Regulatory and Legislative Changes Affecting Rate-Case Strategies

Rick Starkweather

Renewables costs continue to decline, and market penetration rates of distributed resources, like rooftop solar photovoltaics, continue to climb.

Along with the ongoing transformation of the electric grid, this trend is breaking down boundaries between customers and energy providers. Nontraditional players are also becoming increasingly involved in the energy mix. Natural gas remains cheap, which, along with proposed environmental regulations and other mandates, is prompting shifts in power generation sources. Business models are evolving, too, as traditional utility roles and functions are being reconsidered.

As a result, many utilities are rethinking how they interact with customers, regulators, and other key stakeholders.

KEY INDUSTRY DRIVERS ARE CHANGING

For years, electric utilities have had a singular role in providing electricity to consumers, with not only an exclusive franchise territory but also an obligation to serve all customers at reasonable rates. However, with the advent of more distributed approaches to energy production and delivery, some of the traditional utility functions are being assumed by customers and nonutility suppliers. The relationships between electric providers and customers continue to change, and customers' expectations continue to grow as they look for new and perhaps more-tailored options to help reduce electricity and natural gas consumption and out-of-pocket costs.

The lines between supply resources and demand resources are also becoming blurred. The expanding natural gas supply is forcing coal plant retirements. In some regions, market economics are also forcing nuclear plant retirements.

We are experiencing a once-in-a-generation transformation of the nation's power-generation fuel mix. New natural gas-, wind-, and solar-powered generation represent the majority of generating capacity added since 2010 and projected through 2020. During the same time frame, coal and oil generation will have declined and will continue to decline at a historic pace.

Even as utilities seek to enhance their services and the "customer experience," total electricity and natural gas demand remains essentially flat. Retail sales of electricity have declined in five of the past eight years, with overall sales increasing only 1.7 percent on a cumulative basis since 2005. The situation on the natural gas side is similar, with total gas deliveries to consumers in 2010 more or less at the same levels as 2005. The growth in total gas deliveries over the last five years has largely been fueled by new natural gas generation.

This repowering of the generation fleet is having a significant impact on utility investment levels, which are also growing due to aging infrastructure replacement and demands for improved system resiliency and pipeline safety. As a result, electric and gas utilities, and their investors, are increasingly concerned about cost recovery for these investments. Many believe that traditional utility revenue recovery approaches are becoming inadequate.

In some states, regulators are rethinking the hundred-year-old rate-of-return paradigm, and

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fundamental aspects of the vertically integrated utility model are being questioned.

UTILITY BUSINESS MODEL IS ALSO EVOLVING

A business model describes how the pieces of the business fit together to create value. One definition includes three elements—the basic activities that define the scope of the business, the overall market and customer base being targeted, and the key competencies that set the company apart from its competition. For most companies, these pieces include the following:

- The geographies, market segments, customers, and product areas in which the company operates and competes
- The key activities that determine how the company creates value and sustains a business advantage in the market
- The critical skills, business processes, and innovations that are essential to serve customers, exceed expectations, and (it is hoped) grow the business

Given the natural monopoly and exclusive franchise territory within which most natural gas and electricity providers operate, this model also includes an obligation to serve all customers and the provision of universal service at least cost. In return, regulators allow the utility to earn a "return" on the invested assets in the business (i.e., the cost of debt, plus a reasonable return on equity commensurate with risk), the recovery of prudently incurred operating costs, depreciation, taxes, and the pass-through of fuel costs to customers.

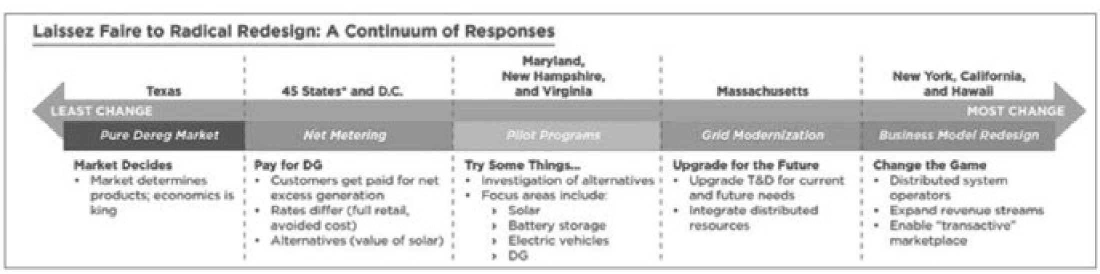
However, to allow utilities to effectively address the current technological, market, and commercial changes driving the industry will also require changes in the underlying regulatory construct. Electric utility industry observers agree that current and future utility business models will be directly impacted by the evolving attributes of the regulatory and legislative environment in which they operate. These attributes include the following:

- The defined roles and responsibilities of the utility
- Allowable infrastructure investments and the level of stakeholder support for new technologies
- The nature of interactions and transactions with customers
- Products and services that utilities and other third parties can offer to customers
- Pricing of existing and new services
- Establishment of financial expectations (revenues, net income, and return on equity) and the ability to achieve them
- Accommodation of societal objectives and, more specifically, state energy policies

HOW SOME STATES ARE CHALLENGING THE STATUS QUO

To support state-level policy goals and objectives, different jurisdictions are taking different approaches to adapting the traditional regulatory construct. These vary from a "hands-off" pure market-based approach to more radical "hands on the tiller" redesign (see **Exhibit 1**).

Exhibit 1. A Continuum of Responses



Note: Includes four states with state-wide distributed generation (DG) compensation rules other than net metering.
Source ScottMadden. (2016, April). Neither fish nor fowl. *ScottMadden Energy Industry Update 16*/1.

In Illinois and Maryland, as well as other states, there are programs and incentive mechanisms to promote the development of certain kinds of energy infrastructure. These include special or accelerated infrastructure cost-recovery programs, grants for projects to increase resiliency, performance-based formula rates, and time-varying rates. Special tariffs or other subsidies (including tax credits) have also been established in some states to encourage certain types of resources or utility behaviors. Another approach taken is to establish legal or regulatory requirements that put a "finger on the scale" for certain technologies, such as solar carve-outs in renewable portfolio standards. In California, this also includes Smart Grid and storage requirements and a tariff for customer-sited generation.

Lastly, a few states have taken more of a "central planning" approach, establishing comprehensive regulatory frameworks and compacts that redefine utility roles, responsibilities, and financial incentives. The best example of this is the Reforming the Energy Vision (REV) initiative in New York, where the regulators are considering the following:

- Utilities as platforms for new and more distributed technologies
- Distribution-level demand response programs
- Community choice aggregation
- A fundamental redesign of the ratemaking process

WHAT IS NEEDED AS BUSINESS MODELS CHANGE?

As traditional cost-based regulation is potentially adjusted to other models, some key issues must be addressed by utilities and their stakeholders. These include the following:

- *Behavioral shifts and customer acceptance*—While regulatory and financial incentives can play a significant role in behavioral change, sustainable conservation and efficiency gains will likely require a longer-term commitment. The incentives must be transparent and linked directly to desired actions. Even with incentives in place, customers' stated preferences (e.g., to reduce energy consumption and out-of-pocket costs) may be belied by their actual responses and reluctance to change their habits. More importantly, implementation of new enabling policies and technologies will likely increase costs, and customers may have difficulty paying as much or more on their utility bill while consuming less.
- *Stranded investment*—Switching regulatory models will undoubtedly lead to some stranded investment, which will require debate over what losses should be compensable, how much should be awarded to the incumbent utilities, and how to recover those costs.
- *Time horizon*—The current system and regulatory framework were developed over decades; unwinding or transitioning them will likewise take time.
- *Proving the counterfactual*—Performance-based regulation (PBR) frequently involves judging utility performance versus what it would have been without PBR, which invites potentially contentious interpretations if resulting costs are not what advocates believe they "should" be.
- *Free riders*—In isolation, a utility could have certain performance incentives under a new regulatory model, while possibly leaning on adjacent systems still under the traditional model for reliability, supply adequacy, and cost containment—this will be more difficult if widespread regulatory changes occur.
- *Level playing field*—Depending upon the regulatory model (i.e., the degree of third-party versus utility provision of services), the utility may have incumbency, affiliate, and brand advantages that need to be accounted for.
- *Accountabilities*—It is unclear whether and how common concepts applicable to regulated utilities—the obligation to serve, used and useful, just and reasonable rates, prudence, and similar considerations—translate equitably to all players in these new regulatory models.

In summary, new and different regulatory strategies and ratemaking solutions will be required to support this industry evolution.

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A TALE OF TWO CITIES (SACRAMENTO AND ALBANY)

To illustrate the dramatic changes in regulatory constructs being explored across the coun-

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try, more details on the changes in California (Public Utilities Code Section 769) and New York (the REV initiative) are provided in the sections that follow. On the surface, the goals of both proceedings are similar—both seek to promote customer choice, achieve environmental objectives, and enhance or modernize the grid.

California

In California, legislation was passed in 2013[1] to promote the increased deployment of distributed energy resources (DERs) to support the achievement of California's 2020 and 2050 greenhouse gas reduction targets, modernize the electric distribution system to accommodate two-way flows of energy and new energy services, enable customer choice of new technologies, and animate opportunities for DERs to realize additional benefits through the provision of grid services. Section 769 of the Public Utilities Code requires that utilities submit to the California Public Utilities Commission (CPUC) a distribution resources plan (DRP) to identify optimal locations for the deployment of distributed resources. Each plan should do the following:[2]

1. The DRP should evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provide to the electrical grid or costs to ratepayers of the electrical corporation.
2. The DRP should propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.
3. Cost-effective methods should be proposed to effectively coordinate existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.
4. Additional utility spending necessary should be identified to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.
5. Barriers to the deployment of distributed resources should be identified, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.

The new regulations allow the CPUC to "modify any (distribution resources) plan as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources." To fund the proposed additional investments to implement the distribution resources plan, utilities are required to submit such investments as part of their next general rate case. In turn, the CPUC may approve the proposed spending if it concludes that "ratepayers would realize net benefits and the associated costs are just and reasonable." Additional benchmarks, accountability mechanisms, and other criteria may also be implemented by the CPUC to evaluate the success of the authorized investments.

This explicit linkage between desired benefits, changes to the grid, and expected costs is important, as the utilities have begun to quantify what the projected investments in the grid will be to facilitate DERs on a large scale. Also of significance is what the CPUC is not asking for: "Some Parties would like this proceeding, and the DRPs, to serve as platforms for reinventing the existing utility distribution services model—perhaps along the lines being investigated in New York State's 'Reforming the Energy Vision' process. That is not the focus of this proceeding."[3]

New York

In New York, in April 2014, Gov. Andrew Cuomo and the State of New York Public Service Commission initiated the REV proceeding with the following stated goals:

- Reforming the electric distribution system to increase the utilization of DERs
- Increasing the efficiency of energy conservation and renewable energy programs
- Integrating innovative technologies into the distribution system
- Creating a competitive market for DERs
- Enhancing customer knowledge and tools and supporting effective management of their total energy bill

The REV initiative is focused on fundamentally changing the utility business model and introducing new markets for distribution resources. These changes will also impact distribution system planning, load forecasting, utility operations, generation interconnection processes, and ratemaking.

The Track 1 Order[4] established utilities as Distribution System Platform (DSP) providers—this is important because it is the first step to creating market functions:

- Through an open planning process, the utility is to identify infrastructure needs and then solicit alternative resources from third-party providers that could defer or alleviate the need for traditional infrastructure investments.
- Ultimately, the DSP is meant to serve as the platform through which market transactions across different resources take place (in effect a wholesale market at the distribution level).

To date, the New York utilities have filed initial and supplemental Distributed System Implementation Plans (DSIPs), which describe how the utility will address the necessary changes to adapt to an environment of increasing DER penetration. This work includes but is not limited to forecasting, integrated planning, technology platforms, operating standards, and the sharing of system and customer data. The DSIPs also provide for enhancement of interconnection processes and establish a benefit-cost analysis framework to provide a common and transparent methodology for evaluating the locational value of DERs. The Track 1 Order also requires utilities to file demonstration projects to test hypotheses regarding the changing utility business model or distribution system platform functionality with formalized pilot projects around potential market-based earnings opportunities, rate-design alternatives, and the value of DERs.

The Track 2 Order was issued on May 19, 2016, and the focus of this decision is to create a modern regulatory model that challenges utilities to take actions to better align shareholder financial interests with consumer interests. The order focuses on four areas:

- *Platform service revenues*—New forms of utility revenues associated with the operation and facilitation of distribution-level markets
- *Earnings adjustment mechanisms (EAMs)*—New performance incentives that are oriented toward near-term measures to create customer savings and develop market-enabling tools
- *Rate design*—Adopted principles for rate design (such as cost causation, policy transparency, fair value, customer orientation, stability, access, and gradualism) and directed further study and demonstrations
- *Scorecard mechanisms*—Metrics that are to be tracked but not monetized now, to be considered as future EAMs.

Track 3 is focused on the Clean Energy Standard and achieving state energy goals, specifically achieving 50 percent renewable sources of generation by 2030. The Track 3 Order[5] has two distinct elements, the Renewable Energy Standard and the Zero Emission Credit Requirement. The Renewable Energy Standard consists of a renewable resource procurement obligation imposed upon every load-serving entity in the state. The Zero Emission Credit Requirement is a phased subsidy to maintain the carbon-free attributes of economically challenged nuclear generators.

Contrasting the Plans

The proceedings in the two states can be contrasted along several dimensions. Market development and design is fundamental to REV, but California has not made this a goal of its proceedings to date. Rate reform is a primary aim of REV, while California is taking a more incremental approach. Regarding data sharing, the DRPs focus on bidirectional data sharing; the focus in New York has been more related to providing access to information about the grid to external parties.

In their DRPs, the California utilities were asked to identify barriers to interconnection; there is an entire initiative under REV related to enhancing the DER interconnection process. In California, advanced metering infrastructure (AMI) is widely deployed and is considered foundational for the integration of DERs. In New York, the utilities are on the front end of their AMI deployments. Lastly, the CPUC defined what they wanted to test related to integration of renewables and associated analyses; in New York, the utilities developed their own proposals to test the different aspects of REV.

Exhibit 2 shows the many interlocking pieces of the REV proceeding, all of which are being carefully considered by each impacted utility. Underpinning the three tracks and other related initiatives (e.g., value of DERs and AMI) are the incumbent utilities' rate cases.

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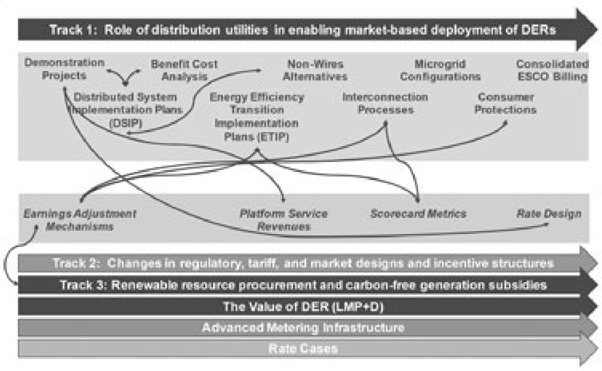
Exhibit 2. New York's REV Proceedings



HOW IS THIS NEW WORLD AFFECTING RATE-CASE STRATEGIES?

In addition to responding to the continuum of redesign initiatives being pursued across the country, key drivers of recent or planned regulatory filings (including rate cases) for electric and gas utilities include increasing capital investment levels and rising employee costs, especially for health care and postemployment benefits. The weakness in (or lack of) sales growth described earlier has also constrained utility earnings, triggering filings for additional rate relief.

Current capital investments include expenditures for the following:

- *Remediating aging infrastructure*—to renew or expand the transmission system to alleviate congestion and improve reliability
- *Environmental compliance*—to meet new regulations
- *New generation needs*—to address load growth or replace retiring facilities
- *Renewable resource requirements*—to connect renewable resources with load centers and deploy advanced technologies to facilitate DERs

Total capital investments for US-investor-owned electric utilities are expected to exceed $100 billion in 2017.[6] On the natural gas side, companies are modernizing, upgrading, and expanding distribution infrastructure to serve new demand, address safety considerations, and comply with state and federal regulations. As one might expect, utilities are increasingly concerned about the potential regulatory treatment of these new investments. As described earlier, some states have instituted various incentives and infrastructure-related investment trackers and riders that certainly aid cost recovery. However, these approaches also draw criticism—that risks are being shifted from utilities to customers and ratemaking outside traditional rate reviews creates a "piecemeal" approach to regulation.

Industry stake-holders have begun to reexamine traditional rate-design practices to address inter- and intraclass subsidization, declining sales, and the issues raised by distributed resources. Proposed rate reform options to address DERs include residential demand charges, increasing customer charges, interconnection fees, buy all/sell all and "value of solar" fee structures, and time-varying rates. For natural gas, zonal rates, surcharges, and waivers of contributions in aid of construction for strategic growth corridors and extension service areas are now being actively discussed. Other revenue and rate-stability mechanisms are also being considered in certain jurisdictions.

It remains to be seen how these innovative ratemaking mechanisms will ultimately play out. It also remains to be seen whether, to what extent, and how long it takes for single-issue-driven modifications to rate mechanisms (such as for DERs) to be integrated into a cohesive approach to the regulatory model. However, based on recent experience, one constant seems to be that for any utility regulatory filing or rate case, heightened scrutiny from all stake holders will continue.

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NOTES

1. Public Utilities Code Section 769 was instituted by AB 327, Sec. 8 (Perea, 2013).
2. Public Utilities Code, Division 1, Part 1, Chapter 4, Article 3, Section 769.
3. *Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769—Distribution Resource Planning* (2015, February 6), p. 5.
4. Case 14-M-0101, *Order Adopting Regulatory Policy Framework and Implementation Plan*, State of New York Public Service Commission (2015, February 26).
5. Case 15-E-0302 and Case 16-E-0270, *Order Adopting a Clean Energy Standard*, State of New York Public Service Commission (2016, August 1).
6. Industry Capital Expenditures, EEI Finance Department, May 2016.

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