assumptions will be difficult, costly, or disruptive to achieve in reality. The building blocks, however, are just what the EPA thinks states can reasonably achieve and were used to develop each state's target. The strategies states actually pursue for compliance are totally up to them (short of using offsets, as the goal is carbon reduction from fossil-fueled power plants). If some states find particular approaches to be too expensive or unworkable, they can try to achieve reductions in other ways.

- There are concerns about the rule significantly underestimating the potential for renewable energy and energy efficiency, making very conservative estimates – sometimes below states' own targets. It is worth noting, though, that every state defines renewable energy differently, and some parts of those definitions do not actually affect carbon pollution from power plants. Furthermore, some states will need time to build up energy efficiency infrastructure.

- There is some confusion about how the interstate nature of renewable energy (e.g., out-of-state renewable energy purchases) will be squared with a state-based compliance mechanism. States will have to work out the allocation issues when they submit their plans or form regional agreements (though if they do not, then the EPA will).

- There is confusion about the role of hydropower in complying with the rule, including the fact that there is ample opportunity for repowering in hydro that does not appear to have been considered by the EPA. The EPA welcomes comments on hydropower's role.

- There are concerns about whether the 111(d) rule could undermine utilities' existing efforts to comply with earlier EPA rules. The EPA factored all existing rules and efforts into the states' trajectories, and future planned and potential regulations (e.g., methane, coal ash, effluent guidelines) will not be blind to what came before or what is coming after.

- There are concerns about how the EPA will enforce the rule's obligations, as the "outside the fenceline" approach means there are potentially many responsible actors – and indeed the EPA teed that issue up in the rule, is soliciting feedback, and would like states to explain how they want to allocate responsibility.

- There are concerns that the rule relies heavily on natural gas, which is only viable if additional work is done to resolve issues such as methane leakage and groundwater contamination.

- There are concerns that the rule will drive the system toward environmental dispatch of the generation fleet as opposed to the current system of economic dispatch, which will raise real coordination issues. The system has been doing environmental dispatch under the CAA for 40 years, though, by incorporating prices for pollutants as a cost in the normal economic dispatch. Some Regional Transmission Organizations (RTOs) may be interested in incorporating a shadow price on carbon in their models and still do economic dispatch – but that involves a somewhat unspoken need for some kind of price on carbon and may run afoul of issues in the Federal Power Act.
- There is concern that the rule might drive things faster than inertia – in machines and mechanical systems, as well as in economic and regulatory policies – can be overcome.
- There are some concerns that smaller players (e.g., co-ops) may get outgunned in the fights that will likely occur among utilities (and other stakeholders) within states when they put their implementation plans together. There will also be fights that break out among state agencies and consumer advocates, which utilities will have to deal with on an ongoing basis.

Impacts the Proposed Rule Has Already Had

Even in its draft form, the proposed rule has already had some beneficial impacts. For instance, internationally, the rule has been very well received as a sign of U.S. leadership on climate change and may well spur action by China, both of which could aid international negotiations.

Domestically, the rule has helped unstick conversations on climate action and clean energy that have been stuck for years. There are now opportunities to talk about clean energy in every state. States are also now having conversations with longer planning horizons, as the rule sets targets for 2030. Some states have already put in a lot of work on how energy efficiency, renewable energy, and climate programs might work within states and across regions, which will inform their discussions and compliance plans. Some states and regions are also fostering conversations between environment commissioners and utilities commissioners, which can be helpful. Public Utilities Commissions (PUCs) will be convening meetings to talk about all of the issues tied up in crafting 111(d) implementation plans, such as non-competitive nuclear plants, dispatch of power, and whether legislative fixes (e.g., to state renewables and efficiency standards) will be needed as part of a grand bargain.

This activity reveals a clear disconnect between politics and the practical, as even states that have governors who have been outspoken in their opposition to EPA's rule also have state officials trying to figure out how to make it work and what the best options are going forward. The 111(d) rule is unleashing a lot of creative and collaborative thinking that can be embraced by states if they so choose; it depends whether politics trumps the substantive policy opportunities.

Recommendations for the EPA

Despite the EPA's promotion of regional opportunities, it is possible that collaboration among states could be difficult. For instance, there will be contentious issues about allocation of costs among states. Also, states that analyze the rule and figure out they are winners may be disinclined to coordinate with losing states. In addition, there could be state actions that disadvantage customers in other states. The EPA could consider issuing guidance that tees up some key principles for state compliance plans, such as that states have a responsibility to take account of the effects of their plans on consumers in other states. Some states would prefer the EPA not provide guidance that is too specific or prescriptive, though.

States are not the only ones with potential coordination issues. Many states are part of multiple Regional Transmission Organizations (RTOs), which make dispatch decisions for the entire RTO footprint, and the RTOs do not always get along with each other. Coordination among RTOs, however, will be essential to deal with issues such as the relative carbon-intensiveness of the plants each one dispatches in a state and the impacts of those decisions on a state's achievement of its 111(d) target. RTOs are key players in making the 111(d) rule work. It could therefore be beneficial for the EPA to encourage a joint operating agreement among RTOs, perhaps at an EPA-organized RTO summit.

Furthermore, although the EPA has developed strong relationships and coordinated closely with other relevant agencies – including the Federal Energy Regulatory Commission (FERC), Department of Energy (DOE), and National Renewable Energy Laboratory (NREL) – it may be valuable to arrange some other coordinating sessions. For instance, it could be helpful to have a meeting between states, the EPA, and FERC to look at what amendments may be needed in the Federal Power Act to ensure states have the authorities they need to implement compliance plans for the rule. The EPA and states may also need to work with the North American Electric Reliability Corporation (NERC) to ensure that state compliance plans reflect an understanding of the complexity of the electricity system and the need for reliability. There may even be a need for a broader summit that involves FERC, NERC, RTOs, and others to address a wide range of the electricity system's attributes.

Fuel Choices

Given that the EPA 111(d) rule is designed to follow where the energy industry is already heading, it is worth considering where exactly that is. There are many cross-currents in the industry, quite apart from EPA rules, that are having a profound impact on existing facilities and future fuel choices – and will continue to do so. It is important to keep in mind, though, that most predictions about energy are wrong; projections about oil, gas, and other fuels made over the past 30 years are astonishingly different from what has actually occurred.

Natural Gas and Coal

There has been a great deal of evolution in the natural gas industry over time. Gas used to be an afterthought in power generation, but conversations about generation today start with gas. The EPA also assumes heavy reliance on natural gas to achieve the 111(d) targets.

America's gas abundance has been profound and sudden. Six years ago, the U.S. Energy Information Administration projected that the United States would have net imports of 7.8 billion cubic feet per day (bcf/d) of natural gas in 2030; its 2014 outlook now projects 9.2 bcf/d in net exports in 2030. That represents a swing of 17 bcf/d, which is the equivalent of almost two Qatars (currently the world's second largest gas exporter). The shale revolution put an emphatic end to U.S. gas price volatility caused by national supply. It also made the United States more hurricane proof, as the country is no longer as reliant on its offshore gas supplies.

Gas has dominated new capacity in power generation for almost 25 years, representing 71% of new capacity since 1990. (Wind is second, though in recent years renewable energy's share has been rising to the point that it is pretty much 50-50 with gas.) When gas prices bottomed out in the spring of 2012, gas briefly caught coal's power generation market share, which is very price sensitive. Market shares of coal and gas have been converging for 25 years and are projected to meet in 2028 without anyone doing anything different – which in itself will get emissions a long way towards the 111(d) targets. Convergence would mean a shift of 236,000 GWh from coal to gas. If that shift is taken up by the existing NGCC fleet, that represents a 60% capacity factor and an additional gas supply of 4.5 bcf/d. There is plenty of gas available to meet that additional supply need. That gas will likely stay in the $4 to $6 price range through 2030, though if carbon capture and storage is required for gas at any point along the way, gas generation will get much more expensive.

In contrast, it is extremely unlikely that anyone will build new coal plants in the U.S., as the risk is too high. It is projected that an additional 40 GW of coal-fired generation will be retired between 2014 and 2026. (The outlook for coal globally, however, is quite robust.) A lot of American eggs are being put in the natural gas basket.

Some utilities and reliability managers are nervous about the high reliance on gas, especially after the polar vortex this winter. They like being able to see the pile of coal outside the window. Their concerns generally fall into three areas: (1) the adequacy of pipeline and storage infrastructure (i.e., all the gas in the world does no good if it does not get to where it is needed), (2) who pays for new capacity, and (3) friction between the gas and electric business models. There are also concerns about inadequate infrastructure and future polar vortexes leading to a return to volatility and high price exposure, which will lead to real problems with affordability. All of these became a big deal in the winter of 2013-2014, and a range of efforts are underway to try to address them, including by the New England Governors and by FERC and the North American Energy Standards Board (NAESB). Gas system issues have historically been poor cousins in electricity discussions, but the near-term future of electricity seems to involve a lot of natural gas, so gas and electricity system planning will need to get much more integrated.

An additional risk from putting so many eggs in the natural gas basket is the potential for states and/or the federal government – even local governments in some states – to adopt new regulations that could stop or severely limit fracking. The reality so far has been that the industry could not have done a worse job of getting in front of the fracking issues – and continues to do itself no favors when it pushes for rights to develop near neighborhoods and schools. There are tremendous technologies and controls out there for fracking, but fracking's future ultimately depends on public trust (i.e., social license to operate) and effective, appropriate regulation.

America's gas abundance has also led to questions about liquefied natural gas (LNG) exports, which are controversial. Applications to DOE exceed 35 bcf/d for new liquefaction, but experts suggest that the whole world only needs about 30 bcf/d of new capacity from all exporting countries (and there is a lot of competition), which means that 10-12 bcf/d is the most likely level of real U.S. projects, leading to about 9 bcf/d of exports. The U.S. can serve that level of export demand without breaking a sweat and most likely with stable prices. The risk is probably small that connecting the U.S. to the global market could result in the global gas price pushing the U.S. price up, though when Australia did a massive push on LNG exports, the price of its domestic gas tripled. Regardless, the U.S. is already somewhat connected to global prices anyway (e.g., contracts with the price tied to Brent instead of Henry Hub).

Natural gas is gaining ground because it is so inexpensive, but it is also promoted as part of the climate solution – and there are some concerns about natural gas from a climate perspective. With respect to LNG, the energy needed for liquefaction reduces the advantage of natural gas over coal. More broadly, the methane leakage issue pervades everything about natural gas and has to be resolved if gas is to have any credibility as a climate solution. The EPA will have to make decisions this fall about what to do on methane, but causes for optimism is that the solutions to the problem are pretty well understood, the technology is pretty basic, and a good portion of the answer is just better leak detection and repair. There is also a need for policy and regulatory change on the gas distribution side, where regulators have not pushed local distribution companies to invest in upgrades and have been allowing a rate of return on “lost” and unused gas. In addition, there is concern that we could start building new gas infrastructure that is not “renewables-ready” – i.e., that exhibits operating characteristics that could be an obstacle to integrating renewable energy instead of characteristics that could complement renewables.

Apart from the climate issues, however, gas is undeniably much cleaner than coal when it comes to SOx, NOx, mercury, and other pollutants.

Renewable / Gas Synergies

In most places, the U.S. power system of the 21st century will depend heavily on both natural gas and renewable energy sources. Over the last few years, as noted, gas and renewables have each represented about 50% of new capacity market share, and projections suggest the bulk of power generation investments through 2035 will be in renewables and gas (particularly given that 70-80% of the current generation fleet will be ready for retirement in the next 20-30 years). Energy produced from renewable sources is now around 100 GW a year globally. More than half of U.S. states have renewable portfolio standards. Prices for renewables have come down a lot, and technological and business model innovations have been accelerating. Modern wind turbines and next generation solar inverters will be providing grid services.

Models for achieving significant CO_2 reductions by 2030 and 2050 while meeting electricity reliability requirements in a least-cost way show very big contributions from gas and renewables. This does not necessarily mean that renewables and gas will stay in a 1:1 ratio. While gas can provide the nimble, fast ramping complement to renewables, analyses show that very high levels of renewable generation could be achieved by 2050 (while meeting reliability requirements) with a relatively small amount of natural gas as backup. As renewable energy proliferates, it starts to achieve enough geographic diversity that renewables can start substituting for other renewables within a bigger balancing area. Even in high renewables scenarios, though, the need for flexibility and reliability necessitates some other generators in the fleet.

Gas and renewables potentially complement each other well over the near- and long-term in several areas, such as fuel supply, policy risk, and grid services. In the bulk energy sector, it is worth noting that the first concentrated solar plant in California was a gas-solar hybrid, and new hybrids are emerging (as are new financial synergies). In residential energy markets, gas-renewable hybrids have lots of upside opportunities with regard to resilience, affordability, and reliability, though there are regulatory and policy challenges.

Opportunities thus clearly exist for natural gas and renewable energy to be integrated at multiple levels, with potential partnerships around hybrid technologies, co-optimized systems integration, energy and security public policy goals, and other areas. But the market needs to value ramping service – or else no financially viable system will be feasible going forward.

Nuclear

If the EPA's 111(d) rule is building on what is happening anyway in the U.S. energy sector, it is really unclear what that 'business-as-usual' means when it comes to nuclear power. There is massive uncertainty – nuclear could disappear entirely, become the biggest source of electricity supply, or anything in between.

Nuclear power now provides about 20% of U.S. electricity – not because of new build but because of impressive capacity improvements at existing facilities. But continued operation of some existing nuclear plants is severely pressured by low natural gas prices, with 6% of the fleet at risk. Some plants have already been retired because of high repair or environmental costs or because of economic reasons. The wind production tax credit is playing almost no role in forcing nuclear retirements. Similarly, the environmental community in the U.S. has played virtually no role in nuclear power's current problems; there are other places in the world that are backing away from nuclear due to strong pressure from Green parties, but in the U.S. the key determinant was low natural gas prices (as well as gross underestimations of the cost of new nuclear).

Most of the current U.S. nuclear fleet has been renewed, adding a 20-year extension to the original 40-year license. Several more units will be applying for renewal soon. There is an important question about whether existing plants should get their lives extended to 80 years (i.e., a second 20-year extension). The Nuclear Regulatory Commission will never approve such an extension just for carbon reasons; it has to assure itself that there will be no safety issues due to aging of the units, and it will take increasing levels of investment to keep these older plants operating safely, including new instrumentation and controls.

Views on the extension to 80 years depend somewhat on one's optimism about new nuclear plants – if one is pessimistic about the likelihood of new nuclear plants in the U.S., then the license renewal to 80 years becomes very important. After a hiatus of nearly 30 years, 2007-2009 saw a "nuclear renaissance" in the U.S., with a surge of applications for new nuclear plants (during a time of high natural gas prices). Since 2008, natural gas prices have dropped, causing a significant pullback (a "nuclear retreat"), with some applications cancelled and others suspended or slowed. Momentum in the U.S. has also slowed on small modular reactors, which at one point were touted as addressing concerns about high capital costs, site selection, and water use. (In some other parts of the world, though, concerns about energy supply are so high that new nuclear plants are indeed getting built – in the United Kingdom, central Europe, Turkey, China, Vietnam, and elsewhere.)

So nuclear's future in the U.S. is very uncertain, reliant on factors including whether a premium is paid for electricity fuel diversity, what natural gas price projections are, whether there is a price on carbon, whether workable capacity markets are in place, whether the units currently under construction are successful with regard to cost and timing, whether nuclear plants are able to secure long-term contracts, the degree of certainty on cost recovery, and water availability.

Energy Efficiency

Energy efficiency cannot be forgotten in a conversation about fuel choices, as it is the cheapest, most abundant, most readily available fuel source there is. It has no footprint, little risk, and costs that are even lower than natural gas. There are efficiency opportunities everywhere in the country. Customers win, providers of efficient appliances and services win, and the cost of the whole system goes down over time through lower demand. Many view efficiency as the first fuel to choose.

Efficiency is also a key compliance option for the EPA's 111(d) rule; it is projected that significant energy efficiency (meeting 50% of increased demand) has the potential to reduce overall compliance costs by about 10%.

Efficiency technologies are making great strides, with efficient houses, smart appliances, synchrophasers on the grid, and other advances making the solution space even bigger. The utility industry invests about $6 billion a year in energy efficiency, having grown significantly over the past few years. The government invests another $1 billion, and states and private actors invest still more. EPA rules will only drive those trends further. As questions rise about the rationale for investing huge sums in risky new traditional generation, energy efficiency presents a low-risk incremental investment opportunity.

Distributed Energy Resources and the Grid

The rate of innovation and change on the grid has been immense, benefiting from the huge R&D budgets in the IT sector. That makes this an exciting time to think about how to redefine the grid and what it provides – and what role distributed energy resources (DER) will play.

The Changing Grid

Today's centralized electricity grid has served us very well. It has been considered the number one engineering achievement of the 20th century. But expectations of what the grid can and should deliver are changing. The core attributes of universal access, safety, reliability, and affordability remain, but emerging attributes include environmental sustainability, resilience, flexibility, and customer control. In addition, some consumers are using new technologies to become more active in managing their energy use, and some are becoming "prosumers" (i.e., both producers and consumers). On top of that, there are pressures from aging infrastructure, minimal to declining load growth, and variable renewable energy integration.

Distributed energy resources are emerging in this context and are likely to play a critical role, though they will not replace the grid. Currently, most consumers with DER are still connected to and reliant on the grid, as they do not always produce power at the time they need to consume it; the grid is the silent partner to DER. The grid provides startup power, voltage quality, 24/7 support, flexibility, and a range of other services that consumers have never had to think about because everything was embedded in one price: dollars per kWh. As DER expands, there will be a need to figure out how to value energy, capacity, and grid services separately and ensure the grid continues to provide the reliability and convenience customers want. Technology will help variable generation provide services other than just energy, and the market will need to respect and accurately value the different services.

Basically, the grid is moving closer to something like an "energy cloud" (similar to "cloud computing"), with DER, two-way energy flows, digitalization of infrastructure, and complex market structures. Integration and control of intermittent resources will grow in complexity as penetration increases, raising security and load balancing challenges.

One could envision five basic ways the grid could evolve with DER, along a spectrum of integration. The first and least integrated way would be with grid defection and islands of self-generation, which has already happened here and there. A second way would be to have DER connected to the grid but not particularly integrated into it, which is basically where we are today; this current model risks enabling individual choices that are beneficial for consumers but have negative spillover effects on the system. A third way involves connection rules that require DER to provide grid voltage services. Fourth on the spectrum would be beginning to plan and integrate with a Distribution System Operator, including guided deployment of DER. The fifth would be a fully integrated grid, with DER operators in constant contact with system operators, maximized use of assets, and efficient use of capital and resources. Places that have very little DER penetration at this point may be able to skip some of the earlier ways and leapfrog to a model that values all the services and guides DER deployment.

To get to an integrated grid, though, there will have to be grid modernization (e.g., new dynamic controls), communication standards and interconnection rules, integrated planning and operations (including physical and cyber security), informed policy and regulation, fair allocation of costs, fair compensation for services provided, enhanced ability to manage big data, and an intense focus on responding to and anticipating the needs of customers. An integrated grid could surpass our current standards of reliability, affordability, safety, resilience, and environmental stewardship while enabling customer choice.

To get started, it is possible that the introduction of new mechanisms and markets to integrate DER may need to be staged, opening the doors first where there are the biggest values on the table, in order to ensure that the markets are truly animated from the beginning. Another option is for regulators to set particular goals for distribution utilities (e.g., shave peak by 10%) and to leave it to the utilities to figure out the best ways to get there. Either way, it is important to figure out what needs to be set up on Day 1 to really get markets for DER going.

DER Technologies

While additional technological investments and innovations are still needed in DER, it may be time to stop talking about whether the technology exists and whether we should have an integrated grid. Most seem to agree that it does (or is on its way) and we should. While a lot of the industry does not have much experience with some of these technologies yet, many technologies have moved even faster than anticipated and are here now.

Demand response, for instance, is an effective alternative to capacity expansion, provides great flexibility to system operators, offers valuable reliability benefits, and has really taken off. There is a bit of a challenge in the fact that increasing market penetration of renewable energy may push the need for demand response into the hours (roughly 4pm–9pm) when it is hardest to ask consumers to curtail their energy use, but there are available technologies and programs that could enable customers to shift their load.

Solar PV is also on an impressive trajectory. It represented 74% of new U.S. electric generating capacity in the first quarter of 2014, though that is primarily due to utility-scale solar. (Solar is also still only 1% of total U.S. generating capacity.) It is projected that total U.S. installed solar capacity in 2020 will be almost 70 GW (up from less than 20 GW today), of which 60% will be distributed. Solar power in particular raises questions about the ways in which subsidies and other measures can affect development of energy resources, given that more solar can generally get built faster and cheaper at utility scale and/or with ground mount than on rooftops, yet net metering policies provide a large incentive for rooftop solar. Part of the reason for that, though, may be that views of what the "product" is can be broadened beyond just interchangeable kilowatt-hours. Rooftop solar can meet a range of customer interests and desires; it can be marketed successfully to environmentalists who care about climate change and to libertarian survivalists who want independence and distrust monopolies. Community solar, too, is more than just kWh; it is an alternative product for consumers who do not want to put things on their roofs (for any number of reasons) but want a low-cost, fixed-price, flexible, no-contract way to displace fossil fuels and want renewables sited in their community (without building transmission).

Electric vehicle sales have also been rising rapidly and have penetrated faster than hybrids, though overall sales are still small. As EVs become much more prevalent, there is the potential for increased vehicle storage and vehicle-to-grid (V2G) technologies that could provide new opportunities for grid management, if the right policies are put in place ahead of time.

Advanced metering infrastructure deployment has fallen from its stimulus peak but is still strong, with over 50 million units deployed. The European Union is also doing a two-year study on smart meters to see if smart inverters can bring reactive power and voltage control. Already, the "enernet" (energy + internet) is starting to appear, with the electricity industry chasing "big data" and trying to figure out what to do with it. ("Big data" could have applications that benefit both consumers and utilities, such as reducing the duration of a major outage.) There are also new entrants like Google looking at creating a very consumer-centric "convenient home" with products like the Nest thermostat that can be part of an integrated system of services.

Energy storage is shaping up to be another key and growing area. There are many types of energy storage currently available, including batteries, compressed air, ice thermal, electric vehicles, and pumped hydro. Storage can be at the generation, transmission, distribution, or customer level and can provide many services, including energy shifting, ancillary services, reducing distribution load, and voltage support and inertia. California recently launched a competitive market for energy storage, with the state PUC setting a storage goal for investor-owned utilities of 1.3 GW by 2020; initial responses to utility requests have yielded an abundance of bids from a range of technologies and sizes. There are important but manageable policy issues that need to be worked out regarding integration of storage into the system, though, including resource adequacy (i.e., how storage should count towards utilities' capacity requirements since it is both a demand for and a supply of power), storage rate structure (i.e., what a storage device should pay for power from the grid and what it should charge when it sells power), storage interconnection (i.e., whether storage counts as demand, which usually gets a free ride for interconnection, or as generation, which has to pick up some of the tab for network upgrades), and storage utilization and control (e.g., whether and how utilities can use behind-the-meter storage, and whether and how storage can be controlled by both an Independent System Operator and a utility's grid control center).

There are also many other DER technologies, including fuel cells and microgrids. There are distributed gas generation technologies, too, though if gas is highly used for distributed generation for residential and commercial markets, a lot of distribution systems would be very stressed and would need to be revamped. Also, if gas-fired gensets become more pervasive, there will be heightened concerns about the fact that they tend to be very inefficient and create a lot of air pollution and health impacts.

Utilities, DER, and the Grid

Technology, policy, and market forces will continue to increase DER deployment and move the industry in new directions (though it is important to recognize that munis and co-ops often have different drivers and incentive structures than investor-owned utilities). Change could come quickly with new business models and regulatory changes.

Utilities (and regulators) could embrace the opportunities presented by DER. The DER technologies mentioned above, as well as others, provide benefits to the system, such as better resiliency; demand response, for instance, was a key reason that PJM could keep the lights on during the polar vortex. DER can also provide improved reliability, faster restoration, reduced emissions, and enabling of innovation. DER can significantly reduce utilities' investment costs, such as through better asset utilization and increased use of demand response and energy efficiency. If utilities can figure out a business model for DER – and can find test cases that are compelling to them and that increase their comfort with adopting new technologies – DER can be a win for everyone.

Despite the potential for DER to be a win-win, there have been many disagreements about DER deployment and appropriate regulations, perhaps because of conflicting worldviews. Utilities are coming from the world of centralized generation, cost of service charges, the regulatory compact, and capital-intensive infrastructure that needs incentives to draw in private capital. This is where we have been for more than 100 years. DER advocates, on the other hand, are coming from a world of distributed infrastructure, more localized benefits, monopolies as market obstacles, and no need for capital incentives because capital already wants to get into the market but cannot. Utilities are focusing primarily on today's legacy system, while DER advocates are generally focusing on the system they want to see in the future. There are particular struggles, it seems, with the rooftop solar trend, with utilities concerned about protecting their customer bases (especially low-income) and their business (especially with regard to getting paid for the cost of transmission and distribution services). No one has really come up with a "best regulatory model" to both promote rooftop solar and address utility concerns, though there are some ideas out there (e.g., coming up with an overall "value of solar", instituting higher fixed fees and lower variable fees, having an integrated distribution resource plan, buying the inverter from the customer to better control voltage quality and outflow to substations).

There are a variety of models being discussed for how best to structure the broader distribution market platform. On a continuum from most aggressive to least aggressive, these include:

1. Having independent distribution grid operators, modeled after RTOs, creating markets welcoming to all market participants (i.e., competition-friendly platforms). Independence would mean the operator would be fair to all, but the downside is that local distribution companies are the ones that know the most about their wires and systems.

2. Allowing distribution owners and operators to be one and the same, but limiting the wires owners to just the wires function. In other words, wires owners could not compete for services in their own territories. They could compete through affiliates in other service territories, but not in their own.

3. Allowing distribution operators to also be market participants, offering services in their own systems. This would require separation of the wires function and safeguards against affiliate preferences.

4. Putting distribution operators in charge of meeting defined goals for energy efficiency and distributed generation, but all through competitive procurement processes.

5. Putting distribution operators in charge of meeting defined goals for energy efficiency and distributed generation in whatever manner they deem appropriate – they could provide services themselves or provide them bilaterally or competitively.

There is also an idea that perhaps some of the disagreements between utilities, DER advocates, and others can be avoided by agreeing on some first principles about DER and the roles of utilities (or, at least, investor-owned utilities), as a foundation for taking action. Possible principles include the following:

1. *Create both short- and long-term frameworks and create a glide path to get from the short-term to the long-term.* We have a system now that we must be committed to maintaining and keeping reliable. In the long-term, we must be committed to capturing new technologies, but if we do it too slowly and poorly, it will be very expensive. Therefore, we need a glide path.

2. *Ensure U.S. electricity consumers have a safe and reliable source of electricity at a reasonable cost, but recognize that with appropriate safeguards, economic regulation (and the regulatory compact) may not be the only means to accomplish this goal.* Safe, reliable, and reasonable cost cannot go away, but there may be other ways of ensuring those attributes.

3. *Retain the natural monopoly from the distribution substation to the meter (but not the data); this infrastructure will remain with the incumbent utility.* This may be part of a long-term vision, though there are important questions around what the scope of the natural monopoly ought to be. The customers will own most of their data, though utilities use some of the data to operate the system.

4. *Allow a fair opportunity for new DER technologies to enter and compete in the market, including storage, distributed generation, demand response and energy efficiency, microgrids, electric vehicles, technologies that increase efficient use of existing assets (e.g., by reducing losses), and flexible reserves for integration of variable energy resources such as wind and solar.* There are important questions, though, about what "fair" means (as it is often in the eye of the beholder) and about how a microgrid is defined (e.g., whether it can grow so big as to be a competitor to utilities). Also, if people are relying on the grid, they should certainly have to pay for it.

5. *Allow public utilities (or, if in a holding company structure, the parent corporation) to compete in this marketplace, thereby allowing them, if well managed, to earn a reasonable profit.* Many utility executives want to be part of DER and even be leaders, and it is possible that DER deployment will go more slowly if they do not lead. If a utility can do DER well and cost-competitively, let them compete. This does not mean the delivery company, though; it means an affiliated company. Affiliates ought to be able to do business on their own system. If this truly becomes a competitive market, though, then it is important to realize that utilities can also fail. In addition, there are decisions to be made about whether utilities could invest in distributed generation on the rate-base side of the business.

6. *Ensure the building of infrastructure that is necessary for our nation's prosperity.* There are questions, however, about how exactly to do this and whether a state should do something for "our nation's prosperity" that is of no benefit to the state itself.

7. *Facilitate the achievement of environmental goals, laws, and regulations.* There are important questions, though, about whether this should go beyond environmental to include economic, energy security, and perhaps other areas, as well as about what to do in the case of goals, laws, or regulations one might want to challenge.

8. *Low-income populations have a right to basic electric service (assuming that they pay at least a nominal fee).* Basically, universal access must still be preserved as an important goal. There is a question, though, about whether electricity service should just be priced on a pure cost basis, with subsidization of low-income populations taking place through other means (e.g., the tax code).

9. *Both shareholders and ratepayers pay for stranded assets.* A corollary might be that stranded assets should be avoided as much as possible. Also, for some electricity providers (e.g., munis and co-ops), shareholders and ratepayers are the same.

Models for Providing Energy Services

Electricity is an incredibly valuable product that people take for granted. Going forward, as the focus becomes more about services, utilities will have to find a way to make electricity interesting and bring it to customers' attention. Utilities will also need to realign strategies and business models to address the various changes in operations, customer needs and expectations, and technology.

A History of Utilities Responding to Circumstances

Utility strategies over the years have largely evolved in response to what was going on in the world and what the industry had done before.

In the 1960s, the industry saw rising demand, declining costs, and optimistic regulations, and so utilities' signature strategy was to build (e.g., big coal and nuclear plants). In the 1970s, everything went a different direction, especially after the 1973 oil embargo, and the industry saw fuel price shocks, stagflation, collapsing demand, and contentious regulation; the signature strategy then was to cancel projects. The 1980s started with a hangover from the 1970s, with the industry traumatized by the realization that it could spend tons of money on projects that would never get built, and so the signature strategy was to diversify; utilities bought banks, insurance companies, real estate companies, and other unrelated ventures that utilities had little experience with (and to which they could make few contributions). In the 1990s, utilities were chastened by their experiences with diversification, but oil prices had stabilized, energy markets were liberalizing, markets in the U.S. and abroad were being restructured, people were feeling confident, and regulators were skeptical about the regulated model – and so the signature strategy was to build, buy (e.g., systems abroad), and trade within the industry. Trading did not work out so well, as the world saw with Enron. In the first decade of the 21st century, there was the financial crisis, and the signature strategy was to go back to basics to run a solid company and control costs. In all these decades, smart people with responsibilities to customers were trying to respond to events to craft a strategy to prosper, survive, and grow. None of these events fundamentally changed the business, though. Things got rearranged within the industry, but the fundamental relationship of supplier, distributor, etc. did not change much.

Challenges to the Current Utility Business Model

In the second decade of the 21st century – now – there are a range of factors in play. Environmental regulations, like 111(d), are a big deal but do not fundamentally change the underlying business of utilities. Financial markets, too, are changing, but they do not yet pose major threats to the utility business model. While there are some investors who think utilities are dinosaurs, investor appetites generally remain strong, there is value and trust in the utility franchise, and there is a trend toward pure-play investing.

There are, however, two factors that are fundamentally changing the nature of the business. First, the industry is facing slowing retail electricity sales growth. In 1980, the relationship between GDP growth and electricity sales growth was 1:1, but electricity consumption intensity has been decoupling since then, and electricity consumption has basically been flat since 2006. That is a fundamental change – that is revenue that is not coming in. At the same time, people's reliance on electricity is greater than ever.

Second, and related to the first, technology is creating competition, with efficient buildings, efficient appliances, LED lighting, solar power, and other technologies giving people the services they want while taking significant amounts of load (and thus revenue) away from utilities. Companies in the technology space are increasingly trying to get into the game of providing comfort and other things customers desire, and these companies could be either competitors or partners for utilities. Utilities need to stay engaged, understand the technologies, and try to get ahead of (rather than be defined by) technological and regulatory issues, though it can be hard to predict which technologies will actually be viable.

Given these game changers, plus increasing grid investment, the signature strategy so far this decade has been enterprise risk management. For instance, there has been a lot of merger activity as companies try to get bigger to achieve diversity of generation portfolios, regulatory regimes, political systems, climates, and customer bases.

In addition to consolidation, utilities need to start behaving as if they need to win their customers; companies that do not know what their customers want fail. There could be a wide range of customer segments for utilities to serve, including millennials and younger people (who tend to like new, shiny, mobile things and assume that utilities are far more technologically advanced than they actually are), higher-income people with social consciousness (who tend to be willing to spend more if their electricity is carbon-free and reduces pollution in the community), middle- and low-income people (who tend to be busy doing their jobs and living their lives and just want low prices and systems they do not have to pay attention to), and libertarian survivalists (who tend to associate distributed generation with freedom). Utilities can never stop analyzing customers' behaviors and preferences – and what competitors are offering to customers. It is challenging, though, for utilities to understand and respond to customer choice. For over 100 years, utilities have been largely made up of engineers who knew the customer would pay at the end of the line, so a lot of people in utilities have not thought much about customer choice and customer experience, and they have limited familiarity with innovation, business development, marketing, and the like.

Once utilities get a sense of what customers want and need, they then have to figure out if they can meet those needs with any kind of competitive advantage, skill, or expertise; it is important for utilities to know who they are and what they are good at, so they know what pitches not to swing at. Utilities then have to work with regulators to make sure the rules allow utilities to meet those needs and get revenue, including possibly transitioning from consumption-based rates to more fixed costs.

Utilities' strategies basically can be categorized as defense or offense. To play defense, utilities can engage with customers and regulators to understand customer choice, improve customer service and reliability (e.g., grid hardening) at the lowest rates possible, charge net metering customers for transmission and distribution services, help customers save money with demand response and energy efficiency tools, and develop utility owned renewable energy assets for environmentally-conscious customers. To play offense, however, is a different game that takes a broader view of the landscape to understand regulations, competition, and technologies. On offense, utilities can think about new revenue streams, new business models, new products and services, transformed organizational culture (not an easy thing to accomplish), and new executives that can both market to customers and understand the realities of the utility world. They also can start building their branding with customers, which is a clear advantage for incumbent utilities; customers may hate them, but they trust them.

Emerging Utility Business Models

Given declining energy consumption, technological competition, environmental regulation, and other factors prevalent this decade, utilities face challenging decisions about what business models to adopt and what to invest in. It will take some time for utilities to figure out what their new business models are, and it will be a messy, jurisdiction-by-jurisdiction process. Utilities will also be trying to sort this out while making decisions about aging infrastructure and working with states to develop 111(d) compliance plans; they have to be careful not to make decisions that have the effect of blocking new business models from emerging.

The risk-reward scenarios for new generation facilities are not very appealing, raising the question of who – if anyone – will actually invest in new central station generation again. The risk-return profile is much better for utilities on distribution than on generation.

Utilities need to find ways to create new revenue streams and offer new products and services to customers. Utilities could become developers, owners, and operators (alone or through partnerships) for many technologies, from rooftop and community solar to in-home management systems. They could provide new products, services, and financing for energy efficiency, demand response, and other DER. They could offer energy saving services within their regulated business for portions of the markets that will not otherwise respond to energy service companies (ESCOs). They could sell data to third parties about the best places in their systems to put DER. They could present themselves as offering bill management services. They could offer space conditioning services for a set fee per month instead of a per kWh charge. They could try to secure an arrangement whereby they get a fee for helping to bring together transactions between consumers and producers on a transmission and distribution platform with millions of customers with generation and demand response. And the ideas for new utility business models are in no way limited to the residential sector; there are natural opportunities in the commercial and industrial sectors too, which is where more of the money is.

Regulation

New business models are not just about the utilities. There is a larger conversation to be had with a broad set of stakeholders about the overall social and regulatory compact related to electricity service. With so many changes already happening in the industry, there is an opportunity to work through the issues and have conversations. Regulators can facilitate those conversations and the new business models – or they can get in the way. Regulators can be both agents of and obstacles to change. There is a need to think hard about the role of regulators in terms of leading and following.

Regulators as Obstacles to Change

Current regulatory models, practices, and processes are lagging behind emerging technologies and generation options. There are many reasons for this, but they all come down to this: the practicalities get in the way of change.

Current Public Utilities Commission appointment practices – or, in some states, commissioner elections – result in a lot of people on commissions who are new to the business and learning on the job, and there is hardly a business more complicated than this. They are also term-limited. This means the people on the PUC staff are the real knowledge experts, but they often have never had any other job but being PUC staff, so they bring a limited range of experience.

PUC staff also often engender a culture of distrust, with the view that utilities are scheming and Machiavellian. Commissioners, as short-timers, really cannot change the overall office culture. In addition, there are jurisdictional silos among executive branch agencies that are rarely breached.

The realities of the law and practice of regulation can pose hurdles as well. Innovation and experimentation are constrained by more than 100 years of legal precedent. Commissions are also very different in their authorities, with some empowered to do more than others. Debates about PUC action are often so grounded in consumer advocacy concerns – i.e., concerns about poorer ratepayers paying too much – that discussions about actual "value of service" are rare. Administrative procedures and practices tend to move very slowly and are heavily influenced by the realities of who has the means and interest to shows up.

There are also the politics of regulation to contend with. Everyone always wants to claim credit. Regulators have a hard time letting go of the old ways of doing things. They have very few incentives for taking risks. Lowest-common-denominator politics tends to dominate. The goals set for electricity service are inherently schizophrenic, with providers told to charge the cost of service but also give discounts for low-income customers, make new markets for storage, promote economic development, and advance environmental protection. In addition, the power of entitlement and incumbency is very strong; people do not want to change the goodies they have (e.g., it will be very hard to ever wean the people now on net energy metering off of it). Beyond all that, we often get stuck in what is urgent versus what is important.

Regulators as Facilitators of Change

Regulators, however, can and often do play a constructive and facilitative role as well. To seize this important moment to think and lead, adapt to changing circumstances, and enable new utility business models, regulators may need to try to shed some of their natural risk aversion. Regulators can pursue efforts to address things such as new rate structures (e.g., rates no longer tied to kWh), revised net-metering arrangements (e.g., to properly recover transmission and distribution costs), or new cost recovery strategies for potential stranded assets. They can help promote system efficiency, including end-use energy efficiency. They can help appropriately monetize the value of DER on the grid. On a grander scale, regulators can also pursue fundamental redesigns of the entire electricity regulatory system, such as the efforts getting underway in the UK and New York *(see below)*.

In addition, regulators have some core functions and roles that are vital to maintain, even if in somewhat adapted form. For instance, regulators are the protectors and enforcers of the regulatory compact, including universal access. Along those lines, there are analogies to FedEx and the US Postal Service to keep in mind. USPS was set up to let everyone have access, but the best customers started peeling off to FedEx, which left USPS as the provider of last resort, with ever increasing costs spread across a system of fewer users. In the electricity realm, regulators have to figure out how to keep a healthy provider of last resort without it becoming the worst of that world.

There is also no getting around the fact that this whole endeavor is not just about letting markets work or getting the rules just right; this is also high-order politics, which means regulators need to be savvy about how to frame the goals being pursued, who has to be satisfied, and where compromises need to be made. Industrial consumers, for instance, are a powerful force in many states, and they tend to hate variable charges to support programs for demand response, efficiency, and renewables. Regulators need to find pragmatic ways of moving forward – taking first steps, avoiding winners or losers, and creating markets.

Looking at the system more comprehensively, though, it is possible that our current energy federalism structure is just too broken to actually protect the planet, protect consumers, establish vibrant markets, aggressively jumpstart energy efficiency, and remove barriers to new market entrants. Congress is so gridlocked it has become largely irrelevant to energy policy, which means the executive branch, states, and local governments have to step in, but many of them are siloed. Judges may end up being the primary makers of energy policy, and they have the least background and training on the issues. These realities, coupled with shrinking demand, aging infrastructure, cyber and physical security threats, droughts, polar vortexes, and other factors, may suggest that, without creative and ambitious regulation, the only hope for change will be innovators, disruptive technologies, and the few market entrants that can manage to muscle their way in.

Regulators Leading the Way: New York's REV

New York offers a prime example of regulators leading the way with creative and ambitious regulation. New York regulators are pursuing a very ambitious agenda focused on Reforming the Energy Vision (REV), which goes beyond Utility 2.0 and instead is about fundamentally changing the industry.

REV envisions managing demand as the first resource on the grid, not the last, and having demand move to meet generation instead of the other way around. It envisions retail and wholesale markets working together. It envisions a new regulatory compact that demands that market-driven, clean-energy innovation is both in front of and behind the meter to create value for consumers. It envisions a consumer-centric system that gives mass market, commercial, and industrial consumers real choice, not just in terms of what supplier they choose, but also how they control and monetize the value of assets. It envisions a Distribution System Platform Provider that can do integrated and transparent planning for meeting future demand, operationalize efficiency and optimize load over the entire system, and promote and provide product and service innovation so that two-way systems are in place to ensure compensation for a range of services. REV is also focused on what New York needs to do with regard to the bulk power market to address concerns about cost of fuel, pipeline requirements, fuel diversity, and other issues.

There are several outcomes expected from REV. One is market animation; rather than having system benefits charges, programs, and mandates on top of rates, REV is driving toward animating a downstream market where retailers offer bill management services. Another expected outcome is system efficiency, aiming for optimized use of resources, so that every dollar spent on energy is of value. Other key outcomes include reliability, resilience, and environmental and economic sustainability (driven from the standpoint of the market, not as a mandate). REV will also necessitate regulatory change, moving toward a model that is long-term, outcome-based, and service-oriented and that achieves environmental goals, promotes energy efficiency and innovation, and allows utilities to really make money.

The REV process is on a very fast timeline. The Public Service Commission will issue a decision by the end of 2014 about the function of the Distribution System Platform Provider and the role of the utility. The idea is for the Commission in early 2015 to then come up with a model for what rate plans need to contain and for utilities to file individual plans to get going in 2015.

The pioneering redesign that New York is attempting may be every bit as important and impactful as the EPA's proposed 111(d) rule. Like 111(d), New York's new vision is a conversation starter, not the final word. As REV is designed and implemented, it will be a learning exercise not only for New York but also for many other states, utilities, and stakeholders that are looking on with great interest.

Appendices

Agenda

Thursday, July 3

6:30 – 9:00 PM	**Opening Reception and Dinner**

Friday, July 4

8:00 – 11:30 AM

SESSION I: CLEAN AIR RULES, IMPLEMENTATION & COSTS

When the EPA's CO_2 rule for new plants is finalized, what guidance will EPA issue to the states (and the industry) for existing plants? What can states do in anticipation? What are the ongoing impacts of rules for other Clean Air Act criteria pollutants? What are the likely costs of complying with various possible standards? How have past projections compared with actual costs for compliance with environmental regulations?

Chair: Sue Tierney, Managing Principal, Analysis Group

8:30 AM – 10:00AM	**Gina McCarthy, Administrator U.S. Environmental Protection Agency**
10:30 – 12:00 PM	**Roger Sant, Chairman Emeritus and Co-Founder, AES** **Doug Scott, Chairman, Illinois Commerce Commission**
Respondents:	**Kevin Fitzgerald, Executive Vice President and General Counsel, Pepco Holdings, Inc.** **Robert Powers, Chief Operating Officer, American Electric Power**

Saturday, July 5

8:30 AM – Noon

SESSION II: FUEL CHOICES

What will happen to the resource mix in response to low gas prices, renewable energy requirements, nuclear retirements, mercury/air toxics rules, EPA GHG regulations, water requirements, and resilience and system stability needs? What is the supply, demand, and price outlook for natural gas, the risks and uncertainties, the prospects for LNG exports, and the impact on other fuels? What delivery infrastructure enhancements are needed for various fuels? How much energy efficiency and demand management remains to be tapped?

Chair: Mark Brownstein, Associate Vice President and Chief Counsel, Environmental Defense Fund

Rick Smead, Managing Director, Advisory Services, RBN Energy LLC

Duane Highley, President and Chief Executive Officer, Electric Cooperatives of Arkansas

Joe Kelliher, Executive Vice President, Federal Regulatory Affairs, NextEra Energy, Inc.

Doug Arent, Executive Director, Joint Institute for Strategic Energy Analysis, National Renewable Energy Laboratory

1:30 – 5:00 PM

SESSION III: DISTRIBUTED ENERGY RESOURCES

What are the game-changing technologies on customer premises? Who is adding them? Why? What's happening to costs? What technologies leapfrog the meter versus being dependent upon it? What system integration issues result? Who is installing microgrids? Why? What are their impacts on distribution system operations and investment needs? How fast is a transition occurring? Is it entirely dependent on net metering?

Chair: Philip Mezey, President and Chief Executive Officer, Itron, Inc.

Stuart Hemphill, Senior Vice President, Power Supply, Southern California Edison

Malcolm Woolf, Senior Vice President, Policy and Government Affairs, Advanced Energy Economy

Anda Ray, Vice President, Environment and Chief Sustainability Officer, Electric Power Research Institute

Lauren Azar, Lawyer, Azar Law LLC

Sunday, July 6

8:30 AM – Noon

SESSION IV: MODELS FOR THE ENERGY SERVICES PLATFORM

What lessons have been learned from industry restructuring in the 1990s? What should utilities do in the face of technology innovation and adoption: Be enablers? Become investors? What is inevitable, and what is subject to changes in regulatory models? What is motivating utility mergers? What are investors saying? What will a utility look like in five years – its roles, responsibilities, services, sources of revenue? What new skills/businesses/capabilities do utilities need?

Chair: Kevin Fitzgerald, Executive Vice President and General Counsel, Pepco Holdings, Inc.

Paul Bonavia, Executive Board Chair, UNS Energy

Robert Powers, Chief Operating Officer, American Electric Power

Doyle Beneby, President and Chief Executive Officer, CPS Energy

Jan Vrins, Leader, Global Energy Practice, Navigant Consulting, Inc.

Samuel Brothwell, Senior Analyst, Energy Income Partners LLC

Monday, July 7

8:00 – 11:30 AM

SESSION V: REGULATION

What is happening to the regulatory compact? What constitutes the natural monopoly today? What does retail competition mean today? What product and service offerings and types of customer differentiation are possible? How should services be priced in an era of lower asset utilization and less throughput? What is the State PUC role? Are there roles for the federal government in retail changes? How are federal/state relationships changing? How are regional electricity markets doing? What is needed to accommodate new roles for the grid in an era of dispersed and centralized generation?

Chair: Ralph Izzo, Chairman of the Board, Chief Executive Officer and President, Public Service Enterprise Group, Inc.

Audrey Zibelman, Chair, Department of Public Service, New York

Bill Massey, Partner, Covington and Burling LLP

Sue Tierney, Managing Principal, Analysis Group

Respondent: Joseph Kelliher, Executive Vice President, Federal Regulatory Affairs, NextEra Energy, Inc.

Participants

Doug Arent
Executive Director
Joint Institute for Strategic Energy Analysis
National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401

Lauren Azar
Azar Law LLC
809 Spaight Street
Madison, WI 53703

Doyle Beneby
President and Chief Executive Officer
CPS Energy
145 Navarro Street
San Antonio, TX 78205

Roger Berliner
Councilmember
Montgomery County Council
100 Maryland Avenue
Rockville, MD 20850

Peter Blair
Executive Director
Division on Engineering and Physical Sciences
National Academy of Sciences
500 Fifth Street NW
Washington, DC 20001

Paul Bonavia
Executive Board Chair
UNS Energy
88 East Broadway, HQE901
Tucson, AZ 85701

Jason Bordoff
Founding Director
Center on Global Energy Policy
Columbia University
420 W 118th Street, Room 901F
New York, NY 10027

Samuel Brothwell
Senior Analyst
Energy Income Partners LLC
49 Riverside Avenue
Westport, CT 6880

Mark Brownstein
Associate Vice President and Chief Counsel
Environmental Defense Fund
257 Park Avenue South
New York, NY 10010

Sandra Byrd
Vice President, Public Affairs and Member Services
Arkansas Electric Cooperative Corporation
PO Box 194208
Little Rock, AR 72219

Kateri Callahan
President
Alliance to Save Energy
1850 M Street NW, Suite 1050
Washington, DC 20036

Bradley Campbell
President
Swan Creek Energy
50 West State Street, Suite 1100
Trenton, NJ 8608

Edward Comer
Vice President, General Counsel and Corporate Secretary
Edison Electric Institute
701 Pennsylvania Avenue NW
Washington, DC 20004

Celia David
Director
Navigant
30 South Wacker Drive
Chicago, IL 60606

Reid Detchon
Vice President, Energy and Climate
United Nations Foundation
1750 Pennsylvania Avenue NW, Suite 300
Washington, DC 20006

Thomas Edgar
Director, Energy Institute
University of Texas at Austin
2304 Whitis Avenue, FAC 428, Stop C2400
Austin, TX 78742

Shelley Fidler
Principal
Van Ness Feldman
1050 Thomas Jefferson Street NW
Washington, DC 20007

Kevin Fitzgerald
Executive Vice President and General Counsel
Pepco Holdings, Inc.
701 9th Street NW, EP 1007
Washington, DC 20068

Michael Fitzpatrick
Senior Counsel and Head of Regulatory Advocacy
General Electric Company
1299 Pennsylvania Avenue NW, Suite 900
Washington, DC 20004

George Frampton
Principal
NewEnergyAdvisors LLC
1054 31st Street NW
Towpath Partners, Suite 340
Washington, DC 20007

Dave Grossman (*Rapporteur*)
Principal
Green Light Group
820 Richmond Avenue
Silver Spring, MD 20910

Jason Grumet
President
Bipartisan Policy Center
1225 I Street NW
Washington, DC 20005

Julia Hamm
President and Chief Executive Officer
Solar Electric Power Association
1220 19th Street NW, Suite 800
Washington, DC 20036

Marilu Hastings
Director, Sustainability Program
Cynthia and George Mitchell Foundation
2630 Exposition Boulevard, Suite 214
Austin, TX 78703

Stuart Hemphill
Senior Vice President, Power Supply
Senior Vice President and Chief Financial Officer, Financial and Operational Services
Southern California Edison
2244 Walnut Grove Avenue
Rosemead, CA 91770

Duane Highley
President and Chief Executive Officer
Electric Cooperatives of Arkansas
PO Box 194208
Little Rock, AR 72219

Ralph Izzo
Chairman of the Board, Chief Executive Officer and President
Public Service Enterprise Group, Inc.
80 Park Plaza
Newark, NJ 7102

Kirk Johnson
Senior Vice President
National Rural Electric Cooperative Association, Inc.
4301 Wilson Boulevard
Arlington, VA 22203

Barbara Judge
Former Chairman
UK Atomic Energy Authority
One Wood Street
London, EC2V 7WZ
United Kingdom

Fred Julander
President
Julander Energy Company
9969 East Aberdeen Avenue
Englewood, CO 80111

Joseph Kelliher
Executive Vice President, Federal Regulatory Affairs
NextEra Energy, Inc.
801 Pennsylvania Avenue NW, Suite 220
Washington, DC 20004

Jelynne LeBlanc Burley
Executive Vice President and Chief Delivery Officer
CPS Energy
145 Navarro Street
San Antonio, TX 78205

Jan Mares
Senior Policy Advisor
Resources for the Future
1616 P Street NW
Washington, DC 20036

Cheryl Martin
Acting Director
Advanced Research Projects Agency – Energy
1000 Independence Avenue SW, AR-1
Washington, DC 20585

William Massey
Partner
Covington & Burling LLP
1201 Pennsylvania Avenue NW
Washington, DC 20004

Gina McCarthy
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue NW
Washington, DC 20460

Philip Mezey
President and Chief Executive Officer
Itron, Inc.
2111 North Molter Road
Liberty Lake, WA 99019

Martin Milani
Chief Technology Officer
Nexant, Inc.
1810 Gateway Drive, Suite 360
San Mateo, CA 94404

Robert Mudge
Principal and Chief Operational Officer
The Brattle Group
1850 M Street NW
Washington, DC 20036

Nelson Nease
Founder
Nelson H. Nease, P.C.
408 West 14th Street
Austin, TX 78701

James Newcomb
Managing Director
Rocky Mountain Institute
1820 Folsom Avenue
Boulder, CO 80304

Richard Newell
Director, Energy Initiative
Duke University
PO Box 90467
Durham, NC 27708

Denton Peoples
Director
NorthWestern Energy
PO Box 4008
Incline Village, NV 89450

Robert Powers
Chief Operating Officer
American Electric Power
1 Riverside Plaza, 30th Floor
Columbus, OH 43215

Anda Ray
Vice President, Environment, and Chief Sustainability Officer
Electric Power Research Institute
3420 Hillview Avenue
Palo Alto, CA 94303

Evan Reese, III Partner
Van Ness Feldman LLP
1050 Thomas Jefferson Street NW
Washington, DC 20018

Roger Sant
Chairman Emeritus and Co-Founder
AES
2100 Pennsylvania Avenue NW, Suite 545
Washington, DC 20037

Doug Scott
Chairman
Illinois Commerce Commission
160 North LaSalle Street, Suite C-800
Chicago, IL 60601

Phil Sharp
President
Resources for the Future
1616 P Street NW
Washington, DC 20036

Richard Smead
Managing Director
RBN Energy LLC
2323 South Shepherd Drive, Suite 1010
Houston, TX 77019

Dianne Solomon
President
State of New Jersey Board of Public Utilities
44 South Clinton Avenue, 7th Floor
Trenton, NJ 8625

Joanne Spalding
Senior Managing Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105

James Spiers
Vice President, Technology, Egineering and Economic Analysis
National Rural Electric Cooperative Association, Inc.
4301 Wilson Boulevard
Arlington, VA 22203

Philip St Baker
Chief Executive Officer
ERM Power Limited
Level 52, 111 Eagle Street
Brisbane, QLD 4000, Australia

Greg Staple
Chief Executive Officer
American Clean Skies Foundation
1875 Connecticut Ave NW, Suite 405
Washington, DC 20009

Michael Sullivan
Senior Vice President
Nexant, Inc.
101 Montgomery Street, 15th Floor
San Francisco, CA 94104

Susan Tierney (Forum Chair)
Managing Principal
Analysis Group
111 Huntington Avenue, 10th Floor
Boston, MA 2199

Susan Tomasky
Director
PSEG
90 Ashbourne Road
Bexley, OH 43209

Barbara Tyran
Director
Electric Power Research Institute
2000 L Street NW, #805
Washington, DC 20036

Clinton Vince
Chair, Global Energy Practice
Dentons US LLP
1301 K Street NW, Suite 600 East Tower
Washington, DC 20005

Jan Vrins
Leader, Global Energy Practice
Navigant Consulting, Inc.
255 Alhambra Circle, Suite 810
Coral Gables, FL 33134

Michael Webber
Deputy Director
Energy Institute
University of Texas at Austin
204 East Dean Keeton Street, Stop C2200
Austin, TX 78712

Malcolm Woolf
Senior Vice President, Policy and Government Affairs
Advanced Energy Economy
1101 14th Street NW, Suite 1200
Washington, DC 20005

Audrey Zibelman
Chair
Department of Public Service, New York
Agency Building 3, Empire State Plaza
Albany, NY 12223

Staff:

Nicole Alexiev
Deputy Director
Energy and Environment
Program

Avonique (Nikki) De Vignes
Project Assistant
Energy and Environment
Program

David Monsma
Executive Director
Energy and Environment
Program

Timothy Olson
Senior Project Manager
Energy and Environment
Program

John A. (Jack) Riggs
Senior Fellow
Energy and Environment
Program