NERI 2-1

Request:

Subject: Book 2—Hevert (Return on Equity)

How do you factor in whether the Company will. be successful in navigating power sector transformation in estimating future earnings growth estimates? What sources do you rely upon?

Response:

Mr. Hevert's understanding is that the Power Sector Transformation initiative is specific to Rhode Island, and is pending before the Public Utilities Commission in Docket No. 4780. Mr. Hevert is aware that several jurisdictions are in the process of investigating or implementing initiatives with similar objectives, although they vary in scope. According to a recent article (provided as Attachment NERI 2-1), more than 30 states are considering electric grid modernization and utility business model reforms. As discussed in Mr. Hevert's Pre-Filed Direct Testimony at Bates Page 67 of Book 2, there is considerable uncertainty in how the industry will transform. Mr. Hevert has considered that uncertainty, and the Company's planned capital expenditures proposed in this proceeding, in determining where within a reasonable range the Company's appropriate return on equity falls.

Prepared by or under the supervision of: Robert Hevert

FEATURE

As feds focus on baseload, grid modernization is sweeping the nation

More than 30 states are considering far-reaching modernization and utility business model reforms, including new initiatives to integrate battery storage into grid planning processes.

By **Herman K. Trabish** • Nov. 14, 2017

As the Trump administration throws its weight behind legacy power assets, states and utilities are busy building the grid of the future.

The Department of Energy's recent proposed rulemaking at the Federal Energy Regulatory Commission (FERC) would provide cost recovery to merchant coal and nuclear plants that keep 90 days of fuel supply onsite. The plan would provide support to many of the oldest generators in the country and observers worry it would unravel wholesale markets if enacted.

But the view from many states is much different. In the third quarter of 2017, there were 184 actions on grid modernization proposed, pending or enacted across 33 states and the District of Columbia, according to a new report. Those findings reflect an ongoing push for modernization nationwide. In Q2, there were 181 grid mod actions in 36 states, up from 148 actions in Q1.

Grid modernization actions make the power sector "more resilient, responsive, and interactive," according to "50 States of Grid Modernization," the new Q3 2017 policy update from the North Carolina Clean Energy Technology Center (NCCETC).

"Actions" are legislation or regulation that addresses smart grid, advanced metering infrastructure, utility business model, or rate reforms, or ways to expand access to DER.

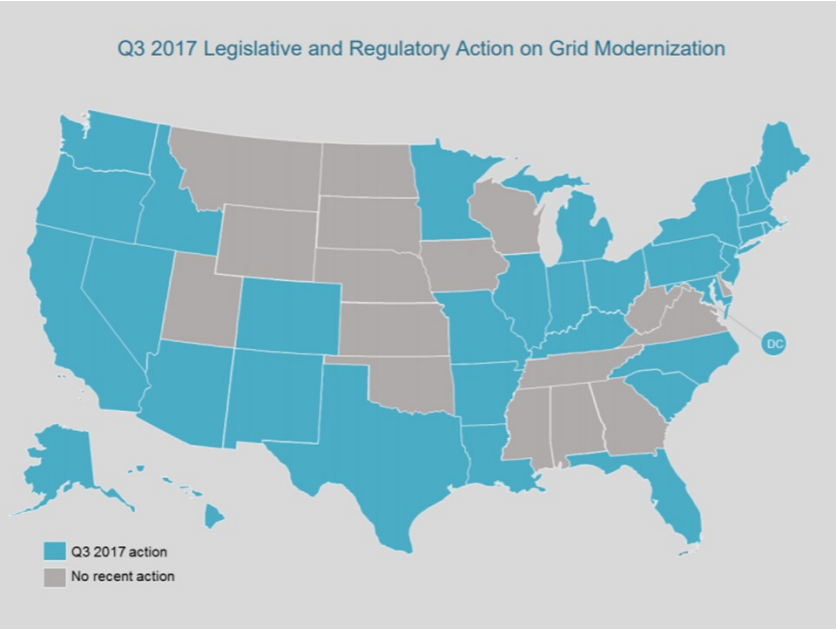
The clear trend this year has been in state-initiated investigations of grid modernization, said Autumn Proudlove, NCCETC Manager of Policy Research and lead author of the update.

“We are still at the beginning of grid modernization but more and more states are doing broad investigations to understand it better," Proudlove said.

There were 40 actions to “tweak” existing policies and 38 actions to implement incipient programs or deploy “first-step” technologies in Q3, she said. But the real trend was in the 32 actions initiating studies or investigations on grid modernization, as well as 74 actions studying markets, planning, rate and business model reforms, and financial incentives, she added.

Also significant was the fact that 26 of the 33 states engaging with grid modernization “took actions on energy storage policies and deployment,” Proudlove said.

The emerging question asked by state investigations, Proudlove said, is what grid modernization should include to enable a 21st century power sector?



Credit: NCCETC Q3 2017 grid modernization policy update

A well-developed grid modernization plan

The most common grid modernization action continues to be on advanced metering infrastructure (AMI), NCCETC reports. That is because AMI is a “foundational” infrastructure, Proudlove said.

Timothy Roughan, director of environment at Northeast utility National Grid, agreed with Proudlove.

“We see AMI as a foundational investment needed for time varying rates, as well as better planning, operational, and storm restoration needs," he said by email.

In Massachusetts, National Grid has had the benefit of one of the few completed state grid modernization investigations, Proudlove said. That is important because there is no widely accepted “best practices” for grid modernization, she added.

The Massachusetts grid modernization investigation identified four objectives: Reducing outage impacts, optimizing demand

and cutting costs, integrating DERs, and improving workforce and asset management. It also addressed the utility business model and rate design.

One of National Grid's basic grid modernization premises is that DERs must be integrated into system planning and operations to enable customer-owned resources, Roughan said. Incentives and falling costs are also driving much higher DER penetrations, he said.

Without significant system investment in "new capabilities and equipment," the underlying value of some of that DER will go untapped," Roughan said. And without "a specific grid modernization plan with cost recovery" to deploy foundational technologies that enable DER would take "much longer," he said.

A just-emerging grid modernization plan

In Missouri, Ameren began working in late 2016 for legislation to support its $1 billion, 5-year grid modernization proposal, Legislative and Regulatory Affairs Vice President Warren Wood told Utility Dive.

The traditional power system based on central station generation is evolving into "the integrated grid," according to Ameren's 2017 integrated resource plan (IRP). Higher penetrations of DERs, variable renewables and connected homes with smart meters and other communications technologies will require a "coordinated, bi-directional" grid to reliably balance distributed resources and customer demand.

Deployment of AMI and DER-enabling energy policies were "key objectives" of the Ameren-backed Senate Bill 190, which did not get through Missouri's General Assembly this year, Wood said. The IRP objectives and the objectives of Ameren's grid modernization plan are very much connected, he added.

Investments in grid modernization, along with constructive regulatory and energy policies, are "key enablers" for realizing

the integrated grid's benefits for Ameren customers, the IRP reported.

The successful deployment of AMI in Illinois proved grid modernization “is not a science fair project anymore and can deliver new customer options,” Wood said. “Missouri is behind other states. Moving forward on this is Ameren’s single highest priority there.”

Some stakeholders “do not see the benefit-cost advantage and are taking a prove-it-to-me attitude,” he added. “But we anticipate a benefit of about $2.40 from every dollar invested.”

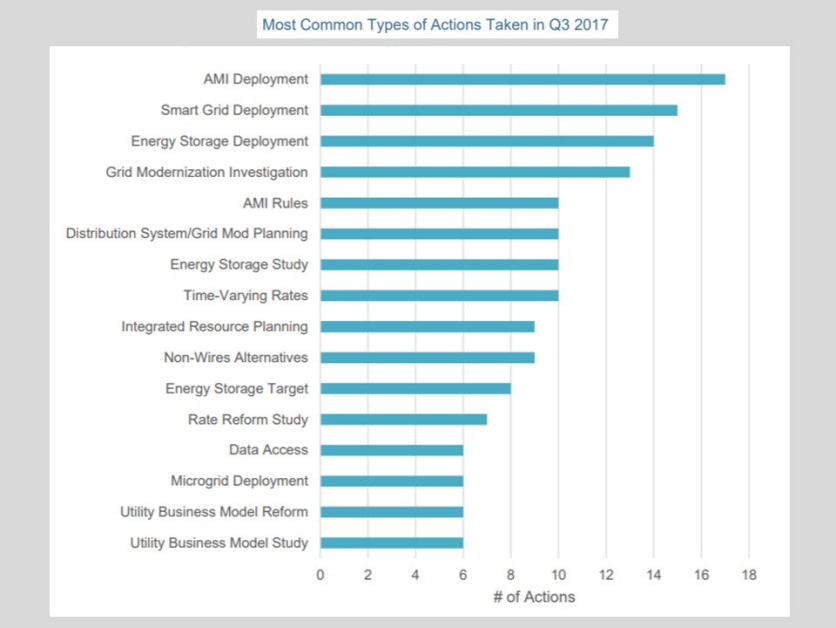
Testimony on behalf of ReNew Missouri in a Missouri Public Service Commission proceeding investigating DER issues showed the utility and the advocacy group aligned in support of grid modernization. And Karl Rabago, executive director for the Pace Center for Climate and Energy Center, told the commission “comprehensive” utility planning for grid modernization is critical. It is the first step in “a deliberate shift in a utility’s approach to infrastructure, services, and engagement with customers and markets," he said.

Grid modernization supports increased DER deployment and operation,” Rabago, a former Texas utilities commissioner and DOE Deputy Assistant Secretary, testified. That allows DER to become “a cost-effective alternative” and “empower customers to manage and reduce their energy costs.”

Ameren, Rabago and the Massachusetts investigation listed similar grid modernization objectives. They include reduced outage impacts, optimized demand and demand costs, the integration of DERs, and improved workforce and asset management.

Planning should emphasize the growth of renewables and DER, more intelligent and self-healing networks, and greater customer empowerment, Rabago argued. There should also be long-range, customer-focused planning and metrics to measure progress.

New technologies must be in place to give customers "new tools and better, more timely information based on real-time grid conditions," he added. That kind of investment in customer-facing grid modernization allows customers to exercise their "desired degree of control over their energy use" and obtain benefits from "reductions in consumption and/or shifting consumption away from peak periods."



Credit: NCCETC Q3 2017 grid modernization policy update

Storage-as-a-solution

Grid modernization policy actions are increasingly addressing DERs, particulary battery storage and microgrids, as potential "non-wires solutions" to distribution system issues, Proudlove said.

NCCETC's update highlighted Q3 policy actions aimed at clarifying the role of energy storage. Right now, energy storage policy is complicated by two conundrums. The first is whether energy storage is generation, load, or both. With a modern grid's dynamic capabilities, storage can do both to benefit

customers and the system. Without grid modernization, batteries' two-way energy flow is a threat to stability.

The second conundrum is how to value the many benefits of storage as load and generation. A power market enabled by grid modernization could value storage's many and unique capabilities and compensate them.

Oregon's SB 978 put a grid modernization investigation in motion. It directs state regulators to "investigate the impact of developing industry trends, technologies, and policy drivers on the existing regulatory system and utility incentives."

Steve Corson, spokesperson for Portland General Electric (PGE), emailed Utility Dive that customer demand for decarbonizing the Oregon grid is driving PGE's commitment to grid modernization. The utility completed its AMI deployment in 2010 and its recent investment in wireless spectrum "will make it easier to upgrade to smarter technologies," Corson said.

PGE also recently asked the Oregon Public Utility Commission to approve an almost 39 MW buildout of storage at multiple sites, including customer-based sites intended to support other DER, Corson added.

Grid modernization will enable "a flexible, two-way grid," Corson said. The result will be a "more complex" system that is "more resilient, cleaner, and responsive to customer needs."

But with the changing regulatory framework and grid modernization, "we need to maintain the positive elements of the regulated business model to assure equitable, affordable and universal electric service," he said.

Proudlove sees another emerging trend in legislation in Washington, New Mexico, and California during Q3 that would require utilities to consider storage-as-a-solution in their IRPs.

California's Senate Bill 338 requires utilities to consider how carbon-free resources can meet peak power needs in their

IRPs. State Sen. Nancy Skinner (D), the bill's author, told Utility Dive the increasing cost-effectiveness of storage and DER and the increasing challenges of the state's dynamic load make storage a timely choice.

Energy Storage Association (ESA) Policy and Advocacy Director Jason Burwen told Utility Dive a push for IRP rule changes followed the failure of utilities to respond to offerings by storage providers in procurement bidding. Including storage in IRPs "will lead to a full consideration of evidence of its potential," he said.

The New Mexico commission changed state IRP rules to require the evaluation of energy storage separately from other demand-side resources. Within weeks of the rule change, Public Service of New Mexico (PNM), the state's dominant electricity provider, issued a public solicitation for new capacity.

"PNM is encouraging renewable and battery storage options beyond those identified in the 2017 IRP," the request for bids on 456 MW of capacity stated. Burwen said he could not recall "a capacity request for proposals in which a utility explicitly asked for storage bids."

Even so, both Proudlove and Burwen agreed the Washington state commission's changes to utility IRP rules was the most important yet.

It specifically asks how "the growth of distributed generation and development of energy storage technologies should be treated in the IRP," NCCETC reported.

And it includes detailed recommendations on how to study and value storage, Burwen said.

There is one completely unprecedented innovation in the commission's order, Burwen said. It says that "utilities must be able to demonstrate in any prudence determination for a new resource acquisition that their analysis of resource options included a storage alternative."

That statement represents “the first time a commission has required consideration of storage as part of a prudency determination,” Burwen said. It tells the state’s vertically integrated utilities that “getting cost recovery requires a serious consideration of storage.”

Washington state electric provider Avista Utilities spokesperson Debbie Simock said the commission’s order aligns with Avista’s 2017 IRP. It shows that “significantly lower” energy storage costs now make it “operationally attractive,” she said. The utility’s next IRP will examine how much storage will benefit Avista's system as energy and capacity.

Beyond the West Coast, AEP Texas's challenge to state regulators to solve the load or generation conundrum for storage could also set precedents.

The utility asked for approval of a 1 MW battery and a 0.5 MW battery as “non-wires solutions” for its distribution system. It also requested approval of cost recovery for the pilot project expenditures.

The requests tested whether ownership and operation of batteries by a regulated transmission and distribution (T&D) utility represents competition with Texas retail electricity providers (REPs).

Proudlove said the decision could be significant for other utilities in Texas. Sierra Club Lone Star Chapter Conservation Director Cyrus Reed agreed.

Opposition from REPs and generators was not because of the market impact of the two small batteries, Reed told Utility Dive. It was because other T&D utilities may request cost recovery for “bigger battery facilities” that would be "real competition" for REPs and generators.

A PUCT administrative law judge (ALJ) decided in AEP's favor, finding “no statutory or regulatory prohibitions.” But the proceeding raised questions of policy, the decision concluded.

Therefore, it limited any precedential value by recommending "the Commission limit its approval to this Application." The commission's order is expected in December.

ESA's Burwen said these policy actions "show there are forward thinking utility commissions and utilities working to meet public policy goals and protect ratepayers." The high number of actions is because "the world is changing, technology is changing, and the capabilities available to grid operators, especially with energy storage, are changing very quickly."

NERI 2-2

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference the statement on p. 8, ll. 11-13, that "To provide the PUC with a reasoned basis for setting an appropriate ROE in this case, I relied on three widely accepted methods, which I applied to a proxy group of comparable, publicly traded electric utility companies." Please provide the basis for the statement that the methods referenced herein are "widely accepted," including a list of all research, reports, publications, and other documentation relied upon.

Response:

Please see Mr. Hevert's Pre-Filed Direct Testimony at Bates Pages 49-51 of Book 2, where he examines Cost of Equity estimation approaches discussed in financial journal publications, as well as academic and practitioner textbooks. As discussed in his Pre-Filed Direct Testimony, the DCF, CAPM, and Risk Premium approaches are commonly discussed in financial journal publications and academic and practitioner texts.

Prepared by or under the supervision of: Robert Hevert

NERI 2-3

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference the statement on p. 9, ll. 1-2, that "Those factors include the Company's small size relative to the proxy group, its projected capital expenditure plans, and its revenue stabilization mechanisms." Please explain how the Company's position as part of a bigger multi-state and multi-national company factors into estimating the Cost of Equity.

Response:

Please see the Company's response to PUC 3-16, a copy of which is provided as Attachment NERI 2-3 for ease of reference.

In addition, under the Decoupling Act[1], "Actions taken by the Commission in the exercise of its ratemaking authority for electric and gas rate cases shall be within the norm of industry standards and recognize the need to maintain the financial health of the distribution company as a stand-alone entity in Rhode Island." Therefore, it is appropriate to evaluate the Company's relative risk on a stand-alone basis. Consistent with that approach, the focus of Mr. Hevert's analysis is to estimate the Cost of Equity for The Narragansett Electric Company, which is an indirect, wholly-owned subsidiary of National Grid. Mr. Hevert has conducted this analysis for the Company on a stand-alone basis, so that other operations of any other entities within the National Grid corporate organization are not considered in the analysis.

[1] R.I. Gen. Laws § 39-1-27.7.1.

PUC 3-16

Request:

How does the fact that The Narragansett Electric Company is part of a larger company that includes a service company, unregulated, and regulated entities impact Mr. Hevert's assessment of The Narragansett Electric Company's risk?

Response:

The fact that The Narragansett Electric Company is part of a larger company that encompasses a service company, as well as unregulated and regulated entities has *no impact* on Mr. Hevert's assessment of The Narragansett Electric Company's risk. The focus of Mr. Hevert's analysis is to estimate the cost of equity for The Narragansett Electric Company, which is an indirect, wholly-owned subsidiary of National Grid. Mr. Hevert has conducted this analysis for the Company on a standalone basis, so that the operations of any other entities within the National Grid corporate organization are not considered in the analysis.

Prepared by or under the supervision of: Robert Hevert

PUC 3-16

Request:

How does the fact that The Narragansett Electric Company is part of a larger company that includes a service company, unregulated, and regulated entities impact Mr. Hevert's assessment of The Narragansett Electric Company's risk?

Response:

The fact that The Narragansett Electric Company is part of a larger company that encompasses a service company, as well as unregulated and regulated entities has *no impact* on Mr. Hevert's assessment of The Narragansett Electric Company's risk. The focus of Mr. Hevert's analysis is to estimate the cost of equity for The Narragansett Electric Company, which is an indirect, wholly-owned subsidiary of National Grid. Mr. Hevert has conducted this analysis for the Company on a standalone basis, so that the operations of any other entities within the National Grid corporate organization are not considered in the analysis.

Prepared by or under the supervision of: Robert Hevert

NERI 2-4

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 9, ll. 6-9 - "risk premium" approaches - how do they differ from other approaches such as the DCF method?

Response:

Please see Section III.C of Mr. Hevert's Pre-filed Direct Testimony for the description of the approaches used by Mr. Hevert to estimate the Company's Return on Equity (Bates Pages 29-61 of Book 2). As discussed at Bates Page 29 of Book 2, the Constant Growth Discounted Cash Flow (DCF) approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. Risk Premium approaches are based on the financial tenet that, because equity investors bear the residual risk of ownership, their returns are subject to more risk than are the returns to bondholders. Equity holders, therefore, require a premium over the returns available to debt holders. The Capital Asset Pricing Model (CAPM) is a form of risk premium approach that estimates the Cost of Equity for a given security as a function of the risk-free return, and the risk premium required by investors as compensation for the security's risk relative to the overall market. As explained at Bates Pages 40-41 of Book 2, Risk Premium-based methods include direct measures of risk and expectations regarding future interest rates and market returns and provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the Cost of Equity.

Prepared by or under the supervision of: Robert Hevert

NERI 2-5

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference the statement on p. 10, ll. 17-20, that "An authorized ROE that is well below returns authorized for other utilities: (1) runs counter to the *Hope* and *Bluefield* 'comparable risk' standard; (2) would place the Company at a comparative disadvantage; and (3) makes it difficult for the Company to compete for capital at reasonable terms." How does the company structure of National Grid impact these factors?

Response:

As described in the Company's response to NERI 2-3 (and the Company's response to Commission's Third Set of Data Requests, PUC 3-16), it is appropriate to evaluate the Company's relative risk on a stand-alone basis. Consistent with that approach, the focus of Mr. Hevert's analysis is to estimate the Cost of Equity for The Narragansett Electric Company, which is an indirect, wholly-owned subsidiary of National Grid. Mr. Hevert has conducted this analysis for the Company on a stand-alone basis, so that other operations of any other entities within the National Grid corporate organization are not considered in the analysis.

Prepared by or under the supervision of: Robert Hevert

NERI 2-6

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 11, ll. 18-19. What are the key characteristics of utility market valuations? Which arise in states where the commission has launched a PST proceeding?

Response:

Market value is commonly used to refer to the market capitalization of a publicly traded company and is obtained by multiplying the number of its outstanding shares by the current share price. As a general proposition, utilities are considered less risky than the overall market, as represented by their Beta coefficients, which typically are less than 1.00. Please see Mr. Hevert's Pre-Filed Direct Testimony at Bates Pages 48-49 of Book 2 for a discussion of Beta coefficients and how they are used to measure relative risk and estimate the Cost of Equity.

Prepared by or under the supervision of: Robert Hevert

NERI 2-7

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 12. What evidence supports the view that valuation increases are reflective of change from a historically discounted valuation position?

Response:

As discussed in Appendix A of Mr. Hevert's Pre-Filed Direct Testimony at Bates Pages 96-97 of Book 2, the long-term average P/E ratio for the proxy group has been approximately 17.82, below the long-term average P/E ratio for the S&P 500 of 18.68. That is, the proxy group's valuation has historically traded at a discount to the market (as represented by the S&P 500), as would be expected considering that utilities' Beta coefficients are generally below 1.00. As shown in Chart A5 (Bates Page 97 of Book 2), however, the P/E ratio for the proxy group has been above its historical long-term average since late 2015, and above the S&P 500 P/E ratio for most of 2016 and 2017.

Prepared by or under the supervision of: Robert Hevert

NERI 2-8

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 12, ll. 19-21. Please provide the Company's basis for the assertion that the growth of distributed generation makes utility operations more risky than ever, including all research, reports, publications, and other documentation in support of this assertion.

Response:

The referenced portion of Mr. Hevert's testimony reads: "In fact, with the growth of distributed generation, it could be argued that utility operations are more risky than they have been. In short, there is no reasonable basis to conclude utilities will trade at a premium to the market in perpetuity, and investors will require historically low returns also in perpetuity, as the Constant Growth DCF model assumes." The testimony speaks to the risks of utilities relative to current valuation levels; it does not say "utility operations are riskier than ever", as the question states.

From the perspective of equity investors, distributed generation resources may lead to disruptions in the traditional cost recovery model for electric utilities and electricity markets and, therefore, introduce an incremental element of uncertainty and risk. Although it is difficult to quantify the effect, the additional risk associated with distributed generation provides additional support for Mr. Hevert's return on equity range and recommendation.

Credit rating agencies have recognized risks associated with an increase in distributed generation resources. Although Standard & Poor's has noted that the competitive threat from rooftop solar panels has not been significant enough to have an effect on credit quality to date, it has outlined the potential risks to the electric utility sector:

> …should solar rooftop use suddenly increase, a utility would be forced to recover its excess electric capacity costs from its remaining customers. The resulting higher bills to the remaining utility customers would only further drive those customers to install solar panels. This could, again, prevent the utility from fully recovering its costs and investments in a timely manner, potentially harming its credit quality.[1]

Moody's has noted that, under certain conditions, there could be "large negative consequences" for utilities as a result of the widespread deployment of distributed generation resources. Under

[1] *See* Standard and Poor's Research, "Why U.S. Electric Utilities' Credit Quality Can Withstand the Rise of Rooftop Solar," November 15, 2013, at 6, provided as Attachment NERI 2-8-1.

those conditions, when the regulatory structure does not address the effect of distributed generation, Moody's suggests that "the likelihood of negative credit events would rise due to the technological disruption." Moody's also refers to distributed generation as a "form of technology event risk, where event risk is low or remote, but with high severity implications should the event actually materialize."[2]

Similarly, a July 2014 article quoted Bernstein Research analysts regarding the risk of distributed generation from a utility's perspective, stating that "[f]or the foreseeable future, distributed solar will exist in a parasitic relationship to the grid, absorbing its revenues while continuing to rely upon it for economic viability,' the analysts said, noting two specific challenges distributed solar creates for utilities: lost sales volume and a 'foregone' need for new capacity."[3]

As to Rhode Island in particular, a recent report identified the state as among the "second tier" of states in which electric industry disruption resulting from distributed generation is most likely to occur.[4]

Lastly, a 2014 Barclays report noted it was downgrading the electric sector to Underweight from Market Weight:

> [o]n concerns that the regulatory responses to the growing competitive threat from solar + storage may prove inadequate to address potential strains to the credit profiles of issuers in these states. Moreover, we think that the mere emergence of a distributed generation transition process could destabilize sector spreads. Overall, they are only in line with the long-term average versus the market and at tight absolute levels. In particular, there is very little spread differentiation in the long end for the regulated [operating companies], so investors are not being compensated for a potential major fundamental shift, in our view.[5]

Barclays also estimated that solar plus storage could reach grid parity in Rhode Island within approximately four years (after the end of 2014). *See* Attachment NERI 2-8-5 at 24.

[2] *See* Moody's Investors Service, *Regulatory framework holds keys to risk and rewards associated with distributed generation*, April 23, 2014, at 2, provided as Attachment NERI 2-8-2.
[3] *See* Copley, Michael, "Despite distributed generation's buzz, grid power 'here to stay,' Bernstein says," SNL Financial, July 21, 2014, provided as Attachment NERI 2-8-3.
[4] *See* Deloitte Center for Energy Solutions, The New Math: Solving the equation for disruption to the U.S. electric power industry, 2014, at 4, provided as Attachment NERI 2-8-4.
[5] *See* Barclays Credit Research, The Solar Vortex: Credit Implications of Electric Grid Defection, May 20, 2014, at 19, provided as Attachment NERI 2-8-5.

STANDARD
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Standard & Poor's Research

Why U.S. Electric Utilities' Credit Quality Can Withstand The Rise Of Rooftop Solar

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Why U.S. Electric Utilities' Credit Quality Can Withstand The Rise Of Rooftop Solar

How much of a threat does the growing use of rooftop solar panels pose to the credit quality of regulated utilities in the U.S.? Not as much as you might think.

It would seem that distributed generation--the use of many small, local sources of energy, such as rooftop solar panels, as opposed to a large, centralized facility--presents a direct challenge to regulated electric utilities' credit quality, in that every kilowatt-hour a solar panel produces directly offsets electricity the consumer would otherwise have purchased from the utility. This threatens the utility's competitive position and reduces its sales--which should, in turn, lead to weaker financial measures and possibly a lower credit rating. But it's actually not that simple.

Although strong sales are an important aspect of credit quality for most industries, other credit factors trump sales growth for regulated utilities. For these entities, the real key to credit quality is successfully managing regulatory risk--which includes fully recovering costs in a timely manner, earning allowed returns on equity, and minimizing volatility in customers' bills through constant open communication with regulators, while also effectively managing costs and maintaining high-quality service. If the use of rooftop solar panels rises only gradually, as we expect, electric utilities should be able to handle this competitive threat without compromising credit quality by continuing to manage regulatory risk, which includes working with regulators to minimize volatility in the customer's bill. As such, our outlook for the electric utility sector continues to be stable despite growing competitive challenges from distributed generation.

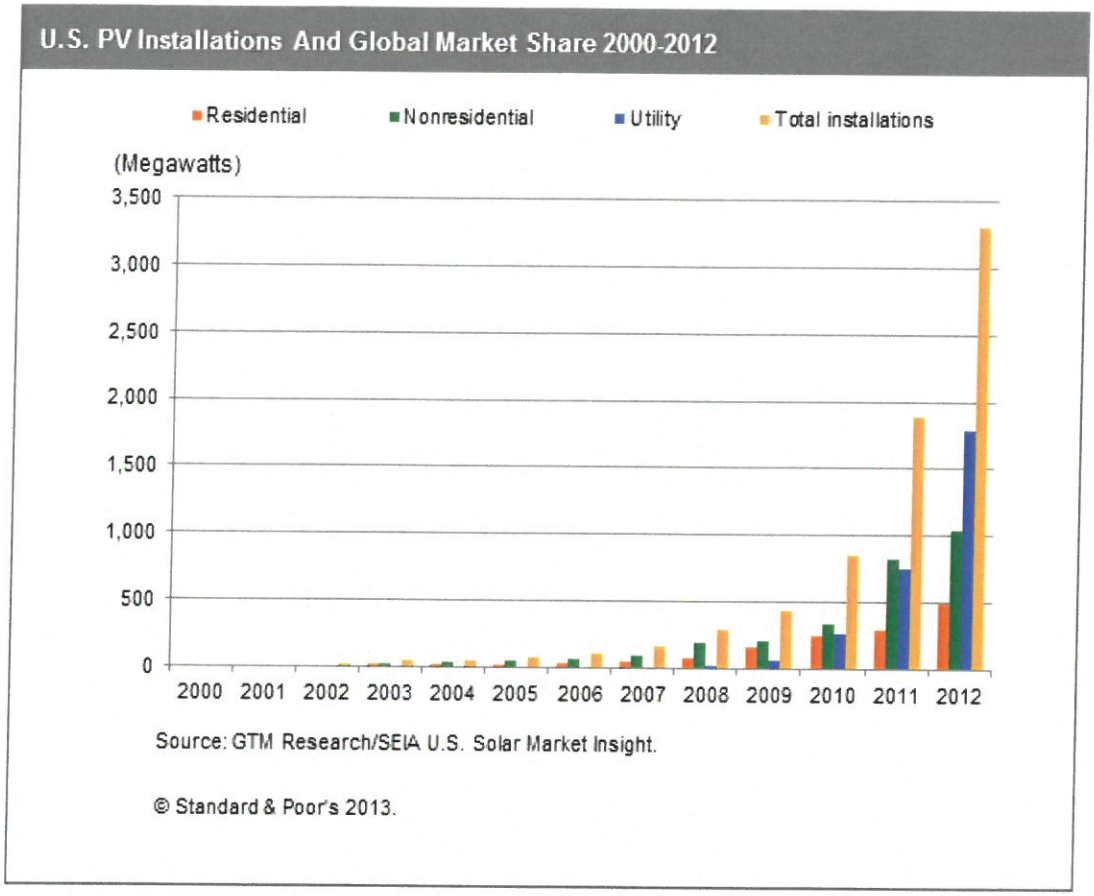
Overview

- The use of rooftop solar panels has gained traction in certain parts of the U.S., providing a competitive threat to the regulated electric utility model.
- However, most regulated electric utilities can withstand the rise with little impact on their credit quality.
- The risks to electric utilities from distributed generation are rate subsidies and a sudden increase in use. However, we don't expect these risks to negatively affect utility credit quality.

Competition From Rooftop Solar

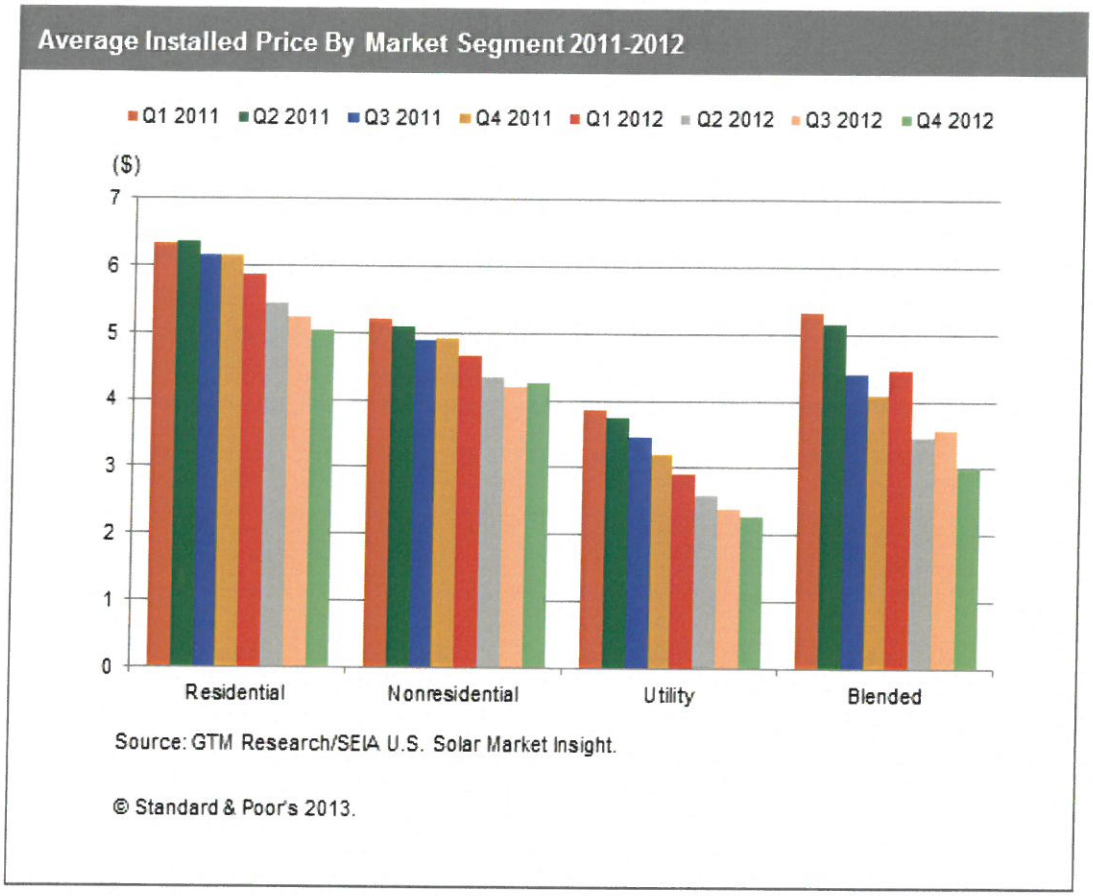
Rooftop solar panels have recently gained traction in the U.S. because of their decreasing costs and governmental incentives (see chart 1). About 200,000 homes now have rooftop solar panels.

Chart 1



According to the U.S. Dept. of Energy, the cost of installed solar panels has decreased markedly since 1998, by about 6% to 7% annually (see chart 2).

Chart 2



Policies that favor rooftop solar panels include federal investment tax credits, various state rebate programs, and certain tariff structures that allow customers to profit from selling power to the utility. Rooftop solar provides customers with an energy alternative to the incumbent monopolistic electric utility and is in direct competition with the regulated utility model.

Distributed Generation Has Not Yet Hurt Utilities' Credit Quality

To date, Standard & Poor's ratings on the electric utility sector have consistently demonstrated that the competitive threat from rooftop solar panels isn't significant enough to have a credit impact, reflecting our expectation that even the most affected utilities will be able to adequately manage this risk.

Regulatory jurisdictions that can economically justify installing the highest percentages of rooftop solar include regions that have the highest "capacity factor," or percentage of actual electricity output compared with potential output. More simply, these are usually the areas with the most sun and include Arizona, California, Nevada, and New Mexico. Rooftop solar is also prevalent in areas where public policies are favorable for solar, such as New Jersey. Currently, our credit ratings on the largest electric utilities in these five states are in the 'BBB' category. Moreover, during the past

year, despite the competitive threat from distributed generation, Standard & Poor's has either upgraded or revised the outlook to positive on most of the potentially affected electric utilities in these states, including:

- Edison International in California (see "Edison International 'BBB-' Corporate Credit Rating Placed On CreditWatch Positive Pending Reorganization Plan Approval," Oct. 21, 2013)
- NV Energy Inc. in Nevada (see "NV Energy Inc. And Subsidiaries Ratings Raised To 'BBB-' From 'BB+' On Projected Credit Measure Improvement," Feb. 20, 2013; "NV Energy Inc. And Subsidiary Ratings Placed on CreditWatch Positive Pending Acquisition," May 30, 2013)
- Pinnacle West Capital Corp. in Arizona (see "Pinnacle West Capital Corp. And Arizona Public Service Corp. Ratings Raised to 'BBB+'; Outlook Stable," Nov. 28, 2012)
- PNM Resources Inc. in New Mexico (see "PNM Resources And Subsidiary Corporate Credit Ratings Raised To 'BBB'; Outlook Stable," April 5, 2013)
- Public Service Enterprise Group Inc. in New Jersey (see "Public Service Enterprise Group Inc. And Subsidiary Corporate Credit Ratings Raised To 'BBB+'; Outlook Stable," April 23, 2013)
- Tucson Electric Power Co. in Arizona (see "Tucson Electric Power Co. Corporate Credit Rating Is Raised To 'BBB' From 'BB+'; The Outlook Is Stable," Aug. 19, 2013)

Most of the positive actions stemmed from a combination of generally improving economic conditions, a strategic return to lower-risk utility operations, or constructive regulatory outcomes that more than offset any potential competitive threat from distributed generation.

The only negative action in this period was the revision of our outlook on PG&E Corp. (in California) to negative following the San Bruno pipeline explosion (see "PG&E Corp. Outlook Is Revised To Negative Reflecting A Potential Weakening Of The Business And Financial Risk Profiles," Aug. 28, 2013).

Keys To Credit Quality For Electric Utilities

For utilities, ensuring full recovery of costs in a timely manner, earning allowed returns on equity, and minimizing volatility in the customer's bill—all aspects of managing regulatory risk—continue to be better indicators of credit quality than sales growth.

The regulated water distribution industry provides a good example of demonstrating strong credit quality despite the constant threat of decreasing sales. Water consumption has been flat or declining for decades: In fact, according to the U.S. Geological Survey, current U.S. water consumption levels are still below those observed in 1980. The water sector's maintenance of investment-grade ratings is a direct result of these companies' ability to effectively manage regulatory risk. This includes aggressively managing costs and capital projects, and having regulatory mechanisms in place that allow the water utilities to more quickly recover their costs in between rate cases.

Our assessment of the regulated electric utility sector assumes that this industry will manage regulatory risk just as effectively. For this reason, we don't expect the credit quality of the regulated electric utility sector to necessarily weaken even if sales declined for an extended period.

The Major Risks Of Distributed Generation

The primary risks to the electric utility sector from distributed generation are, in our view, rate subsidies for solar power and the potential for rapid increase in its use.

Rate subsidies, if mild, are not harmful for utilities' credit quality. In fact, there is some degree of rate subsidization in almost all jurisdictions today, to help low-income customers or to attract industrial business, for example. These subsidies generally won't harm a utility's credit quality because customers will not decide to shift from one rate category to another simply to receive the subsidized rate.

However, certain subsidy scenarios could jeopardize credit quality if the subsidy is the determining factor for a customer's decision, which can create a vicious cycle that eventually incentivizes all customers to make the same decision. For example, if a jurisdiction has a subsidy for industrial customers--which residential customers essentially subsidize--and then decides to deregulate electricity, residential customers with artificially higher rates would increasingly be compelled to sign up with one of the cheaper alternative energy suppliers, reducing the remaining pool that supports the industrial subsidy. Without a constructive regulatory response, this could harm the credit quality of a utility that is forced to continue to provide the industrial subsidy without sufficiently collecting that subsidy from its remaining residential customers.

A similar scenario could occur with distributed generation: If a subsidy provides a significant financial incentive for rooftop solar, customers may opt to install solar panels only because of the subsidy, leaving a smaller pool of remaining utility customers to support that subsidy. Furthermore, the remaining pool of customers would likely continue to dwindle as they are forced to shoulder a larger percentage of the subsidy. This could harm the credit quality of the regulated utility because it would have to continue to provide a subsidy to rooftop solar customers without fully recovering its cost from the remaining customers.

A sudden increase in the use of rooftop solar would pose similar credit risks to an electric utility. Nationally, rooftop solar panel penetration rates are low (at less than 1% of homes), and even the highest rate within a single utility's jurisdiction is still less than 3%. However, should solar rooftop use suddenly increase, a utility would be forced to recover its excess electric capacity costs from its remaining customers. The resulting higher bills to the remaining utility customers would only further drive those customers to install solar panels. This could, again, prevent the utility from fully recovering its costs and investments in a timely manner, potentially harming its credit quality.

Electric Utilities' Credit Quality Will Likely Remain Stable

Although Standard & Poor's recognizes the potential long-term risk that distributed generation poses to the electric utility sector, we do not view it as major threat to the sector's credit quality because of the current low penetration levels for rooftop solar panels and our expectations for constructive regulatory responses. Even in regulatory jurisdictions where an increase in the use of rooftop solar panels is most likely, we expect that the utilities will continue to manage their regulatory risk successfully. For instance, California recently passed Assembly Bill 327, which we view as potentially credit supportive for the regulated California utilities. The bill provides the California Public Utilities

Commission the power to reform rates on a forward-looking basis and the authority to either reduce or remove rooftop solar subsidies that may already be in place.

Standard & Poor's expects that the technological advances for distributed generation will continue and that production, installation, and financing costs for solar panels will keep falling. However, we anticipate that the growth of rooftop solar will not be sudden, allowing electric utilities to continue to effectively manage regulatory risk so that they are able to minimize volatility to the customer's bill, recover costs in a timely manner, and earn allowed returns, without hurting credit quality. For these reasons, our outlook for the electric utility sector continues to be stable despite growing competitive challenges.

--Shraddha Mittal contributed research to this article.

Related Criteria And Research

- Solar Is Powering Up, On The Roof Or Over The Grid, Nov. 15, 2013
- Rapid Growth Is Expected In Rooftop Solar In The U.S., Nov. 15, 2013

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US Regulated Utilities

Regulatory framework holds key to risks and rewards associated with distributed generation

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» Trying to assess the impact of distributed generation (DG, including smart grid technologies) on the US regulated utility infrastructure requires a considerable amount of subjective interpretation and qualitative judgment. The technologies are still years from commercial mass-market deployment, which leaves plenty of time for utilities to work with their regulators to amend or restructure the suite of recovery mechanisms, refine its service offerings and protect their credit profiles.

» The benefits that DG brings to a utility's infrastructure could be significant and go beyond simple costs per mega-watt hour ($/MWh) or cost per MW capacity comparisons. Capital expenditures in the distribution component of the rate base could rise materially and steadily, a credit positive, but DG could also pose a threat of spiraling volume declines if consumers look to drop off the grid. Today's suite of recovery mechanisms are not designed to address DG-related technology risks in a timely manner, so if volumes drop, so will cash flows.

» A breakthrough of two unrelated DG technologies could have a material impact on the credit quality of US regulated utilities over the next decade. The commercial deployment of small modular nuclear reactors could be a credit positive, despite their potential to create stranded assets in other parts of the utility's infrastructure, while mass market demand for battery storage associated with new electric vehicles could be a credit negative, possibly offset by sizeable investment increases in a utility's distribution network and better utilization of the infrastructure assets.

» Near-term, the center point of DG's technology risk and the response from utilities and regulators can be found in Arizona and California, because of the growing popularity of residential roof-top solar using net energy metering. We'll keep an eye on the regulatory proceedings, but so far, we see regulators acknowledging a mis-matched allocation of fixed costs, which hurts some customer classes. For now, we think regulators tendency to find a balance between several competing interests, mean they will be reluctant to upset the fragile economic proposition that DG currently enjoys.

» The utility sector has had to contend with these types of long-term technology event risks in the past. About 15 years ago, the sector was worried about the mass market deployment of small fuel cells – devices that were looking to corner the market to power both homes and autos. The consequences associated with the best case outlook for regulated utilities would have been dire, but today's fuel cell technologies are still largely sitting on the laboratory bench.

Distributed generation is a form of energy technology event risk

At its core, DG represents a form of technology event risk, where event risk is low or remote, but with high severity implications should the event actually materialize. In general, our credit analysis does not rate to the outcome of a specific event, such as a catastrophic earthquake, but we take into consideration the risk or exposure associated with any reasonable potential outcomes, as well as any likely mitigation measures a company might implement. For example, in the case of an earthquake, we consider the diversity of the infrastructure and the likelihood of repair costs recovery. In the case of severe storms, we consider the breadth and timeliness of storm recovery mechanisms.

With respect to DG, we consider the technology event risk associated with various forms of distributed generation a longer-term risk factor, which is not, at this time, materially affecting our ratings or rating outlooks. We think the electric grid is efficient and reliable, and because it constitutes a critical infrastructure asset necessary for a functioning economy, we expect a material amount of political and regulatory support to maintain grid reliability. We also note that most of the DG technologies or services currently being evaluated require a connection to the existing grid.

From a credit perspective, we think today's DG risks are more conceptual than specific. To have a truly distributed generation electric network, a number of different technologies would need to be synchronized, spanning all three components of the traditional, vertically integrated electric utility rate base: generation, transmission and distribution.

EXHIBIT 1

Some of the Utilities Currently Contending with the Various Challenges Associated with DG

Utility	Rating	Comment
Arizona Public Service	A3	Roof top solar
UNS Energy	Baa2	Roof top solar
Southern California Edison	A2	Roof top solar; energy efficiency
Pacific Gas & Electric	A3	Roof top solar, energy efficiency
Hawaii Electric	Baa1	Unique island needs

Source: Moody's Investors Service

Potential benefits attributable to DG

We see three key benefits for both utilities and customers associated with DG, which we can broadly categorized as economic; environmental; and reliability and security. Today, all of these benefits are more conceptual than practicable, in our opinion, as a material technological breakthrough is still needed before they reach a state where they become commercially viable on a mass market scale.

Economic: For the consumer, the economic benefits associated with DG are primarily related to self-generation, where consumers can avoid or lower their reliance on the utility's grid and infrastructure, thereby saving money. For example, if a consumer can pair a roof-top solar installation with the storage capacity embedded in an electric vehicle, or install an air-conditioner-sized, fuel-cell-powered electric generating device in the home, he or she could disconnect from its local utility and save approximately $100 per month, or $1,200 per year.[1] Another economic benefit for the consumer includes the use of smart meter technologies, which provide remote (active or passive) management of a home's heating and cooling needs, thus potentially reducing its volume demand.

[1] Assumes 10 cents per kWh residential rate and 1,000 kWhs usage per month.

For the utility, the economic benefits associated with DG relate primarily to the creation of a more efficient load (demand) curve, where peak volume requirements are smoothed out, which reduces capital investment needs and operating costs. A wide-spread intelligent network also provides a utility with a more interactive grid management tool (at the local level) which results in better outage management and keeps customers reasonably happy.

Environmental: The environmental benefits associated with DG comes in two forms. The first is a reduction in greenhouse gas emissions, especially if the technologies are associated with solar and electric vehicle (EV) battery storage. The second is a reduction in the need for land resources associated with both big generation needs and big transmission lines.

Reliability and security: The principal reliability benefit is associated with reduced outage times and higher-quality power. The principal security benefit is two-fold. First, a wide-spread deployment of DG creates a stronger and more resilient electric grid, which can better withstand storms, cyber-attacks or other large disruptions. This is most helpful for other critical infrastructure assets, such as military stations, telecommunications equipment and hospitals. Second, DG can also help insulate a region from energy import needs, or the security of energy supplies, such as natural gas transmission to New England during a polar vortex.

Potential negative consequences attributable to DG on a utility

There are large negative consequences for regulated utilities associated with a widespread DG deployment, but only if we assume everything else associated with the utility structure as we know it today stays the same. In other words, if DG emerges quickly and catches a utility and regulator somewhat flat-footed where neither has taken any meaningful strategic steps to address whatever the impact DG has created, the likelihood of negative credit events would rise due to the technological disruption.

Taking this assumption a step further, widespread deployment of economically compelling DG technologies means that consumers could easily decide to disconnect from their utilities and drop off the grid. If enough customers decided to go this route, a potential "death spiral" scenario could develop where the customers that stay with the utility will bear the increasing burden of covering the utility's fixed costs. In this scenario, the utility's volumes would steadily decline, pressuring its revenues and cash flows, damaging its credit profile and upsetting its equity owners. This would undoubtedly evolve into an environment of consumer backlash as non-DG customers became intolerant of absorbing steadily rising rates. We think this would create a period of heightened regulatory contentiousness, and the risk of a sizeable amount of stranded assets.

Nevertheless, we are reluctant to incorporate a view that the utility sector will enter a period of material and significant volume reductions associated with a mass market DG deployment without a change in the rate making structure. These technologies are all still in the very early stages of development, which leaves time – decades, perhaps – for utilities to evaluate and adapt. Moreover, utilities have seen this movie before, about 15 years ago when fuel cells were looking to corner the energy market for both homes and autos. For example, we recall a time when big industrial companies such as General Electric Company (Aa3 stable) were promoting a fuel cell generating device (the size of an air conditioning unit) that would eventually allow millions of home-owners to drop off the utility grid. Other companies, such as General Motors Company (Ba1 stable) and Toyota Motor Corporation (Aa3 stable), were promoting fuel cell-powered vehicles. At the time, the market was anticipating that more than one million fuel cell powered cars would be on the road by 2010.

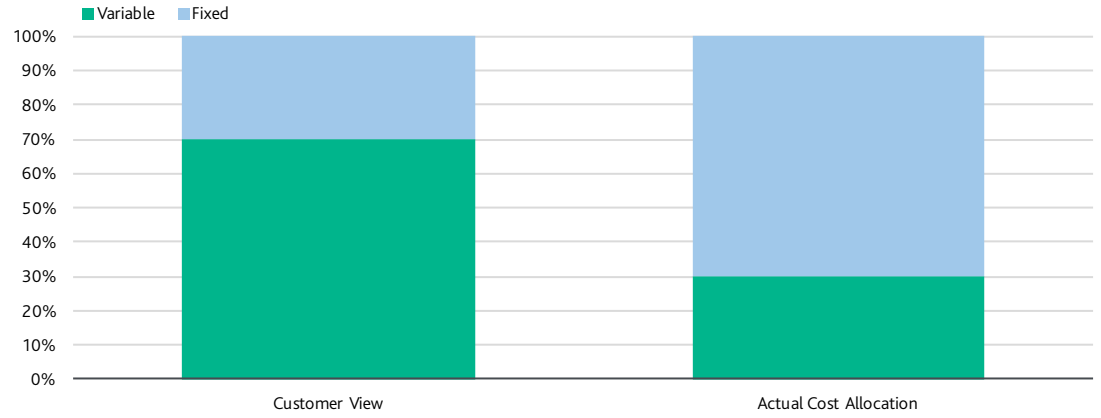
The key resides with the regulated rate structure

The risks and rewards associated with commercially available DG technologies ultimately reside with the regulators, because they approve the revenue recovery mechanisms associated with the grid's installed infrastructure. As DG technologies develop and mature, utilities will be keen to change the rate design to properly capture any benefits and allocate their costs.

The basic premise before the regulators is the allocation of a utility's fixed and variable rates, and how to classify their customers. Assuming an average monthly residential bill of $100, we think around $70 would be associated with the utility's fixed costs (on the high end of the range) – that is, the infrastructure built to serve a customer. However, today's rate structure is actually inverted in the manner in which it is presented to the customer. For example, a customer sees an average monthly demand charge (i.e., the fixed costs) of approximately $30 and a variable (i.e., volumetric charge) of $70. The rationale for why the regulated rate structure is presented to customers this way is long and complex and is beyond the scope of this report.

EXHIBIT 2

Illustrative Mis-match: How Utilities Present Costs to Customers, Compared to Actual Allocation



Source: Moody's Investors Service

With respect to customer classification, utilities consider most residential customers "full requirements customers", which means that these customer get 100% of their electrical energy needs from the utility's infrastructure – its grid. Moreover, the utility's infrastructure is designed to meet the customer's need on both the hottest and coldest days of the year. So by design, the infrastructure is underused on most "normal" weather days.

Theoretically, if a customer decided to self-generate a portion of his or her electric needs, the utility would no longer view the customer as full-requirements customer. If a utility, or its regulator, changed the designation of the DG customer to a "partial requirements customer", that customer's allocation of the utility's fixed and variable costs would change, as would the economic proposition that the DG service provider is using to market its product or service.

In this case, were the regulator to change the customers' classification, we still think DG customers would have lower bills, but the lower bills would be solely due to reduced energy usage associated with lower volume needs. A change in rate classification would address the mis-allocation of fixed charges. Because this solution appears to be so simple, that is, a change in the rate making structure, we think today's DG economic proposition is somewhat fragile.

Another big regulated consideration relates to planning. Because utilities manage the electric grid, a critical infrastructure asset, a considerable amount of planning goes into the engineering of the grid's reliability. As a result, we do not, at this time, think regulators will allow customers to add numerous DG devices across the grid without including some form of planning in the mix.

For example, with respect to rooftop solar installations, the lack of planning and coordination between roof-top solar installers and utilities in our view is an area that might get addressed over the next two to three years. Whereas rooftop solar companies prefer customers with high credit scores and southern facing roofs (which maximize solar output and thus potential savings for the customer), a utility might prefer roof-top solar installations concentrated in a more diverse section of its service territory or with the panels facing west (to better coordinate solar production with the utility's peak need).

Two distributed generation technologies to monitor

We illustrate two unrelated distributed generation technologies that deserve watching because breakthroughs could have a material impact on the credit quality of US regulated utilities over the next few decades: the development of (1) small modular nuclear reactors to supplement or replace large power plants and (2) battery storage devices associated with electric vehicles. For now, we think these technologies are at least a dozen years away from full commercial adoption, leaving the utility sector with plenty of time to refine long-term strategic plans.

SMRs look good on paper

Conceptually, small modular reactors (SMRs) look really good on paper, and could be a compelling complement to today's big, central station utility model. SMR designs are likely to share many common principles with existing reactor technologies to address safety and produce a competitive economic proposition. They require a much smaller footprint than big reactors and can be built in stages, which helps a utility layer in its generation supplies with its load demands. The primary system components are being designed into a single vessel, which should help with passive cooling designs, much like the advanced technologies associated with the much larger Westinghouse AP1000, and thus reduce "first of a kind" risk.

The SMR designs will also rely on a modular assembly that optimizes manufacturing and construction costs, construction schedules and quality control through standardized components and processes. And because nuclear power does not produce any harmful greenhouse gas emissions, more widespread adoption of SMRs can help with climate change concerns, especially if the SMRs are deployed to replace fossil-fueled generation.

In effect, the SMR concept marries the logic of economies of scale with the economies of mass production. Together, these SMR designs will translate into operating-cost efficiencies, and can help reduce transmission congestion if they are sited near load pockets.

Regulated utilities, especially the municipally owned and G&T cooperative sectors, stand to benefit the most from the development of SMRs, especially if they are located in regions where coal sets the price of power on the margin or in the Pacific North West, where population densities are lower.

EXHIBIT 3

Selected Utilities That Could Benefit from Commercially Available SMR Generation

Utility	Rating	Region	Comment
Tri-State G&T	Baa1	Western US	Benefits from low population density; need for incremental generation supplies
Idaho Power	A3	Western US	Benefits from low population density; need for incremental generation supplies
TVA	Aaa	Eastern US	Proto-type partner for SMR

Source: Moody's Investors Service

Storage – the holy grail for utilities

A breakthrough in battery storage would disrupt the regulated utility and unregulated power business models because revenues and volumes would fall as homeowners decide to drop off the grid (for electric power needs only, not natural gas or water and sewer). We think the likelihood of this technology is also remote for now, given an apparently higher level of uncertainty than for the SMR technology.

Tesla Motors (not rated) made a big splash in the marketplace when it announced plans to build a massive new battery production facility to facilitate a ramp-up in its electric vehicle production plans. If Tesla is successful in driving down the costs for its EVs, which can be recharged by some other form of distributed generation thereby prompting customers to drop from the grid, the regulated utility revenue model will likely experience some stress on the allocation of its fixed demand charges. Specifically, customers who cannot afford a new EV and do not drop off the grid will likely end up with higher utility bills, which raises the risk of equitable rate allocation for regulators.

We don't think EVs will have a dramatic market acceptance over the near-term, in part because the of the material performance advancements in internal combustion engines, with more to come. In addition, battery storage technologies will need a technological leap in size, or customers will need to string several batteries together in order to provide enough power to serve all of a home's appliances. There are also some engineering constraints associated with the power surges needed to cycle the bigger appliances, such as an air conditioner. Still, the process of marrying battery storage with increasingly competitive distributed generation is something to monitor.

From a credit perspective, we'd expect to see a material increase in a utility's distribution capital investments, as the grid is refurbished to meet the needs of a mass market EV network which could offset some of the risks presented by a mass deployment of battery storage devices.

Appendix A: *The following was originally published in the Global Infrastructure Focus in September 2013*

Technology risks represent a material threat to utilities, but resiliency of business model remains intact

In the technology sector, everything gets cheaper and more efficient exponentially. For the global utility sector, the technology model could smash into utilities' existing market framework and create material threats to the business model. These big-picture, long-term risks have been highlighted as a challenge for utilities for decades, but the resiliency of the utility business model will be very difficult to attack.

When Moody's thinks about technology risks for the utility sector, we usually focus on distributed generation resources, such as solar power, accompanied by smart grid products that empower a customer to manage their usage. We can envision a scenario where every home-owner and building within a defined, monopoly service territory is equipped with a battery capable of managing the load. Under this scenario, customers would likely be inclined to drop off the utility's grid, thereby creating significant stranded assets, and destroying the utility of the utility business model. But such a day seems to be many years in the future, absent a major technological breakthrough, so threats like these are considered, for now, as remote probability-high severity event risks.

Still, we see the emergence of the scenario developing, especially in some US states such as California and Arizona, where subsidized roof-top solar programs with net-metering rate structures are distorting the fixed cost allocation among different consumer groups. While still small, and not material to the consolidated financial profile of the utilities involved, Arizona Public Service (A3 stable), Southern California Edison (A2 stable) and Pacific Gas & Electric (A3 stable), if extrapolated to a more meaningful penetration, the existing regulatory recovery mechanisms will create big costs for those consumers left on the grid. This will, theoretically, incentivize more consumers to leave the grid, thereby creating a negative spiral.

We don't think the existing model can be applied and extrapolated indefinitely. Instead, we see a material restructuring to the traditional suite of rate recovery mechanisms, where the utility's fixed costs are more equitably distributed across its customer base.

In Germany, we see the social and political agendas focusing on climate change, a push towards renewable solar and wind power and the avoidance of fossil and nuclear generation. This has created significant financial stress for the big German generators, such as RWE (Baa1 stable) and E.ON (A3 negative). Have consumers really benefited?

There are other scenarios to consider, especially with respect to the mass adoption of electric vehicles (EV's). To be clear, today, we do not view electric vehicles as a material threat for utilities. We consider these auto-manufacturer's product lines as both low volume and low margin – not a robust business line for major global industrials. Moreover, we think auto-manufacturers have already identified significant and material advancements in the efficiency of their internal combustion engines, so we are at least another decade before EV's start to compete for consumer attention.

Still, for illustrative purposes, lets imagine a scenario where a multi-story parking garage opened in center city London or New York. The parking garage only allows EV's, and the costs for a monthly parking pass is offered at a significant discount to other parking alternatives. Once safely parked, the driver plugs his EV into the garage's grid and is given a key-fob which the driver will activate about 30 minutes before returning to take his vehicle.

Theoretically, the parking garage has just become a 15[2] MW power plant, located in the heart of the load demand pocket. On the hot summer day, usually around mid-day when electric demand is highest, the utility would access the garage's capacity, and drain every EV's battery. Once the peak demand passes, usually in the early afternoon, the EV's begin to recharge – just in time for the evening rush home.

Of course, a mass adoption to EV's also brings material challenges for many toll road operators. Some toll roads, such as the New Jersey Turnpike Authority and the Pennsylvania Turnpike Authority, rely on the concession fees and gasoline taxes that motorists utilize at rest stops. EV's don't use gasoline, so those revenues will fall. In addition, EV's ought to have a range many times greater than a standard gasoline tank, so perhaps they will be less likely to stop as well. In Virginia, we see elected officials moving to revamp their gasoline tax structures, in part to address the improving mileage of today's auto's.

Technology also brings the promise of energy efficient gains, so the expected volumes that utilities might be looking to sell are going to flatten, or worse, decline. This phenomena is most evident in the natural gas distribution sector, which has experienced falling volumes for years. More efficient appliances use less power and natural gas, and if consumers were given easy control of their thermostats, perhaps through their wireless mobile phones, utilities could see a more meaningful drop in volumes.

Declining volumes spell more trouble for electric utilities than gas distribution utilities, because in the gas distribution sector, a more proactive approach to reallocating the fixed costs across all customers is already well underway.

In summary, technology risks are a threat, but the adoption rates are likely to prove slow enough for both utilities and regulators to revise and amend their recovery mechanisms.

[2] Assumes 500 parking spots and an average EV engine capacity of 30kw's.

Moody's Related Research

Sector Comments:

- Risks in Commercial Solar Contracts Differ from Residential, June 2013 (SF333536)
- Long Contract Tenors Accentuate Four Major Risks for Residental Solar Securitizations, April 2013 (SF327239)
- Expiration of Department of Energy Loan Guarantee Program Is Credit Negative for US Solar Companies, October 2011 (136546)

Special Comments:

- Rooftop Solar, Distributed Generation Not Expected to Pose Threat to Utilities, November 2013 (160080)
- Regulatory Changes Have Proved Beneficial to Date but Affordability Issues May Exert Negative Pressure on Electricity TSOs, August 2013 (156573)
- German Utilities Face Structural and Cyclical Challenges to Profitability and Credit Profile, July 2013 (156251)
- Spanish Utilities: Further Regulatory Reform Likely Despite Measures to Eliminate Tariff Deficit, April 2013 (148485)
- Wind and Solar Power Will Continue to Erode Thermal Generators' Credit Quality, November 2012 (146913)
- Solar Photovoltaic (PV) Industry Faces Challenges from Overcapacity, June 2011 (133234)
- Renewable generation in the US: Sunny skies or storm clouds ahead, April 2011 (132140)
- PV Solar Power Generation Projects, July 2010 (125811)

Pre-Sale Reports:

- Solar Star Funding LLC, June 2013 (154989)
- CPV Power Plant No. 1 Bond SPV (RF) Limited, December 2012 (148012)
- Topaz Solar Farms LLC, February 2012 (139706)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

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Monday, July 21, 2014 6:03 PM ET Extra

Despite distributed generation's buzz, grid power 'here to stay,' Bernstein says

By Michael Copley

Talk of utility death spirals and grid defection has colored much of the debate around distributed generation and its place in an electric system long defined by big, centrally located power plants. But with a levelized cost of energy that is roughly 12 times the average U.S. residential electricity rate, grid-independent solar systems — and notions of a decentralized future — are distracting from "the very real near-term threat" utilities face, Bernstein Research analysts said July 21.

Hawaii is the often-cited example of what could lie ahead for utility companies. High energy costs and a corresponding surge in distributed solar power generation have thrust the state to the forefront of a national debate about what viable utility business models might look like. Upon returning from vacation there, Jon Creyts, executive director of the Rocky Mountain Institute, related to an industry conference in New York City in April the sensation of seeing television commercials promising to help people drop off the grid. Hawaii is a "postcard from the future," Creyts said, adding that within a decade similar commercials would be airing in the northeastern U.S.

But even assuming an 80% drop in the cost of battery storage and solar photovoltaics, the price of a grid-independent solar system would be roughly three times the average U.S. electricity rate of 12 cents per kWh, Bernstein analysts said. Add to that the fact that physical roof space and the efficiency of available solar systems limit distributed solar's generation potential to no more than about a quarter of the country's electricity use, and Bernstein analysts concluded that grid-supplied electricity "is here to stay."

"For the foreseeable future, distributed solar will exist in a parasitic relationship to the grid, absorbing its revenues while continuing to rely upon it for economic viability," the analysts said, noting two specific challenges distributed solar creates for utilities: lost sales volume and a "foregone" need for new capacity.

The Bernstein report echoes prior assessments from Moody's and Macquarie Capital (USA) Inc., which separately concluded that utility companies have time to adapt to a business landscape that is shifting with the rising popularity of rooftop solar panels and the prospect of one day pairing those systems with affordable battery storage.

Jeffrey Goltz, a commissioner with the Washington Utilities and Transportation Commission, does not dispute the serious consequences that many say could come from the rising popularity of distributed solar. But he said most areas of the U.S. are not likely to see a broad shift toward off-grid power. "There will be some outposts in Hawaii where people go off the grid," he said at an industry conference in San Francisco in April, but "I do not see that happening in the Pacific Northwest."

That is not to say, however, that adapting will be easy, regulators and analysts note. Broadly speaking, there is an interest among regulators in moving toward performance-based ratemaking.

"I do not think the utility central station model is a dinosaur yet. I am not sure it ever will be a dinosaur, but … utilities need to think differently," Wisconsin Public Service Commissioner Eric Callisto said at the conference in San Francisco. "And the same goes for solar companies. It is time for the solar companies to start wearing long pants. As my colleague said, at some point, if you want to act and talk like a generator, then you get paid like a generator. We need to move away from the net-metering model and find something that really talks about value," he said.

Minnesota regulators in March approved a methodology for calculating the value of distributed solar, which could be used to replace net energy metering in the state. The move, which is unpopular with solar-leasing companies that favor net metering, was watched closely by regulators in other states.

Still another option being discussed is allowing utility companies to enter the rooftop business and rate-base their costs, another approach the solar industry opposes. "My views on this are evolving continually, but I have felt for some time that an investor-owned utility should be able to get into the distributed generation business, even as a part of its regulated business, with the caveat that you have to be careful about the effect on competition," Goltz said. "I would like to see more competition in the provision of distributed generation services. That would benefit customers. If a regulated utility gets into it, then it is still subject to our consumer protection jurisdiction. If the utility abuses its power, we can hammer it."

All that is to say that many regulators and analysts are working under the assumption that electricity delivered through a central grid will remain cheaper than off-grid self-generation. "Just the up-front cost of such a [grid-independent solar] system exceeds $140,000, equivalent to 110 years of average U.S. electricity bills," Bernstein analysts said.

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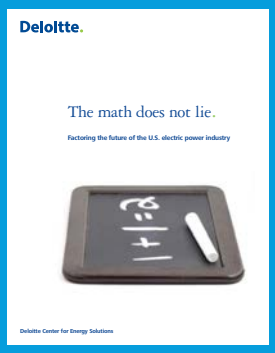

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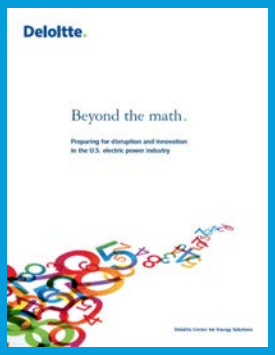


www.deloitte.com/us/beyondthemath

The *New Math* is the third and final paper in a series from the Deloitte Center for Energy Solutions. The first two papers, *The Math Does Not Lie* (November 2012) and *Beyond the Math* (March 2013), are available at http://www.deloitte.com/us/dothemath and http://www.deloitte.com/us/beyondthemath, respectively.

Our goal in writing these three pieces is to assist electric companies' managements, their boards of directors, and their other stakeholders as they evaluate the rapidly changing U.S. electric industry landscape. This final paper examines the fundamental shifts that are already occurring in the electric industry's *license to do business* and in the field of players and new technologies that are providing electric services to U.S. business and residential customers. It also sets forth frameworks that are designed both to assist in analyzing and monitoring critical marketplace dynamics, and to serve as platforms for dialogue, consensus building, and the creation of new business models required to confront the challenges and seize the opportunities that lie ahead.

This paper is informed by a number of in-person interviews and discussions with electric company executives, leaders of clean tech companies, regulatory experts, and other stakeholders whose insights helped shape the vision of the *new math* that is emerging in the United States electric power industry. A full list of interviewees is provided at the end of the paper.

Introduction

Impending disruption to the traditional U.S. electric industry business model has been the topic of much discussion. Many believe profound change is inevitable and, in some respects, may well be self-fulfilling. However, many aspects of this subject continue to be debated:

- How fast will today's business model change?
- What will the new model(s) look like?
- Who will be the industry participants?
- What roles will technology, customers, and regulators play?

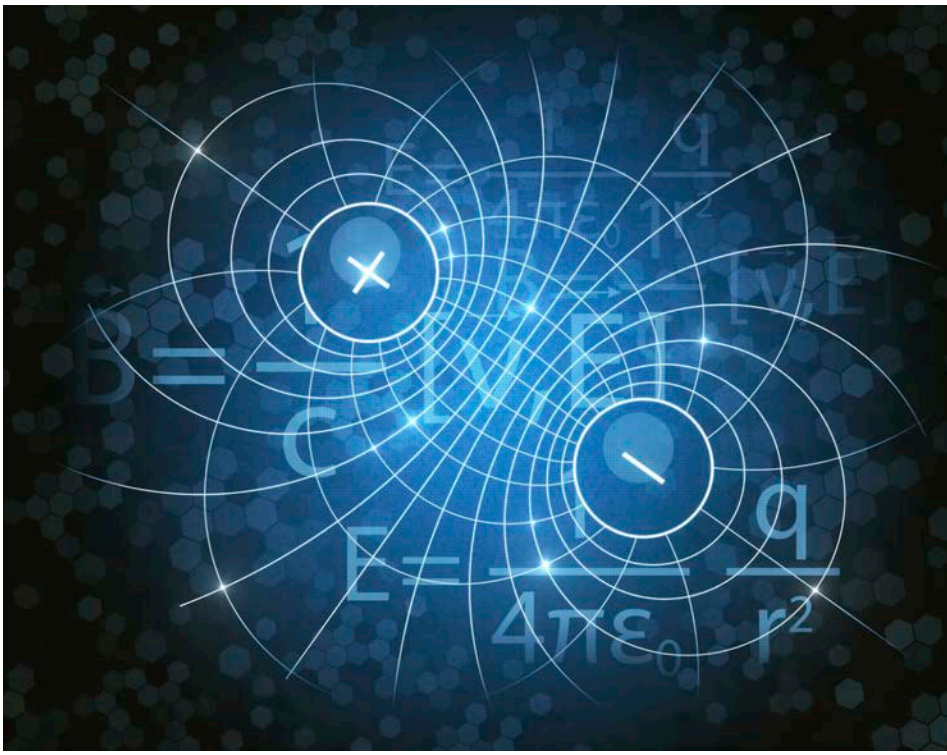
The sustainable U.S. electric business models of the future are simply unknown — and the same is true for the strategies that will ultimately be developed and executed by the successful participants.

As electric companies of all types confront this complex challenge, a dynamic framework will be required in order to:

- Assess the current landscape
- Determine the critical factors that will shape the future U.S. electric marketplace and develop points of view around those factors
- Monitor marketplace and policy trends and recalibrate business strategies in real time

This paper provides such a framework. It examines the major industry participants shaping the business models of the future and advances tactics for consideration, analysis, discussion, and debate. Finally, it suggests *game changers* that could quickly alter the path to the industry's future.

This paper does not advocate a particular strategy for addressing the coming disruption, nor does it suggest what business models will emerge as successful in the future. This paper will have served its intended purpose if it: 1) facilitates discussion and consensus-building among electric company managements and their boards as they address the challenges and opportunities presented by the changing landscape, and 2) serves as a catalyst and platform to advance the dialogue among the various stakeholders with roles in solving the equation.



A fundamental shift in the variables of the equation

The Math Does Not Lie[1] examined the implications of rising costs to generate and deliver a kilowatt hour (kWh) of electricity in an environment where future kWh sales are flat or declining for a sustained period of time — something the U.S. electric sector has never experienced.[2] As significant as this scenario is for the electric industry, two other changes in the industry's relationship to the marketplace may have equal or greater implications for the current electric business model — *the new license to do business* and the *new participants in the game* of providing electric services to customers.

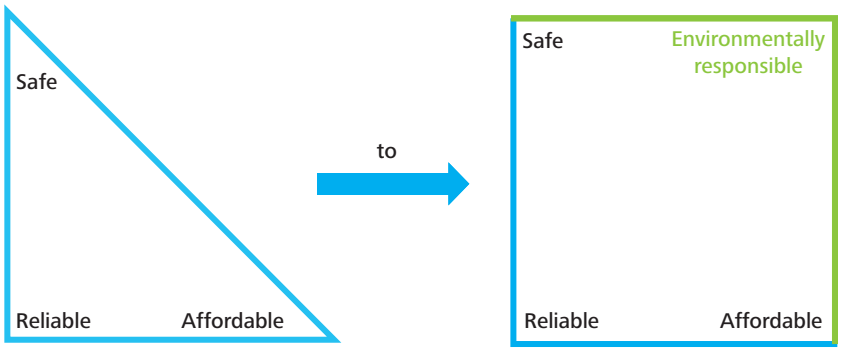
Environmentally responsible electricity is no longer an option — it is an imperative to doing business regardless of its cost and the associated price of the product. And, while some new technologies and products may come and go, new market entrants, or disruptors, are here to stay.

In a relatively short span of time, the traditional way of doing business has begun to change while, for the most part, the electric industry business model has stayed the same — setting the stage for disruption.

Disruption to the electric industry business model has been the topic of much recent discussion and debate. It is important to frame this topic in a way that allows it to be examined and discussed on a common basis among the various stakeholders. To that end, the next section provides a definition of disruption and explores how it could manifest itself across the U.S. electric industry.

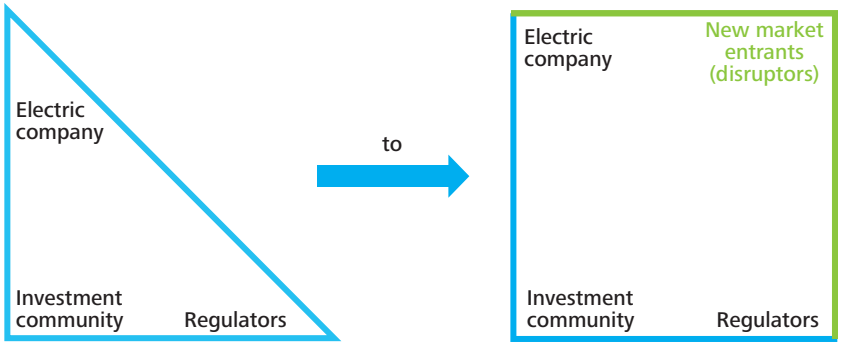
With this framework in mind, electric companies and stakeholders will be better equipped to assess the challenges and opportunities likely to confront them in the evolving electric industry landscape that is explored later in this paper.

License to do business



Traditional **New**

Participants in the game



Traditional **New**

[1] Deloitte Center for Energy Solutions, *The Math Does Not Lie – Factoring the future of the U.S. electric power industry*, November 2012, http://www.deloitte.com/us/dothemath

[2] From 2008-2012, U.S. electricity sales declined year over year in four out of five years, and are expected to show a slight uptick in 2013, according to the Energy Information Administration (EIA), *Electric Power Monthly* and *Annual Energy Outlook 2014 Early Release*, accessed February 2014, http://www.eia.gov/electricity/monthly/, http://www.eia.gov/forecasts/aeo/er/index.cfm

Modeling disruption in the U.S. electric power sector

What does disruption mean?

The Innovator's Manifesto describes "disruption" as a process of innovation by which entrants often displace incumbents in a wide variety of markets.[3] In the context of this paper, disruption to the U.S. electric business model refers specifically to those circumstances in which the traditional central generating station model ceases to function in its current role as the primary provider of safe, reliable, affordable, and environmentally responsible electric service to customers — both businesses and consumers. This is not meant to imply the near-term death of this business, but does suggest that its role in the marketplace diminishes over time as other business models evolve that better meet certain customer needs and expectations. The pace of this evolution will most likely dictate the magnitude of the disruption. The magnitude, in turn, will determine the alternatives and actions available to those companies with investments in the infrastructure underpinning the traditional U.S. electric business model.

Disruption across the U.S. electric power sector

While the nature and pace of disruption are the subject of much debate, there is general consensus that disruption in the U.S. electric sector will occur at different times and in different ways across the country. Consequently, the ability to explore the potential timing of the coming disruption provides a useful foundation for further examination of the new license to do business and new participants in the game.

In *Beyond the Math*,[4] Deloitte examined the dimensions of change that most likely signal if market forces are, in fact, accelerating disruption in the U.S. electric sector. Using this same framework, Deloitte has developed a predictive model to provide insights into the relative pace of disruption across each of the 50 states.

The model analyzes four specific dimensions of disruption at the individual state level and defines them as follows:

Dimensions	Definition of dimensions	Indicators of disruption
Demand	Demand for electricity from central generation assets — measured in terms of near-term changes from current levels of kWh sales	• Lowest electricity growth/largest decline in sales • Highest retail electricity prices • Lowest projected economic growth
Technology	Forecasted investments in new electric service technologies	• Highest projected level of renewables penetration • Highest projected level of smart meter penetration • Highest level of distributed generation penetration
Product	Customers' incentives to purchase electricity service (product) from other sources	• Highest level of major electricity outages • Highest projected household incomes • Solar price competitiveness
Policy & Regulation	Magnitude of policy and regulation promoting environmentally responsible electricity (including energy management)	• Highest level of renewable portfolio standards (RPS) targets • Highest level of energy efficiency investment as a percentage of electric sales • Highest concentration of state and local tax credits, renewable energy financing, and other incentives

Across each of these dimensions, the model identified and measured indicators of disruption. The objectives were to identify states across the United States with the highest likelihood of disruption and to determine which indicators were the most likely to signify the enhanced probability of disruption. In general, where the model's indicators are forward-looking, projections for the year 2016 were used when available.

[3] Michael E. Raynor, *The Innovator's Manifesto* (New York: Crown Business, 2011)
[4] Deloitte Center for Energy Solutions, *Beyond the Math – Preparing for disruption and innovation in the U.S. electric power industry,* March 2013, http://deloitte.com/us/beyondthemath

Overall findings from the model

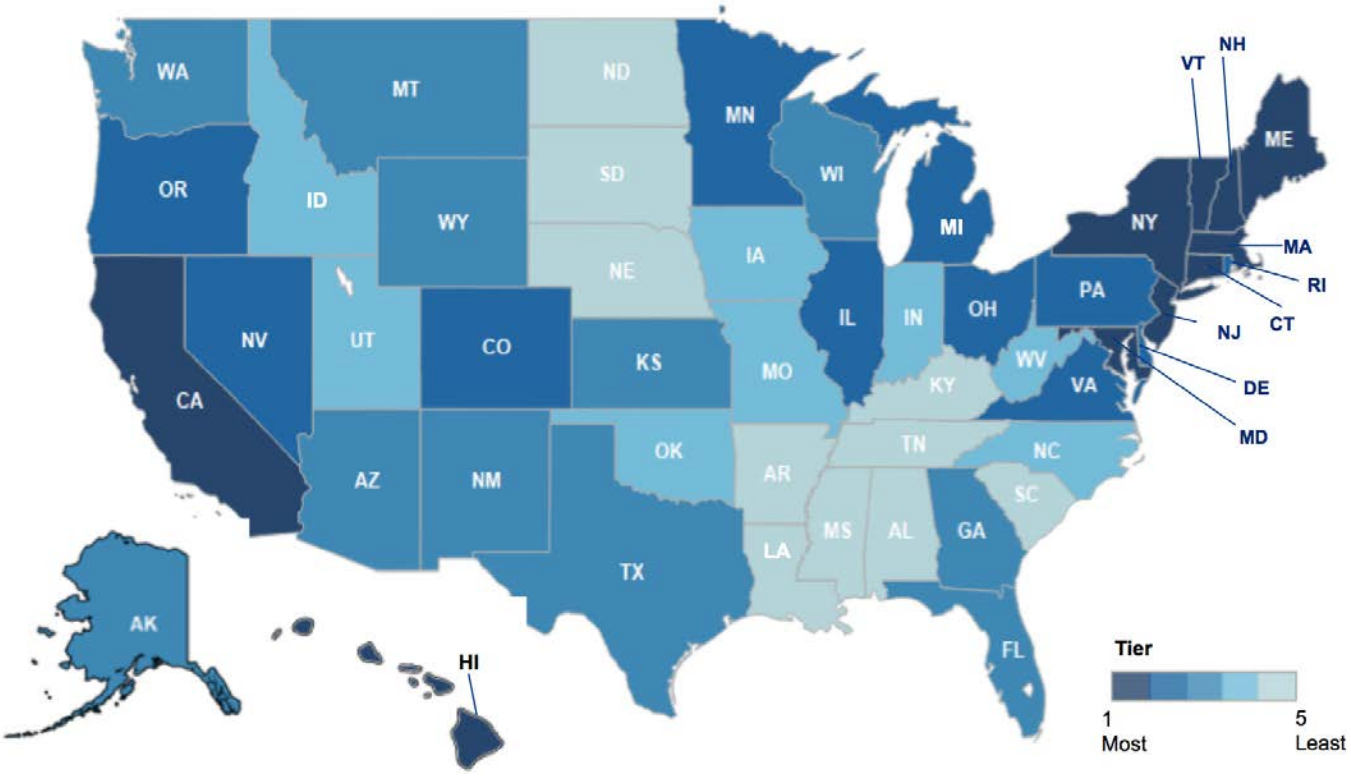
Based on the findings, the 50 states were divided into five tiers — from the tier with the highest likelihood of disruption to the lowest. The specific states where disruption is most likely to occur first (top-tier) are:

- California
- Hawaii
- Maryland
- Connecticut
- New Jersey
- Maine
- Vermont
- Massachusetts
- New York
- New Hampshire

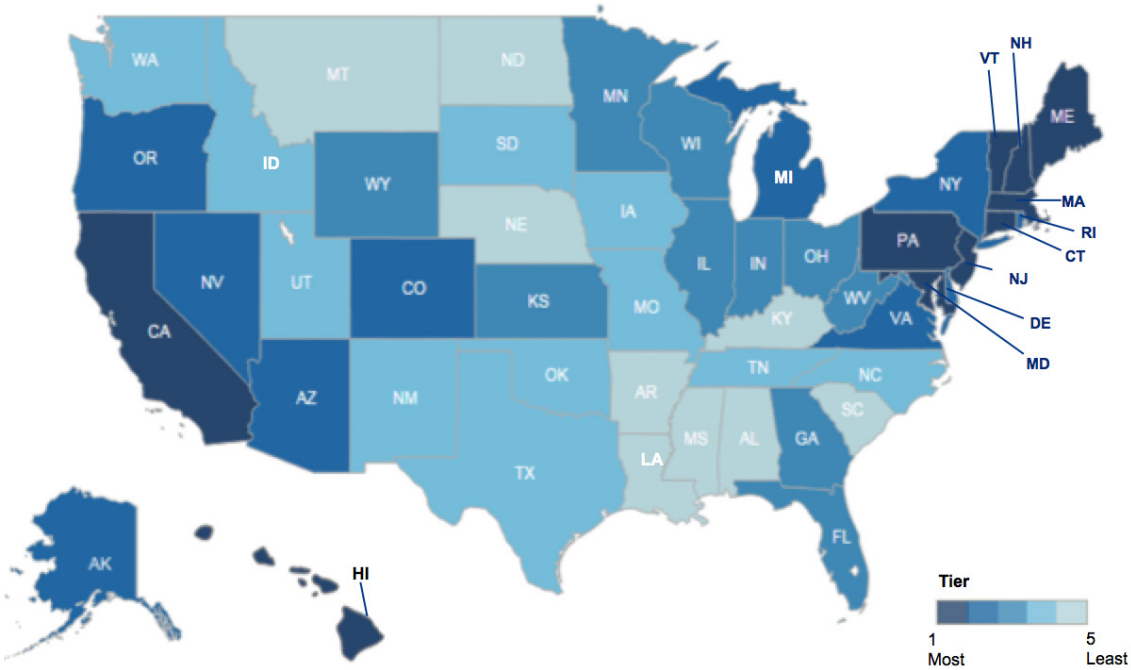
Through sensitivity analysis, the model also identified the following indicators as contributing the most to the top-tier ranking of the aforementioned states:

- Lowest electricity growth/largest decline in kWh sales
- Highest level of distributed generation penetration
- Highest level of energy efficiency investment

Potential electric industry disruption across the United States

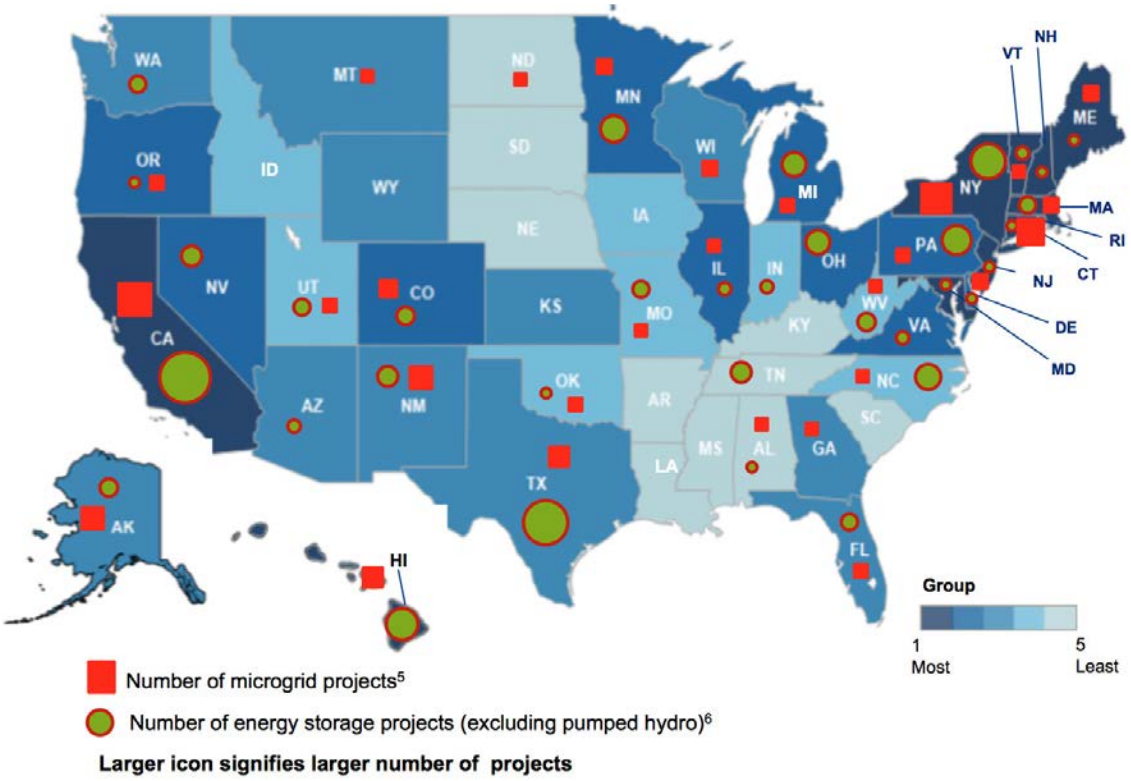


Potential electric industry disruption across the United States (excluding policy & regulation dimension)



Arguably, the demand, technology and product dimensions can be characterized as "market" forces, while policy & regulation is a "non-market" or political force. With that in mind, Deloitte ran the model without the policy & regulation dimension. This change minimally affected the top-tier, with the only difference being the substitution of Pennsylvania for New York.

Microgrid and electricity storage projects in the United States



In separate analyses, the model was used to examine other potential indicators of disruption. For example, an analysis was performed to explore the correlation of the top-tier states with the current geographic concentration of energy storage and microgrid projects. The correlation was high, as shown.

[5] GTM Research, a Greentech Media company, "U.S. Microgrids, Operational and Planned," March 2014

[6] U.S. Department of Energy, "DOE Global Energy Storage Database," accessed February 2014, http://www.energystorageexchange.org/

What can be concluded?

One might draw the following general conclusions from the model's findings. The first wave of disruption to the traditional electric business model is likely to occur across the northeast region of the United States. Additionally, disruption to the traditional U.S. electric model may already be underway in California and Hawaii, as suggested by the level of non-traditional electricity services currently available in these states. And perhaps more importantly, electric companies may wish to keep a particularly sharp eye on the forecasted levels of growth or decline in kWh sales, of distributed generation penetration, and of energy efficiency investment within their territories as potential signposts of impending disruption.

These findings have significant implications, regardless of an electric company's geographic footprint. In the short-term, the strategic priorities will likely vary locally depending on each electric company's situation. In the longer term, the solutions that emerge — whether technology or policy, or likely a combination of both — and the successful business models that evolve will simply have no geographic boundaries.

While the model is somewhat rudimentary, and the elements and their weighting are subject to debate, it serves as a platform to change the dialogue as companies in the electric sector confront the challenges and opportunities presented by both the new license to do business and the new participants in the game. Likewise, the model provides a framework to evaluate the emerging roles of new market entrants, to assess alternative future business models, and to align policy and regulation with the new electricity marketplace realities.

The California Public Utilities Commission has ordered the state's largest electric utilities to collectively procure a targeted 1,325 megawatts (MW) of energy storage by the end of 2020, with installation no later than the end of 2024[7] — enough storage to supply electricity to almost one million homes. On the Hawaiian island of Oahu, where the price of electricity is about 37 cents per kWh (triple the U.S. national average), residential rooftop solar penetration was 5.2% in 2012[8] and several neighborhoods are saturated with potentially more than 100 percent of the daily minimum load on circuits.[9] This has prompted the Hawaiian Electric Company (HECO) to ask its customers to confirm local circuit capacity, through HECO's website, before applying for a new solar connection. In some cases, an interconnection study or additional safety and reliability modifications will be required.[10]

The next section explores the emerging new market entrants and their role in the evolution of the electric sector business model.

[7] California Public Utilities Commission Decision Adopting Energy Storage Procurement Framework and Design Program, Docket #: R. 10-12-007, approved October 17, 2013, http://www.cpuc.ca.gov/PUC/energy/electric/storage.htm

[8] Solar Electric Power Association, *2012 SEPA Utility Solar Rankings*, June 2013, p. 17, http://www.solarelectricpower.org/media/8186/final-2012-top-10-report-v2.pdf

[9] Hawaiian Electric Company, "Locational value map for Oahu," accessed February 2014, http://www.heco.com/portal/site/heco/lvmsearch

[10] Hawaiian Electric Company, "To our valued customers," accessed February 2014, http://www.hawaiianelectric.com/heco/_hidden_Hidden/CorpComm/To-Our-Valued-Customers?cpsextcurrchannel=1

New market entrants

New market entrants can be described as businesses that provide electricity services formerly supplied by regulated utilities and power generators, or that offer services previously not available to electricity customers to a great extent. New market entrants can be divided into two general categories — those that provide services ***up to the meter*** and those that provide services ***behind the meter***.

The first category, *up to the meter*, primarily consists of generators of electricity from renewable sources (e.g., wind, solar, and biomass) and a growing number of businesses designed to enhance the value proposition of large-scale renewables. These businesses would include, among others, large-scale battery storage providers and sophisticated forecasters of day-ahead wind and solar capacity based on weather patterns.

The second category, *behind the meter*, consists of a variety of electric service providers that are leveraging new and improving technologies deployed under evolving, innovative business models. The breadth of activity behind the customer's meter, at both the business and residential levels, is astounding. While solar is the largest "new" source of self-generation (or distributed generation), fuel cell technologies and small-scale natural gas generation are receiving substantial attention, as is the feasibility of distributed electricity storage through advanced battery technologies. In addition, small, self-sufficient electricity systems with their own generation and delivery capabilities, called microgrids, are beginning to emerge as alternative electricity providers for entire neighborhoods.

In April, 2013, NRG Solar, a division of NRG Energy, launched a residential solar system with battery storage.[11] The system consists of a solar panel pergola (i.e., a landscaping structure that provides shade) combined with batteries that store excess solar electricity for use at night or for backup purposes during a power outage.

Opower is a software-as-a-service company that partners with electric companies to promote energy efficiency and customer engagement. Its software is designed to provide residential and business electricity customers with information about their energy consumption and ways to become more energy efficient. The company's mission is to help everyone, everywhere save energy. Its software products follow five design principles:[12]

- Design for how people actually behave
- Assume people do not care
- Always lead to action
- Aim for a long-term relationship
- Build for everyone…who receives an electric bill

Substantial developments are also taking place in the area of energy management. For instance, new technologies, combined with real-time data related to physical conditions and human behavior, are enabling businesses and consumers to significantly reduce their energy consumption, often with minimal incremental investment.

The ultimate role these new market entrants will play in the evolving U.S. electric business model is unclear. What is clear is that they are receiving considerable attention, as evidenced by the growing capital investments being made in them by a number of traditional electric companies. In light of this attention, some trends appear to be emerging that should likely be monitored and factored into the view of the changing electric landscape.

- **The changing role of the new market entrants.** Many of these businesses initially viewed themselves as disruptors that were "out to destroy traditional electric companies." Today, they largely see traditional players, particularly electric distribution businesses, as their channel to the marketplace on both sides of the meter. Many, in fact, describe their businesses as *enablers* of a smooth transition to future electric business models, and they are actively seeking to partner with traditional electric distribution businesses.

[11] Ucilia Wang, "NRG Rolls Out Solar Pergola to Target Residential Market," *Forbes.com*, April 2, 2013 http://www.forbes.com/sites/uciliawang/2013/04/02/nrg-rolls-out-solar-pergola-to-target-residential-market/
[12] Opower, "Opower's Design Principles," accessed February 2014, http://opower.com/company/design-principles

- **The maturity curve of new technologies**. There is a growing belief among market participants that substantial new technology breakthroughs are not a prerequisite for significant disruption to the electric industry. Instead, the maturation of existing technologies may be sufficient to effect major change. This is particularly perceived to be the case with large-scale renewables (i.e., wind and solar), distributed generation (i.e., solar), and battery storage. Many argue that the greatest disruption to the industry will be distributed solar, and that the last hurdle to overcome is the level of cost embedded in the solar value chain — namely costs related to customer acquisition, installation, billing and collection, and maintenance. They contend that economies of scale are the remaining critical factor in reaching cost competitiveness. Similar views are espoused regarding the current price to manufacture, install, and operate battery storage. As manufacturing volumes — largely associated with electric vehicles — increase in both the U.S. and China, battery prices are expected to decline.

In December 2013, Geostellar launched a website that enables residential consumers to compare the benefits of leasing versus buying rooftop solar, and to register to have a system installed. The website's key goal is to help installers and third-party financiers reduce customer acquisition costs. Geostellar's platform uses satellite data to build representations of neighborhoods and rooftops, and a simulation model to calculate the amount of sun a rooftop receives throughout the year. The website incorporates solar credits and other incentives, as well as local utility electricity prices.[13]

Google Inc. may be the largest new market entrant to date. The company acquired Nest Labs Inc. in January 2014. This deal effectively gives Google direct access to every utility customer in the United States through Nest's signature product, the Nest Learning Thermostat, and other smart devices, such as its smoke and carbon monoxide detector, Nest Protect. Of additional note, some electric companies have dipped into the smart home space through partnerships with Nest to supply thermostats to participants in their demand response programs.[14]

- **Solutions to the solar affordability barrier.** The large up-front cost of distributed solar, particularly to the residential consumer, has been a major impediment to its adoption. New financing models that share the incentives (i.e., tax credits and rebates) and the benefits (i.e., lower electricity bills) are emerging to create win-win scenarios for the homeowner, the system installer or owner, and the financing party. In those geographies where distributed solar is approaching cost parity, will affordability, in fact, lead to mass adoption over time?

Soft costs as percentage of total solar system cost (per watt)[15]

	2012	Department of Energy[16] SunShot Initiative 2020 target
Residential	64%	43%
Small commercial	52%	35%

As these trends suggest, the new market entrants are here to stay. They introduce a critical new variable in the evolving electric business model by serving as disruptors, enablers, or both.

[13] Nichola Groom, "U.S. online startup makes going solar as easy as booking travel," Reuters, December 2, 2013, http:www.reuters.com/article/2013/12/02/us-solar-geostellar-idUSBRE9B102V20131202

[14] Andrew Engblom, "Google's Nest Acquisition: Threat or opportunity for utilities?," SNL Energy, January 15, 2014, http://www.snl.com/InteractiveX/Article.aspx?cdid=A-26542692-11566

[15] Soft costs include installation labor, permitting, inspection, interconnection, customer acquisition, and financing. Percentages are out of total installed PV system costs per watt for each sector in first half 2012 and target costs for 2020. Source: Barry Friedman, Kristen Ardani, David Feldman, Ryan Citron, Robert Margolis and Jarett Zuboy, National Renewable Energy Laboratory (NREL), *Benchmarking Non Hardware Balance-of-System (Soft) Costs for U.S. Photovoltaic Systems, Using a Bottom-Up Approach and Installer Survey – Second Edition*, October 2013, p. 6., http://www.nrel.gov/docs/fy14osti/60412.pdf

[16] The U.S. Department of Energy's SunShot Initiative is a national collaborative effort to make solar energy cost-competitive with other forms of electricity by the end of the decade. http://www1.eere.energy.gov/solar/sunshot/index.html

Evolving electric sector business models

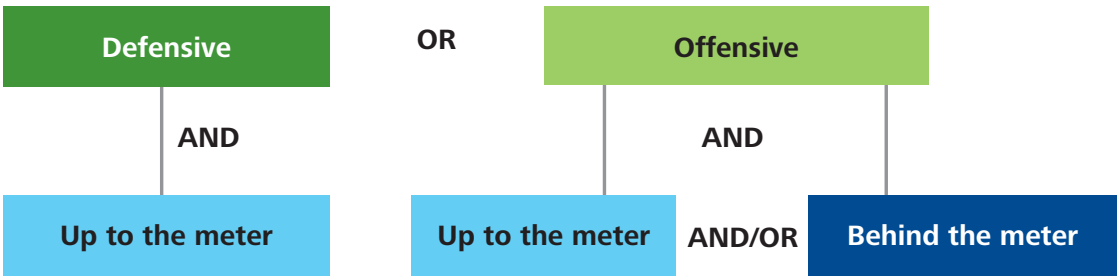
Much has been reported about the dramatic changes occurring in the traditional U.S. electric industry.[17] Electric companies will need to examine a host of potential strategies and associated business models in order to navigate these changes. To facilitate this process, potential strategies can be grouped into one or more of the categories described in this section.

Thinking of strategies in terms of these categories can be helpful in evaluating and debating the tactics, opportunities, and risks associated with each.

Defensive strategies

Defensive strategies can be characterized as those designed to effectively defend the status quo. By their nature, they are exclusively *up to the meter* strategies associated with electric generation, transmission, or distribution investments. These strategies take into account the new license to do business, which requires ongoing infrastructure investment to ensure both system reliability and environmentally responsible electricity. At present, growth in this area is largely associated with replacing generation plants or investing to ensure the reliability of the grid. As a result, companies pursuing defensive strategies often employ the following tactics:

- Keep costs — and prices — as low as possible to retain customers.
- Redesign customer rates to allow for better transparency and provide greater assurance of fixed cost recovery.
- Explore opportunities to increase kWh sales with minimal incremental investment, such as through economic development, electric vehicle penetration, and port electrification.



[17] See for example: Peter Kind, *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business*, Edison Electric Institute, January 2013, http://www.eei.org/ourissues/finance/Documents/disruptivechallenges.pdf

In September 2013, Alliant Energy agreed to sell its Minnesota electric and natural gas distribution businesses. The electric distribution business will be sold to Southern Minnesota Electric Cooperative, a group of 12 electric cooperatives, while the natural gas business will be sold to Minnesota Natural Resources Corporation, a subsidiary of Integrys Energy Group, Inc. Alliant's operations in Minnesota represented less than four percent of its total customer base, suggesting these businesses might be of more value to other parties who are focusing more intensely on this geography. Commenting on the sale, the president of Alliant's Minnesota and Iowa utility noted: "Our Minnesota customers will be part of utilities with a significant, long-standing presence in the state."[18]

In addition, mergers and acquisitions may be evaluated as a mechanism to keep costs down through synergy savings or through realizing *in the money* optionality, whereby assets are sold because they are of greater value to another party.

Successful execution of these strategies is expected to result in predictable earnings, cash flows, and shareholder dividends. The associated risks are largely tied to the requisite investments in large-scale, long-lived assets. These risks are compounded in today's environment where new technologies are emerging, and where substantial investments in traditional infrastructure are often non-productive, in the sense they create little or no increase in kWh sales — or real growth.

Offensive strategies

Offensive strategies can be described as those designed to exploit opportunities created by the changing electricity landscape. They can be *up to the meter* or *behind the meter*.

Up to the meter strategies

These strategies are generally designed to take advantage of the environmentally responsible criterion of the new license to do business and most often leverage new technologies. Common examples of *up to the meter* strategies are:

- Investments in large-scale wind, solar, and biomass generation assets designed to meet RPS mandated by many states.
- Efforts to achieve greater efficiencies within traditional and renewable generation assets through technology investments aimed at improving load management and storage capabilities. Breakthroughs in grid-scale storage are often cited as a potential game changer as they would move intermittent wind and solar assets in the direction of becoming firm sources of electric power generation.

Up to the meter strategies are generally expected to be low risk because the revenues associated with these investments are largely contractual in nature, and the risks incurred are most often associated with the realization of the expected value of the assets at the end of the contract.

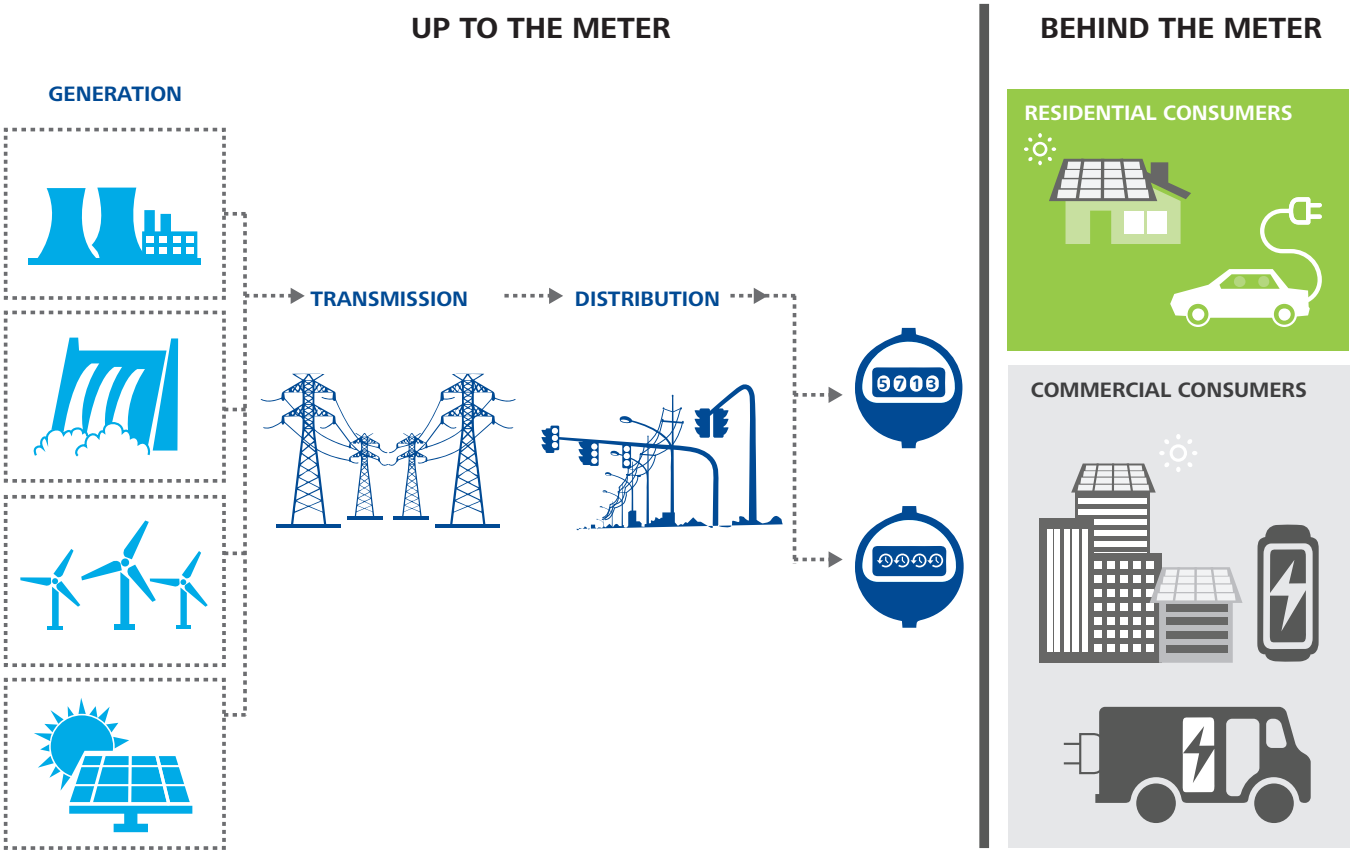
AES Energy Storage operates one of the largest fleets of battery-based, grid-scale energy storage resources in the United States, with 106 MW of operational projects and another 1,000 MW in development. The fleet is primarily focused on reserve and peak capacity, but provides other services, such as voltage regulation, fuel diversity, elimination of water usage, and deferred transmission benefits. The company's 40 MW project at Dayton Power & Light's Tait generating station in Moraine, Ohio, provides frequency regulation and grid stabilization services to the Pennsylvania, Jersey, Maryland Interconnection (PJM).[19] AES Energy Storage also delivers reserve and peak capacity for utilities, generators, or load-serving entities in New York Independent System Operator (NYISO), PJM, and Electric Reliability Council of Texas (ERCOT) markets under long-term contracts.[20]

[18] Alliant Energy Corporation, "Alliant Energy announces agreements to sell its Minnesota electric and natural gas distribution businesses," September 3, 2013, http://www.alliantenergy.com/AboutAlliantEnergy/Newsroom/NewsReleases/014894

[19] Eric Wesoff, "AES Surpasses 100 MW Grid-scale Energy Storage Milestone," greentechmedia.com, October 7, 2013, http://www.greentechmedia.com/articles/read/AES-Surpasses-100-MW-Grid-Scale-Energy-Storage-Milestone

[20] AES Energy Storage, "AES Energy Storage Services," accessed January, 2014, http://www.aesenergystorage.com/services.html

Up to and Behind the Meter



> "Value is a function of risk and return – therefore, risk matters as much as return in generating value."
>
> — Thomas Fanning, Chairman, President and Chief Executive Officer, Southern Company

Behind the meter strategies

Some believe *behind the meter* strategies represent the new frontier of opportunity and associated risk. Several factors underlie this belief, including a variety of developing technologies, distributed generation and storage, and the changing face of the electric customer. But that is not all. Another factor is also emerging and it may ultimately be the most important: the evolving *energy management mandate*. Energy efficiency in the past has largely been voluntary, as motivated customers sought out ways to lower their electricity bills and/or reduce their carbon footprints. Energy efficiency today, however, is becoming more of a mandate. Under the new license to do business, environmentally responsible electricity will come at a price — and the debate is just how high. Energy efficiency is widely acknowledged as a means — most likely an indispensable one — of making environmentally responsible electricity affordable as it enables businesses and consumers to do the same, or more, with less kWhs.

In January 2014, Integrys Energy Group, a utility holding company subsidiary of Integrys Energy Services, announced the creation of a residential solar finance fund through the CPF Market®, an online platform operated by Clean Power Finance (CPF) that facilitates electric company investment in residential solar. Partnering with CPF enables Integrys to expand its reach beyond its northeastern and midwestern customer base. Through the platform, the company first plans to make funds available to installers in California, Hawaii, and New Jersey markets, followed by New York, Maryland, and Massachusetts. The Integrys program comes on the heels of equity investments in CPF by Duke Energy Corp, Edison International, and Dominion.[21]

Many believe offensive, *behind the meter* strategies will be limited within an electric utility's franchised territory due to regulatory approval requirements. On the other hand, doing business outside of the franchised territory creates new challenges and associated risks. Both sides of this coin will need to be evaluated, with an eye toward balancing the risks and rewards of venturing into uncharted waters. The risks include:

- **Technology** – What advances are coming around the bend that might be better and cheaper?
- **Customer** – What happens to the customer relationship dynamic when a company is operating in its customers' parking lots, on their roofs, and in their living rooms?
- **Policy and regulatory** – Will the stroke of a pen create winners and losers, rendering customer and market trends moot?
- **Execution** – Competition for the customer's limited dollars will not only exist, but it may also be furious. Will a company be able to develop the superior programs, brands, and execution skills required to be successful?

Under these conditions, it is not surprising that most *behind the meter* strategies to date can be described as dip the toe, or perhaps the foot, in the water. Their overarching objective is to position a company to participate in *behind the meter* opportunities as the marketplace develops, with the main variables being timing and degree of investment. So what types of opportunities are companies pursuing to get their feet wet?

[21] "U.S. Midwest utility Integrys creating residential solar fund," Reuters, January 8, 2014, http://www.reuters.com/article/2014/01/08/integrys-solar-idUSL2N0KH28Z20140108

Nevada-based NV Energy, Inc., has collaborated with home energy management start-up, EcoFactor, to provide integrated demand-side management solutions to NV's customers. The program was launched under NV's mPowered brand using EcoFactor's patented, cloud-based energy services to analyze residential heating and cooling system information, thermostat settings, personal preferences, indoor temperatures, local weather, and other behavioral factors. By combining data analytics with smart thermostat capabilities, the EcoFactor solution is expected to provide significant energy savings to consumers and load reduction in the Las Vegas market.[22]

The greatest prospects *behind the meter* today appear to fall into two broad areas:

- Distributed generation — solar, small-scale natural gas generation, storage, and microgrids.
- Energy management technologies — both hardware and software.

Tactics to seize these opportunities and balance the associated risks include the following:

Product development companies

Companies are setting up programs or subsidiaries specifically charged with identifying, developing, field-testing, and launching products and services to customers *behind the meter*. A recognized subject matter expert hired from the outside often leads this "product development company," which operates with a degree of autonomy from the parent. A common challenge is to instill and maintain an entrepreneurial spirit in the new organization. This may require a combination, or all, of the following:

- Acquisition of start-ups or even established businesses
- Joint venture arrangements with new market entrants
- Compensation and incentive programs that are different from those of the parent
- New capital and/or ownership structures — including joint ventures, alliances, and public/private partnerships

Pilot programs

Pilot programs in franchised service areas approved by regulators are not new to electric utilities. However, the role they play may differ from the past. Today, electric utilities are using pilot programs to field-test potential products and services with the objective of launching successful ones at scale, most often beyond the company's franchise territory. Well-executed pilot programs offer several potential benefits:

- Proving the concept to management, the board of directors, and potential investors
- Building requisite skills and expertise, and identifying resource gaps
- Fine-tuning the business model
- Creating goodwill with customers and regulators

Importantly, pilot programs will be successful only if they are proposed and conducted in a win-win environment. Not only must the programs make sense for the utility, but regulators must see tangible benefits to customers. Even if future services are provided to customers by third parties or competitors, a proof of concept that benefits customers in the company's franchised territory can create this win-win by building goodwill with regulators while pointing to opportunities beyond the present service area.

"We are not pouring huge amounts of money in it, but we are trying to develop relationships and we are trying to develop products and joint ventures that will provide an income stream for growth."

— Thomas Farrell, Chairman, President and Chief Executive Officer, Dominion Resources

[22] EcoFactor, "NV Energy begins massive deployment of EcoFactor", November 13, 2012, http://www.ecofactor.com/nv-energy-begins-mass-deployment-of-ecofactor/

Distributed generation value chain

Much like the value chain to generate and sell an electron, a distributed-generation value chain is evolving and maturing. At a high level, its components include:

Electric companies, often through their product development companies, are examining this budding value chain in terms of its growth potential. Based on initial explorations, some believe growth opportunities exist throughout the distributed generation value chain as traditional utility skills and experience, in areas such as large-scale deployment, system monitoring, smart meter applications, and billings and collections, still apply.

Additional potential opportunity likely lies in enhancing the value of distributed generation assets by integrating them with storage and energy management tools, and growth opportunities may also exist related to the ownership structure and associated financing of the distributed system.

Leveraging natural gas

The emergence of abundant, low-cost natural gas has profoundly affected the electric industry, and the implications for the future are a constant topic of discussion. The central question here is: Can natural gas create incremental value to customers behind the meter — in areas such as small-scale generation, microgrids, and beyond?

The vastness and uncertainty surrounding the answer suggest that *behind the meter* strategies should include a point of view on future natural gas prices, and should factor in the sensitivity of these assumptions on the economics of new and existing business models. Also, close monitoring of emerging technologies that enable customers to use natural gas in more ways would likely be warranted.

Potential game changers

Much attention has been given to the role of technology in shaping the future of the U.S. electric sector on both sides of the meter, including the potential for breakthroughs that could substantially alter the economics of existing business models and their underlying assets. Even more, many industry stakeholders generally acknowledge that today's world is ripe for game changers that may not yet be visible.

Two potential game changers, however, have come into view, and they are the subject of much discussion: 1) the changing face of the customer and 2) broadband, which is already in almost every American home.

Changing face of the customer

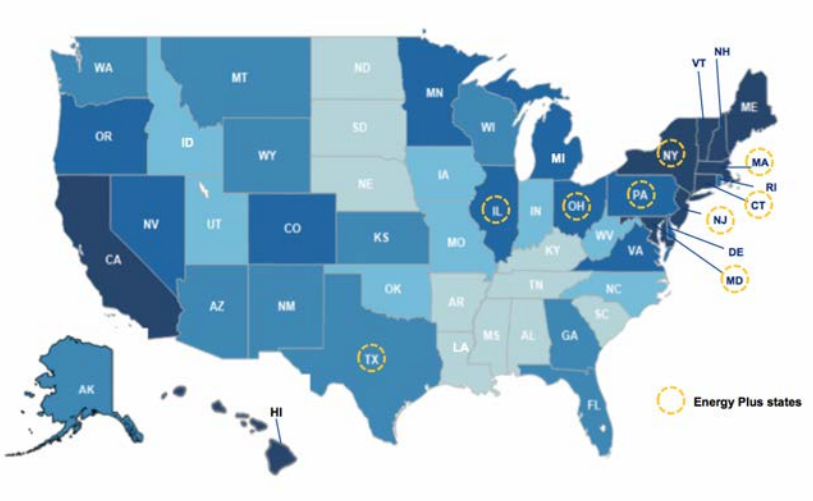
Annual studies conducted by Deloitte since 2011[23] have revealed the changing mindset of electric customers — both businesses and consumers. On the one hand, businesses have intensified their focus on all forms of energy management because they see opportunities to reduce costs, remain competitive, and increase earnings. On the other hand, consumers see energy efficiency as being resourceful on their part as opposed to sacrificing comfort, and they are willing to invest in associated products and services if energy management can be made easy.

The U.S. electric industry has traditionally segmented its customers based largely on how much electricity they consume, and not on the reasons they consume it. This generally stands for all types of customers — residential, commercial, and industrial. As customers' choices increase, particularly *behind the meter,* new customer segmentation models will likely be required. For commercial and industrial customers, segmentation based on business models will probably be necessary in order to understand customer needs — for that matter, who the real customer is. This will allow for redefining and bundling services that better meet the specific needs of manufacturers, big-box stores, hotels, colleges, hospitals, and other large energy consumers.

For residential consumers, demographic segmentation could have a similar effect. Grouping customers by age, income, education, and other demographics could greatly enhance a company's ability to package services in order to better meet changing needs. And, smart meters can substantially heighten the level of sophistication in employing this technique.

Residents of nine states have an added incentive to choose Energy Plus® as their electricity supplier. Once they sign up, they can earn rewards based on their energy consumption toward their favorite reward plans — including airline miles, hotel/rail points, retail rewards, cash back, or even contributions to a college savings plan. For example, American Airlines' AAdvantage® members can earn two miles for every dollar they spend on the supply portion of their monthly electric bill, plus 10,000 bonus miles after two months of active service as an Energy Plus® customer.[24] The nine states where residential customers have these opportunities are highlighted in the map below.

Energy Plus® Service Territory[25]



[23] Deloitte Center for Energy Solutions, *Deloitte reSources 2013 Study*, July 2013, http://www.deloitte.com/us/resources
[24] American Airlines, Inc., AAdvantage® program email "Your electric bill is worth 10,000 miles," received by AAdvantage program member December 12, 2013
[25] Energy Plus Holdings, "Service Areas," accessed February 2014, http://www.energypluscompany.com/service_areas/service_areas.php

Gateway behind the meter

Today, broadband is inside practically every business and home, providing services ranging from telephone, television, and Internet to security monitoring and home automation. As *behind the meter* strategies evolve, electric companies should analyze the potential risks and opportunities that broadband could create for electric services. The new *smart home*, with its diverse mix of broadband-enabled hardware and software components, opens the door for electric companies to partner with installers, maintenance providers, retailers, security system manufacturers, home automation companies, and others. Electric companies today appear to be well positioned to capitalize upon broadband as a *gateway behind the meter*. And, they can choose whether or not to participate in developing the "internet of things," where physical objects (i.e., smart appliances, alarms, thermostats, etc.) will have virtual identities and will be able to communicate with users and networks through a web of wirelessly connected devices.

Barriers to change

Barriers to change represent an important, and often complex, set of obstacles to the successful execution of both defensive and offensive strategies. That is because they are often institutional in nature or simply too costly to break down. To the degree these obstacles can be identified, addressed in advance and monitored over time, the associated risks can often be mitigated or managed. Barriers to change within the traditional U.S. electric sector can be generally grouped as follows:

- **Culture** – The culture of the U.S. electric industry has served it well for many years. It has allowed the industry to provide safe and reliable electricity throughout its history while reducing real electricity prices to consumers over 40 percent in the last 50 years.[26] It can be described as a culture that is risk averse and that does not tolerate mistakes — both of which would be expected to go hand in hand with safe and reliable electric service. However, as electric companies venture into new technologies and seek to exploit the changing marketplace dynamics *behind the meter*, accepting a higher level of risk and learning from mistakes are likely to be table stakes in order to participate in a meaningful way.

- **Expectations of owners** – Electric company shareholders are attracted to the sector for what it is expected to deliver — steady, predictable earnings and dividends, along with long-term growth in investment value consistent with the relatively low level of investment risk. There is an expectation there will be few, if any, ˝dry holes,˝ and if they do occur, they will be small.

- **Regulation** – The old and new licenses to do business coincide with regulatory oversight that functions within boundaries set by policy and associated legislation. Regulation has evolved as the electric industry has evolved and has, for the most part, successfully fulfilled its role of overseeing the license to do business. In many respects, the regulatory system has become an institution; therefore, change will not come easy. But, in an environment of evolving marketplace dynamics and new technologies, particularly *behind the meter*, the existing regulatory construct is likely to be ill-equipped to support a smooth transition, and thereby constitutes a major barrier to change. Transforming regulation from a barrier to change to an enabler of it deserves additional examination.

[26] The 1960 price was 20.61 cents per kWh in 2013 dollars and the 2013 price was 12.2 cents/kWh. U.S. Energy Information Administration (EIA), *Short Term Energy Outlook, Real Prices Viewer, Residential Electricity Prices (annual, 1960-2013)*, Release date: January 7, 2014, http://www.eia.gov/forecasts/steo/realprices/

Changing face of electric regulation

An environment of regulatory certainty, where the risks and rewards of strategic alternatives and related investments can be analyzed, will need to exist in order for the U.S. electric sector to smoothly transition to new ways of doing business. The concept of regulatory certainty comes with the expectation of objective regulatory monitoring and evaluation of future outcomes, with realignment as required. The evolution of the regulatory frameworks at the state level, along with possible regional compacts, will be crucial given the disparate pace of disruption discussed earlier. At the state level, creating and sustaining a new era of collaboration among electric utilities, new market entrants, and regulators will likely be necessary as a foundation for addressing the collective challenges to, and opportunities for, creating real incremental value to electricity customers.

There are a few ways to establish and enhance the collaboration among the aforementioned parties. An ability to move the dialogue out of the rate case environment will be essential. And, the ongoing role of education should be addressed early on and over time. State regulatory commissioners' average tenure today is about five years.[27] This is particularly significant because few regulators come into the position with prior electric utility experience. Making sure both veterans and newcomers are knowledgeable about the current landscape and the critical factors shaping the future marketplace will help to sustain an environment of mutual interest, transparency, and collective trust. Likewise, ongoing customer education is of paramount importance. Where education of customers is viewed as a joint responsibility, collaboration will likely be enhanced.

A framework for assessing the new license to do business

As the electric sector evolves, the issues to be considered become increasingly complex and are often interrelated. Solutions may have multiple, and sometimes unintended, outcomes elsewhere in a business model. A useful framework for assessing the new license to do business is to examine the issues in the context of *up to the meter*, *behind the meter*, or both.

Up to the meter

Issues *up to the meter* are generally historical in nature. Thus, the process of examining and developing solutions for them may be less complex, and it may also be helpful in establishing a foundation for confronting the emerging challenges *behind the meter*. At least three issues *up to the meter* warrant attention.

Rate transparency – In order to understand the true cost of the electric grid today, it is essential to unbundle the components of current electricity prices to customers. Rate transparency is also necessary for examining the future price implications of 1) incremental investments to maintain or enhance grid reliability and 2) future changes in kWh sales. Smart meters, in many instances, are improving electric utilities' ability to disaggregate the costs of the grid into its component parts (i.e., frequency, voltage control, etc.) and to determine which customers are creating the costs, also known as *cost causation*.

[27] Janice A. Beecher, PhD, "Commissioner Demographics 2013," IPU Research Note, Michigan State University Institute of Public Utilities Regulatory Research and Education,March 2013, http://www.ipu.msu.edu/research/pdfs/IPU%20Commissioner%20Demographics%20(2013).pdf

Once the costs of the grid, the sources of such costs, and the prices charged to recover them and earn a profit are understood, the manner of compensating the owners of the electric grid for the services they provide must be addressed. At a high level, compensation for giving customers the ability to net meter must be considered, along with compensation for investments in programs designed to promote and support energy management. Companies will likely need to weigh the trade-off between greater certainty, which comes with compensating for the grid through fixed charges, and the potential, or lack thereof, for traditional earnings growth, which comes with maintaining the status quo of compensating for the grid largely through kWh sales. At a minimum, initial thresholds for recovering the costs of the grid through fixed charges should be established, along with a process for monitoring and adjusting rates as the marketplace evolves.

The cost of a reliable grid – For the first time in the history of the U.S. electric industry, investments in the electric grid often do not result in real economic growth. Investments made to maintain or enhance electric reliability, without associated growth in kWh sales, may result in increased earnings in the short term, but may be essentially uneconomic in the long term. In an environment where there is more distributed generation and an increasing focus on energy management, the situation may be exacerbated, and scenarios can be envisioned where portions of the electric grid are no longer essential to the reliable delivery of electricity. Against this backdrop, the possibility of stranded electric assets should be acknowledged by all parties and should become part of an ongoing dialogue designed to develop equitable solutions.

Diversification *up to the meter* – As electric companies grow their investments in large-scale renewables and storage, their expertise and experience can be valuable in fulfilling customer needs in their franchised service territories. Where third parties are also involved in fulfilling a portion or all of these needs, regulators should assess the incumbent electric company's ability and level of participation in order to provide equal opportunity for all marketplace participants.

Behind the meter

The various components of the distributed generation value chain were previously highlighted. As the role of distributed generation matures and the line between *up to* and *behind the meter* blurs, the owner of the grid, most likely the utility, may be well-positioned to participate in various aspects of this value chain, perhaps offering the greatest value to business or residential customers. Early discussion and examination of this possibility is warranted. Even though the role of the utility *behind the meter* is not yet clear, it will, no doubt, develop over time.

The regulatory clash

There has long been an inherent trade-off, at least at some level, between safe and reliable electricity and affordability. In an environment of rising costs to maintain a reliable grid and flat or declining kWh sales, this trade-off will become more acute. Introducing *environmentally responsible* as a requirement for the license to do business further suggests that a transition from economic to environmental dispatch may occur over time. A consequence of these converging forces is a clash of regulatory objectives that heretofore has not existed.

This situation implies the need to re-examine the definition of "affordable" — which has historically, for the most part, meant the lowest price to customers. Regulators and electric utilities may be well served to examine the license to do business linearly in its component parts, introducing the element of risk. That is, what is the maximum level of acceptable risk and what will it cost to ensure, or perhaps literally to *insure*, this level is not exceeded? This is not to suggest that similar analyses have not been performed in the past. However, the changing marketplace dictates the need for re-examination, discussion, and resolution.

The changing marketplace additionally presents an opportunity to evaluate the short- and long-term benefits of energy management in a new light. What role can energy management play in resolving the regulatory clash by mitigating, at least in part, the impact of rising prices on customers? When elements of energy efficiency and demand response (on both sides of the meter) are incorporated and the grid owner functions as a comprehensive network manager, the concept of "intelligent efficiency" emerges — where the goals of energy efficiency and demand response are simultaneously rationalized.

Basic analysis of the potential for, and objectives of, intelligent efficiency should start now as an integral part of determining the overall regulatory framework. As cost and rate transparency become prevalent, new light can be shed on the opportunities for exponentially increasing short- and long-term benefits to electricity customers by offering services such as time-of-day and dynamic pricing.

"Intelligent efficiency is different from demand response. It does not involve products that purposely respond to signals to reduce electricity usage. Intelligent efficiency involves implementing efficient systems and choices that are beneficial from a time and location perspective, and thereby support renewable power, lower electricity prices, and enhance reliability."

— Jon B. Wellinghoff, Partner, Stoel Rives, LLP, and past Chairman of the Federal Energy Regulatory Commission

Closing thoughts

"This is a genie you are not going to put back in the bottle."

— David Owens, Executive Vice President of Business Operations, Edison Electric Institute

Profound changes to the traditional U.S. electric industry are not just inevitable, they are already occurring. The question is no longer if, but where and how fast. This is clearly evidenced by the addition of environmentally responsible to the requirements for a license to do business, the emergence of proven new technologies, and the prevalence of established new market entrants with different models that are just waiting to scale their businesses.

Equally profound are the likely long-term economic implications of substantial investments in traditional electricity infrastructure for the sake of reliability, without the assurance of sustainable increases in kWh sales.

From a strategic perspective, the evolving electric industry will experience, maybe in a relatively short time frame, a blurring of the line between offensive and defensive strategies. To some, electric companies may even appear schizophrenic now and then based on the variety of tactics they employ. This blurring will likely occur primarily in the distribution system, as an increasing amount of electricity generation moves to distributed networks located in close proximity to the source of consumption — as close as the rooftop, basement, garage, or closet.

As a result, the distribution system's role may well transition to one of assuring reliability as a network manager, even at a local level. As the focal point for data, both *up to* and *behind the meter*, the distribution utility will be responsible for managing both variable supply and variable demand in a manner that achieves maximum energy efficiency. As such, the utility may well operate on both sides of the meter, continuing to own the transmission and distribution assets *up to the meter* and potentially the distributed generation and storage behind it. In many respects, the business model may look more like an information company than one that sells electrons.

In light of such profound changes, and considering the critical nature of electricity in Americans' everyday lives, a smooth industry transition is essential for electric companies, their shareholders, and consumers. But, getting there will require a concept of the end state in order for stakeholders to develop a flexible road map designed to achieve the paramount end objective — safe, reliable, affordable, and environmentally responsible electricity. The evolution of the U.S. electric industry set forth in this paper provides a foundation for discussing, analyzing, and modifying a vision of this end state — both within electric company managements and among managements, their boards of directors, and other stakeholders.

"We are talking about the inevitable marriage of megawatts and megabytes."

— Alexander "Andy" Karsner, Chief Executive Officer, Manifest Energy Group, former U.S. Assistant Secretary for Energy Efficiency and Renewable Energy

As the evolution progresses, it is useful to keep in mind that change will not take place evenly across the United States. Successful solutions developed and executed in a certain geography may be applicable and implemented elsewhere, thereby accelerating the overall pace of change to the electric business model. In formulating strategies to confront these changes and take advantage of new marketplace opportunities, successful companies will evaluate certain common elements and incorporate tactics for addressing the associated implications. These elements include:

- A point of view on the short- and long-term prices of natural gas, and the available options if these forecasts do not come to pass.
- The recognition of key barriers to change, including the strategic limitations imposed by non-negotiable barriers, and the identification of tactics to break down the negotiable ones.
- A road map for a paradigm shift in the regulatory compact to an environment of mutual trust and the shared objective to create win-win outcomes.
- An evaluation of the key game changers that could suddenly and dramatically alter a company's ability to successfully execute a given strategy, including the identification of tactics for managing this risk.

Finally, and perhaps most importantly, all successful strategies and their associated business models will have one constant overriding goal. The strategy must be designed with the objective to create incremental value to electric customers — in their eyes, regardless of the source of the electrons they consume.

Acknowledgements

This paper was enriched by a series of interviews and discussions with industry experts from across the electric power industry, new market entrant companies, and the legal/regulatory and academic communities. The author would like to express his sincere gratitude to the following people for sharing their valuable time, experience, and insights:

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HG Electric - Downgrading to Underweight

The Solar Vortex: Credit Implications of Electric Grid Defection

"Conventional power generation, quite frankly, as a business unit, is fighting for its economic survival." – CFO of RWE, Germany's second-largest utility[1]

Electric utilities, which make up nearly 7.5% of the US Corporate index by market value, are seen by many investors as a sturdy and defensive subset of the investment grade universe. Over the next few years, however, we believe that a confluence of declining cost trends in distributed solar photovoltaic (PV) power generation and residential-scale power storage is likely to disrupt the status quo. Based on our analysis, the cost of solar + storage for residential consumers of electricity is already competitive with the price of utility grid power in Hawaii. Of the other major markets, California could follow in 2017, New York and Arizona in 2018, and many other states soon after.

In the 100+ year history of the electric utility industry, there has never before been a truly cost-competitive substitute available for grid power. We believe that solar + storage could reconfigure the organization and regulation of the electric power business over the coming decade. **We see near-term risks to credit from regulators and utilities falling behind the solar + storage adoption curve and long-term risks from a comprehensive re-imagining of the role utilities play in providing electric power.**

Spreads appear to be ignoring this risk, for now. Valuations suggest credit investors are depending on the "regulatory compact," (whereby the monopoly utility agrees to invest in assets to service customers in return for prices that are set to allow them a reasonable return) to give sufficient protection from industry changes. While the regulator/utility construct has usually resulted in low-risk returns to credit in the past, technological change creates precisely the environment where slower-moving incumbents and their regulators can fall behind the curve, risking credit volatility, or disrupt the regulatory compact, possibly leading to unexpected losses for bondholders. Investors may be also wary of optimism about solar power, given a recent history of losses in that industry. **We believe that sector spreads should be wider to compensate for the potential risk of regulator missteps and/or a permanent change in the utility business model.**

Whether because of biases or analytical complexity, the market (and its constituent prognosticators) has tended to be late in pricing technology-driven shifts, particularly in industries that have had stable operating models (such as telcos and airlines). As a result, we see a rare opportunity for investors to express views about a potential for a major change at low cost and with good liquidity and recommend the following trades:

- Underweight the Electric sector versus the US Corporate Index on tight relative spreads, as investors start to price in the disruptive risk of solar + storage.
- Rotate out of a basket of bonds issued by utilities where solar + storage is closer to competitiveness into one where solar + storage grid parity are more distant.
- 5s-10s and 5s-30s curve steepeners across the industry.

[1] "How to lose half a trillion euros," *The Economist*, October 2013

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Relative Value

Underweight electric utilities relative to the US Corporate Index

Rotate out of a basket of utilities in regions closer to solar + storage grid parity and into less exposed issuers.

Across utilities and pipelines, we recommend putting on 5s-10s and/or 5s-30s curve steepening trades.

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THE SOLAR VORTEX

Cost-Competitive Solar + Storage Is a Risk to Electric Utilities

As one of the few industries in the United States where businesses operate as regulated monopolies, electric utilities have generally offered a low-risk return to credit investors. In the history of the US Corporate index, electric utility bonds have averaged OAS 10bp tighter than the broad index and outperformed strongly during the 2008 financial crisis and 2011 European sovereign crisis.

However, we believe that over the next several years, utilities will face a legitimate threat to their business models. Declining costs for distributed solar photovoltaic (PV) power generation, coupled with lower costs for batteries large enough to power homes when the sun is not shining, means that homeowners and businesses could install off-grid systems that will be cost-competitive with the price of grid power.

The key threat is not widespread full grid independence. Rather, we envision an electricity market where demand for grid power falls, peak hours shift (perhaps dramatically), and regulatory mechanisms need to be adjusted or overhauled to accommodate some utilities becoming the electricity generators of last resort. We expect the net effect to be higher grid power costs (thereby exacerbating the consumer shift to solar + storage), lower average credit quality for regulated utilities and unregulated power producers, and increased recognition of the long-term threat to grid power.

We think the following caveats are important to consider:

- We recognize that this analysis is too early, in the sense that it is not a risk that has yet emerged for the majority of the industry. We are focusing on it now because we believe that the risk to our estimates is for quicker, not slower, grid disruption. Historically, the cost of technology and its absorption rate tend to outperform initial expectations, and we believe that the trades that will work need to be set before the industry pressure is fully realized. At this point, we see no evidence that the risks of distributed generation are priced into utility and generation (genco) credit spreads.

- We expect utilities to continue to play an important (albeit possibly more diminished) role in the nation's power markets in the long term. But history has shown that transition periods can be painful, occur rapidly and cause considerable value destruction before renewed stability sets in.

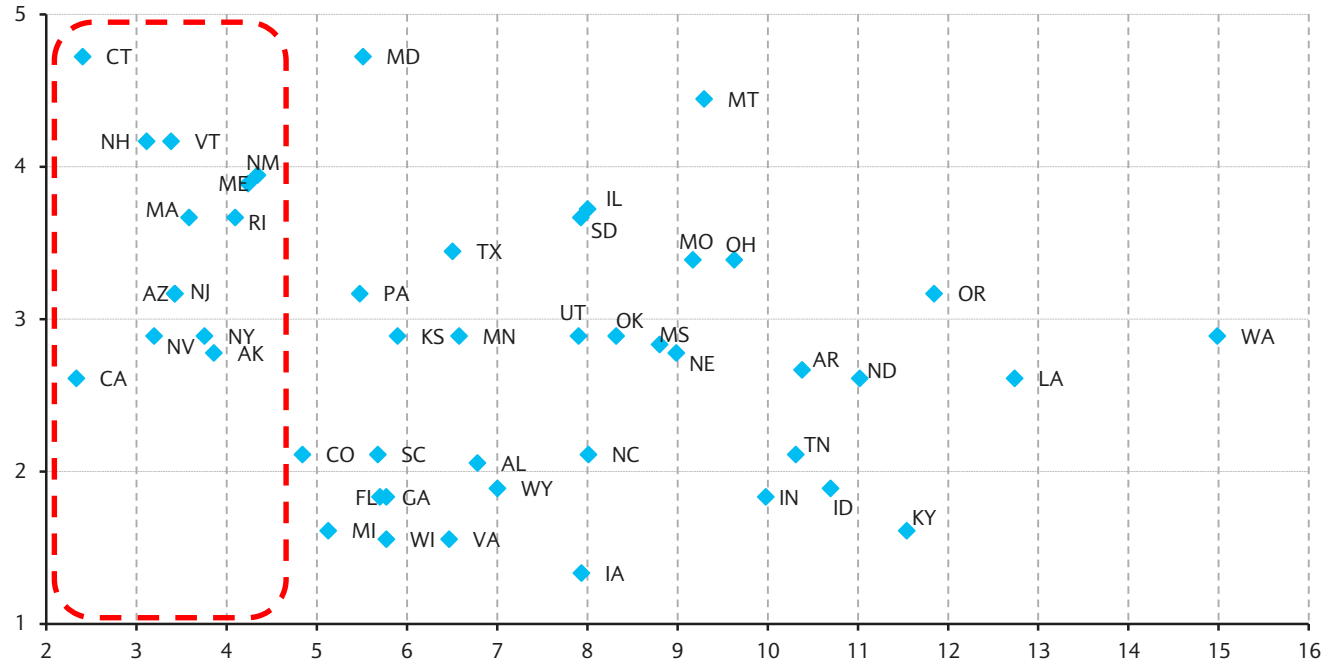
- Our analysis focuses only on the residential market, which accounted for less than 40% of total electricity sales in 2012. Industrial and commercial users typically face lower power costs, but may also see more advantage in distributed generation (because of scale benefits that are not available to residences).

- An important consideration is the response from utilities, regulators and legislators to the competitive threat of solar + storage. We see five potential responses, some of which have already begun: utility and/or regulatory obstruction of customer adoption; a reduction of subsidies; grid connection fees as a stop-gap measure/evolving regulatory framework; the entry of utilities into the solar + storage space; and a focus by utilities on the industrial and commercial electricity markets.

- Utilities that are located in states with high power costs and high insolation (ie, the amount of solar radiation that falls in a given area) are at the highest risk of lower customer demand because of distributed generation. In this regard, California stands out as vulnerable, while the state of Washington is at considerably less risk (Figure 1).

FIGURE 1

Years until Solar + Storage Reaches Grid Parity from end-2014 (x-axis), versus Perceived Regulatory Risk (y-axis)



Note: Perceived regulatory risk on a blend of Barclays Equity Research regulatory ranking (lowest cost of capital with a score of 1 to 5 for highest cost of capital, Figure 32), and RRA state regulatory ranking (we convert their nine tiers into a similar 1 to 5 range with the score of 1 awarded to Above Average/1 and 5 awarded to Below Average/3, (Figure 33); see Appendix B. Years from end of 2014. Source: SNL RRA, Barclays Research

The Evidence for Grid Defection

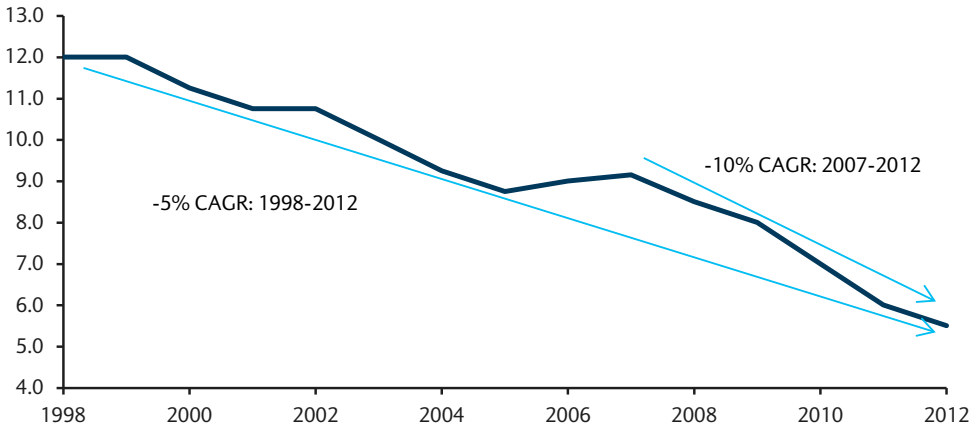
We see two trends that may be converging to foster significant change in what has been an extremely stable industry. First, solar photovoltaic systems have become increasingly competitive with thermal generation, even as thermal prices have declined because of fracking-driven supply growth of natural gas. Second, an unrelated but just as important technological advancement has been the start of a viable electric car market shifting the cost curve for lithium-ion battery storage.

As a consequence, systems that combine solar generation and battery storage are approaching the point at which they may become competitive with traditional thermal generation and distribution.

Solar Generation and Battery Storage Costs Have Fallen Sharply

Renewables have been growing their share of generation capacity in the U.S., which has pushed the cost of solar photovoltaic generation down sharply (Figure 2). This decline in costs has been quite intentional, with many governments around the world offering subsidies for the installation of PV capacity. These subsidies have encouraged a major increase in PV manufacturing capacity: Bloomberg New Energy Finance (BNEF) estimates that the annual output of PV modules increased almost 30x in the past decade, from 1,000MW per year in 2005 to more than 30,000MW in 2013.

FIGURE 2
U.S. Residential System Photovoltaic (PV) Costs ($/Wdc)

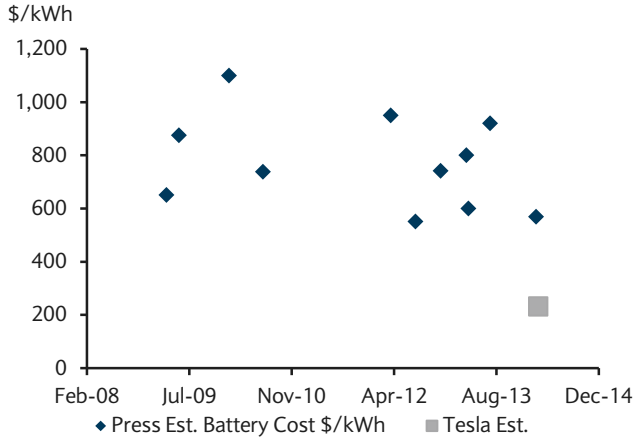


Note: Reported residential system price for a 10 kW installation. Source: NREL, Barclays Research

Independently from the decrease in cost for solar, Tesla's (TSLA) ramp up in production capacity for electric vehicles (EVs) has driven down the cost of large-scale battery storage for power. Although solid data are difficult to come by, it appears that the average cost of automotive batteries was in excess of $1,000/kWh as recently as 2009 (Figure 3). In early 2014, TSLA indicated that its battery costs were $200-300/kWh, with the company guiding to significant (5-10% annually) reductions in the next several years (Figure 4). Once TSLA completes its battery "Gigafactory" in 2017 (see *Tesla Motors Inc.: Battery cost optimism, but margin conservatism reminds us of reality* for details), management thinks that costs could decline 30% because of increased scale.

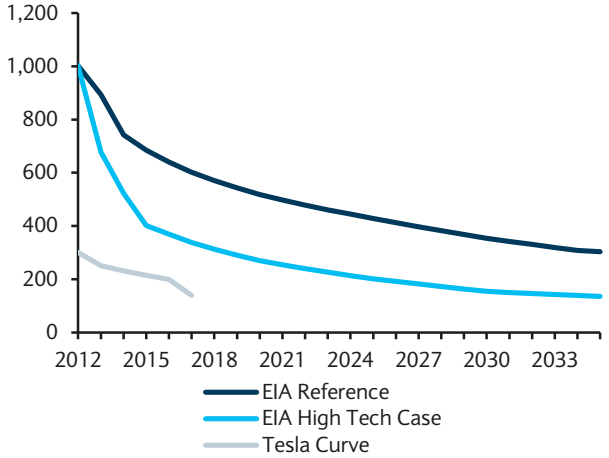
In our opinion, it is fair to characterize TSLA's battery cost goals as aggressive, but that does not make them any less credible in light of what the industry has achieved in just the past few years. Historically, EV battery prices were high because they were customized to large formats, with limited production runs, making each battery much more expensive (per

FIGURE 3
Industry Estimates for Battery Costs in 2013-14



Source: Bloomberg, Barclays Research

FIGURE 4
EIA Lithium-ion Cost Estimates in 2012 versus Tesla EV Batteries ($/kWh)



Note: EIA estimates as of Annual Energy Outlook 2012. High Tech Case is intended to reflect aggressive assumptions about the pace of technological improvements in battery construction. Source: EIA, Barclays Research

kWh) than the smaller models used to power consumer devices. As early as 2009, when estimates placed EV battery prices as high as $1,200/kWh, consumer laptop batteries were priced at $200-300/kWh (near Tesla's current levels). In our view, TSLA's innovation was to bundle cheaper laptop cells into batteries large enough to power their vehicles, capturing the production efficiencies that already existed, rather than scaling a new process. It seems to be mainly a coincidence that the power required to operate an electric vehicle can power the average home for 2-3 days, potentially opening a new use in residential distributed generation systems.

Residential Solar + Storage Is Rapidly Approaching Cost Competitiveness with the Retail Cost of Power

For most consumers, it is now technically feasible, and reasonably cost effective, to assemble a combination roof-top solar PV and battery storage (solar + storage) system that would allow a residence to operate with virtually no grid power. Rather than more expensive designs that would allow a home to be disconnected from utility grids entirely, we expect a practical evolution to start with a system that is able to cover almost all of a home's needs, but retain a grid connection that serves as a backup if the solar system does not generate enough power. Although this product has not yet emerged as a full-scale alternative to utility service, SolarCity has offered a solar installation with a battery backup (using Tesla batteries) in California. While the marketing emphasizes solar + storage's use as a backup for emergencies that result in grid outages, the ability to shift consumption of solar power to other times of day is highlighted as an additional benefit. We estimate that a theoretical system is already cost-competitive with the consumer price of electric power in limited areas and may be competitive across much of the U.S. over the next 3-5 years (and almost nationwide within a decade).

Figure 5 shows what we believe is an illustrative viable model for the lifecycle cost of a solar + storage system in California. Key features are:

- The system is sized to draw no net power from the distribution system through a normal year. We do expect it to provide some power into the utility grid at certain times and draw at others, but assume that the additional income and costs would net to zero.
- We simplify by ignoring the cost of capital, assuming that the cost of financing and discount rates are identical.

FIGURE 5
2013 Cost of Solar + Storage in California

Label	Input	2013 Unit Cost Bridge	Notes
a	Average daily consumption (kWh)	19.1	EIA data for 2012, held constant
b	Estimated average sun hours equivalent (h)	4.0	Calculated based on NASA and NOAA data
c	DC to AC de-rating (x)	0.77	NREL assumption
d	Size of PV panel needed (kW)	6.2	a/b/c
e	Average annual electricity generated (kWh)	6,972	a*365
f	Unit cost of PV panel ($/Wdc)	3.84	SolarCity Presentation; inclusive of upfront rebates
g	Total cost of PV panel ($)	23,944	d*f*1000
h	Average panel life (years)	25.0	Upper end of PV panel warranties
i	Annual depreciation cost of PV panel ($)	957.7	g/h
j	Annual cost of PV panel per unit of electricity generated ($/kWh)	0.14	i/e
k	Amount of day desired for backup (%)	50.0	Barclays assumption

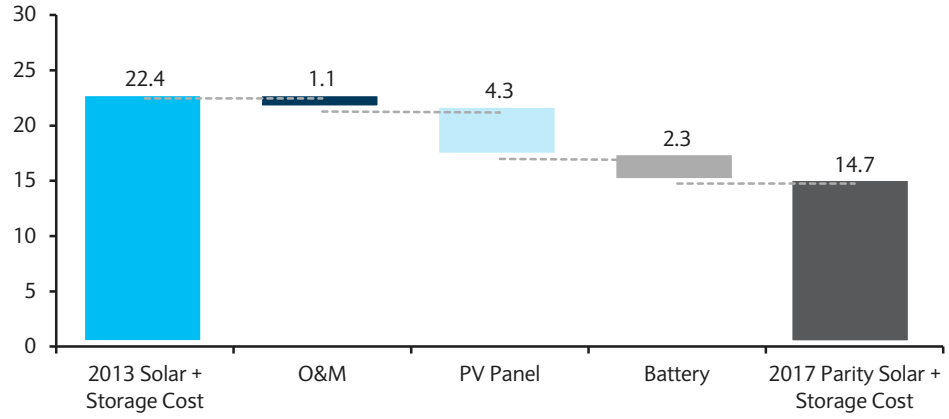
Label	Input	2013 Unit Cost Bridge	Notes
l	Available capacity as % of rated capacity (%)	65.0	Assumes that battery will not be discharged below 10% or charged above 95%, and that only 80% is effective
m	Approximate rated battery size as % of daily consumption (%)	76.9	k/l
n	Average size of battery required (kWh)	14.7	a*m
o	Unit cost of battery ($/kWh)	250	Tesla says current costs are $200-300/kWh
p	Total cost of battery ($)	3,673	n*o
q	Average battery life (years)	10.0	SolarCity's warranty on Tesla batteries for home backup
r	Annual depreciation cost of battery ($/kWh)	367.3	p/q
s	Annual cost of battery per unit of electricity generated ($/kWh)	0.05	r/e
t	% of PV panel cost assumed to be O&M	1.0	Barclays assumption
u	Annual O&M cost ($)	239.4	t*g
v	Annual O&M cost per unit of electricity generated ($/kWh)	0.03	u/e
	Annual cost ($/kWh)	0.22	j+s+v

Source: BNEF, Barclays Research

While the expected cost of $0.22/kWh in California exceeds the state's average retail power price of $0.15/kWh, we calculate that these systems are already economically viable in the highest-cost state, Hawaii (Figure 7). And as the costs of PV modules and batteries continue to decline, we expect these systems to become competitive in certain other states by 2018 (Figures 8-10). The key catalyst for solar adoption is a combination of high power costs and high insolation, with the quantity of power consumed an important swing factor (eg, although New York is not a particularly sunny state, its power costs are high and its residents consume far less power on average than Arizona, for example). Assumptions for our model are listed in Figure 27 of the appendix.

Figure 6 illustrates how the costs can quickly decline, with a solar + storage system reaching grid parity in California as early as 2017.

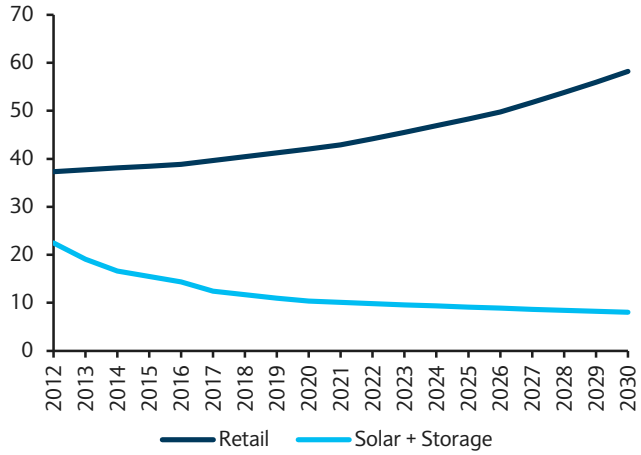
FIGURE 6
California Solar + Storage Cost Bridge (cents/kWh)



Source: BNEF, Barclays Research

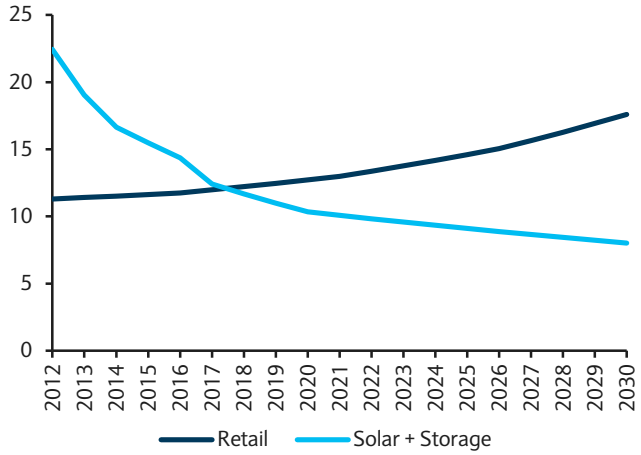
In Figures 7-10, we detail our state-by-state cost analyses for grid-supplied power versus distributed solar + storage. Reflecting the high cost of fossil fuel-fired generation in Hawaii, we estimate that customers in that state already find it economic to install solar plus storage systems. According to Hawaiian Electric Company, Inc. (HEI), there were 300 MW of installed solar capacity at the end of 2013, with 129 MW added in the past year (up 39% from 2012). Notably, 10% of HEI customers had rooftop solar as of December 31, 2013. Based on our model and historical PV prices, we estimate that it became economic for the average Hawaiian household to install roof-top solar beginning in 2011, which corresponds with when installed capacity (Figure 11) began to ramp higher. In California, we estimate that grid parity could be achieved in 2017, followed by New York and Arizona in 2018.

FIGURE 7
Hawaii Cost of Retail vs Solar + Storage (y-axis, c/kWh)



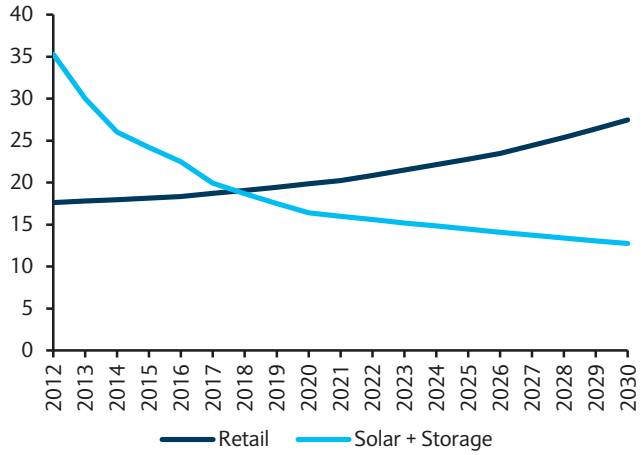
Source: EIA, RMI, BNEF, NREL, Barclays Research

FIGURE 8
Arizona Cost of Retail vs Solar + Storage (y-axis, c/kWh)



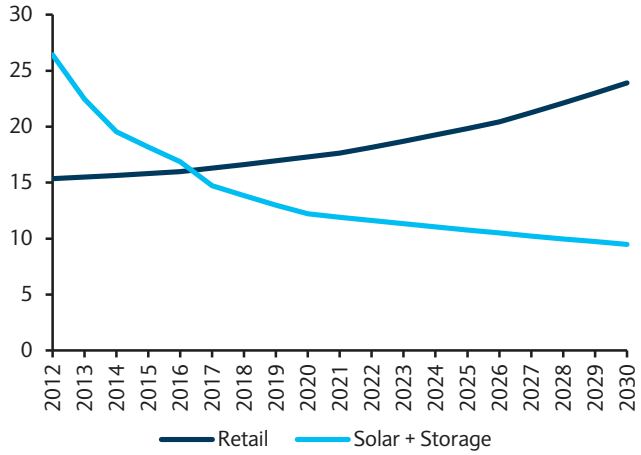
Source: EIA, RMI, BNEF, NREL, Barclays Research

FIGURE 9
New York Cost of Retail vs Solar + Storage (y-axis, c/kWh)



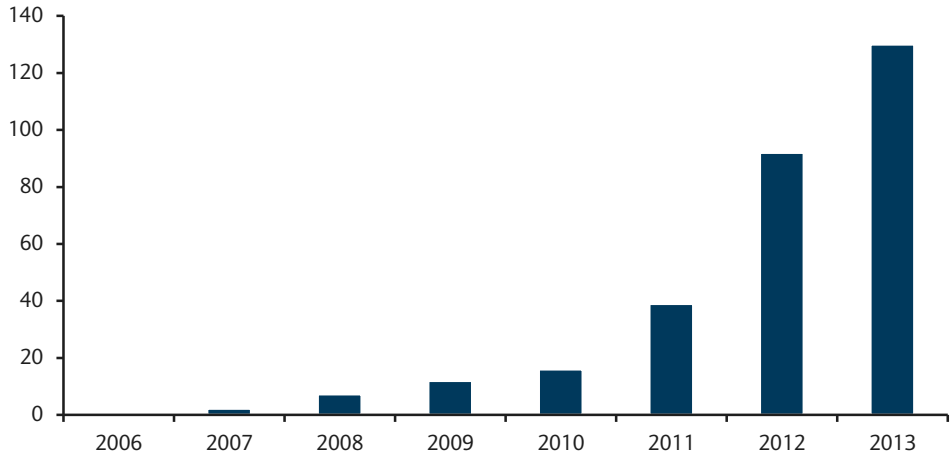
Source: EIA, RMI, BNEF, NREL, Barclays Research

FIGURE 10
California Cost of Retail vs Solar + Storage (y-axis, c/kWh)



Source: EIA, RMI, BNEF, NREL, Barclays Research

FIGURE 11
Annual PV Installations in Hawaii (MW)



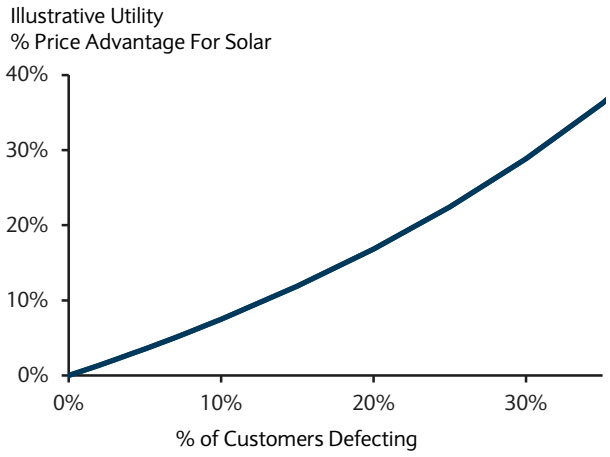
Source: Hawaiian Electric Company, Inc.

Defection Spiral Escalates Utility Risks as Cost Parity Reached

Although in most states solar + storage is not yet cost competitive on average, we expect some customers to pursue these installations for non-economic reasons, such as personal preferences for green power or reduced dependence on utilities. Once the cost of these systems is the same as grid utilities, it can create a self-reinforcing "defection spiral" that accelerates the relative cost advantage of moving off-grid.

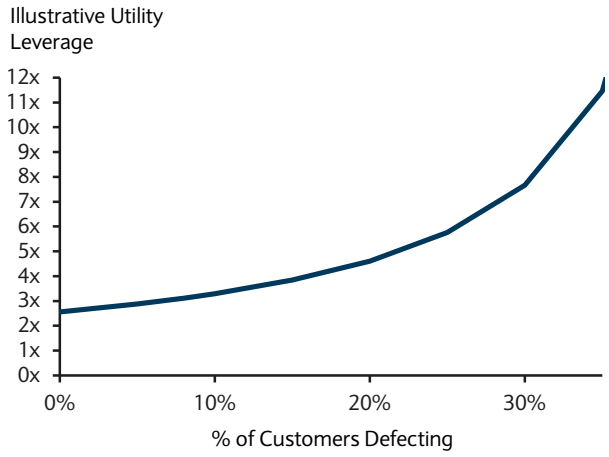
We develop a model to illustrate how growth in defections can pressure utilities. We begin with a model utility where the retail price of electricity is at parity with off-grid solar + storage systems. As some customers install the systems, the utility has fewer customers left to absorb the fixed costs of its distribution system. At that point, if it raises prices for the remaining customers, it creates a stronger incentive to defect, which raises the defection rate further, and so on. As a result, once solar + battery approaches the retail cost of power, its advantage can scale quickly (Figure 12).

FIGURE 12
If Retail Prices Adjust to Spread Fixed Costs Across Fewer Customers, Off-Grid Naturally Gains a Cost Advantage…



Source: Barclays Research

FIGURE 13
…But If Retail Prices Are Not Adjusted, Absorbing Costs Will Stress Utility Financial Health



Source: Barclays Research

The most direct alternative is for the utilities to absorb the fixed costs. While this can slow their relative disadvantage, it can be costly in terms of financial performance (Figure 13). Another alternative is for regulatory commissions to allow fixed charges for distributed generation and/or tweak net metering rules. We believe that this could slow the initial adoption rate (and potentially buy a little more time for fundamental changes to be made to the regulatory construct or for utilities to adjust their business model), but potentially have the unintended consequence of subsequently accelerating the adoption rate once full independence becomes cost-effective.

As Costs Decline, the Market Can Turn Very Quickly

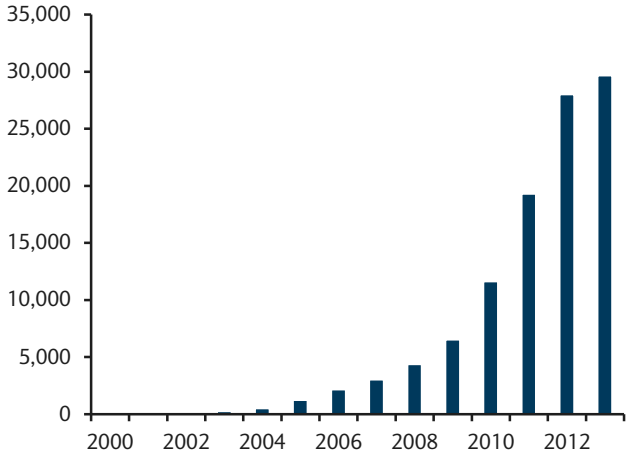
In our view, the experience of the largest utilities in Germany is illustrative: aggressive subsidies and a move away from nuclear power fueled a major expansion of the installed base of renewables and led to a steep drop in the cost of important components such as photovoltaic (PV) panels. From 2006 through 2013, the cost of PV panels declined nearly 70%, largely because of gains from scale manufacturing and competition. Although not only related to the penetration of distributed generation, since the beginning of 2010, Germany's two largest utilities had stock price declines of 55-60%, compared with a near 60% gain in the country's major stock index.

Utilities and Regulators Starting to Respond to Mitigate Risk

Whatever risks solar + storage pose to the status quo utility business model, we think utilities and their regulators have options to mitigate these risks. We see five potential responses that could let utilities slow the adoption of solar + storage and expect others to emerge as grid defection pressures utilities.

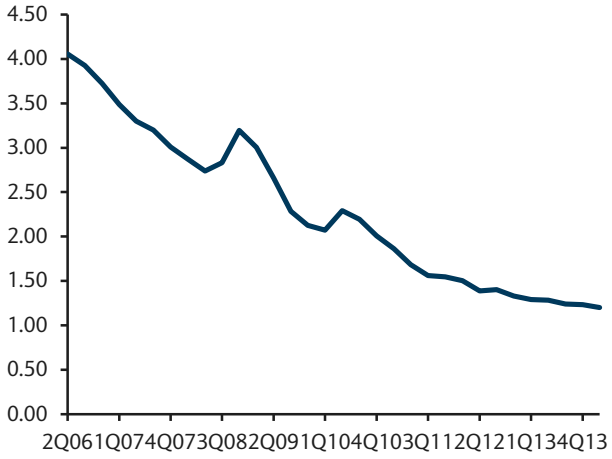
- **Utilities are seeking practical and regulatory barriers to solar + storage systems.** Solar advocates have accused Southern California Edison and HECO of slowing the approval process for solar systems. While this can slow the rate of adoption, it is not likely to present a permanent barrier to conversion for homeowners who seek systems. On March 18, 2014,

FIGURE 14
Solar PV Generation in Germany (mn kWh)



Source: German Solar Industry Association (BSW-Solar), BSW-Solar/www.solarwirtschaft.de

FIGURE 15
Cost of German Residential PV Capacity (converted to USD/Wp)



Note: Average end-customer prices (system prices) for installed roof-mounted systems of up to 10 kWp, per kWp without tax. Converted from EUR at average exchange rate during quarter. Source: German Solar Industry Association (BSW-Solar), BSW-Solar/www.solarwirtschaft.de

Bloomberg reported ("SolarCity Freezes Energy-Storage Program as Grid Connections Lag") that SolarCity was halting its push to install solar + storage systems in parts of California because of delays and charges associated with receiving approvals from utilities to hook the systems up to the grid. The California Public Utilities Commission subsequently barred utilities from imposing such charges (including connection fees of as much as $800) in a proposed decision on April 15 (final ruling pending). While SolarCity may have paused in its rollout, Tesla CEO Elon Musk has made it clear that he still expects to provide batteries to SCTY and other solar firms ("Musk Sees Need for Many 'Gigafactories' for Battery Demand", *Bloomberg*, May 15, 2014). *We estimate this could slow solar + storage adoption by six months, though it would also likely result in a steeper adoption curve once it is cleared.*

- **Regulators and legislatures could reduce the value of rebates and incentives.** As the number of solar installations has increased and prices have fallen, governments have already begun phasing out their initial subsidies. For example, a U.S. federal grant for 30% of the value of a solar installation was phased out in 2011, although other federal tax incentives remain. Similarly, state-level subsidies have been reduced. Although it is difficult to estimate the average value of these (due to situation-specific rules), California data suggest that the average incentive subsidy has fallen from $2/Wdc in 2009 to as little as $0.35/Wdc at the end of 2013. Although our model starting price is inclusive of rebates, our rate of cost improvement reflects the end price that has included their phase out. *We estimate that the elimination of subsidies could slow solar + storage adoption in higher-risk areas (such as California, Arizona and New York) by 12-24 months (based on the average incentive in California) if they were to be reduced to zero immediately.*

FIGURE 16
Grid Parity Dates

	With Subsidies	Without Subsidies
Hawaii	Present	Present
California	2017	2018
Arizona	2018	2019
New York	2018	2020
Illinois	2022	2025

Source: Barclays Research

- **Utilities may seek to charge solar + storage customers a fixed fee to offset their option on using grid power, while regulators rethink their framework.** This has already begun to emerge, with Arizona, California, Hawaii, and New York regulators all evaluating (and in some cases levying) fixed fees on customers with rooftop solar installations (Figure 17, details in Appendix A).

FIGURE 17
Examples of State Regulatory Actions on Fixed Fees

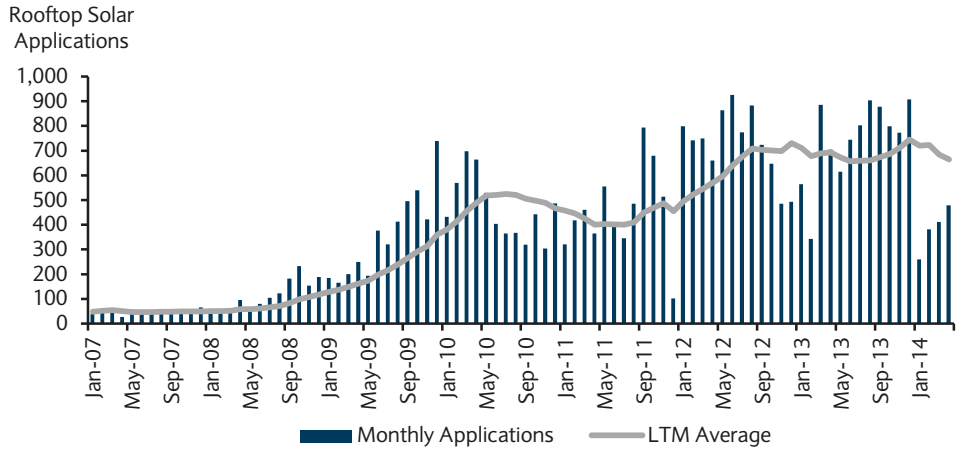
State	Actions
Arizona	$0.70/kW grid connection fee for new solar installations (~$5/month)
California	AB327 passed giving CPUC ability to increase monthly fixed charge from less than $1/month to no greater than $10/month (higher charges applicable to customers installing DG)
Hawaii	Hawaii PUC offering unbundled rate structure to adjust relative cost sharing of utility fixed costs between DG and non-DG customers
New York	NY PSC initiated order to review regulatory paradigm and market design to address policy objectives and regulations (including DG) comprehensively
Oklahoma	SB1456 signed into legislation, requiring Oklahoma Corporate Commission to create a tariff for new class of customer with DG

Source: Bloomberg, commission filings, company filings

These fees do appear to be effective in curtailing solar installations, at least temporarily. Arizona's monthly fee of $0.7/kW installed (equivalent to about $5/month for the average installation) appears to have reduced the number of new rooftop solar applications by 50% or more (Figure 18). But while they may slow the penetration of solar, any relief they offer utilities is likely to be short lived. In Arizona, the fee increases the cost of a rooftop solar installation about 5%. With the costs of solar installations falling about 10% per year (Figure 2), we expect the pace of installations to recover before the end of 2014. While we need more months of data to confirm our view, this may prove to be an example of how quickly the technological/cost curve can overtake regulatory responses.

FIGURE 18

AZ Solar Applications Dipped after Connection Fee, but Are Already Rising Again



Source: www.arizonagoessolar.org

Although the balance struck suggests that regulators in more states will adopt the idea that solar customers should pay a grid connection fee, external factors may limit their freedom to act:

- Politics are likely to play a role. Elected officials and their voters in a number of states view solar power as a laudable goal and want to encourage deployment. On the other hand, the perception that less wealthy consumers (dependant on the grid) are subsidizing grid connections for wealthy ones (able to install solar + storage) could present political difficulties. In addition, both utilities and solar installers can and will spend lobbying and public relations dollars to promote their opposing interests.

- As the cost of solar + storage continues to decline, the size of this fee will need to be carefully balanced against the risk of pushing customers off the grid entirely. If fees are so high that it becomes economic to forego even backup utility access, regulators and utilities could see defection spirals that accelerate beyond their control.

We estimate the introduction of fixed grid fees could slow solar + storage adoption by 12 months or longer (based on the Arizona fixed fee), but larger fees increase the risk of a steeper adoption curve once it becomes economic to defect entirely from the grid.

Utilities may seek to be the provider of solar + storage installations. By independently providing the solar + storage alternatives, or partnering with solar installers, utilities may be able to hedge some of the defection risks from their regulated services. Conceivably, a local utility, or its retail arm, could offer a service plan similar to those offered by companies like SolarCity, where customers receive a solar installation and pay a fixed

rate for power whether it is sourced from the solar system, local storage such as a battery, or the grid. Examples of this strategy adjustment are already happening. For example, Edison International (EIX) acquired SoCore Energy LLC (a Chicago-based distributed solar developer) in August 2013; NextEra (NEE) acquired Smart Energy (a small distributed solar generation business that focuses on commercial and industrial customers); and NRG Energy, Inc. (NRG) has nearly 3 million retail customers and sees distributed generation as a growth engine. To that point, NRG recently acquired Roof Diagnostics Solar, a residential solar company, and indicated that it sees at least 2 million American homes that economically should have solar on the roof by 2015. Southern Company (SO) has also embraced this and expects to produce a report at its AGM on May 28, 2014, that describes its existing renewable and distributed generation assets and new projects it expects to bring online in 2015. *Utilities that begin to provide solar + storage solutions are less likely to slow adoption, and may even accelerate it, but reduce the risk of being dislodged from their markets.*

FIGURE 19
Examples of Company Actions

Company	Actions
Edison International (EIX)	Acquired SoCore Energy (distributed commercial & industrial solar developer)
NextEra (NEE)	Acquired Smart Energy (distributed commercial & industrial solar developer)
NRG Energy (NRG)	Sees DG as growth engine; recently acquired Roof Diagnostics Solar (leading residential solar company)
Southern Company (SO)	Embracing and going to compete in DG (AGM on May 28, 2014 to detail existing renewable & DG assets and expected new 2015 projects)

Source: Company filings, Bloomberg

- **The industrial and commercial electricity markets consumed over 60% of electricity in the U.S. in 2012.** Although our analysis focuses only on the potential for residential roof-top solar, industrial and commercial users constitute the majority of consumption and are a key market for utilities and power generators. Although businesses typically pay lower unit electricity prices for power (thereby raising the cost bar for solar + storage), they may also be better placed in certain states to install larger PV and battery systems at lower cost than what is available at the residential level. Catering to this market, for which reliability of supply will remain paramount, could be a key mitigant for electricity providers. *We remain uncertain about the direction and magnitude of effect that industrial and commercial customers will have on solar + storage grid disruption.*

We fully expect utilities and regulators to make a good faith effort to preserve the status quo "regulatory compact," whereby the monopoly utility provides a safe and reliable service and regulators allow it to earn a reasonable low-risk return. However, we also expect them to be playing a constant game of catch-up as solar develops. The costs of solar and storage technologies are falling quickly and may fall even faster as higher demand builds additional scale. But the cost of distribution grids and thermally generated power are more likely to rise than to fall, in our view. As a result, regulators and utilities will be constantly trying to respond to a moving target, which is precisely the environment where slow-moving incumbents can fall behind. During the last round of major market changes in California – the partial deregulation that allowed wholesale prices to float while retail prices were capped – regulators found themselves playing catch-up to the actions of new, unregulated companies such as Enron that were able to transact power across states. Even without a technological threat, many utilities became stressed (and Pacific Gas & Electric was forced to file for bankruptcy) before regulators/legislators were able to respond adequately.

While the 1999-2001 crisis in California was ultimately resolved through an emergency suspension of the regulatory reform law, that is less likely to be effective in the face of utilities' grinding loss of competitiveness versus the cost of unregulated solar + storage. Regulators are ultimately answerable to voters, and the latter are unlikely to tolerate a long halt in their ability to access a clearly beneficial product. We suggest that the failure of various cities' taxi commissions to prevent the entry of Uber, an on-demand mobile car service app, into their markets provides a fresh example of how even regulators who favor incumbents are unable to stop a market shift if the alternative is too compelling. As long as the price of solar + storage is falling, while the cost of distribution grids and thermal generation are fixed or increasing, utilities will be at risk.

Rating Agencies Have Mixed Concerns on Distributed Generation

All three rating agencies recognize DG to be an emerging/potential threat to the regulated utility business model, although their assessment of the potential risk to credit quality is somewhat mixed.

Moody's views DG as a form of technology event risk, where event risk is low or remote, but with high severity implications should the event materialize. The agency assesses ratings effects based on risk/exposure associated with "any reasonable potential outcomes, as well as any likely mitigation measures a company might implement" and not to the outcome of specific events.[1]

S&P assumes a gradual rise in the use of rooftop solar and, as such, does not view it as a risk to credit quality. The agency writes that electric utilities "should be able to handle this competitive threat without compromising credit quality by continuing to manage regulatory risk, which includes working with regulators to minimize volatility in the customer's bill".[2]

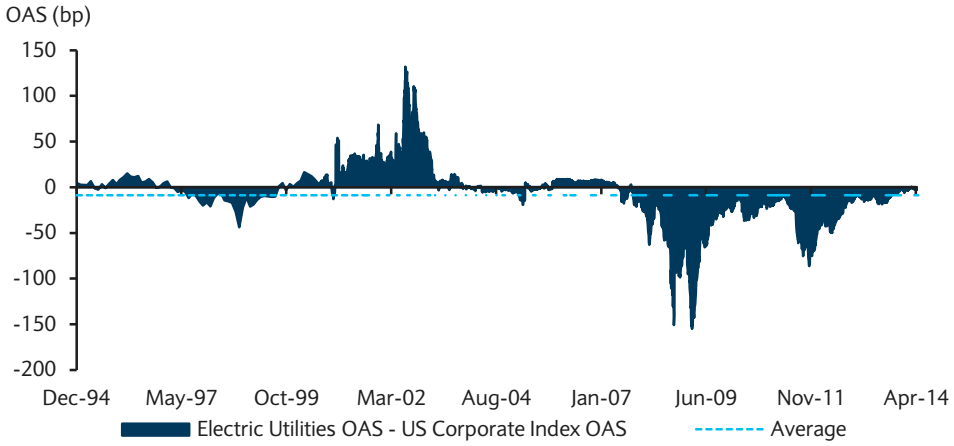
Fitch believes that rooftop solar and DG trends could disproportionately curtail peak load demand in certain regions, and grid parity can be achieved in certain parts of New York, California, Nevada, Arizona and New Mexico even without federal and state incentives. Fitch believes that the combination of energy efficiency and the emerging trend of DG will result in competitive generators' further rationalizing their balance sheets to reflect structural shifts and looking for ways to incorporate efficiency and DG in the business mix, with generators that have retail arms in a better position to exploit emerging trends.[3]

Why Is This Not Already Reflected in Valuations?

At present, we believe that electric industry credit spreads are pricing in virtually no risk of a significant industry disruption. The electric utilities index currently trades with an OAS about 3bp tighter than the US Corporate Index, within a few basis points of the long-term average. Although there is noise in the relationship from periods where aggregate spreads were higher, when US Corporate Index spreads have been less than 120bp, utilities have traded within 10bp (plus or minus) more than 95% of the time.

[1] Moody's: "Arizona Public Service: Getting a Jump on Rooftop Solar Distributed Generation", May 16, 2014, Moody's; "Regulatory framework holds key risks and rewards associated with distributed generation" April 23, 2014, Moody's; "Rooftop solar, distributed generation not expected to pose threat to utilities" November 8, 2013.
[2] S&P: "Why U.S. Electric Utilities' Credit Quality Can Withstand the Rise of Rooftop Solar", November 15, 2013
[3] Fitch, "Emerging Headwinds for Power Consumption Growth – Disruptive Impact of Energy Efficiency and Distributed Generation", December 13, 2013.

FIGURE 20
Electric Utilities Are Close to Long-Term Average Levels Relative to the Index



Source: Barclays Research

If the risks we describe are as serious, and as near term, as we suggest, why are they not reflected in valuations? We think that the shift in the potential for residential-scale battery storage at a reasonable cost is a new development that has not been integrated into investors' views. Using old estimates of battery plus PV costs suggested that we were a decade or more away from storage as a viable threat. Without storage, utilities faced some challenges in integrating roof-top solar into their systems, but they remained relatively immune to widespread disruption: if a consumer wanted electricity that was available consistently, at night, and on cloudy days, they needed the utility. With storage costs potentially a step-change lower than expected, utilities may be poised to lose their criticality path.

We also think that existing models for grid defection have focused on full grid independence, which remains farther away even with less expensive storage. While that is the long-term risk, the risk of disruption to the business and regulatory model should be priced long before that becomes a reality.

Finally, we believe that many credit investors have given less scrutiny to the utility industry than sectors with more apparent risks. This is not unreasonable, absent a significant industry disruption, as the utility-regulator regulatory compact results in modest operational risks and strong asset coverage. Now, however, we think it is only a matter of time before investors begin to focus on the potential for that significant dislocation.

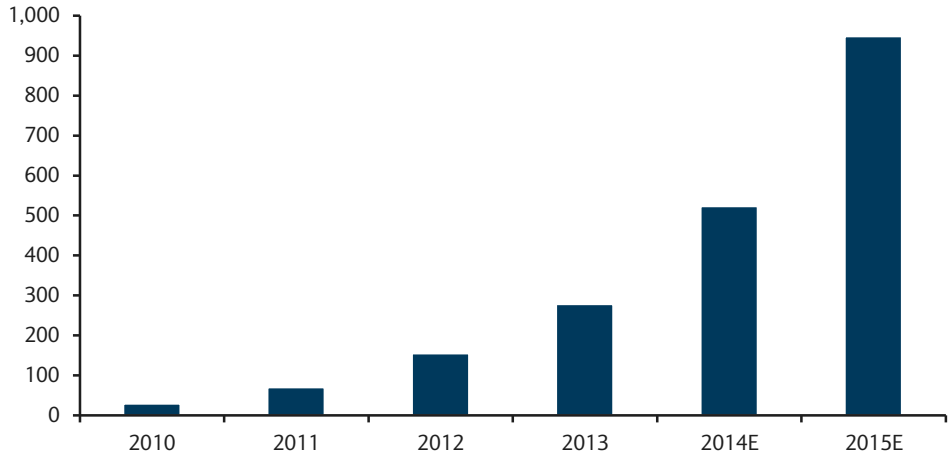
Early Indicators

As early indicators, we believe that utility and pipeline credit investors should be following quarterly results from TSLA, SolarCity (SCTY) and NRG Energy (NRG) to gauge the pace and penetration potential of solar + storage distributed generation. Although our report focuses on customer-owned solar + storage systems, we note that SCTY offers a third-party owned option with no-cost installation in exchange for long-term contracts to purchase power from SCTY. The company's average residential PPA rate is 16.4 c/kWh, which is competitive with the average retail cost of electricity in some states today.

Hawaii Electric (HECO) likely represents the first line of utility stress. Because retail power prices are so high in Hawaii, there has already been significant penetration of roof-top solar, with more than 10% of the utility's customers having installed solar panels (75% of them in the last two years). The experience of HECO in navigating the transition will provide clues as to the path other utilities and regulators may follow. We would also look to California, New

York and Massachusetts for potential broad changes in regulatory frameworks and policy with respect to distributed solar + storage.

FIGURE 21
SolarCity PV Installations (MWs deployed by year)



Source: Company reports, Barclays Research

Consequences Will Extend Beyond Utilities

In our view, the consequences of residential adoption of solar plus battery storage systems will extend beyond the direct lateral implications for utilities and generating companies. Demand for batteries could reinforce a positive feedback loop that further drops their price, which could lead to better economics for electric vehicles (both all-electric and hybrid) and feed into slower demand growth for gasoline and crude oil. If solar penetration results in more unpredictable periods for baseload generation (driven by sunshine hours and storage limits), utilities could be encouraged to decommission existing baseload capacity earlier and replace it with efficient peaking units. Thermal coal miners could find themselves facing even weaker demand for coal and lower credit-quality counterparties on existing supply agreements. Companies that produce raw materials may see much higher demand for materials that feed into battery production, while battery manufacturers could also benefit.

Finally, credit quality in the pipeline opco sector ultimately hinges on four factors: where the pipeline originates, where it terminates, the quality of customers that ship on that pipeline, and what the pipeline carries. In our opinion, lower credit quality for utilities could shift investor preferences away from power generation demand-pull pipelines, particularly for those that move natural gas into states that are at risk of grid disruption. Conversely, pipelines that supply LNG export terminals, utilities in states with low-cost power and little sun, and/or industrial users could outperform.

CREDIT IMPLICATIONS; DOWNGRADING ELECTRIC TO UNDERWEIGHT AND RATING CHANGES

Implications for Credit

U.S. utility bonds represent almost $450bn of market value in the corporate index, more than 10% of the U.S. Corporate Index debt by market value. Electric utilities comprise over $280bn of this total. An industry-wide shift in operating and financial conditions could result in a severe technical, especially in the long end of the curve, where electric utilities are ~13% of the debt outstanding. As a group, electric utilities currently trade just inside the U.S. Corporate Index in OAS terms; over the next several years, we expect utilities to face a potential disruption not seen since deregulatory pressures that resulted in the California electricity crisis in 2000-01. At that time, utility spreads peaked more than 125bp wider than the U.S. corporates, and while we believe regulators and utilities are trying to get in front of this issue, the potential for credit stress can be easily envisioned. We believe that there is virtually no disruption risk priced into utility spreads. We recommend the following:

- Long-only cash investors should reduce their exposures to utility bonds, especially at the long end of the curve.
- Shorting a basket of more exposed utilities versus a basket of less exposed ones, either in cash or CDS:

FIGURE 22
Utility Issuers in Respective States and Illustrative Securities Baskets

State/Geography	Issuers	More Liquid Illustrative Securities Basket
Short basket		
California utilities		
	EIX: Edison International, Southern California Edison	EIX 3.5s of 2023, EIX 4.65s of 2043
	PCG: PG&E Corp, Pacific Gas & Electric	PCG 2.4s of 2019, PCG 3.75s of 2024, PCG 6.05s of 2034, PCG 4.75s of 2044
	SRE: Sempra International, San Diego Gas & Electric	SRE 4.05s of 2023, SRE 6s of 2039, SRE 3.6s of 2023, SRE 4.45s of 2044
Northeast utilities		
Connecticut:	Connecticut Light & Power (NU), United Illuminating Co (UIL)	NU 2.5s of 2023, NU 4.3s of 2044
Maine:	Central Maine Power (IBESM), Bangor Hydro Electric (EMACN)	IBESM 5.7s of 2019
Massachusetts:	Massachusetts Electric (NGGLN), Western Massachusetts Electric (NU), NSTAR Electric (NU)	NGGLN 5.9s of 2039, NU 4.4s of 2044
New Hampshire:	Public Service Co of New Hampshire (NU), Unitil Energy Systems (UIL)	NU 3.5s of 2023
New Jersey:	Public Service Electric & Gas (PEG), Jersey Central Power & Light (FE)	FE 4.7s of 2024, PEG 3.75s of 2024
New York:	Consolidated Edison Co of New York (ED), Orange & Rockland (ED), New York State Electric & Gas (IBESM), Rochester Gas & Electric (IBESM), Niagara Mohawk (NGGLN), Central Hudson Gas & Electric (FTSCN)	ED 4.45s of 2044, NGGLN 2.721s of 2022
Rhode Island:	Narragansett Electric (NGGLN)	NGGLN 4.17s of 2042
High insolation state utilities		
Arizona:	PNW: Pinnacle West, Arizona Public Service UNS: Tucson Electric Power, UNS Electric	PNW 5.05s of 2041, PNW 4.5s 2042, PNW 4.7s of 44, UNS 5.15s of 2021
Nevada:	NV Energy, Nevada Power, Sierra Pacific Power (all MIDAM)	MIDAM 5.45s of 2041, MIDAM 5.375s of2040
New Mexico:	PNM: PNM Resources, Texas-New Mexico Power, Public Service Co of New Mexico EE: El Paso Electric	PNM 5.35s of 2021, EE 6s of 2035

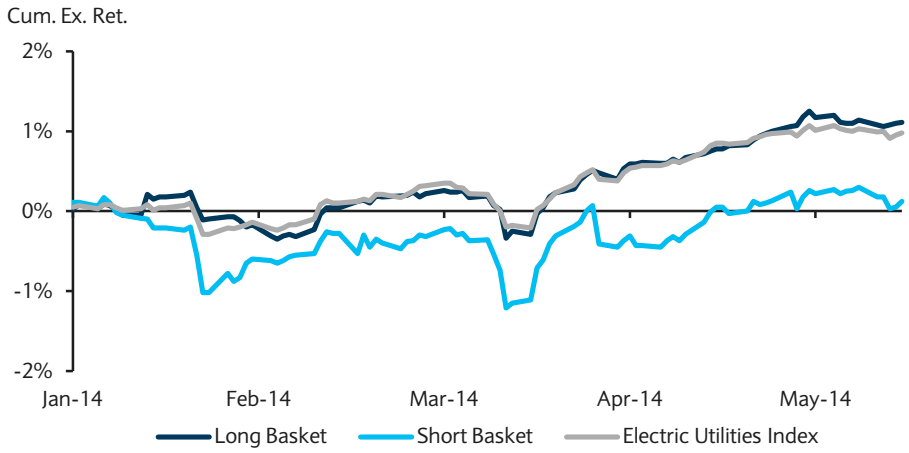
State/Geography	Issuers	More Liquid Illustrative Securities Basket
Gencos	FirstEnergy Solutions (FE), Allegheny Energy Supply (FE), PPL Energy Supply (PPL), PSEG Power (PEG)	PEG 4.3s of 2023
Long basket (>10y solar + storage grid parity)		
Northwest utilities		
Washington:	PSD: Puget Energy, Puget Sound Energy AVA: Avista Utilities MIDAM: PacifiCorp	PSD 6.5s of 2020, PSD 5.625s of 2022, PSD 5.638 of 2041, AVA 5.125s of 2022, MIDAM 3.6s of 2024, MIDAM 4.1s of 2042
Oregon:	POR: Portland General Electric MIDAM: PacifiCorp IDA: Idaho Power	POR 6.1s of 2019
Idaho:	IDA: Idaho Power AVA: Avista Utilities MIDAM: PacifiCorp	
North Dakota:	MDU: MDU Resources Group XEL: Northern States Power Co of Minnesota OTTR: Otter Tail Power	
Southeast/Midwest utilities		
Louisiana:	ETR: Entergy Louisiana, Entergy Gulf States, Entergy New Orleans	ETR 4.05s of 2023, ETR 5.59s of 2024
Kentucky:	AEP: Kentucky Power DUK: Duke Energy Kentucky PPL: LG&E and KU, Kentucky Utilities, Louisville Gas & Electric	PPL 3.75s of 2020, PPL 4.375s of 2021, PPL 5.125s of 2040 (KU), PPL 5.125s of 2040 (LGE), PPL 4.65s of 2043 (KU),
Arkansas:	ETR: Entergy Arkansas	ETR 3.7s of 2024
Tennessee:	Tennessee Valley Authority	TVA 3.5s 2042

Source: Barclays Research

Although some of these bonds have relatively small issue sizes, the total short basket has a face value of nearly $14bn, which should allow investors to implement trades of reasonable size by selling short small amounts within each issue. Finally, we note that the short portfolio has lagged the long portfolio, and electric utilities as a group, in 2014 (Figure 23).

FIGURE 23

Short Basket Has Underperformed the Long Basket and Electric Utilities in 2014



Source: Barclays Research

Across utilities and pipelines, we recommend putting on 5s-10s and/or 5s-30s curve steepening trades (Figure 25). In the case of utilities in California, where we estimate that solar

plus storage could be a viable alternative, on average, by 2017, investors should err toward keeping longs in the 3y part of the curve.

Downgrading Electric Sector Rating to Underweight from Market Weight

We have been concerned about the longer-term load growth profile for the sector, given the effect of energy efficiency programs and demand side management programs, which could be compounded by upcoming CO2-related guidelines and implementation (the EPA is expected to publish its CO2 emission related guidelines on June 2, 2014, for existing generation sources). In our opinion, the implementation/compliance is probably going to occur over a longer period, giving utilities and regulators/legislators time to adjust.

However, we believe that the competitive effect of solar + storage could warrant a much more urgent response, and the adequacy of a regulatory/business response is not clear. We recognize that regulatory commissions and utilities are taking steps in response to this emerging competitive threat, but the regulatory response (eg, raising fixed charges for DG connection) could exacerbate the problem and accelerate the adoption rate of solar + storage. For utilities venturing into the distributed generation/storage business, we believe this to be a good first step in potentially gaining a better understanding of the solar + storage trend and acting as a business hedge, with the potential for some companies to become leaders. However, we believe it is too early to call winners at this juncture.

Our initial screen for generators and regulated utility issuers that are exposed to states where grid parity could be reached in under four years from the end of 2014 (California and Connecticut under 2.5 years; New Hampshire, Nevada, Vermont, Arizona, New Jersey, Massachusetts, New York and Alaska within four years) found that affected issuers represent about 25% of the IG Electric index by market value (the percentage goes up to 31% if we include Florida, a high annual average insolation state). As a result, **we are downgrading the Electric sector rating to Underweight from Market Weight on concerns that the regulatory responses to the growing competitive threat from solar + storage may prove inadequate to address potential strains to the credit profiles of issuers in these states**. Moreover, we think that the mere emergence of a distributed generation transition process could destabilize sector spreads. Overall, they are only in line with the long-term average versus the market and at tight absolute levels. In particular, there is very little spread differentiation in the long end for the regulated opcos, so investors are not being compensated for a potential major fundamental shift, in our view.

We are lowering our ratings for utilities that are most likely to reach grid parity in under 4-years and are most connected with California (high insolation, sub-3 year to grid parity) and Connecticut (sub-3y duration to grid parity despite lower insolation). We believe that investors are likely to pare back holdings in the most at-risk states, barring fundamental regulatory reform that adequately addresses the competitive threats from solar + storage and supports current credit profiles.

FIGURE 24
Change in Barclays Ratings

Ticker	Type	Issuer Name	Current Rating	Previous Rating	Credit Notes
California					
EIX	Holdco	Edison International	Underweight	Market Weight	
EIX	Opco	Southern California Edison	Market Weight	Overweight	
PCG	Holdco	PG&E Corp	Underweight	Market Weight	
PCG	Opco	Pacific Gas & Electric	Underweight	Market Weight	Awaiting ALJ's proposed decision on San Bruno accident penalty
SRE	Holdco	Sempra International	Market Weight	Overweight	Considering MLP
SRE	Opco	San Diego Gas & Electric	Market Weight	Overweight	
Northeast					
NU	Holdco	Northeast Utilities	Underweight	Overweight	Outstanding FERC 206 complaints against high base ROE for transmission for CL&P, NSTAR Electric, PS New Hampshire and WMECO that remain outstanding
NU	Opco	Connecticut Light & Power	Underweight	Overweight	Connecticut: Notice of intent to file rate case
NU	Opco	Public Service Co of New Hampshire	Market Weight	Overweight	New Hampshire
NU	Opco	NSTAR Electric	Market Weight	Overweight	Massachusetts
NU	Opco	Western Massachusetts Electric	Market Weight	Overweight	Massachusetts
PEG	Opco	Public Service Electric & Gas	Market Weight	Overweight	New Jersey
PEG	Genco	PSEG Power	Underweight	Market Weight	PJM/potentially weaker metrics in the interim to support PSE&G's capex program
FE	Opco	Jersey Central Power & Light	Underweight	Market Weight	Ongoing rate case proceeding with the NJ BPU and awaiting approval and details of storm cost recovery
FE	Genco	Allegheny Energy Supply	Underweight	Market Weight	
FE	Genco	FirstEnergy Solutions	Underweight	Market Weight	
ED	Opco	Consolidated Edison Co of New York	Underweight	Market Weight	Awaiting NTSB report on Harlem explosion
ED	Opco	Orange & Rockland	Underweight	Market Weight	
High insolation					
PNW	Opco	Arizona Public Service	Underweight	Overweight	Arizona
MIDAM	Holdco	NV Energy	Market Weight	Overweight	Nevada
MIDAM	Opco	Nevada Power	Market Weight	Overweight	Nevada
MIDAM	Opco	Sierra Pacific Power	Market Weight	Overweight	Nevada

Note: Opco = regulated operating subsidiary utility, Genco = unregulated generation subsidiary. Source: Barclays Research

FIGURE 25

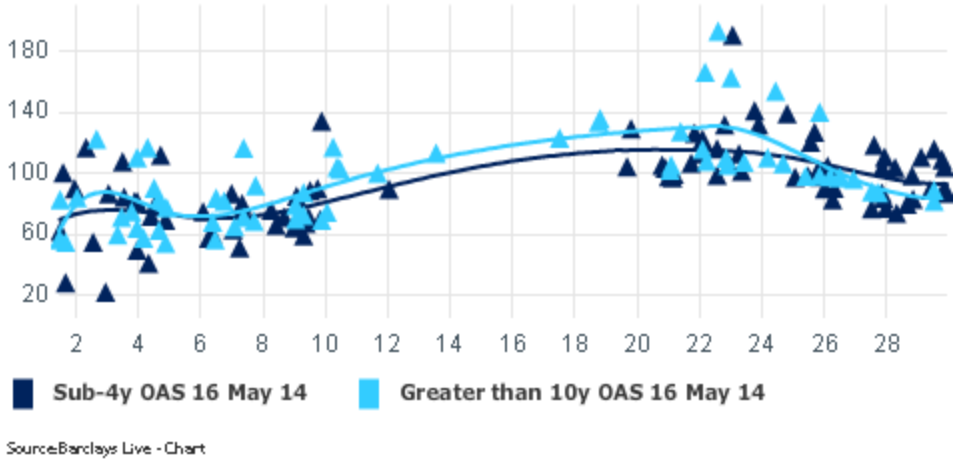
5s10s and 5s30s Relationship (2000-to-date)

	5/15/14	Average	Median	Wides	Tights
5s10s					
U.S. Credit	+47	+15	+17	+50	-65
IG Electric:					
Holdco	+19	+6	+8	+134	-125
Regulated opco:					
FMB	+5	-3	-1	+108	-229
Senior Unsec	+3	+3	+5	+87	-196
5s30s					
U.S. Credit	+63	+41	+46	+119	-85
IG Electric					
Holdco	+51	+17	+29	+126	-197
Regulated opco:					
FMB	+16	-2	+11	+55	-205
Senior Unsec	+13	+14	+18	+70	-141

Source: Barclays POINT

FIGURE 26

Little spread differentiation between issuers with sub-4y (dark blue) and greater-than-10y (bright blue) to solar + storage grid parity: OAS (bp)



Source: Barclays Research

APPENDIX A

Detailed Solar + Battery Cost Model

Figure 23 presents our grid disruption model assumptions for the five states that we consider to be a representative sample of the U.S.

Unlike other models that contemplate the costs of moving completely off the grid, we assume only that residential customers will look to take most of their electricity consumption off the grid and seek to balance costs. Ultimately, we expect battery sizes to grow and move toward full grid independence, but as for a near-term threat to the prevailing regulatory and economic scheme for utilities, our assumption is that only the economics of partial grid independence need to compete with traditional grid power to disrupt the status quo materially. Based on our model, the key driver of solar-backed grid independence is the cost of storage.

FIGURE 27
Model Assumptions

Assumptions	Hawaii	Arizona	New York	California	Illinois
Average retail electricity costs (% y/y)					
2012-2016	1.0	1.0	1.0	1.0	1.0
2017-2021	2.0	2.0	2.0	2.0	2.0
2022-2026	3.0	3.0	3.0	3.0	3.0
2027-2040	4.0	4.0	4.0	4.0	4.0
Estimated hours per day that generate full solar power (average)	5.0	5.0	2.8	4.0	3.3
Battery cost assumptions ($/kWh)					
2012	300	300	300	300	300
2013	250	250	250	250	250
2014	231	231	231	231	231
2015	214	214	214	214	214
2016	198	198	198	198	198
2017	139	139	139	139	139
Battery costs post-2017 (% decline y/y)	2.5	2.5	2.5	2.5	2.5
Battery life (years)	10.0	10.0	10.0	10.0	10.0
Starting capital cost of PV ($/w)	3.28	3.28	3.28	3.28	3.28
PV costs through 2020 (% decline y/y)	7.0	7.0	7.0	7.0	7.0
PV cost reductions post-2020 (% decline y/y)	2.5	2.5	2.5	2.5	2.5
Life of PV panel (years)	25.0	25.0	25.0	25.0	25.0
Annual operating costs (% PV capital cost)	1.0	1.0	1.0	1.0	1.0
Days of battery redundancy needed	0.77	0.77	0.77	0.77	0.77
Power of PV on sunny days (%)	80.0	80.0	80.0	80.0	80.0
Power of PV on cloudy days (%)	15.0	15.0	15.0	15.0	15.0
DC to AC de-rating (x)	0.77	0.77	0.77	0.77	0.77

Note: Cost of inverter assumed to be included in PV costs. Source: Tesla and SolarCity company reports, National Renewable Energy Laboratory (NREL), National Oceanic and Atmospheric Administration (NOAA), Barclays Research.

FIGURE 28

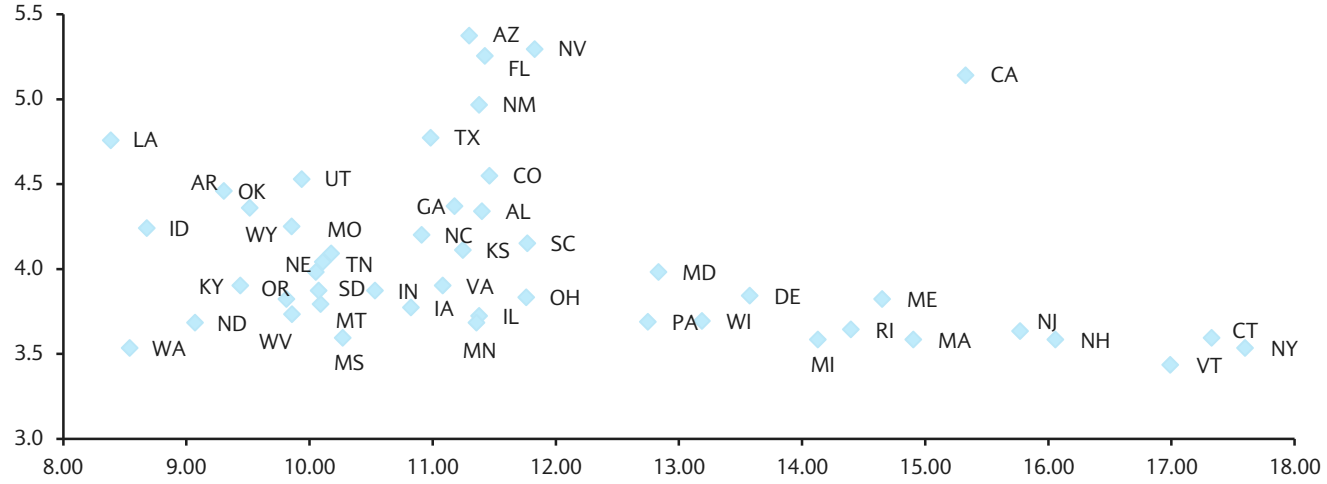
Sunlight Assumptions

	Hawaii	Arizona	New York	California	Illinois
Annual sunshine hours	3,806	3,806	2,120	3,055	2,567
per day	10.4	10.4	5.8	8.4	7.0
Full sun (%)	50	50	50	50	50
Cloudy (%)	50	50	50	50	50
Full sun hours	5.2	5.2	2.9	4.2	3.5
Partial sun hours	5.2	5.2	2.9	4.2	3.5
Full sun solar potency (%)	80	80	80	80	80
Partial sun solar potency (%)	15	15	15	15	15
Converted hours of sun	5.0	5.0	2.8	4.0	3.3

Source: NOAA, Barclays Research

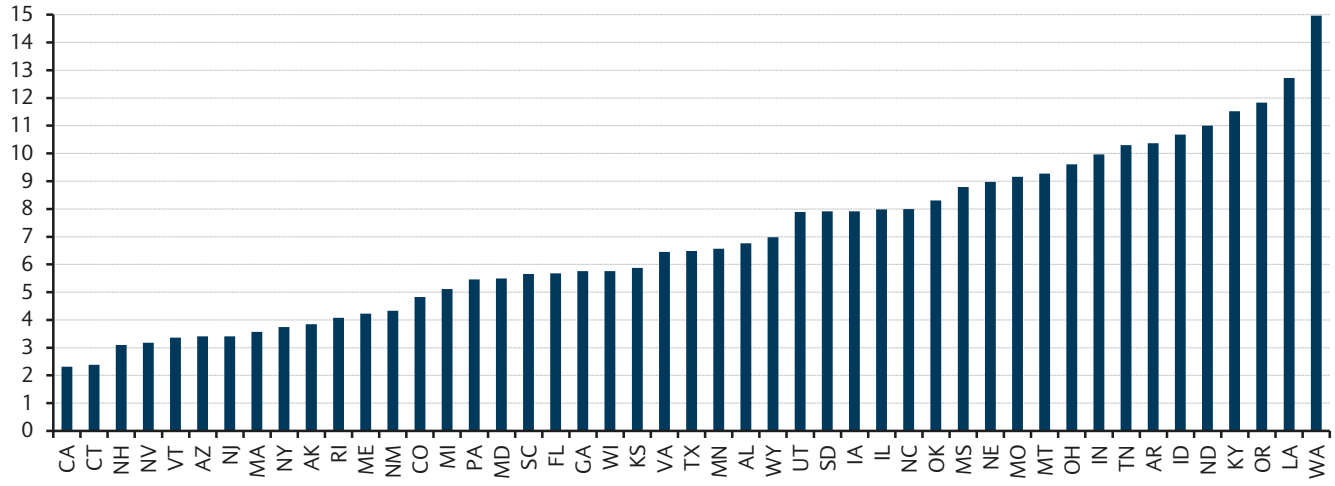
FIGURE 29

Residential Retail Cost of Electricity (cents/kWh, x-axis) versus Annual Average Insolation (kWh/m^2/day, y-axis)



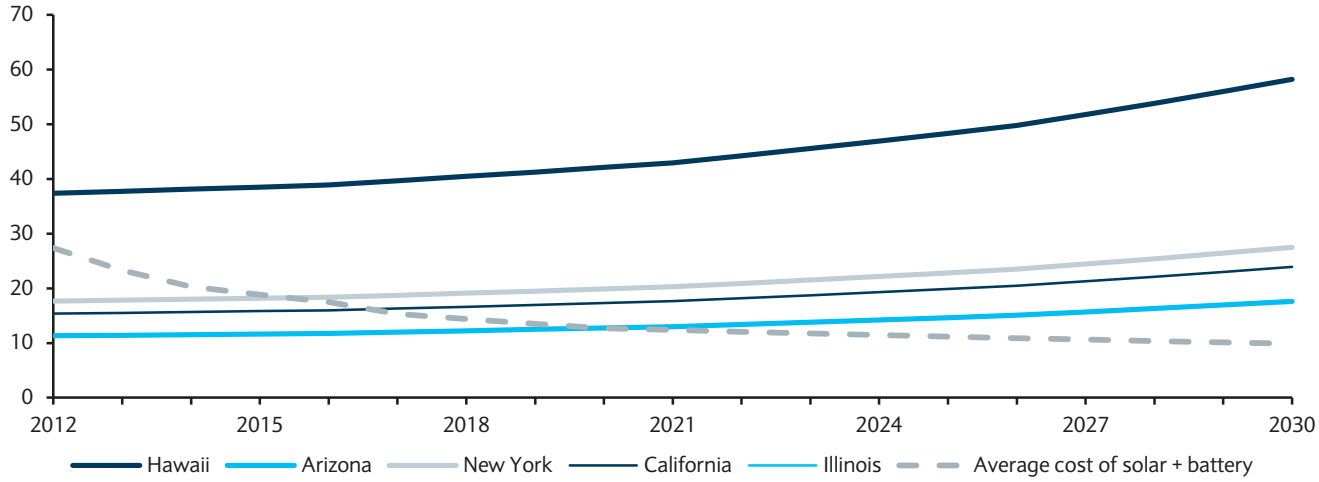
Source: EIA, Rocky Mountain Institute (RMI), Bloomberg New Energy Finance (BNEF), National Renewable Energy Laboratory (NREL), Barclays Research

FIGURE 30
Years until Solar + Storage Reaches Grid Parity by State (years from end of 2014)



Source: Barclays Research

FIGURE 31
Residential Retail Cost of Electricity by State versus Average Cost of Solar and Battery (cents/kWh)



Source: EIA, Rocky Mountain Institute, Bloomberg New Energy Finance, National Renewable Energy Laboratory, Barclays Research

Regulatory and Legislative Responses

Arizona: At the beginning of 2014, the Arizona Corporation Commission adopted a $0.70/kW grid connection fee for new solar installations (which will cost the average residence with a solar power system about $5/month). Existing systems are grandfathered for 20 years. Arizona Public Service (APS), the largest utility in the state, contends that net metering for solar customers shifts higher costs for maintaining the grid onto non-solar customers and had sought a fee of up to $100/month for solar customers. We see Arizona (where ample sun makes solar cells comparatively cost effective) as a preview of why such challenges may not provide full protection against the downside of solar + storage defections: while APS asked for a much higher fee, the solar power industry spent a substantial sum opposing the change entirely. Figure 18 shows the annual amount of PV capacity installed in APS's service territory since 2002, plotted against the average price per watt of PV panels for the utility's customers.

California: With the recent passage of Assembly Bill 327 (AB327) in October 2013, lawmakers in California took a conscious step in giving the California Public Utilities Commission (CPUC) the ability to modify the rate design to make it more equitable (and moderate the incentives for high-usage customers to self-generate while maintaining incentives for conservation). Essentially, the CPUC is allowed to increase the monthly fixed charge to no greater than $10 a month (from less than $1 a month for certain customers), and the CPUC is also authorized to require higher fixed charges beyond the $10 cap that is applicable to customers installing distributed generation. The CPUC has established a target for California investor-owned utilities to install 1,325MW of energy storage by 2020.

Hawaii: Regulators have recognized that the current rate structure is not well suited for a future environment of "significant variable renewable energy, customer sited distribution energy resources and increasingly smart grid technologies." The Hawaiian PUC offered for consideration unbundled rate structures, to fit customer preferences for varying levels of electricity service better and adjust the relative cost sharing of utility fixed costs between customers with distributed generation and those without. Hawaii also adopted Act 37, which gives the PUC options to protect the utility against stranded assets.

Massachusetts: According to SNL (May 20, 2014), Massachusetts is wrapping up closed-door negotiations with electric utility stakeholders, the solar industry and clean energy advocates, with the expectation of passing legislation that would uncap the state's net metering program, cut back on virtual net metering while imposing a minimum charge on all customers for grid services and upkeep, and move the state away from a traded market for renewable energy credits and toward a declining block grant program.

New York: The State of New York Public Service Commission (NYPSC) initiated an order instituting proceeding (14-M-0101[4]) on April 25, 2014, to review the regulatory paradigm and retail and wholesale market design on how it is effectuating/impeding progress in achieving its policy objectives and how it is regulating its electric distribution utilities. Some of the key questions it is seeking to address (with respect to the regulation of its distribution utilities) include the role of distribution utilities in enabling system-wide efficiency and market-based deployment of distributed energy resources and load management and changes that can and should be made in regulatory, tariff, market design and incentive structures in New York to align utility interests with energy policy objectives. Track 1 of the order addresses the functions of "distributed system platform provider," or DSPP (includes DG), and, among other things, would address whether the DSPP should be the incumbent utility or an independent entity and whether utilities should be permitted to own/control distributed energy resources. Audrey Zibelman (chairman of the NYPSC) noted in an interview with Bloomberg on May 12, that the "21st century grid is going to have a lot more distributed resources." The preliminary schedule for Track 1: a status report to be presented to the NYPSC by July 10, final recommendations to be filed with NY PSC by year-end 2014, and utilities to file implementation plans in 2015 (in the context of rate case filings).

Oklahoma: Governor Mary Fallin signed Senate Bill 1456 on April 21, 2014 (which passed the state House on April 14 and state Senate on March 12), that would require the Oklahoma Corporate Commission (OCC) to create a tariff for a new class of customer with distributed generation. She also issued an executive order directing executive agencies (including the OCCC) to support renewable (including DG), in keeping with the Oklahoma First Energy Plan that enhances all of the state's energy production (oil, natural gas, wind and solar).

[4] http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={9CF883CB-E8F1-4887-B218-99DC329DB311}

APPENDIX B

FIGURE 32

Barclays Equity Research 2013 Regulatory Ranking by Cost of Capital (September 9, 2013)

Tier 1	Tier 2	Tier 3	Tier 4	Tier 5
Lowest Cost		**2013**		**Highest Cost**
Of Capital		Kansas		**Of Capital**
		Newfoundland & Labrador		
Ofgem (U.K.)		Nevada		
FERC		Alabama		
		Minnesota		
		Oklahoma		
		Pennsylvania		
		Washington		
		Illinois		
	Indiana	North Dakota	New Mexico	
	South Carolina	Louisiana	Missouri	
	North Carolina	Utah	Ohio	
	Virginia	New Jersey	Mississippi	
British Columbia	Nova Scotia	California	West Virginia	
Kentucky	Wisconsin	Delaware	Massachusetts	Maryland
Michigan	Florida	Oregon	Hawaii	Maine
Wyoming	Colorado	Ontario	South Dakota	Vermont
Iowa	Arkansas	Arizona	Rhode Island	Connecticut
Idaho	Tennessee	Texas	District of Columbia	New Hampshire
Alberta	Georgia	New York	Prince Edward Island	Montana

Source: Barclays Research

Regulatory Research Associates (RRA) State Regulatory Evaluations

RRA evaluates the regulatory climate of the 50 states and the District of Columbia on an ongoing basis and approaches its evaluations from an investor perspective by indicating the regulatory risk associated with the ownership of securities issued by each jurisdiction's electric and gas utilities. RRA ratings consider numerous factors affecting the regulatory process in the state and are changed based on major events that change its view of the regulatory risk accruing to ownership of utility securities in an individual jurisdiction. The final evaluation reflects RRA's assessment of the probability level and quality of earnings to be realized by the state's utilities as a result of regulatory, legislative and court actions.

RRA maintains three principal rating categories, Above Average, Average, and Below Average, with the first indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint and the last indicating a less constructive, higher-risk one. Within the three principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger (more constructive) rating; 2, a mid-range rating; and, 3, a weaker (less constructive) rating.

FIGURE 33

RRA State Regulatory Rankings (April 17, 2014)

Above Average	Average	Below Average
AA/1	A/1	BA/1
	California	Montana
	Colorado	New Mexico
	Hawaii	Texas PUC
	Kentucky	West Virginia
	Louisiana – PSC	
	Louisiana – NOCC	
	Michigan	
	North Carolina	
	North Dakota	
	South Carolina	
	Tennessee	
AA/2	A/2	BA/2
Alabama	Alaska	Illinois
Virginia	Delaware	Connecticut
Wisconsin	Idaho	Maryland
	Kansas	
	Maine	
	Minnesota	
	Missouri	
	Nebraska	
	Nevada	
	New York	
	Ohio	
	Oklahoma	
	Utah	
	Washington	
	Wyoming	
AA/3	A/3	BA/3
Florida	Arizona	
Georgia	Arkansas	
Indiana	District of Columbia	
Iowa	Massachusetts	
Mississippi	New Hampshire	
	New Jersey	
	Oregon	
	Pennsylvania	
	Rhode Island	
	South Dakota	
	Texas RRC	
	Vermont	

Source: SNL RRA

Analyst Certification
We, Brittany Chen, Yung Chuan Y.C. Koh, Harry Mateer, Ryan Preclaw, CFA and Greggory Price, CFA, hereby certify (1) that the views expressed in this research report accurately reflect our personal views about any or all of the subject securities or issuers referred to in this research report and (2) no part of our compensation was, is or will be directly or indirectly related to the specific recommendations or views expressed in this research report.

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Overweight: Expected six-month excess return of the sector exceeds the six-month expected excess return of the Barclays U.S. Credit Index, the Pan-European Credit Index, or the EM Asia USD High Grade Credit Index, as applicable.
Market Weight: Expected six-month excess return of the sector is in line with the six-month expected excess return of the Barclays U.S. Credit Index, the Pan-European Credit Index, or the EM Asia USD High Grade Credit Index, as applicable.
Underweight: Expected six-month excess return of the sector is below the six-month expected excess return of the Barclays U.S. Credit Index, the Pan-European Credit Index, or the EM Asia USD High Grade Credit Index, as applicable.

Explanation of the Barclays Research High Grade Credit Rating System
The High Grade Credit rating system is based on the analyst's view of the expected excess returns over a six-month period of the issuer's index-eligible corporate debt securities relative to the Barclays U.S. Credit Index, the Pan-European Credit Index or the EM Asia USD High Grade Credit Index, as applicable.
Overweight: The analyst expects the issuer's index-eligible corporate bonds to provide positive excess returns relative to the Barclays U.S. Credit Index, the Pan-European Credit Index, or the EM Asia USD High Grade Credit Index over the next six months.
Market Weight: The analyst expects the issuer's index-eligible corporate bonds to provide excess returns in line with the Barclays U.S. Credit Index, the Pan-European Credit Index, or the EM Asia USD High Grade Credit Index over the next six months.
Underweight: The analyst expects the issuer's index-eligible corporate bonds to provide negative excess returns relative to the Barclays U.S. Credit Index, the Pan-European Credit Index, or the EM Asia USD High Grade Credit Index over the next six months.
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Coverage Suspended (CS): Coverage of this issuer has been temporarily suspended.
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For Australia issuers, the ratings are relative to the Barclays U.S. Credit Index or Pan-European Credit Index, as applicable.

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NERI 2-9

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 21, Table 2. Please provide an Excel spreadsheet table containing the information in Table 2 for the years 2001 through 2016.

Response:

Please see Attachment NERI 2-9. The source of the data is FERC Form 1 for the respective year (including the most recent revision filed with FERC).

Prepared by or under the supervision of: Robert Hevert

NERI 2-10

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 21, Table 2. How did the Company select the years reflected in Table 2?

Response:

As noted in Mr. Hevert's Pre-Filed Direct Testimony at Bates Page 24, Lines 6-7 of Book 2, the Company selected the three most recently reported years for the summary financial and operating statistics provided in Table 2.

Prepared by or under the supervision of: Robert Hevert

NERI 2-11

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 22, ll. 13-15. Please describe and provide complete and detailed information as to:

a. Why did the Company exclude companies whose regulated income over the most 3 years represent less than 60% of combined total income?

b. Which companies did the Company exclude?

c. Why did the Company apply a 3-year time period?

Response:

a. As stated in Mr. Hevert's Pre-Filed Direct Testimony at Bates Page 25 of Book 2, Mr. Hevert's objective in selecting a proxy group is that the proxy group is highly representative of the risks and prospects faced by the Company. Therefore, Mr. Hevert selected companies with at least 60.00 percent of consolidated net operating income derived from regulated operations to ensure that the proxy companies had rate-regulated operations that reasonably reflected the subject company. The threshold to eliminate companies with significant unregulated operations must balance the need to develop a group of companies that is fundamentally comparable to the Company with the need to develop a proxy group of sufficient size. In Mr. Hevert's view, the 60.00 percent threshold reasonably balances those objectives.

b. Please see Attachment NERI-2-11.

c. Because one-time events may skew the analysis for a single year, it has been Mr. Hevert's consistent practice to screen his proxy group for the average regulated operating income over the three most recently reported fiscal years. For example, an acquisition or sale of a business unit may affect the calculation of regulated income for a single year.

Prepared by or under the supervision of: Robert Hevert

NERI 2-12

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 22. How many of the remaining companies are directly owned subsidiaries of a larger holding company that also owns other distribution utilities?

Response:

None of Mr. Hevert's proxy companies are directly owned subsidiaries of a larger holding company that also owns other distribution utilities. The models Mr. Hevert used to estimate the Cost of Equity require market data such as stock prices and Beta coefficients; therefore, proxy companies must be publicly traded. There are no companies that are publicly traded that are direct subsidiaries of a larger holding company that also own other distribution utilities. The publicly traded company is generally at the holding company level. El Paso Electric Company and Portland General Electric Company are publicly traded electric companies; however, neither company owns other distribution utilities.

Prepared by or under the supervision of: Robert Hevert

NERI 2-13

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 24, Table 3. Please describe:

a. Which companies were eliminated?

b. What ROE do the excluded companies currently enjoy?

Response:

a. Please see the Company's response to NERI 2-11.

b. Mr. Hevert has not performed the requested analysis for companies excluded from his proxy group. However, the rate case details for all electric and gas utilities covered by Regulatory Research Associates since 1980 (including the authorized return on equity) is provided in Attachment NERI 2-13.

Prepared by or under the supervision of: Robert Hevert

NERI 2-14

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 25.

a. How did the Company adjust for the fact that Narragansett Electric Co. ("Narragansett") does not own generation and that proxy group utilities do?

b. What is the power sector transformation status of the proxy utilities?

Response:

a. Please see the Company's response to the Rhode Island Public Utility Commission's (PUC) Third Set of Data Requests, PUC 3-6. As explained in Mr. Hevert's Pre-Filed Direct Testimony on Bates Page 28 of Book 2, there are no "pure play", state-jurisdictional electric transmission and distribution companies that may be used as a proxy for the Company's electric distribution operations. Therefore, including vertically integrated electric companies in the proxy group is reasonable and necessary. However, in recommending a return on common equity on the lower end of his recommended range, Mr. Hevert has considered the fact that the Company is a distribution-only utility.

b. Mr. Hevert's understanding is that the Power Sector Transformation (PST) initiative is specific to Rhode Island and that the Company's PST Plan is current pending before the PUC in Docket No. 4780. He is aware that several jurisdictions are in the process of investigating or implementing initiatives with a similar objective, although they may vary in scope. As noted in the Company's response to NERI 2-1, more than 30 states are considering far-reaching modernization and utility business model reforms (see Attachment NERI 2-1).

Prepared by or under the supervision of: Robert Hevert

NERI 2-15

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 36.

a. Please quantify the impacts of adjustments the Company made based on predictions relating to the unwinding of Quantitative Easing policies.

b. What time period did the Company evaluate?

c. What change in interest rates did the Company assume?

d. How does this translate to changing the weight of the Constant Growth DCF analysis results?

e. What would have been the result if this adjustment had not been made?

Response:

a. As noted in Mr. Hevert's Pre-Filed Direct Testimony on Bates Page 12 of Book 2, Mr. Hevert did not make explicit adjustments to the analytical return on equity estimates for company-specific and general capital market risks; however, Mr. Hevert considered these factors in assessing where the Cost of Equity should fall within the range of methodological results. In arriving at his recommended ROE range of 10.00 percent to 10.75 percent, Mr. Hevert did not place primary weight on the DCF-based results. Rather, because Risk Premium-based methods directly reflect measures of expected capital market conditions, these methods are more likely to provide reliable estimates of the Cost of Equity than other approaches during periods of market change, as is the current market environment.

b. As discussed in Appendix A of Mr. Hevert's Pre-Filed Direct Testimony (beginning on Bates Page 85 of Book 2), his analysis of the capital market conditions cover the time period between 2008 and 2017 to capture the Federal Reserve's market intervention policies in the wake of the Great Recession. Mr. Hevert's analysis also considers market-based data regarding investor expectations of future interest rates.

c. Since the Federal Reserve completed its Quantitative Easing program in 2014, it has raised the target Federal Funds rate from 0.00 percent to 0.25 percent, to 1.25 percent to 1.50 percent, an increase of 125 basis points. As discussed in Appendix A of Mr. Hevert's Pre-Filed Direct Testimony at Bates Pages 89-90 of Book 2, at the time Mr.

Hevert's direct testimony was prepared, the market was projecting a 77.10 percent probability of at least two more interest rate increases before September 2018.

d. Please see the response to part a. above.

e. Please see the response to part a. above.

Prepared by or under the supervision of: Robert Hevert

NERI 2-16

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 36, ll. 10-19. Please explain how ROEs awarded over the past nearly 40 years (since 1980) establish a basis for an appraisal of reasonableness. Please provide all research, reports, publications, and other supporting documentation the Company relied upon.

Response:

As discussed in of Mr. Hevert's Pre-Filed Direct Testimony on Bates Page 21 of Book 2, one of the guiding principles for establishing a fair return on capital established by the Supreme Court cases *Bluefield Water Works v. Public Service Comm'n*, 262 U.S. 679 (1923) and *FPC v. Hope Nat. Gas. Co*., 320 U.S. 591 (1944) was the recognition that the fair return on equity (ROE) should be comparable to returns investors expect to earn on other investments of similar risk. Therefore, an authorized ROE that is well below returns authorized for other utilities runs counter to the *Hope* and *Bluefield* "comparable risk" standard.

It is important to note that Mr. Hevert's Bond Yield Plus Risk Premium analysis does not make a direct comparison to returns authorized 40 years ago to determine a fair and reasonable return in today's market. Rather, Mr. Hevert performed a regression analysis on that historical data to estimate the relationship between authorized ROEs and the prevailing 30-year treasury yield during the pendency of the rate cases. Mr. Hevert then applied the current and projected 30-year Treasury yield to the regression coefficients to estimate the ROE in today's market.

Prepared by or under the supervision of: Robert Hevert

NERI 2-17

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 50. How does the Company's Market Risk Premium method account for the regulated nature of utilities, especially a distribution-only utility like Narragansett?

Response:

As explained in Mr. Hevert's Pre-Filed Direct Testimony on Bates Pages 48-49 of Book 2, the Beta coefficient applied in the CAPM measures the company-specific non-diversifiable risk and represents both relative volatility (*i.e.*, the standard deviation) of returns, and the correlation in returns between the subject company and the overall market. Therefore, the Beta coefficient that is applied to the Market Risk Premium accounts for the regulated nature of utilities.

Prepared by or under the supervision of: Robert Hevert

NERI 2-18

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 58, ll. 12-13. Please explain in detail and provide complete and detailed documentation as to why "the mean results do not necessarily provide an appropriate estimate of the Company's Cost of Equity."

Response:

Mr. Hevert's analyses are based on a proxy group of comparable, publicly traded utilities. In Mr. Hevert's view, however, the Company's small size and planned capital expenditures are additional factors specific to the Company that affect the Company's business risk and its Cost of Equity and therefore must be considered. These risks are not captured in the analytical results. Although Mr. Hevert has not made a specific adjustment on account of these risks, Mr. Hevert considered them in determining where, within a reasonable range of returns, the Company's return on equity appropriately falls. Please see Mr. Hevert's Pre-Filed Direct Testimony at Bates Pages 61-68 of Book 2 for a discussion of Mr. Hevert's assessment of these additional risk factors.

Prepared by or under the supervision of: Robert Hevert

NERI 2-19

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 60. How does the Company's size risk analysis account for the fact that Narragansett is one of 3 National Grid utilities operating in the northeast?

Response:

As described in response to NERI 2-3 (and the Company's response to Commission's Third Set of Data Requests, PUC 3-16), it is appropriate to evaluate the Company's relative risk on a stand-alone basis. Consistent with that approach, the focus of Mr. Hevert's analysis is to estimate the Cost of Equity for The Narragansett Electric Company, which is an indirect, wholly-owned subsidiary of National Grid. Mr. Hevert has conducted this analysis for the Company on a stand-alone basis, so that other operations of any other entities within the National Grid corporate organization are not considered in the small size analysis.

Prepared by or under the supervision of: Robert Hevert

NERI 2-20

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 60, ll. 13-20. Do the Company's citations on the "small size premium," or any of the studies the Company references, account for the small utility being a part of a larger regional and international holding company?

Response:

As described in the Company's response to NERI 2-3 (and the Company's response to Commission's Third Set of Data Requests, PUC 3-16), it is appropriate to evaluate the Company's relative risk on a stand-alone basis. Consistent with that approach, the focus of Mr. Hevert's analysis is to estimate the Cost of Equity for The Narragansett Electric Company, which is an indirect, wholly-owned subsidiary of National Grid. Mr. Hevert has conducted this analysis for the Company on a stand-alone basis, so that other operations of any other entities within the National Grid corporate organization are not considered in the small size analysis.

Prepared by or under the supervision of: Robert Hevert

NERI 2-21

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 60, l. 20 to p. 61, l. 3. Why is trading volume relevant to Narragansett?

Response:

Mr. Hevert has not asserted that trading volume is relevant to the Company. The reference in question is not a reference to the Company. Rather, it refers to empirical research regarding the size effect. The intent is to demonstrate that, although some research has focused on explaining the size effect as a function other factors (such as trading volume), the proposition that the Beta coefficient fails to reflect the risks of smaller firms persists.

Prepared by or under the supervision of: Robert Hevert

NERI 2-22

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference Section B - Capital Expenditures, beginning on p. 62. Is it the Company's position that the ROE should be directly correlated with level of capital expenditures?

Response:

No. As discussed in Mr. Hevert's Pre-Filed Direct Testimony on Bates Pages 65-68 of Book 2, the allowed return on equity should enable the subject utility to finance capital expenditures and working capital requirements at reasonable rates and to maintain its financial integrity even in strained capital market conditions. From a credit perspective, the additional pressure on cash flows resulting from high levels of capital expenditures puts pressure on credit metrics and, therefore, credit ratings. The Public Utilities Commission's decision in this proceeding, therefore, will have a direct bearing on the Company's ability to maintain its financial profile and its ability to access the capital market at reasonable cost rates.

Prepared by or under the supervision of: Robert Hevert

NERI 2-23

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 64.

a. Please explain the correlation, if any, between power sector transformation and capital spending.

b. Does the Rhode Island PST increase capital requirements?

c. Why or why not?

d. If yes, by how much does the Rhode Island PST increase capital requirements?

Response:

a. Mr. Hevert's understanding is that the Power Sector Transformation (PST) initiative is specific to Rhode Island, and that the Company's PST Plan is currently pending before the Public Utilities Commission in Docket No. 4780. Mr. Hevert is aware that several jurisdictions are in the process of investigating or implementing "transformational" initiatives with similar objectives, although they vary in scope. The correlation between "transformation" and capital spending, therefore, depends on the scope of the program. Mr. Hevert's general assumption is that there is a positive correlation, such that a large program that is broad in scope would likely require greater capital investment than a small program narrow in scope.

b. It is unclear what is meant by "capital requirements." Mr. Hevert understands that the Company's proposed PST Plan is pending before the Public Utilities Commission in Docket No. 4780. The Company's PST Plan proposes a broad suite of investments to respond to the impact of decentralization, decarbonization, and digitization. These investments include grid-side investments to enable distributed energy resources, deployment of advanced metering functionality, beneficial electrification programs in transportation and heating, and investments in energy storage and solar. As shown in Appendix 10.1 (beginning on Bates Page 130 of PST Book 2) of the Company's PST Plan, the estimated total incremental revenue requirement for the Company's PST Plan ranges from $80.00 million (shared AMI and Grid Modernization scenario) to $137.53 million (Rhode Island standalone AMI and Grid Modernization scenario).

c. Please see the response to part b. above.

d. Please see the response to part b. above.

Prepared by or under the supervision of: Robert Hevert

NERI 2-24

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 64. Does the Company's opinion about the relationship between PST and capital requirements account for performance-based earnings incentives? Does it matter if these incentives are asymmetrical or symmetrical?

Response:

It is unclear what is meant by "capital requirements." It is Mr. Hevert's understanding that the capital investment proposed in the Company's PST Plan in Docket No. 4780 does not depend on the proposed performance incentives. As stated in Schedule PST-1, Chapter 9 – Performance, Bates Pages 162-183 of PST Book 1, performance incentives provide a financial reward to a utility based on its performance in certain metrics, where the utility can earn higher returns if it meets or exceeds certain targets. The incentives proposed in the Company's PST Plan support the delivery of new benefits and savings to customers and in many cases reflect new areas of accountability for the Company that expand beyond its core obligations.

Prepared by or under the supervision of: Robert Hevert

NERI 2-25

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 64, l. 15.

a. Is it the Company's opinion that capital spending is a focus of Narragansett's management? Please explain.

b. Has the Company seen any evidence that this capital spending has strained credit metrics for Narragansett or for the parent company National Grid? Please explain.

Response:

a. Yes, as described in the Pre-Filed Direct Testimony of Company Witness Timothy F. Horan, each year, experts from the Company consult with experts from the Division of Public Utilities and Carriers to develop the annual Infrastructure, Safety, and Reliability Plans for both Narragansett Gas and Narragansett Electric that are the optimal balance for customers, subject to PUC review and approval. The Company's management is focused on maintaining a level of capital spending to enable safe, reliable, and cost-effective service to Rhode Island customers.

b. As described in the Pre-Filed Direct Testimony of Company Witness Robert B. Hevert, high levels of capital expenditures puts pressure on cash flows, which affects credit metrics. This effect was evident in Standard and Poor's most recent report on the Company. As shown in Attachment NERI 2-25, with respect to the Company and National Grid plc, Standard and Poor's has observed:

> Narragansett Electric's significant financial risk profile mirrors that of [National Grid plc] and reflects constraints posed by the group's relatively high financial leverage and recurrent negative discretionary cash flows on the back of substantial capital expenditure (capex) program and past acquisitions.
>
> …
>
> We believe that National Grid USA's financial measures and earned RoEs will modestly improve due to continued cost control, operating efficiencies, and prospects for additional rate relief. Yet, given a heavy capital expenditure program that is likely to require some debt financing, timely and sufficient rate relief and alternative-cost-recovery mechanisms, as well

Prepared by or under the supervision of: Robert B. Hevert

> as credit-supportive actions by management, will be important to enhance cash flow and earnings protection. Therefore, the subsidiaries' ability to manage regulatory risk will be a key credit determinant.

This is consistent with Mr. Hevert's observation that the regulatory environment is one of the most significant factors in investors' assessment of risk and especially important when significant capital investments may require efficient access to capital markets.

Prepared by or under the supervision of: Robert B. Hevert

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Summary:

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Summary:

Narragansett Electric Co.

Corporate Credit Rating	A-/Stable/NR

Profile Assessments		
BUSINESS RISK	EXCELLENT	Vulnerable — Excellent
FINANCIAL RISK	SIGNIFICANT	Highly leveraged — Minimal

Rationale

Business Risk: Excellent

- Historically challenging regulation in Rhode Island, but becoming more responsive
- Focus on low-risk electric and gas distribution operations
- Limited industrial load; provides some insulation from cyclical volatility
- Large and diversified parent company that is focused on low-risk electricity and natural gas transmission and distribution operations
- Eight-year visibility of earnings under the new RIIO regulatory regime in ultimate parent National Grid Plc's U.K. regulated businesses

Financial Risk: Significant

- Low regulatory reset risk in the U.K. and moderate regulatory reset risk in the U.S. Relatively high consolidated financial leverage at National Grid Plc as a result of past acquisitions
- Persistent negative discretionary cash flow generation on the back of large investments in the U.K. and high dividend payout
- Some volatility of measures, due to foreign exchange exposure

Outlook: Stable

The stable outlook on Narragansett Electric Co. mirrors our outlook on ultimate parent National Grid Plc (NG) and reflects our view that the group will maintain its satisfactory operational and financial performance. It also reflects our expectations of low regulatory risk and belief that National Grid will continue to focus on its regulated gas and electricity network businesses in the U.K. and the U.S. We see consolidated adjusted FFO to adjusted debt of more than 12% as being commensurate with the current rating.

Downside scenario

We could lower the ratings if we forecast a decrease in consolidated FFO to adjusted debt to less than 12% on a sustainable basis. This could result from inability to control costs, poor operating performance, acquisitions, high investment levels, or aggressive dividend levels--absent any offsetting measures that would lead to a swift recovery in credit measures.

Upside scenario

Based on the group's heavy investments and our forecasted base-case credit measures, we see limited ratings upside. However, a sustained improvement in credit measures, such that our forecast of FFO to adjusted debt improves to sustainably above 15% over the ratings period, could trigger an upgrade.

Standard & Poor's Base-Case Scenario

Assumptions

- U.K.: Revenue and cost allowances as per final RIIO determinations and slower uptake in capital and replacement expenditure than granted
- U.S.: Positive discretionary cash flows, slightly improving return on equity (RoE)
- A dividend increase in line with inflation (until board announcement in early 2013) and 20% scrip uptake.
- Issuance of £2.1 billion in "intermediate" hybrid securities in 2013

Key Metrics

	2012A	2013E	2014E
FFO to adjusted debt	14.3%	13.5%-14.5%	13%-14%
FFO interest coverage	3.3x	3.5x-4x	3.5x-4x

All figures fully adjusted by Standard & Poor's. Debt adjusted for operating leases, pension deficit, surplus cash, currency swaps and hybrid securities. FFO adjusted for index-linked debt charge, capitalized interest, replacement expenditure and operating leases. A--Actual. E—Estimate.

Business Risk: Excellent

We base our ratings on Narragansett Electric on the consolidated credit profile of ultimate parent, U.K.-based NG. The parent is a U.K.-based, investor-owned utility which operates the monopoly gas and electricity transmission systems (TSOs) in England and Wales, and four U.K. local monopoly gas distribution networks (GDNs). Narragansett Electric is

also a subsidiary of National Grid USA (NGUSA). NG is also, through NGUSA, one of the largest utilities in the U.S. by number of customers.

We believe that the group will continue to benefit from predictable cash flows from its low-risk, in our view, regulated activities under broadly credit-supportive regulatory regimes in the U.K. and U.S. That said, the key risk remains regulatory reset, although the group benefits from cross-border and, in the U.S., cross-state regulatory diversity. We have good earnings visibility now that the U.K. grids (contributing about 60% of operating profile in the year ended March 31, 2012) have accepted their regulatory determinations for the first RIIO revenue equals incentives plus innovation plus outputs) regulatory period, which ends on March 31, 2021. (For more information, refer to: "How The Proposed RIIO Regulatory Framework Could Affect Ratings On U.K. Energy Utilities," Sept. 13, 2011 and "How Ofgem's Latest RIIO Proposals Could Increase Credit Risk For National Grid And Gas Networks In England And Wales," July 25, 2012)

We view the group as having better-than-peers market and operational diversity and as benefiting from relative resilience to economic conditions. This is because earnings under the U.K. regulatory framework are insulated from electricity or gas demand while in the U.S. decoupling mechanisms sever the relationship between sales and revenue. Furthermore, there are other mechanisms in the U.S. such fuel and purchased gas adjustment clauses, pension and environmental true-up mechanisms, bad debt, capital expenditure and other trackers, and property tax riders, that can enhance or smooth cash flow, eliminate or reduce rate-case lag, minimize rate volatility, and avoid rate shock to consumers, while preserving creditworthiness. Nevertheless, future operating margins in both jurisdictions are mostly dependent on the group's ability to control operational and capital delivery costs, while meeting its operational targets. We see the track record of regulation in National Grid's U.S. service territories as reasonably supportive of creditworthiness, but long-term rate plans, rate moratoriums, and regulatory lag have resulted in RoE somewhat below the national average in some jurisdictions. However, with a $200 million reduction in operating costs (achieved in 2011/2012) and realization of rate relief and various rate trackers, returns have improved. In that regard, National Grid USA earned 8.8% in 2011/2012 compared to less than 7% a few years ago. Nevertheless, the subsidiaries' ability to continue manage regulatory risk will be critical to credit quality.

Narragansett Electric also has an "excellent" business risk profile, reflecting low risk electric and gas distribution operations, a largely residential and commercial customer base, efficient operations, offset somewhat by regulation in Rhode Island, which we view as less credit supportive. However, the Rhode Island Public Utilities Commission (RIPUC) appears to be becoming more responsive to the company's rate needs, as demonstrated by approval of a recent rate settlement agreement and implementation of various alternative ratemaking mechanisms.

In January 2013, the RIPUC adopted a comprehensive rate settlement providing for a $21.5 million electric and an $11.3 million gas rate increase, predicated on a 9.5% return on equity, effective Feb. 1, 2013. The order includes revenue decoupling and a variety of true-up and rate tracking mechanisms that allow for timely cost recovery. Currently, the company's earned returns are well below the allowed level. Full realization of this rate relief should enable the company to earn closer to its allowed RoE.

Financial Risk: Significant

Narragansett Electric's significant financial risk profile mirrors that of NG and reflects constraints posed by the group's relatively high financial leverage and recurrent negative discretionary cash flows on the back of substantial capital expenditure (capex) program and past acquisitions. We are uncertain as to the group's medium-term dividend policy, which is due to be announced by the board in early 2013. Until the announcement, we assume dividend increase in line with inflation, which is less aggressive than the dividend policy in the past.

We expect that NG's cash flow and debt coverage measures will weaken over the eight-year RIIO period compared with its adjusted funds from operations (FFO)-to-debt ratio of about 14.7% in the 12 months to March 31, 2012. In any case, we forecast that adjusted FFO-to-debt will stay at or above 12% in each year of the forecast period. We see the recent £2 billion hybrid issues (in different currencies) as providing some headroom to our rating guideline. This headroom could be needed, given the group's exposure to foreign exchange translation risk. We expect good internal funding of capex as the heavy capital requirements of the U.K. transmission grids is offset by mostly positive free operating cash flows from the U.K. GDNs and the U.S. activities. The extent of negative discretionary cash flows will in our view be determined by the new dividend policy.

We believe that National Grid USA's financial measures and earned RoEs will modestly improve due to continued cost control, operating efficiencies, and prospects for additional rate relief. Yet, given a heavy capital expenditure program that is likely to require some debt financing, timely and sufficient rate relief and alternative-cost-recovery mechanisms, as well as credit-supportive actions by management, will be important to enhance cash flow and earnings protection. Therefore, the subsidiaries' ability to manage regulatory risk will be a key credit determinant.

Liquidity: Adequate

The 'A-2' short-term rating on NG, NGUSA, and subsidiaries largely reflects the companies' long-term corporate credit ratings and our view of the group's "adequate" liquidity, under our criteria. We expect the group's liquidity sources--including cash, operating cash flow and available bank lines--to exceed projected uses (mainly necessary capex, debt maturities, and dividends) by more than 1.2x. We understand that there are no restrictive covenants in the documentation attached to the group's debt.

Principal Liquidity Sources	Principal Liquidity Uses
• Access to unrestricted short-term cash and short-term marketable securities of about £2 billion as of Dec. 31, 2012; • Undrawn £2.6 billion committed credit facilities with a maturity longer than 12 months, which are available for general corporate liquidity purposes;; and • Our expectation that National Grid will generate higher adjusted funds from operations (FFO) in the fiscal year end March 31, 2013, than in the previous fiscal year, when it was about £3.3 billion.	• About £3.6 billion in capex; • Dividend payments of about £1 billion (based on 48% scrip uptake of the final 2011/12 dividend and 20% scrip dividend going forward); and • £2.4 billion in short-term debt maturing over the next 12 months as of Dec. 31, 2012. Apart from frequent senior debt issues in the first quarter of 2013, National Grid has also placed about £2.1 billion of hybrid securities in March 2013.

Recovery Analysis

Key analytical factors

- We assign recovery ratings to first mortgage bonds (FMBs) issued by U.S. utilities, which can result in issue ratings being notched above a utility's corporate credit rating (CCR) depending on the rating category and the extent of the collateral coverage.
- The FMBs issued by U.S. utilities are a form of "secured utility bond" (SUB) that qualify for a recovery rating as defined in our criteria.
- The recovery methodology is supported by the ample historical record of 100% recovery for secured bondholders in utility bankruptcies in the U.S. and our view that the factors that enhanced those recoveries (limited size of the creditor class and the durable value of utility rate-based assets during and after a reorganization given the essential service provided and the high replacement cost) will persist in the future.
- Under our SUB criteria, we calculate a ratio of our estimate of the value of the collateral pledged to bondholders relative to the amount of FMBs outstanding. FMB ratings can exceed a utility's CCR by up to one notch in the 'A' category, two notches in the 'BBB' category, and three notches in speculative-grade categories depending on the calculated ratio.
- Narragansett Electric's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating one notch above the CCR.

Related Criteria And Research

- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008
- Use Of CreditWatch And Outlooks, Sept. 14, 2009
- Business Risk/Financial Risk Matrix Expanded, Sept. 18, 2012
- Standard & Poor's Revises Its U.S. Utility Regulatory Assessments, Dec. 28, 2012
- Collateral Coverage and Issue Notching Rules for '1+' and '1' Recovery Ratings on Senior Bonds Secured by Utility Real Property, Feb. 14, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012

- Methodology: Short-Term/Long-Term Ratings Linkage Criteria For Corporate And Sovereign Issuers, May 15, 2012
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- 2008 Corporate Ratings Criteria: Ratios And Adjustments, April 15, 2008
- Methodology And Assumptions: Recognizing The Sustainable Cash Cost Of Inflation-Linked Debt For Corporates, Feb. 10, 2009
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008
- Methodology: Differentiating The Issuer Credit Ratings Of A Regulated Utility Subsidiary And Its Parent, March 11, 2010
- Parent/Subsidiary Links; General Principles; Subsidiaries/Joint Ventures/Nonrecourse Projects; Finance Subsidiaries; Rating Link to Parent, Oct. 28, 2004
- How Ofgem's Latest RIIO Proposals Could Increase Credit Risk For National Grid And Gas Networks In England And Wales, July 25, 2012
- How The Proposed RIIO Regulatory Framework Could Affect Ratings On U.K. Energy Utilities, Sept. 13, 2011

Business And Financial Risk Matrix

	Financial Risk					
Business Risk	Minimal	Modest	Intermediate	Significant	Aggressive	Highly Leveraged
Excellent	AAA/AA+	AA	A	A-	BBB	--
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	--	BBB-	BB+	BB	BB-	B
Weak	--	--	BB	BB-	B+	B-
Vulnerable	--	--	--	B+	B	B- or below

Note: These rating outcomes are shown for guidance purposes only. The ratings indicated in each cell of the matrix are the midpoints of the likely rating possibilities. There can be small positives and negatives that would lead to an outcome of one notch higher or lower than the typical matrix outcome. Moreover, there will be exceptions that go beyond a one-notch divergence. For example, the matrix does not address the lowest rungs of the credit spectrum (i.e., the 'CCC' category and lower). Other rating outcomes that are more than one notch off the matrix may occur for companies that have liquidity that we judge as "less than adequate" or "weak" under our criteria, or companies with "satisfactory" or better business risk profiles that have extreme debt burdens due to leveraged buyouts or other reasons. For government-related entities (GREs), the indicated rating would apply to the standalone credit profile, before giving any credit for potential government support.

NERI 2-26

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 65, ll. 5-7.

a. Please explain what the Company means by the statement that "the Company's need to access the capital markets will continue, and there is considerable uncertainty regarding how the transformation will affect utility companies."

b. Please explain how this uncertainty impacts the Company's ROE recommendations.

Response:

a. As stated in Mr. Hevert's Pre-Filed Direct Testimony on Bates Page 67 of Book 2, the industry is undergoing a substantial transformation, which will require significant capital investment that may not be revenue producing. As the industry transforms, the Company will need to maintain its financial integrity to ensure access to the capital markets to finance those investments at reasonable rates.

b. Uncertainty implies risk, and greater uncertainty, or risk, increases the Cost of Equity. Mr. Hevert has considered the effect of this uncertainty in determining where, within a reasonable range, the Company's return on equity appropriately falls.

Prepared by or under the supervision of: Robert Hevert

NERI 2-27

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 66-68.

a. Please explain whether revenue stabilization and cost recovery methods provide any ROE benefits to ratepayers, either for the Company or for its peer group of utility companies.

b. Does the Company have evidence that revenue stabilization and cost recovery methods have reduced the cost of capital for the utility sector in general?

c. Please provide copies or citations to publicly available sources to support your response..

Response:

a. As noted in Mr. Hevert's Pre-Filed Direct Testimony on Bates Page 71 of Book 2, revenue stabilization and cost recovery methods reduce regulatory lag and help utilities sustain cash flow measures, earning power, and, ultimately, credit quality to the benefit of customers. A company with higher credit quality can access the capital market at lower cost, which is then passed along to customers. Any return on equity benefits as a result of revenue stabilization or cost recovery mechanisms in place at the proxy group companies would be captured in Mr. Hevert's analysis.

b. Because the cost of capital is dependent upon a number of factors (both company specific and market specific), it is not possible to determine the specific effect of revenue stabilization and cost recovery methods on the cost of capital for the utility sector. As stated in response to part a., however, to the extent revenue stabilization and cost recovery methods sustain or improve a company's credit quality, the cost of debt could be reduced, thus reducing the cost of capital, all else equal.

c. Not applicable.

Prepared by or under the supervision of: Robert Hevert

NERI 2-28

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 71. If the Company's view is that the Decoupling Act should not now be used to make an adjustment to the Company's ROE, what is the Company's view of the purpose of the repeal of the prohibition on consideration of decoupling and its effect on ROE?

Response:

The question mischaracterizes Mr. Hevert's Pre-Filed Direct Testimony. As noted in Mr. Hevert's Pre-Filed Direct Testimony on Bates Pages 70-71 of Book 2, the principal analytical issue is whether the Company is less risky than its peers because of its recovery mechanisms to such a degree that investors would specifically and measurably reduce their return requirements. That the Company's existing recovery mechanisms may, to a degree, stabilize the Company's revenues does not affect its Cost of Equity because it cannot be demonstrated that (1) the Company is materially less risky than the proxy group by virtue of those mechanisms; and (2) investors are likely to react to the incremental effect of those mechanisms. Revenue stabilization and cost recovery mechanisms are common among the proxy companies; there is no reason to assume that the Company would be materially less risky and that its Cost of Equity would be lower than the Company's peers as a result of the Company's recovery mechanisms.

Prepared by or under the supervision of: Robert Hevert

NERI 2-29

Request:

Subject: Book 2—Hevert (Return on Equity)

Reference p. 71, ll. 9-18.

a. Has the Company evaluated the extent to which revenue stabilization mechanisms impact the Company's revenues as compared to its peers? Please explain.

b. What are the key metrics of the stabilization mechanisms' impacts on revenues?

Response:

a. Mr. Hevert has not evaluated the extent to which revenue stabilization mechanisms impact the Company's revenues as compared to its peers. As stated in the Company's response to PUC 3-7, because no two companies are identical, the regulatory mechanisms adopted to address company-specific issues also are not likely to be identical. As a result, evaluating in the revenue impact of each proxy company's revenue stabilization mechanisms would be a complex and significant undertaking.

b. Please see the response to part a. above.

Prepared by or under the supervision of: Robert Hevert

NERI 2-30

Unless otherwise specified below, "the Company" and "Narragansett" refers to the Narragansett Electric Co. d/b/a/ National Grid. Where work papers are requested, please provide work papers in Excel format.

Subject: Book 2—Hevert (Return on Equity)

Request:

Reference p. 71, ll. 14-15.

a. Please explain how the impact of the forms of revenue stabilization mechanisms should be compared given the wide variety in such mechanisms.

b. Please provide analysis conducted to support the conclusion that because "all proxy companies have such mechanisms in place in at least one jurisdiction," it is therefore not appropriate to reduce the Company's ROE in connection with its rate mechanisms.

Response:

a. Given the wide variety in the forms of revenue stabilization mechanisms, in Mr. Hevert's view, the important comparison is whether a utility has such mechanisms or not. As explained in the Company's response to NERI 2-28, revenue stabilization and cost recovery mechanisms are common among the proxy companies. Therefore, there is no reason to assume that the Company would be materially less risky and that its Cost of Equity would be lower than its peers' cost of equity as a result of its revenue stabilization mechanisms.

b. Please see Schedule RBH-10 and Bates Pages 68-74 of Mr. Hevert's Pre-Filed Direct Testimony (Book 2).

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