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REGULATORY INCENTIVES AND DISINCENTIVES FOR UTILITY INVESTMENTS IN GRID MODERNIZATION

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Reports and webinar materials are available at feur.lbl.gov. Additional reports are underway.



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Foreword by U.S. Department of Energy

The provision of electricity in the United States is undergoing significant changes for a number of reasons. The implications are unclear.

The current level of discussion and debate surrounding these changes is similar in magnitude to the discussion and debate in the 1990s on the then-major issue of electric industry restructuring, both at the wholesale and retail level. While today's issues are different, the scale of the discussion, the potential for major changes, and the lack of clarity related to implications are similar. The U.S. Department of Energy (DOE) played a useful role by sponsoring a series of in-depth papers on a variety of issues being discussed at that time. Topics and authors were selected to showcase diverse positions on the issues to inform the ongoing discussion and debate, without driving an outcome.

Today's discussions have largely arisen from a range of challenges and opportunities created by new and improved technologies, changing customer and societal expectations and needs, and structural changes in the electric industry. Some technologies are at the wholesale (bulk power) level, some at the retail (distribution) level, and some blur the line between the two. Some technologies are ready for deployment or are already being deployed, while the future availability of others may be uncertain. Other key factors driving current discussions include continued low load growth in many regions and changing state and federal policies and regulations. Issues evolving or outstanding from electric industry changes of the 1990s also are part of the current discussion and debate.

To provide future reliable and affordable electricity, power sector regulatory approaches may require reconsideration and adaptation to change. Historically, major changes in the electricity industry often came with changes in regulation at the local, state or federal levels.

DOE is funding a series of reports, of which this is a part, reflecting different and sometimes opposing positions on issues surrounding the future of regulation of electric utilities. DOE hopes this series of reports will help better inform discussions underway and decisions by public stakeholders, including regulators and policymakers, as well as industry.

The topics for these papers were chosen with the assistance of a group of recognized subject matter experts. This advisory group, which includes state regulators, utilities, stakeholders and academia, works closely with DOE and Lawrence Berkeley National Laboratory (Berkeley Lab) to identify key issues for consideration in discussion and debate.

The views and opinions expressed in this report are solely those of the authors and do not reflect those of the United States Government, or any agency thereof, or The Regents of the University of California.



Introduction

Electric power is America's most capital-intensive industry. According to the Edison Electric Institute (EEI),¹ its member companies invest more than \$100 billion each year on energy infrastructure, with an estimated \$120.8 billion in spending in 2016. Of that amount, these companies invested an estimated \$52.8 billion in the grid's transmission and distribution infrastructure, more than twice the level of investment a decade ago — \$20.8 billion for the transmission system and \$32 billion for the distribution system.²

Investments for modernizing transmission and distribution systems — the focus of this report — are likely to grow as electric utilities harden these systems to maintain reliability and resiliency in the face of cyber and physical security threats, deploy advanced digital technologies, and facilitate new services to meet some consumers' increasing expectations for greater choice and control over energy production and use.

The U.S. Department of Energy (DOE) envisions a modern electric power grid with:³

- greater resilience to hazards of all types;
- improved reliability for everyday operations;
- enhanced security from an increasing and evolving number of threats;
- affordability to maintain our economic prosperity;
- superior flexibility to respond to variability and uncertainty; and
- increased sustainability through additional clean energy and energy-efficient resources.

Do current regulatory approaches for U.S. electric utilities provide the appropriate incentives to enable grid modernization investments to achieve these goals? This report presents three perspectives on that question: a chartered financial analyst specializing in utility investment incentives (Kihm), an expert in institutional frameworks for utility regulation (Beecher), and an attorney, clean energy consultant and former public utility commission chair who calls for broader changes in regulatory processes to achieve state policy goals (Lehr).⁴

Kihm makes the case that all major investor-owned utilities (IOUs) wishing to modernize the grid have easy access to capital at low cost. The more relevant issue, he explains, is whether such investments create value for existing shareholders. Investor-owned utilities have a financial incentive to modernize the grid only if such investments create the most value for their existing shareholders. He illustrates mechanisms that regulators could use to provide explicit incentives

¹ EEI (2017).

² These figures are only for the investor-owned utility sector of the electric power industry. Other sectors are making commensurate infrastructure investments: competitive generation and transmission owners, publicly owned utilities, rural electric cooperatives and federal power marketing agencies.

³ Adapted from DOE (2015).

⁴ All of the authors have direct experience at state public utility commissions.



to pursue grid modernization in cases where other utility investments are more attractive to the utility.

In contrast, Beecher makes the case that the traditional ratebase/rate-of-return model for utility regulation provides ample incentives for utilities to pursue investments in grid modernization, or other infrastructure upgrades, as well as incentives for cost control, efficiency and even innovation. However, effective implementation is needed. Beecher evaluates the relevance of six distinct incentives embedded in this regulatory model as they relate to grid modernization, pointing out where criticism may be misguided. She cautions that additional incentive mechanisms should be used only if they promote economic efficiency consistent with the core goal of economic regulation and meet the values and objectives expressed through democratic institutions.

Lehr maintains that rapid changes in the electric industry require a review of traditional regulatory approaches to utility incentives. In particular, Lehr raises concerns about financial incentives embedded in the current regulatory model that promote utility capital investment over expense-based solutions that may be preferable from a consumer point of view. Further, he asserts that these incentives ignore solutions that third parties and consumers can offer. Lehr also calls for alternative regulatory processes to replace or augment today's trial litigation-type processes, in order to better align incentives with desired outcomes such as grid modernization.

The following summary provides further detail on each of these perspectives.

Financial analyst perspective – Steve Kihm (Chapter 1)

Kihm focuses on utility managers' narrow economic interests. As leaders of investor-owned corporations, IOU managers have obligations to customers and regulators, as well as an explicit fiduciary obligation to protect the interests of their firms' current owners — present shareholders.⁵ Kihm also considers the fact that utility managers may have other, private incentives that could affect their corporate investment decision-making.⁶

At the outset, he aims to clear up widespread confusion related to the capital allocation process. For example, some argue that the financial market is stingy in providing capital, and that utilities hoping to raise funds for plant investment are at its mercy. The implication is that only those IOUs earning the highest returns on their investments will readily attract capital, leaving those with lower corporate returns to scramble for the limited remaining funds and perhaps coming up short. They then might not be able to make all necessary plant additions or upgrades, which could threaten reliability.⁷

This logic is incorrect. The financial market does not make a utility's investment decisions — the utility's managers do. Any major investor-owned electric utility today that wants to raise capital

⁵ Gordon (1974).

⁶ Jensen and Meckling (1976).

⁷ Mitnick (2016).



can do so at a reasonable cost.⁸ In fact, investment bankers will stumble over themselves for the opportunity to raise that capital for any of those companies — that is how investment bankers make their money. Rather than being stingy, the financial market makes raising capital easier.

Further, IOUs earning low returns on equity have equal access to capital when compared to their higher-return counterparts because higher *corporate returns* do not translate into higher *investor returns* for new capital providers. If the expected return for new investors buying shares of any two given utility stocks is about the same, providing capital to either company is equally attractive to new investors.

Properly framing the problem, the issue is not whether utility managers today *can* raise capital for grid modernization, or any other capital investment — we know they can as capital is plentiful.⁹ It is whether the managers of a utility *want to* raise capital for grid modernization projects. The difference is far more than semantics. The utility's desire to raise capital depends on the presence of a shareholder value proposition, not for the new capital providers, but for the present shareholders. Under the right conditions, discussed at length in Chapter 1 of this report, present shareholders benefit from the opportunity for the utility to make capital investments because it drives the stock price higher.¹⁰

The ultimate issue is whether grid modernization investments create the *most* value for the utility's present shareholders. Grid modernization investments are the best choice in terms of shareholder value in some cases, but not others. Kihm concludes with a high-level overview of various incentive mechanisms that could be used to encourage grid modernization over other particular utility investments, if such incentives are in fact necessary. He identifies which approaches are likely to enhance the financial attractiveness of a utility's grid modernization investments, and which might detract from it or have no effect.

Institutional perspective – Janice Beecher (Chapter 2)

Beecher acknowledges that technological opportunities, business models, and market structures in the electricity sector are evolving, in search of the trifecta of reliable, affordable, and clean energy services. At issue is whether incentives to IOUs, particularly those embedded in the traditional cost of service model of economic regulation, are sufficient to help achieve state and federal grid modernization goals, or whether alternative approaches and additional incentive mechanisms are needed and justified. In other words, is reform toward an entirely new regulatory paradigm in order?

Beecher's essay offers a general institutional perspective on the role of incentives in utility regulation. She postulates that the traditional economic regulatory paradigm and ratemaking model are well proven, very accommodating, and actually well suited to the policy objectives of grid modernization, perhaps more so than many seem to think. Effective implementation is key.

⁸ Mauboussin and Callahan (2016).

⁹ Mauboussin and Callahan (2016).

¹⁰ Myers (1972).



Ratebase/rate-of-return regulation provides powerful incentives for investment but also cost control, efficiency, and even innovation. Three primary tools are regulatory lag, prudence reviews, and incentive returns. Critics of this form of regulation, and by extension the traditional regulatory paradigm, focus on what they see as fundamental incentives embedded in the model that would appear to thwart expeditious progress toward achieving energy policy goals. Beecher considers six distinct incentives that have drawn criticism. She also discusses the related issues of subsidy and wealth transfer and regulatory activism.

As a general proposition, Beecher stresses that incentives should be used only if they promote economic efficiency consistent with the core goal of economic regulation, constrained as appropriate by other values and objectives. Just because an investment is associated with infrastructure modernization is not sufficient proof of system, ratepayer, or societal benefits; nor is it sufficient proof of either prudence (fair returns) or the need for special incentives (bonus returns). When new paradigms and incentive “fixes” are advocated, policymaking should be informed by the answers to a series of questions.

Ironically, in a contest to design from scratch a system of incentives for infrastructure modernization, the winner might actually look a lot like the model under which that infrastructure was built in the first place. Realizing the promises of grid modernization depends on whether regulators are willing and able to respect the social compact and utilize the powerful economic incentives at their disposal to serve the public interest. If regulators are unable or unwilling to regulate consistent with the paradigm, then strategies for building regulatory capacity or alternative structural models will be needed. If for whatever reason regulation no longer serves the public interest, its institutional time may be up.

Broader public policy perspective – Ron Lehr (Chapter 3)

Lehr finds that rapid electric industry changes require careful review of traditional regulatory approaches to utility incentives.

Today, profits allowed by regulators on IOU equity investments provide the most common financial incentives. Lehr calls for better alignment of utility investment incentives with changes currently challenging the electricity sector, with emerging grid modernization options and benefits, and with today’s public policies. Investor-owned utilities have incentives to choose capital investments to respond to every problem and opportunity they face, since their profitability depends on investing equity to gain their authorized returns. Correspondingly, IOUs have less (or no) financial incentive to employ expense-based solutions, since they do not earn profits on expenses.

Utilities have incentives that are constructed by their regulators, because regulators control how much utilities can charge consumers, what utility investments and expenditures these charges can recover, and how consumers’ charges are constructed. Lehr points out that IOUs face many incentives beyond financial incentives. Some of these regulators control directly, like regulatory lag, prospective rules and regulatory guidance, and planning. Other incentives result from outside forces. Markets, consumer expectations, shifting technologies and changing economics



can cause utilities to change how they do business and make money. With rapid change pressing on the regulatory system, the past becomes a less useful guide to the future.

Lehr calls for relatively less regulatory attention to the traditional cost of service question “did we pay the correct amount for what we got?” and relatively more attention to the incentive question “what do we want and how do we pay for that?”

Lehr raises a series of questions for consideration by policymakers, utility regulators, utility executives and stakeholders, including:

- Should regulators consider how to pick up the pace of their regulation to better match the pace of industry changes?
- Could regulatory incentives, and industry financial incentives, be better aligned with both traditional and emerging public interest values?
- Are better-defined outcomes and improved metrics and measurements for progress possible or required?
- Are there alternatives that can improve utility regulatory processes?
- What incentives and disincentives do utilities have to invest in grid modernization for energy efficiency and distributed generation?
- How do regulatory incentives impact utility decision-making at the bulk grid level?





1. Financial Analyst Perspective: Utility Incentives, Shareholder Value and Grid Modernization

By Steve Kihm, CFA, Seventhwave

Introduction

This chapter sets forth a financial valuation framework to demonstrate how utility managers' decisions related to grid modernization activities could create or destroy value for their current shareholders and how regulatory incentives could influence those decisions. I also discuss how incentives embedded in traditional cost of service regulation — and any other incentives provided by regulators — can affect those outcomes.

Determining whether particular grid modernization investments will increase or decrease shareholder value requires a thorough understanding of stock valuation principles, one that is often lacking in discussion of regulatory incentives. Before proceeding to an analysis of specific incentive mechanisms, I lay a foundation that explains how investor-owned utilities can create value and which investors capture it.

In so doing I dispel popular notions that regulatory incentives are about creating attractive value propositions for *new capital providers*. As finance principles state, and as the empirical evidence supports, incentives are about creating value for *current shareholders* (the group that utility managers represent), not potential new investors (which operate at arm's length from the utility in the capital attraction process). No major investor-owned utility will have difficulty attracting capital for grid modernization, but that is not the constraint that might stand in its way. The utility's key concern is whether such investments will create value for its current shareholders.

The resource choice that maximizes current shareholder value is often not apparent on the surface, as the value propositions depend on the joint interaction of risk, return and scale characteristics. Over the past several years my colleagues at Berkeley Laboratory and I have been analyzing the impacts of electric utility shareholder value under various scenarios using this risk-return-scale framework.¹¹ Our work reveals that shareholder value propositions associated with any utility investment, including investments to modernize the grid, will depend heavily on specific circumstances of both the utility and the project.¹²

I explore the issue of regulatory incentives by first reviewing at a high level the impact of a high-profile regulatory incentive structure — the Federal Energy Regulatory Commission's (FERC's) bonus returns on equity for new transmission projects. I then introduce the valuation framework that allows a forward-looking examination of incentives. I apply this framework in analyzing proposals that: (1) allow for different returns for grid modernization investments compared to other utility investments, (2) de-risk grid modernization investments, and (3) permit rate-base treatment of certain grid modernization expenses. I also examine the degree to which more general ratemaking approaches — price caps, formula rates, return-

¹¹ Kihm, Satchwell, and Cappers (2016a).

¹² Kihm, Satchwell, and Cappers (2016b).



sharing mechanisms, and performance-based rates — can create or reduce incentives for investor-owned utilities to modernize the grid.

A couple of caveats are in order. Even if we restrict the discussion just to the interests of utility managers and their investors we must recognize that investors' interests are not necessarily aligned with those of utility managers.¹³ Because their interests differ, corporate managers' decisions often deviate, sometimes substantially, from those that shareholders would prefer. Understanding the shareholder value framework provides a reference point from which we can observe any tendency for utility managers to make such departures.

Furthermore, my analysis is not a substitute for a comprehensive look at all of the public interest aspects of regulatory decisions. I focus on the shareholder value, demonstrating how utilities create it. The fact that a particular utility resource choice maximizes shareholder value does not necessarily mean that it is the best public interest choice. Rather, shareholder value is an input to the regulatory decision-making process, not the output. The co-authors of this report, Janice Beecher and Ron Lehr, examine incentive issues from broader perspectives.

Example Incentive: Bonus ROEs for Transmission Investment

I begin exploring the role that incentives can play in utility investment decisions by examining an actual mechanism. In 2006, FERC set forth a policy allowing for higher-than-average returns on equity (ROE) to incent utility managers to build transmission.¹⁴ FERC explicitly expressed a need for such incentives.

Some commenters have argued that few or no incentives are needed to encourage new transmission investment. We reject these comments as fundamentally inconsistent with section 219. Section 219 reflects Congress' determination that the Commission's traditional ratemaking policies may not be sufficient to encourage new transmission infrastructure. Although section 219 does not permit approval of rates that are inconsistent with section 205 or 206, section 219 nonetheless constitutes a clear directive that "the Commission shall establish, by rule, incentive-based . . . rate treatments . . . for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion." We therefore cannot simply rely on existing ratemaking policy to faithfully implement section 219.¹⁵

There is no question that more transmission investment followed the issuance of the incentives order.¹⁶ Although it seems highly likely that the incentives helped to spur that investment, it is always difficult to disentangle the amount of transmission that would have occurred with and without the incentives. But even if the FERC incentives were the primary driver, how did they affect utility investment decisions?

¹³ Jensen and Meckling (1976), 305-360.

¹⁴ U.S. Federal Energy Regulatory Commission, Docket No. RM06-4-000; Order No. 679. July 20, 2006.

¹⁵ *Ibid.*, 4.

¹⁶ EEI (2016).



I will demonstrate in a moment that properly designed incentives are not about attracting capital, but rather are about influencing utility managers to choose to invest in one type of project versus another so as to create value for current shareholders. Raising capital for transmission without the bonus return was not the issue. Investor-owned utilities could have done that, but perhaps at the expense of their then-current shareholders. Simply put, the risk–return trade-off might have required that utility stock prices declined to raise the capital. No corporate manager would like to raise capital under such conditions (although they could if they had to). As FERC’s returns on equity increased through the incentive mechanism, the risk–return balance was corrected. Transmission projects created shareholder value. Utility managers chose to build transmission.

In recent years FERC returns on transmission projects have declined. This has created an industry reaction, one that is in keeping with finance principles.

According to EEI [Edison Electric Institute], the need for continued transmission investment is undisputed, and many of the projects that will provide the most significant benefits to customers are the large regional and inter-regional backbone projects. As EEI explains, “these projects also carry the most upfront development time, longer construction schedules, and overall risk.” However, without a sufficient ROE, *electric utilities are likely to choose* short-term, more local projects, instead of riskier, more strategic options.¹⁷ (Emphasis added.)

This is good financial analysis. It does not suggest that the financial markets would stop financing transmission. Investment bankers stand ready to raise capital for such projects regardless of the rate of return. They will simply price the utility’s securities to raise the necessary funds. The issue is one of choice, not capital availability. At lower return levels, utility managers, who make the investment decisions, might choose different projects because the value proposition associated with transmission projects for current shareholders might no longer be sufficient.

The ultimate decision to invest rests on the joint effect of three key factors: risk, return and scale. We see risk in EEI’s comments; returns in FERC’s order. The scale variable (total dollars invested) enters the picture as well. Utility managers who focus on shareholder value should examine these factors in concert to determine whether transmission projects create value. The fact that they developed numerous transmission projects speaks to the likelihood that they saw a value proposition. Whether such projects could have been developed without the incentives is an unanswered question.

Some parties suggested that the incentives were unnecessary. Several states took actions that effectively unwound the net impact of the higher FERC returns by authorizing lower returns on utility assets under state jurisdiction.

¹⁷ Kuzika (2013).



What Drives Investor-Owned Utility Investment Decisions?

To analyze the need for, and effectiveness of, utility financial incentives requires a thorough understanding of shareholder value creation. We often hear the suggestion that firms should attempt to maximize profits, but that's incorrect for two primary reasons: (1) profit is an accounting concept — firms interested in their investors should focus on market value concepts¹⁸ and (2) firms can't maximize anything because they are not living entities capable of making decisions. Corporate managers serve this function and therefore firm decisions are ultimately driven by human behavior.

The decisions under review here are those related to grid modernization investments,¹⁹ so we want a model that describes investment choices. In his classic text, *The Cost of Capital to a Public Utility*, Gordon established the first-order link between utility shareholders and the managers who represent them in the investment process.

The immediate decision maker with respect to a utility's expenditures on capital facilities is the *utility management*. As a first approximation we may assume that the objective of a utility management in its investment and other decisions is to serve the company's owners — its *present* shareholders.²⁰ (Emphasis added.)

This quote makes two critically important points. Many people believe that the financial markets decide where and when investor-owned utilities allocate capital, and that utility managers attempt to entice capital to the firm by offering new investors higher returns than those available from similarly-situated firms (i.e., other electric utilities). Neither is accurate and those who adopt that position miss the essence of corporate finance.

First, utility managers, not the financial market, make the investment decision.²¹ Second, utility managers have no obligation to represent the interests of future potential investors, such as those who might provide new capital to finance grid modernization. Their obligation is to the current shareholders. The corporate finance literature shows that utility managers achieve this objective by maximizing *today's* per-share stock price.

¹⁸ When economists use the term *profit*, they typically mean economic profit, which is the return over and above the cost of capital. That is a key ingredient in value maximization, and it effectively incorporates the risk and return aspects. However, it still comes up short because it ignores the investment scale variable. *Investment scale* is the total dollar amount of capital invested in a project.

¹⁹ See the following links for examples of earlier grid investments under the Smart Grid Investment Grant program:

- Advanced metering infrastructure and customer systems: https://www.smartgrid.gov/recovery_act/deployment_status/ami_and_customer_systems.html
- Distribution system assets: https://www.smartgrid.gov/recovery_act/deployment_status/distribution.html
- Transmission system assets: https://www.smartgrid.gov/recovery_act/deployment_status/transmission.html

²⁰ Gordon (1974).

²¹ Mauboussin, Callahan, and Majd (2016).



The appropriate goal for the financial manager can thus be stated quite easily:
The goal of financial management is to maximize the *current* value per share of the existing stock.²² (Emphasis added.)

Attracting capital vs. raising capital

To dispel the myth that higher utility returns attract more new investment capital, consider an actual, highly illuminating example from outside the electric utility industry. As investment bankers note, rather than being a scarce resource, capital is plentiful.²³ Corporations can attract capital in almost any economic environment.

Aluminum producer Alcoa is a case in point. It decided to raise equity capital in March 2009, in the middle of the Great Recession. Conditions could hardly have been more challenging. Alcoa's most recent return on equity, for 2008, was 2.0 percent. The company forecasted a loss for 2009. Industry experts predicted a difficult time for Alcoa going forward and they were correct. Over the next five years it earned a median return on equity of only 5.4 percent.²⁴

Why would anybody buy the stock of risky Alcoa with its 2 percent to 5 percent returns on equity? Clearly those returns are below the minimum investors require for such a firm. It seems as though Alcoa would come up dry, but it didn't. Many investors jumped at the chance to provide Alcoa with the new equity capital it needed. The company raised \$900 million of equity, and also acquired another \$400 million of debt.²⁵

How could Alcoa achieve this feat? Before I answer that, consider the following analogy. Which is the better automobile: a new Honda Civic or a 15-year old Toyota Corolla with 300,000 miles of wear and tear? The Civic wins hands down. Does that mean that the Corolla's owner couldn't attract any buyers? Of course not. The asking price on the Honda might be \$22,000; the Corolla might list at \$1,000. The Corolla may very well sell before the Honda.

Alcoa was like a used Corolla. It raised almost \$1 billion of equity capital, not because it had great investment opportunities, but rather because it didn't cost new investors much to buy in. That is, it offered its shares at a bargain-basement price. At the time of the stock issuance, Alcoa's book value was \$14.59 per share. Alcoa's underwriting syndicate of Morgan Stanley, Credit Suisse Group, Citigroup and Barclays Capital priced Alcoa's new stock issuance at \$5.25 per share, or at only 36 cents on the dollar relative to the book value reference point. They sold 172.5 million shares of stock for Alcoa at this discount price.²⁶ The point is that the company could issue capital even under such severe conditions.²⁷

²² Ross, Westerfield, and Jordan (1991).

²³ Mauboussin, Callahan, and Majd (2016).

²⁴ Silva (2016).

²⁵ Moore (2009).

²⁶ Ibid.

²⁷ This is not to suggest that this was good financial practice on the part of Alcoa managers, or one that others should attempt to emulate. The purpose is to demonstrate financial principles for capital attraction. Alcoa's existing shareholders — not the new ones — suffered greatly as a result of this issuance, absorbing the substantial stock price decline necessary to raise the capital.



The electric utility industry today is in strong financial shape; much stronger than Alcoa was at the time of its stock issuance. The typical electric utility stock trades at an 80 percent premium, not a discount, to book value. Any major investor-owned utility that wants to raise capital today will have no difficulty doing so and will continue to have that ability even if conditions deteriorate. In *The Cost of Capital: Estimating the Rate of Return for Public Utilities*, the authors reinforce the notion that if conditions worsen significantly to the point where returns on equity lie below the investor-required returns, utility managers can still attract capital if they need it, but they may not want to raise it because doing so will harm the stockholders who have already provided capital.

Managers will recognize that they are penalizing stockholders whenever they make a new investment, because the expected return will fall short of the cost of capital. *Managers will grow increasingly unwilling to add to existing capacity.*²⁸ (Emphasis added.)

The authors assume correctly that utility managers can raise capital under these challenging circumstances if they wish, just as Alcoa did. The proper question then is not whether the utility can attract capital, but whether utility managers see any benefits to the present investors if they raise it.

Investing to create value for current shareholders

If the return on equity exceeds the investors' required return, the opportunity to make new investments provides a windfall gain to the current shareholders. Myers explains this in his classic article, "The Application of Finance Theory to Public Utility Rate Cases."

Note that an opportunity to invest in a project offering more than the cost of capital generates an *immediate* capital gain for investors. This is a *windfall gain*, since it is *realized ex ante*.²⁹ (Emphasis added.)

The windfall occurs because, before the utility issues the shares to finance new investment, the market sees the value opportunity and impounds it in the price. When the utility actually raises the new capital, any takers will pay the higher price, the one that already reflects the gain.

For high corporate returns to attract more capital than low corporate returns, the expected returns on the stocks of the former companies would have to exceed those on the stocks of low-return firms. They don't. We see this by examining the electric utility stocks followed by the *Value Line Investment Survey*.³⁰ Figure 1-1 reveals a positive relationship between the return on equity the utility is expected to earn and its relative stock price (price-to-book value). More specifically, observe that Alliant Energy, which earns an equity return of 12 percent, trades at 2.0 times its book value. In contrast, PNM Resources, which earns an equity return of 9 percent, trades at 1.4 times book value.

²⁸ Kolbe, Read, and Hall (1984). *The Cost of Capital: Estimating the Rate of Return for Public Utilities*. MIT Press.

²⁹ Myers (1972).

³⁰ The analysis here excludes utilities that are parties to a proposed merger or acquisition, as such activities can distort pricing.



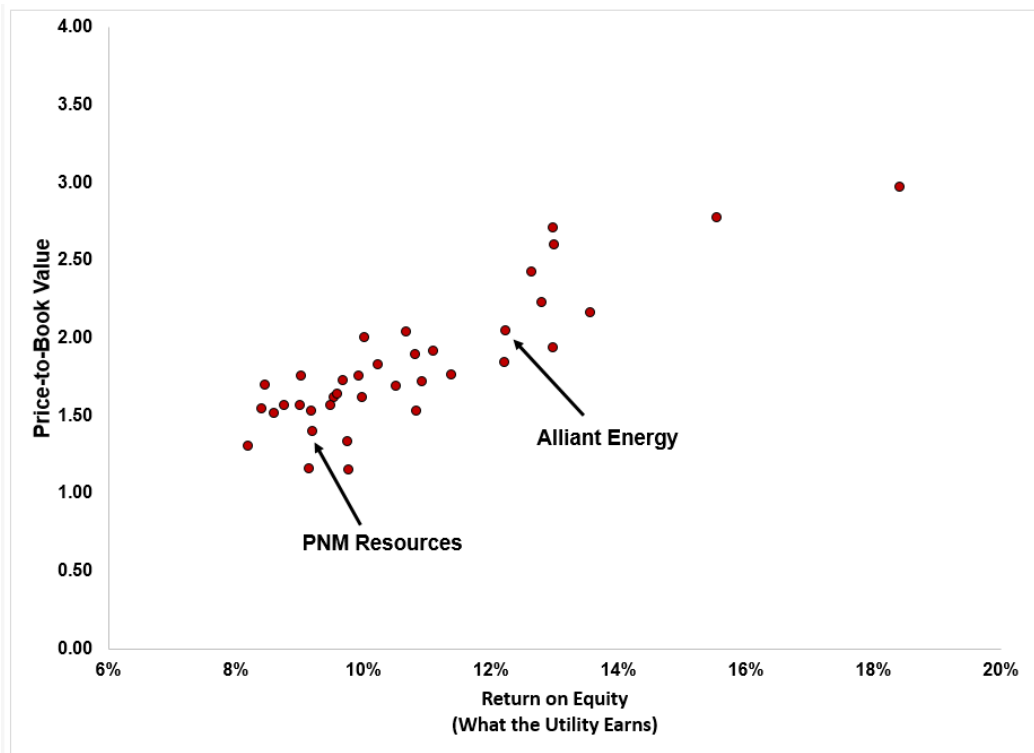


Figure 1-1. Value Line Electric Utilities' Price-to-Book Ratio vs. Utility Return on Equity

The higher the corporate return, the more investors pay for the stock on a relative basis and the more they dilute the return they can expect to earn on the stock. Combining the corporate return and the price-to-book data allows an estimate of the investors' expected return. See Figure 1-2 for the results and the Appendix for a discussion of the model used to develop these estimates.



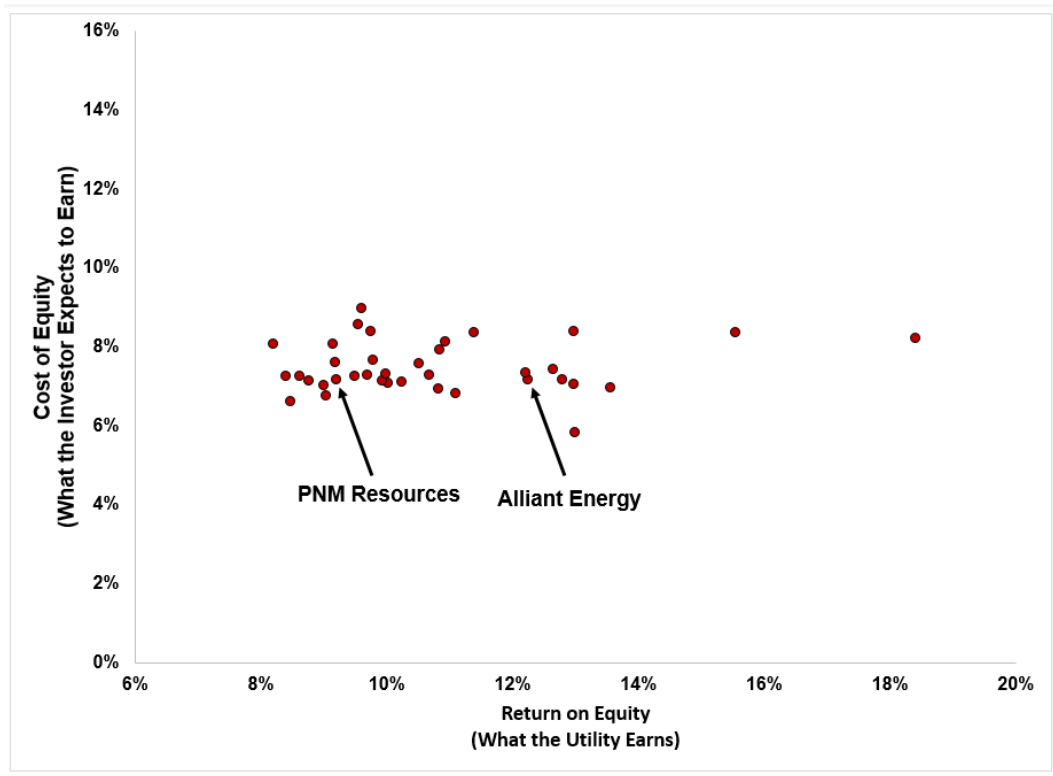


Figure 1-2. Value Line Electric Utilities' Expected Investor Return vs. Utility Return on Equity

Figure 1-2 shows that, just as finance theory suggests, the investors' expected return on electric utility stocks is not related to the utilities' returns on equity. Alliant Energy stock offers investors the same return as does PNM Resources stock. Even though Alliant earns much higher returns than PNM, investors have to pay over 40 percent more on a relative basis to buy Alliant's stock.³¹

This result should have intuitive appeal. If utilities that earned higher returns on equity produced higher long-run investor returns, picking winning stocks would be quite an easy task. Simply buy the stocks of high-return firms and avoid those of low-return companies. In sophisticated financial markets it can't be that easy, and it isn't.

This has implications for raising capital. The incentive for new investors to provide capital depends on the expected return on the stock, not on the utility's return on the capital it invests. Since the expected return on PNM Resources' stock is about the same as the expected return on Alliant Energy's stock, PNM will have the same access to capital at the same cost rate as Alliant. Furthermore, if PNM Resources' return on equity rose to 12 percent, its relative stock price would in turn quickly rise to about 2.0 times the book value. That would make the present shareholders happy, but it would eliminate any above-average expected returns for eventual new capital providers.

³¹ Alliant's price-to-book ratio is 2.0; PNM's is 1.4. The relative premium is $2.0/1.4 = 1.43$, or 43 percent.



Creating (or destroying) shareholder value

The following equation describes the core of the shareholder value creation process, which my Berkeley Lab colleagues and I refer to as the *shareholder value engine*:

$$V = (r - k)I$$

V is the incremental annual economic shareholder value added by investing an amount of capital (I) at a return on equity (r) for a given investor required return (cost of equity, or k). If r exceeds k , the greater the amount of investment capital the utility invests, the more shareholder value is created.

This simple shareholder value engine approach is quite helpful as an analytical tool. However, the result is not the *full* shareholder value created by the investment. Instead, it is the *first year's* contribution to shareholder value. This approach allows ranking of assets in terms of shareholder value creation if they have the same estimated lives. When dealing with more complex comparisons, more advanced versions of shareholder value models can be applied. The simple version works here for illustrative purposes. Regulators can use this approach to gain insights into shareholder value opportunities associated with utility investment alternatives.

Returning to the equation, what happens if r equals k ? Then no matter how much capital the utility invests, it creates no economic shareholder value. That means that such investment has no effect on the utility's stock price.

When ROIC [(return on invested capital)] equals the cost of capital, we can draw the dividing line between creating and destroying value through growth. On that line, value is neither created nor destroyed regardless of how fast the company grows.³²

Put in terms of the context of this report, if r equals k , there is no gain to current shareholders if the utility modernizes the grid (or makes any other investments for that matter). This creates a situation in which utility managers are in the economic doldrums, unable to create value for their investors.

It's as if management were on a treadmill. They're working hard, but after the workout, they are right where they started.³³

Institutional economists, such as Kahn, suggested that instead the utility's r should exceed k . In *The Economics of Regulation*, he stated:

It [setting the return on equity at the investors' required return] does not necessarily tell us how to best promote economic progress.... [T]he rate of return must fulfill what we may term an institutional function: it somehow must provide the incentives to private management that competition and profit-

³² Koller, Goedhart, and Wessels (2015).

³³ Ibid.



maximization are supposed to provide in the nonregulated private economy generally. We have already identified this as a central problem of regulation.³⁴

Setting the rate of return at the cost of capital is a prescription for stagnation, not progress. That seems antithetical to regulatory policy objectives, especially today. Kahn suggests that r should exceed k , and the evidence supports that contention. Investment advisory firm Morningstar reviews the data and agrees.

State and federal regulators typically grant regulated utilities exclusive rights to charge customers rates that allow the utilities to earn a fair return on and return of the capital they invest to build, operate, and maintain their distribution networks.... This implicit contract between regulators and capital providers should, on balance, allow regulated utilities to *earn more than their costs of capital in the long run*.³⁵ (Emphasis added.)

In his text entitled *Investment Valuation*, New York University professor Damodaran sets forth the foundational relationship between a firm's stock price, its book value, its return on equity and its cost of equity.

The price-book ratio of a stable firm is determined by the differential between the return on equity and the cost of equity. If the return exceeds the cost of equity, the price will exceed the book value of equity; if the return on equity is lower than the cost of equity, the price will be lower than the book value of equity.³⁶

Per finance principles, if investors expected regulators to limit utility returns on equity to the cost of equity, utility stocks would trade at book value. They don't. The 40 investor-owned utilities followed by the *Value Line Investment Survey* today trade at a median price-to-book of 1.8 times, which suggests that they earn returns in excess of their costs of equity, just as Morningstar suggests. This also implies that the typical utility has an incentive to make investments because doing so will create value for its current shareholders.

One caveat is in order here. If grid modernization investments have noticeably more risk than conventional utility assets, the value proposition could change (i.e., the price-to-book ratio could drop). But since that risk is largely technological in nature, it would manifest in lower expected earned returns on equity (which would reflect expected disallowances of cost overruns or technological failures, for example), not in higher costs of equity. As McKinsey & Co. valuation experts stress, both finance theory and the empirical evidence suggest that most risks a utility faces do not affect its cost of equity.³⁷ Where the risk manifests, though, is of little concern to utility managers who are focused on the stock price. It does matter, however, to investors who can diversify away such firm-specific risks in a portfolio, but who cannot eliminate the effect of macroeconomic risks, which affect all stocks. So risk concerns are more likely a problem for

³⁴ Kahn (1988).

³⁵ Bischof (2016).

³⁶ Damodaran (2012).

³⁷ Koller, Goedhardt, and Wessels (2016).



utility managers than for investors. See the section below on principal-agent conflicts and Beecher and Kihm (2016).³⁸

Another important policy point deserves mention. Some would argue that the fact that the typical utility stock trades at about twice book value suggests that regulators are providing utilities with too much incentive to invest in new facilities, not too little. That is a fair point to raise. While utilities in general should have some opportunity to create value through investment, what is the appropriate gap between r and k ? That is a policy question, not one of finance. I take no position on this issue here, but I do support close inspection of this issue when incentive issues are discussed. The fact that Southern California Edison is proposing a \$12 billion investment in grid modernization suggests that there is enough incentive under current ratemaking practices, at least for that utility, to make certain types of grid modernization investments.³⁹

Do Investor-Owned Utilities Need Incentives to Modernize the Grid?

I now apply the financial framework to begin my assessment as to whether utilities need incentives to make grid modernization investments.

- *New capital providers.* Capital attraction is not an issue under almost any scenario. If Alcoa can raise \$900 million of new equity in the middle of a recession, electric utilities today have ready access to new capital, whether they earn returns on equity of 8 percent or 12 percent. If the risk is similar, the market will price the capital so that new investors will make about the same return on any utility stock (see Figure 1-2).
- *Current shareholders.* Today the typical utility return on equity is about 10 percent; the typical investor-required equity return is about 7 percent. Valuation analysis suggests this is consistent with a price-to-book ratio of 1.8, which is where the typical utility stock trades.⁴⁰ The shareholder value engine therefore takes on the following form:

$$V = (0.100 - 0.070)I > \$0 \quad \text{[Utility has an incentive to invest]}$$

Utility investment today creates positive economic value for the current shareholders. Again, this is a windfall because they don't have to put up any of the new capital (I). The result for the equation above is for the average electric utility. The actual incentive varies from utility to utility. Some investor-owned utilities have expected returns close to the cost of equity; others have returns well in excess of that rate.

- *Utility managers.* Grid modernization requires expansion of the utility asset base, which is a form of growth. If the investments aren't particularly risky, managers should be favorably disposed to making such investments. (See the principal-agent discussion below.)

³⁸ Beecher and Kihm (2016).

³⁹ Penn (2015).

⁴⁰ The formula for price-to-book is: $\frac{P}{B} = \frac{r(1-b)}{k-b(r)}$. The typical utility earnings retention rate b is 35 percent. Entering the values yields: $\frac{P}{B} = \frac{0.10(1-0.35)}{0.07-0.35(0.10)} = 1.85$.



Grid modernization investments may require more capital than other resource options. Again, Southern California Edison's recent announcement that it plans to spend \$12 billion on grid enhancement over the next three years suggests that at least that utility has no need to be incented to make such investments.⁴¹ But the analysis must be expanded to consider other key issues:

- *Macroeconomic risk.* If interest rates rise dramatically, the gap between r and k might close or even go negative⁴² — for example:

$$V = (0.120 - 0.130)I < \$0 \quad \text{[Utility does not have an incentive to invest]}$$

Note that profitability rises from 10 percent in the base case to 12 percent here. That means that profits will increase if the utility makes investments, but those same investments will also cause the utility's per-share stock price to decline. This would switch investments from shareholder value-creating to shareholder value-destroying. All utility investments, including those made to modernize the grid, would then destroy investor value.

- *Technology risk.* If a utility invests in grid modernization technology that is nascent, there is a risk that some functions might not perform as intended, and not all of the expected benefits will be realized. That might lead to regulatory disallowance of some of the utility's capital expenditures. This could reduce the expected rate of return and, in the end, could destroy investor value instead of creating it.

If the utility invested \$1 billion of equity at the industry median return, and investors required the industry average cost of equity, we would see the following shareholder value proposition:

$$V = (0.100 - 0.070)\$1,000,000,000 = \$30,000,000 \quad \text{[invest]}$$

The annual contribution to market value is substantial. But if some aspects of the technology fail, the regulatory agency might allow the 10 percent return on only, say, half the investment, or \$500 million. Applying the 10 percent return to that base produces profits of \$50 million. But the utility invested \$1 billion, so the effective return on the full capital base would be 5 percent, not 10 percent, leading to the following shareholder value proposition:

$$V = (0.050 - 0.070)\$1,000,000,000 = -\$20,000,000 \quad \text{[don't invest]}$$

The expected annual contribution to present shareholders declines from a positive \$30 million per year to a negative \$20 million per year. That loss of shareholder value will cause the stock price to decline. If the utility sees this as a plausible outcome, it may not make the investment.

⁴¹ Penn (2015).

⁴² Allowed returns generally do not track interest rate changes one for one.



- *Technology obsolescence.* Many technologies become obsolete prior to the end of their useful lives. For example, advanced metering infrastructure continues to evolve quickly. It is possible that such technology installed today will fall short of the utilities' and consumers' needs over the next 10 years. But the useful life of the technology may be longer. If technology costs are recovered over the useful life, but the utility must abandon the technology less than half the way through that period, cost recovery risk looms large. Some regulators use shorter depreciation lives to adjust for this problem.

How the value engine varies from utility to utility

The fact that *new* capital providers earn about the same return across all electric utility stocks does not mean that the *shareholder value proposition* is similar for all investor-owned utilities. The latter is where the return on equity looms large. Let's return to the Alliant Energy and PNM Resources example. We start with the basic shareholder value propositions:

$$\text{Alliant: } V = (0.120 - 0.070)I > \$0 \quad [\text{invest}]$$

$$\text{PNM: } V = (0.090 - 0.070)I > \$0 \quad [\text{invest}]$$

Both utilities have an incentive to invest, but Alliant has the potential to create more shareholder value for every dollar invested. So the magnitude of the incentive is not the same from utility to utility, even though new investors themselves expect to earn essentially the same return on the utilities' stocks. Now assume that a combination of factors causes both utilities' rates of return to decline by two percentage points and their costs of equity to increase by one percentage point:

$$\text{Alliant: } V = (0.100 - 0.080)I > \$0 \quad [\text{invest}]$$

$$\text{PNM: } V = (0.070 - 0.080)I < \$0 \quad [\text{do not invest}]$$

The signal to invest is still positive for Alliant, although diminished, but the signal has reversed for PNM. This demonstrates that we could find investor-owned utilities with considerably different incentives to modernize the grid, and those incentives could change over time as utility-specific and general market conditions change.

Principal-agent conflicts

The preceding analysis assumes that utility managers and shareholder interests are perfectly aligned. That is, if it is free to do so, utility management will choose the project that maximizes shareholder value. The evidence suggests that may not be true.

Gordon extends the managerial objective model, incorporating behavioral notions into the framework.

When the shares of a company are widely held, as is usually the case for public utilities, management gains some freedom from stockholders' control.



Management then may subordinate the maximization of the price of its firm's stock in its investment and financing decisions to other goals.⁴³

The idea that managers have objectives that differ from those of shareholders dates back to Adam Smith's *Wealth of Nations*.⁴⁴ The fact that firms go to great lengths to craft managerial incentives linked to stock price performance suggests that principal-agent issues⁴⁵ are significant in corporate America.⁴⁶ If both parties' interests aligned perfectly, such incentives would be redundant and inefficient.

Growth as a managerial objective

Research suggests that utility managers often prefer to maximize growth, which may not be the optimal path for the shareholders, as corporate growth can sometimes destroy shareholder value.

Only if ROIC [(return on invested capital)] exceeds cost of capital will growth increase a company's value. Growth at lower returns actually reduces a company's value.⁴⁷

Researchers find widespread belief that growth and firm performance go hand in hand, even though the evidence suggests that the actual relationship is much weaker and often negative — that is, high growth often ultimately leads to lower stock prices.⁴⁸ In that case, managerial preference for growth may simply be due to misconception or cognitive bias.

There also is strong evidence that executive compensation is linked positively to firm size.⁴⁹ Such a link may be appropriate because larger firms tend to be more difficult to manage than their smaller counterparts. The desire for growth among managers may therefore simply be a reaction to the economic incentives inherent in modern corporations.

If growth doesn't necessarily help shareholders, but it generally benefits managers, we have conflicting principal-agent incentives. Incentive compensation tools that directly link managerial compensation to stock performance may help to reduce the natural inclination of managers toward growth for growth's sake, but even in their presence it may be difficult to eliminate growth-is-good thinking.

Managerial attitudes toward risk

Utility managers also have an incentive to take on less risk than is optimal for investors because the consequences of downside risk for utility managers are much greater than they are for

⁴³ Gordon (1974).

⁴⁴ Smith (1776).

⁴⁵ Principals (stockholders) own the company. Agents (managers) run the company.

⁴⁶ Rappaport (1998).

⁴⁷ Koller, Goedhart, and Wessels (2015).

⁴⁸ Hess (2010).

⁴⁹ Vieito et al. (2008).



utility shareholders.⁵⁰ Shareholders can ignore most risks a utility faces, as they can eliminate their associated impacts through portfolio diversification.

One of the key insights of academic finance that has stood the test of time concerns the effect of diversification on the cost of capital. If diversification reduces risk to investors and it is not costly to diversify, then investors will not demand a return for any risks they can easily eliminate through diversification. They require compensation only for risks they cannot diversify away...[S]ince most of the risks that companies face are in fact diversifiable, most risks don't affect a company's cost of capital.⁵¹

Utility managers have no such alternative because their salaries are tied solely to the prospects of the utility, with no offsetting compensation from potential good outcomes at other companies.⁵² A bet on a large-scale investment that fails (e.g., the investment needs to be written off) has very little effect on an investor holding the utility's stock as one of 200 stocks from across all sectors of the economy. But the utility managers could lose their jobs as a result of such a failure.

Analysis of Specific Grid Modernization Incentive Mechanisms

With the valuation and principal-agent concepts established we can now proceed to analyzing actual grid modernization incentives. Such mechanisms typically are quite complex, as Joskow explains.

The implementation of incentive regulation concepts is more complex and more challenging than may first meet the eye. Even apparently simple mechanisms like price caps are fairly complicated to implement in practice, are often imbedded in a more extensive portfolio of incentive regulation schemes, and depart in potentially important ways from the assumptions upon which related theoretical analyses have been based.⁵³

Joskow continues, identifying the disadvantage that regulators have with respect to the information needed to create new regulatory approaches.

Regulators have imperfect information about the cost and service quality opportunities and the attributes of the demand for services that the regulated firm faces. Moreover, the regulated firm generally has more information about these attributes than does the regulator or third parties which have an interest in the outcome of regulatory decisions. Accordingly, the regulated firm may use its information advantage strategically in the regulatory process to increase its profits or to pursue other managerial goals, to the disadvantage of consumers.

⁵⁰ Beecher and Kihm (2016).

⁵¹ Koller, Goedhart, and Wessels (2015).

⁵² Beecher and Kihm (2016).

⁵³ Joskow (2006).



With these caveats in mind, the following discussion analyzes, from a financial perspective, several types of incentive mechanisms.

Differential r and k for grid modernization investments

The most straightforward application of the shareholder value engine is to develop differentiated, more advantageous parameters for assets that regulators want to promote.⁵⁴ For example, assume that the utility has two options to meet a distribution system need in a particular location: (1) upgrade a series of substations or (2) install equipment that allows for two-way power flows so the utility can make more purchases of power from customer-sited solar photovoltaic systems. Assume that an independent analysis of the options finds that option 2 is the least-cost alternative.

Let's start with a base case situation. Assume that the return on equity (r) and the cost of equity (k) are the same for all utility assets, at 10 percent and 7 percent, respectively. The substation upgrade costs \$500 million while the equipment that allows for greater two-way power flows costs \$400 million. If r and k are the same, the determining factor is the investment scale:

$$\text{Substations: } V = (0.100 - 0.070)\$500,000,000 = \$15,000,000$$

$$\text{Two Way Flows: } V = (0.100 - 0.070)\$400,000,000 = \$12,000,000$$

It is not useful to compare the annual shareholder value contribution that inures to the benefit of the *present shareholders* with the amount of capital *new investors* provide. Dividing \$15 million by \$500 million in the case of the substations project is a meaningless calculation as the numerator flows to one party while a different party contributes the capital in the denominator.⁵⁵ The present investors will take any positive shareholder value because they don't have to invest any capital to obtain it. They will therefore simply prefer the investment that produces the largest absolute dollar amount. The question for managers who represent the present shareholders is therefore quite simple: Which is larger — \$15 million or \$12 million?

A utility interested in creating shareholder value will choose to upgrade the substations. If the regulator wants to create an incentive for the utility to invest in the two-way flow equipment instead, it could apply a different r to that option. Say that the regulator raised the return on that investment to 12 percent.

$$\text{Substations: } V = (0.100 - 0.070)\$500,000,000 = \$15,000,000$$

$$\text{Two Way Flows: } V = (0.120 - 0.070)\$400,000,000 = \$20,000,000$$

Now the utility manager will prefer the two-way flow project because it creates more value (a larger windfall) for present investors. In this case the solution was simple, but the real analysis is likely to be more complicated.

⁵⁴ Kihm et al. (2015).

⁵⁵ Higgins (1989).



Let's step in that direction by considering risk. Most analysts do a risk assessment by changing the cost of equity. That represents bad financial practice, one that can substantially overstate that cost rate.⁵⁶ As McKinsey and Co. valuation experts state, contrary to what we often hear, most risks a company faces have no effect on its cost of equity.⁵⁷ Only macroeconomic risks, such as sensitivity to recessions or interest rate changes, affect that figure. Valuation experts such as those at Morningstar suggest that the cost of equity for utilities today is well below the typical return on equity authorized for utilities. This is its analysis for Xcel Energy.

Beyond 2019 we assume a systemwide normalized 10% average allowed ROE and 0.5% average annual long-term usage growth. *We assume a 7.5% cost of equity in our discounted cash flow valuation.* This is lower than the 9% rate of return we expect investors will demand of a diversified equity portfolio. A 2.25% long-term inflation outlook underpins our capital cost assumptions. Our cost of capital assumption is 5.9%.⁵⁸ (Emphasis added.)

Morningstar therefore suggests that while Xcel Energy investors will require a 7.5 percent return, the utility will earn a 10 percent return. Morningstar suggests that this gap will exist indefinitely. This suggests that Xcel Energy should trade at a noticeable premium-to-book value, which it does (its current price-to-book is 2.0). These return estimates agree with analysis we recently conducted. The median cost of equity for electric utilities I estimated with my Berkeley Lab colleagues in July 2016 was 7.7 percent.⁵⁹ Utility stock prices have risen since then, which has caused the median cost of equity to decline to 7.3 percent today.

The impact of most risks manifests in changes in the expected earned return on equity. In keeping with the approach finance theory suggests, let's adjust the expected return on equity to reflect risk changes. The first risk scenario returns to the base case assumptions ($r = 10$ percent; $k = 7$ percent). Say the substation upgrade will rely on conventional technology, so the risk of disallowance, while real, is not large. I lower the expected effective return to 9.8 percent to reflect that disallowance risk. In contrast, the particular two-way power flow equipment that is being considered is nascent technology, so the risk of disallowance is probably greater.⁶⁰ I lower the expected effective return for that potential investment to 8.5 percent. Now the two-way flow equipment option is at a greater disadvantage.

Substations: $V = (0.098 - 0.070)\$500,000,000 = \$14,000,000$

Two Way Flows: $V = (0.085 - 0.070)\$400,000,000 = \$6,000,000$

⁵⁶ Brealey, Myers, and Allen (2006).

⁵⁷ Koller, Goedhart, and Wessels (2015).

⁵⁸ Miller (2006).

⁵⁹ Kihm, Satchwell, and Cappers (2016).

⁶⁰ This analysis assumes that the regulator allows for recovery of costs for whichever resource the utility implements. In some cases, the regulator may disallow recovery of costs for resources that cost more than a reference technology. While that issue can be integrated into this discussion, the example becomes complicated. The example here is simply for illustrative purposes.



The substation project is clearly more valuable to the present shareholders in this case. But if we increase the authorized return on the two-way flow investment so that the effective return increases by two percentage points, can we switch the utility managers' preference?

$$\text{Substations: } V = (0.098 - 0.070)\$500,000,000 = \$14,000,000$$

$$\text{Two Way Flows: } V = (0.105 - 0.070)\$400,000,000 = \$14,000,000$$

Not quite. We have made shareholder-focused utility managers indifferent between the two, but that's not an incentive.

We see that applying this simple but powerful framework allows us to begin the discussion of incentives using differential r and k figures. If the gap between r and k is the same for all utilities, then the only parameter that matters in the shareholder value equation is the investment scale (I). Under that condition, the biggest asset creates the most shareholder value (assuming r is greater than k). If grid modernization involves adding the largest assets (in terms of dollars), under these conditions there would be little need for additional incentives.

De-risking grid modernization assets

There are other risk considerations. For example, what if the regulator essentially guaranteed full cost recovery of the two-way power flow equipment project? If the regulator could truly insulate the utility from all risks, not only would the expected effective return go from 8.5 percent in the base case to 10 percent, the cost of capital would also approach that of the Treasury bond yield. Let's use 3 percent for that figure.⁶¹

$$\text{Substations: } V = (0.098 - 0.070)\$500,000,000 = \$14,000,000$$

$$\text{Two Way Flows: } V = (0.100 - 0.030)\$400,000,000 = \$28,000,000$$

Now we see a huge advantage for the two-way power flow equipment. We could actually lower the return on equity in this case and still maintain an economic advantage:

$$\text{Substations: } V = (0.098 - 0.070)\$500,000,000 = \$14,000,000$$

$$\text{Two Way Flows: } V = (0.070 - 0.030)\$400,000,000 = \$16,000,000$$

The problem with this scenario is that it may really not be possible to eliminate all risk, especially the sort of long-run technological risks discussed above. And would we want to actually guarantee full cost recovery, regardless of the performance of the utility in implementing the system? (See Janice Beecher's chapter in this report.) In any event, some risk reduction might be in order for grid modernization assets, but only in the case that investing in them wasn't already the utility's preferred choice.

⁶¹ U.S. Federal Reserve Board, Schedule FRB H15, Nov. 25, 2016.



Providing rate-base treatment for grid modernization expenses

In addition to a return of prudently incurred costs, capital investments increase the utility's rate base,⁶² with an opportunity to earn a return on such investments at its authorized return on equity. The utility has no such opportunity for operating expenses.⁶³ It simply recovers its prudently incurred costs.

In cases where a capital investment is not the least-cost solution to an identified need, regulators may consider allowing a utility to capitalize the expense-based alternative. Today there is considerable interest in addressing cloud computing in this manner. Obtaining such services from an outside vendor appears to be cost-effective for utility customers. Utilities typically pay an annual fee for such service. That is an expense item. The conventional approach in which the utility owns its computing infrastructure requires investment, which under the right conditions creates shareholder value.

The utility customers prefer the cloud-based solution — it's less expensive. The utility prefers to use its own infrastructure — it creates shareholder value. If the utility were able to capitalize cloud-computing costs, that would lead us into the shareholder value engine. Let's consider three scenarios: (1) the utility earns more than the cost of equity; (2) the utility earns the cost of equity; and (3) the utility earns less than the cost of equity. Assume the first-year expense is \$2 million.

$$1. \quad V = (0.100 - 0.070)\$2,000,000 = \$600,000$$

$$2. \quad V = (0.070 - 0.070)\$2,000,000 = \$0$$

$$3. \quad V = (0.050 - 0.070)\$2,000,000 = \$ - 400,000$$

The conclusion is clear. Only if the utility earns an r in excess of k will rate-base treatment of items typically expensed create shareholder value.⁶⁴

An interesting application of this approach evolved out of the distributed generation incentive investigation in California.⁶⁵ In that case, the administrative law judge proposed that a 4 percentage point pre-tax return be applied to the payment the utility makes to a third party provider of distributed energy resources, a payment that normally would earn no return for utility shareholders. This is not a perfect match for ratebase treatment, however, as there appears to be no depreciation component in the incentive mechanism.

⁶² The net (depreciated) value of utility investment used to provide service, including working capital.

⁶³ Operating expenses are those associated with short-lived activities, such as salaries and fuel. Those costs tend to be fully recovered in the year they are incurred.

⁶⁴ This does not imply that regulators should necessarily allow utilities to provide rate-base treatment for cloud computing. See Janice Beecher's section for discussion of this issue.

⁶⁵ See Proposed Decision of ALJ Hymes, Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning and Evaluation of Integrated Distributed Energy Resources, CPUC Rulemaking 14-10-003, Nov. 10, 2016, p. 58.



Formula rates

Under the traditional regulatory model, utility rates are set at discrete intervals. Formula rates serve as an alternative approach, one in which rates automatically adjust, typically when the utility's earned return on equity falls outside a given range.⁶⁶

Lowry and Makos provide a high-level overview of formula plan rates (FRPs), as cited in a prior report in the Future Electric Utility Regulation series:

Proponents of FRPs cite some of the same benefits that are attributed to multiyear rate plans. Regulatory cost is markedly lower than frequent rate cases. Formula rates can mitigate rate shock. Senior utility management can devote more attention to their basic business. Operating risk is reduced, and utilities are less likely to experience significant over- or underearning. A common argument against FRPs is that they reduce incentives for a company to operate efficiently.⁶⁷

Formula rates are essentially another de-risking approach, but they generally apply to a utility's entire revenue stream rather than individual costs. This typically does not allow for differential, asset-specific treatment, as all assets are essentially treated the same.

This approach might lower the cost of equity slightly, as it insulates the utility from systematic macro risks, such as the possibility of lower sales due to a recession. If the regulator makes no adjustment to the return on equity to reflect the risk reduction, r stays the same, but k declines. Returning to the original base case example, and assuming that the cost of equity drops from 7.0 percent to 6.5 percent, the substation is still preferred under the formula rate approach.

Traditional Regulation (Initial Base Case)

$$\text{Substations: } V = (0.100 - 0.070)\$500,000,000 = \$15,000,000$$

$$\text{Two Way Flows: } V = (0.100 - 0.070)\$400,000,000 = \$12,000,000$$

Formula Rates

$$\text{Substations: } V = (0.100 - 0.065)\$500,000,000 = \$17,500,000$$

$$\text{Two Way Flows: } V = (0.100 - 0.065)\$400,000,000 = \$14,000,000$$

Recall that the expected effective return under traditional regulation is not necessarily the authorized return, but rather could reflect the chance of disallowance. While formula rates may stabilize short-run returns, they do not insulate the utility from potential disallowances over the long run. So substituting the lower effective returns from the earlier example leads to the following result.

⁶⁶ Moody's Investors Service (2016).

⁶⁷ Wood et al. (2016). See also Hemphill and Jensen (2016).



Formula Rates

Substations: $V = (0.098 - 0.065)\$500,000,000 = \$16,500,000$

Two Way Flows: $V = (0.085 - 0.065)\$400,000,000 = \$8,000,000$

The formula rate doesn't change the situation in terms of managerial preference (assuming no special adjustments).

The investor-owned utilities helped most by formula rates are those that struggle to earn an r that exceeds k . Say that the regulator authorizes a return on equity equal to the cost of equity, both set at 7.0 percent, but the utility has trouble earning the return. So its expected return on equity is only 6.5 percent.

Substations: $V = (0.065 - 0.070)\$500,000,000 = -\$2,500,000$

Two Way Flows: $V = (0.065 - 0.070)\$400,000,000 = -\$2,000,000$

If the utility has to pick one project, the two-way power flow option is the lesser of two evils because it destroys less shareholder value. (If the utility can avoid both projects, it should.)

Unless the formula rate treats different asset types differently, it is difficult to see that it would have a major effect on the incentive for the utility to invest in grid modernization equipment. On the other hand, if there were an opportunity for differential treatment, the conclusion could be different.

Sharing mechanisms (sliding scale)

One way to increase the return on equity is to use a sharing mechanism, sometimes referred to as a *sliding scale*.⁶⁸ This approach involves splitting returns over and above the authorized level between the utility and its customers. If the return lies below the target there may be some sharing of the net loss.

The implications for grid modernization investments under a sliding scale approach are unclear. Grid modernization-related items appear to take on no more or less prominence than they would under traditional regulation. If the approach affects the choice of expenses versus capital spending, the mix of resources might change, but the attractiveness of a grid modernization expense relative to a payroll expense would appear to be unchanged by the implementation of a sharing mechanism. The same would appear to hold for grid modernization-related capital investments relative to conventional assets.⁶⁹

Such general regulatory reform approaches have advantages and disadvantages. If regulators are interested in specific technology types, then general approaches such as sharing mechanisms need to be modified to send signals to incent specific activities. That said, however, some policymakers suggest that making such modifications requires that regulators pick winning

⁶⁸ Lyon (1996).

⁶⁹ Lowry and Woolf (2016) and Lowry, Makos, and Deason (forthcoming).



technologies. Under the pure form of sharing mechanisms, the most cost-effective technologies emerge more naturally. Those resources might or might not include grid modernization investments. This leads to a critically important question, the answer to which is beyond the scope of this chapter — are regulators trying to make the grid most cost-effective or are they trying to modernize it? The paths to each could be different. Janice Beecher looks more closely at such issues in her chapter.

Performance-based incentives (rewards/penalties)

Under this approach, the utility's earned return on equity depends in part on the ability of the utility to meet explicit goals. These can be specific performance targets under standard regulation or part of a multiyear rate plan approach.⁷⁰ If the regulator sets grid modernization goals with clear performance metrics, then there could be an incentive to take such action.

This takes us back to the discussion of granting a higher return for grid modernization efforts. The approach works its way through the ratemaking process differently, but the end result may be the same as shown earlier:

$$\text{Substations: } V = (0.100 - 0.070)\$500,000,000 = \$15,000,000$$

$$\text{Two Way Flows: } V = (0.120 - 0.070)\$400,000,000 = \$20,000,000$$

The topic of performance-based incentives has generated a vast literature. The variants of this approach are many. Because performance-based incentives provide for very specific performance targets, this approach could provide a strong incentive to modernize the grid.

Lowry and Woolf⁷¹ provide a useful list of grid modernization metrics that could be used under this approach:

- Energy efficiency (EE): Indication of participation, energy and demand savings and cost effectiveness of EE programs
- Demand response (DR): Indication of participation, demand savings and cost-effectiveness
- Distributed generation (DG): Indication of the technologies, rate of DG penetration, energy and demand savings, and cost-effectiveness
- Energy storage: Indication of the technologies, capacity and growth of utility and customer-sited storage installations and their availability to support the grid
- Information availability: Indication of customers' ability to access their usage information
- Time-varying rates: Indication of saturation of time-varying rates
- Electric vehicles (EVs): Indication of customer adoption of EVs and their availability to support the grid
- Advanced metering capabilities: Indication of metering functionality

⁷⁰ See Lowry and Woolf (2016).

⁷¹ Ibid.



- Interconnection support: Indication of DG installation support
- Third party access: Indication of network access by third party developers
- Provision of customer data: Indication of customer access to relevant data

In the context of this report, the issue is whether these performance metrics allow the utility to create more shareholder value than other resource choices.

Nevertheless, the framework discussed in this chapter makes it clear that simply being rewarded for taking some action by earning a higher return does not necessarily mean that the utility has an incentive to take that action. Investment scale (I) is critically important in the shareholder value construct. In some cases, investor-owned utilities may create more shareholder value by acquiring large conventional resources even if the return those assets earn is lower than, and the risk associated those assets is higher than, the return and risk associated with grid modernization activities.⁷²

Price caps

Price caps are sometimes viewed as a form of performance-based ratemaking, but I separate them out here to discuss some of the details. Under this approach, the regulator gathers information from utilities and sets a price that increases at a rate equal to the inflation rate less a productivity factor. This is often referred to as the CPI-X approach, where CPI is the consumer price index and X is a productivity factor adjustment. The rate schedule then applies to the utility for a long period, such as five to eight years.

This approach is not likely to provide incentives for grid modernization for a variety of reasons. First, it probably increases the cost of equity to some extent because it increases the utility's exposure to macroeconomic risk. All else equal, the gap between the return (r) and the cost of equity (k) narrows. The utility can increase r in a number of ways, one of which is reducing expenses. If grid modernization involves expenses, and if investor-owned utilities can maintain service without making them, at least in the short run, they are more likely to be cut under this approach. The empirical evidence suggests that utilities appear to scale back on capital investment under this approach.⁷³

Therefore, even though the rates are set for a long period, if regulators don't impose specific conditions on utilities, this approach could encourage utilities to focus on the short-run, cutting expenses and reducing investment. This seems antithetical to a policy that promotes long-term changes to the grid. Careful incentive design requires that regulators impose conditions to prevent such unintended consequences.

Conclusion

If financial conditions for electric investor-owned utilities remain similar to where they stand today, and if the risk of different utility asset options — including grid modernization alternatives — is about the same, then investing in the largest asset (in terms of dollars) creates

⁷² Kihm, Cappers, and Satchwell (2016b).

⁷³ Roggenkamp et al. (2012).



the most shareholder value for the present shareholders. It also would meet utility managers' typical preference for growth. Under these conditions, if grid modernization requires the most capital of any expansion plan, the utility will prefer it.

That conclusion, however, merely sets up the key questions that need to be addressed by regulators when considering the need for grid modernization incentives.

- *Are utility financial conditions and the macroeconomic environment stable, or are we likely to experience substantial change?*

An unstable environment could make utility managers reluctant to invest in any type of asset.

- *How does the risk of grid modernization investments compare with that of conventional assets?*

If the scale and expected return on grid modernization investments are the same as they are for conventional utility investments, but grid modernization investments are riskier, managers may prefer more conventional investments.

- *Does grid modernization provide greater opportunities than conventional investment for investor-owned utilities to create value for their current investors?*

This is the ultimate financial question. This chapter provides a framework to consider it specifically for any utility. It's all about the risk, return and scale of the utility's various resource choices.

Regulators evaluating any potential grid modernization investment, and any incentive mechanism to facilitate such investments, must address all of these questions in the context in which they operate. For example, in Wisconsin a specific statute permits the regulator to fix a utility's allowed return on a particular project for an extended period (up to 25 years).⁷⁴ This provides a flexible option beyond traditional regulation. In other cases, institutional arrangements restrict regulatory action. For example, in Illinois the authorized return on equity for electric utilities is set by statutory formula — the U.S. Treasury bond yield plus 580 basis points.⁷⁵

In addition to institutional differences, investor-owned utilities operate under different market structures. An urban distribution utility operating in New York, where generation is deregulated, faces different issues from those facing a fully regulated utility operating in rural South Dakota. The end result with respect to grid modernization is that regulatory solutions are likely to vary, perhaps considerably, from state to state.

⁷⁴ See Wis. Stats. § 196.371 Ratemaking principles for electric generation facilities.

⁷⁵ Hemphill and Jensen (2016).



One point that needs to be stressed is that this piece is highly analytical, assuming rational economic actors with no political adjustment. That leads us to Kahn’s overarching discussion of regulatory economics:

We have stated that we are interested in the principles that govern regulation and “the principles that ought to govern it.” What policy ought to be is a topic about which the politician and political scientist, sociologist, philosopher and clergyman, and indeed in a democracy, anyone who votes has important and relevant things to say. Public economic policies are not, cannot and should not be framed on the basis of “purely economic” considerations alone. Economic institutions and policies are in the last analysis only means to ultimately noneconomic ends.⁷⁶

Rather than providing specific recommendations on what actions to take, this chapter provides a framework that allows regulators to understand current incentives and disincentives for grid modernization and how their decisions could change the regulatory conditions that create them. Much like a chapter in a novel, this section does not stand alone. It should be read in concert with the other chapters prepared by my colleagues Janice Beecher and Ron Lehr. This triangulation of perspectives provides a rich exposition of the existence, or lack thereof of, grid modernization incentives, and any need for regulatory responses.

⁷⁶ Kahn (1988), 14.



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2. Institutional Perspective: The Role of Incentives in Public Utility Regulation

By Janice A. Beecher, Ph.D., Institute of Public Utilities, Michigan State University⁷⁷

Introduction

The global and U.S. energy sectors are undergoing intense technological and policy transformation. A centerpiece of this movement is grid modernization, including but not limited to infrastructure along the supply chain for power. The driving goals of modernization are to enhance system reliability, security, and resilience; responsiveness to variable and uncertain conditions; affordability and economic prosperity; and environmental sustainability through the development of clean and efficient energy resources.⁷⁸ Grid modernization is meant to enable the “utility of the future,”⁷⁹ expectantly to the benefit of the “customer of the future” and society.

Without a doubt, technological opportunities, business models, and market structures in the electricity sector are evolving at a remarkable pace in search of the trifecta of reliable, affordable, and clean energy services, the priority of which depends on perspective. At issue is whether incentives to utilities, particularly those embedded in the traditional economic regulatory paradigm and ratemaking model, are sufficient to help achieve state and federal grid modernization goals, or whether alternative approaches and incentive mechanisms are needed and justified. In other words, is reform toward an entirely new regulatory paradigm in order?

Economic regulation of public utilities is a particularly critical piece of the public policy portfolio. The vast majority of the U.S. electric utility sector, as measured by energy production and sales, is privately owned. While some industry segments involved in organized wholesale generation markets are subject to a structured form of competition and are essentially price-deregulated, privately owned monopolies with integrated operations that include generation or in the business of transmission or distribution are invariably subject to economic regulation; that is, prices and profit potential are authorized by the state. Intrastate companies providing integrated or distribution functions are subject to regulation by state public service or public utility commissions (PUCs). Based on their interstate character, electricity transmission companies are subject to regulation by the Federal Energy Regulatory Commission (FERC).

An inherent tension between what is understood as traditional economic regulation and the goals of market transformation and infrastructure modernization is widely presumed. A central argument is that regulation in general, and the ratebase/rate-of-return (RBROR) methodology specifically, are at best insufficient and at worst barriers to technological progress. Supposedly, “old-school” economic regulation provides weak and sometimes conflicting incentives, if not disincentives, for grid modernization, clean energy, and other socially beneficial investments. How to motivate utilities toward economic efficiency and technological innovation, of course, is

⁷⁷ The author takes full responsibility for all views expressed here, but is grateful for the insights of the series editor, Lisa Schwartz, and reviewers Timothy Brennan, David Dismukes, Danny Kermode, Tommy Oliver, and Kenneth Rose.

⁷⁸ Adapted from U.S. Department of Energy’s Grid Modernization Multi-Year Program Plan (2015).

⁷⁹ Also known as “next generation utility” or “21st century utility.”



hardly a new question in the field of regulation. In terms of the pace of change, it is widely held that utilities lag behind other sectors and regulators lag behind utilities.⁸⁰ However, motivating utilities toward evolving social ends should not automatically be viewed as outside of the scope of the paradigm or beyond the model and the means already available to economic regulators.

The presumption of regulatory failure in this context rests on a false dichotomy between what many regard as “traditional” regulation and “incentive” regulation, as if the relevance to regulation of both performance and incentives is somehow revelatory.⁸¹ In many cases, compensatory pricing models and rate design in support of emerging utility business models are confused or conflated with the regulatory paradigm writ large. In reality, all regulation is and has always been imbued with performance expectations and economic incentives; that “all regulation is incentive regulation” is a well-worn adage.⁸² Necessary corollaries are that incentives are not always well aligned and consistent, incentives can be both used and abused, and incentive regulation should impose regulatory risk, so attention to the details of implementation and enforcement matters.

To neglect the power of economic regulation to limit, channel, and mold the behavior of regulated firms is to neglect the very purpose of “regulation in the public interest” and the obligation of regulators to cogently deploy the tools at their disposal. The design and effect of particular incentive mechanisms can be debated, but not their basic intent or potential value. In the hands of capable regulators, and guided by clear requirements, the traditional model actually provides very powerful performance incentives. Put differently, the granting of an exclusive franchise to a monopoly by the state has strings attached.

This essay offers a general institutional perspective on the role of incentives in utility regulation, stipulating to the economic theory that incentives “work.”⁸³ It is postulated that the traditional regulatory paradigm and ratemaking model are well proven, very accommodating, and actually well suited to the policy objectives of infrastructure modernization, perhaps more so than many seem to think. Of course, effective implementation is key.⁸⁴

One objective of this essay is to push back on the apparent impulse toward a “new paradigm” that will better “incent” utilities toward technical and economic modernization. The focus here is not on whether the policy objectives associated with incentive mechanisms are worthy or on

⁸⁰ For a discussion of these issues, see Costello (2016).

⁸¹ Three iconic treatments of the economic regulation of utilities are those by Bonbright (1962), Phillips (1984), and Kahn (1988).

⁸² The phrase has been attributed to Peter Bradford and its inspiration to Alfred Kahn. Bradford (1992) wrote that “all ratemaking is incentive ratemaking.” Another rendition is that “all regulation rewards performance” (Biewald, et al., 1997).

⁸³ Not all disciplines see incentives the same way. According to psychologist Barry Schwartz, author of *The Paradox of Choice*, “Too little attention is paid to the dark side of incentives. They are anything but a magic bullet. Psychologists have known this for years, but it seems largely hidden from the world of commerce... The truth is that there are no incentives that you can devise that are ever going to be smart enough. Any incentive system can be subverted by bad will... When you rely on incentives, you undermine virtues. Then when you discover that you actually need people who want to do the right thing, those people don’t exist because you’ve crushed anyone’s desire to do the right thing with all these incentives...”

⁸⁴ As utility executive John Rowe once put it, “The rat must smell the cheese.”



the particular mechanics of their application.⁸⁵ Rather, consideration is given to the rationale for incentives, their consistency with regulatory theory and principles, and the implications of their use for wealth transfer. Another objective is to advance the idea that what might be needed is not a new paradigm, but a new conception of prudence within the regulatory compact, informed by tools available to utilities and enforced by tools available to regulators.

The Regulatory Compact

The fundamental purpose of regulation is to correct market failure in order to serve the public interest. Markets can fail in a variety of ways; economic regulation focuses primarily on market failure as manifested by market power, particularly in the form of monopoly. Monopolies, which may be owned or sanctioned by the state, are defined in terms of absolute market dominance by a single firm. Unregulated monopolies and tight oligopolies (firms with unbridled market power) are unlike competitive firms that must continually work hard and perform well to maintain or gain market share.

In the absence of competition, economic regulation imposes behavioral discipline and provides incentives for both efficiency and, relatedly, innovation. Where competition will drive prices toward the marginal cost of production and returns toward the cost of capital, unchecked market power will allow service to suffer and prices to creep higher than efficient levels, resulting in both windfalls to the firm and welfare losses to society. In addition to efficiency, regulation also helps to ensure economic equity, which markets tend to neglect.

The guiding paradigm for economic regulation in the United States, reinforced by more than a century of jurisprudence, centers on a social compact under which investor-owned utilities fulfill a “public convenience and necessity” and thereby serve the interests of the state.⁸⁶ The compact can be understood as a living charter; the standards, incentives, and accountability organized under it have co-evolved. Importantly, the compact is not between the regulatory *agency* and the utility, but between the institutional *state* and the utility. The regulatory compact is seen here through the eyes of the state; regulated utilities may see it differently.

Any doing or undoing of the regulatory compact necessitates a determination by the state with the consent of the people. The compact is freely entered and attaches various rights and obligations to the utility’s exclusive franchise. For public policy reasons, the state can exercise its coercive powers by conditioning the compact with various terms and enforce these terms through regulation. Chief among these may be compliance with basic performance and service standards for safety, reliability, and quality that may come from the economic regulator, other governmental agencies, or even private self-regulatory bodies.⁸⁷

In accordance with the compact and the U.S. Constitution, utility investors are entitled to fair compensation for devoting private capital to a public purpose and for providing service

⁸⁵ See Kihm in this report.

⁸⁶ “A railroad is a public highway, and nonetheless so because constructed and maintained through the agency of a corporation deriving its existence and powers from the state. Such a corporation was created for public purposes” (*Smyth v. Ames*, 169 U.S. 466, 1898).

⁸⁷ These include standards-setting boards for public utility accounting and electricity system reliability.



consistent with all applicable mandates and specified conditions. Fundamentally, regulated utilities are entitled to have “a *reasonable* opportunity to earn a *fair* return,” and the compact navigates them along a path to profit.⁸⁸ Despite common assertions to the contrary, however, the compact guarantees neither cost recovery nor returns, as both depend on utility performance between rate cases and over time. Nor does the compact guarantee investment opportunity, sales growth, or corporate survival in perpetuity.

The regulatory compact also provides a means of allocating risks and rewards; utilities operating under the compact are not supposed to be shielded from all economic or business risks nor denied the rewards that come with effective risk management. Regulated utilities should not be viewed as entirely different from private firms operating in the competitive environment. For utilities, the state supplies regulatory risk in the absence of market risks.⁸⁹ The state could choose to shift all risks to ratepayers, guaranteeing full recovery of all costs incurred and ensuring realization of authorized returns, but this would negate the value of a structural model centered on private investment and prompts the question of whether the state should instead assume public ownership and operation of the utility.

As utility managers and financial markets will generally cultivate “shareholder value,”⁹⁰ regulators should tend to “ratepayer value.” Economic equity under the compact takes the interests of captive ratepayers into consideration with respect to the burdens of costs and risks, and how they are allocated. Regulators consider cost causation within and across customer classes and generations, and thus the parameters “due” and “undue” price discrimination. Regulators also have latitude with regard to “legal equity” as expressed by the “just and reasonable” standard for ratemaking. Traditionally, however, broader issues of “social equity” requiring democratic deliberation and wealth transfer are considered beyond the economic regulator’s intended purview or “remit.”⁹¹ Constitutional or statutory provisions for environmental and distributive justice are exemplary. Regulators must be cautious about exceeding the boundaries of their jurisdiction and authority, as activism may jeopardize their institutional independence and efficacy (more on activism later).

This complicated balancing act is not about splitting differences but rather about divining the public interest through fair processes that encompass a wide range of issues and perspectives and take into account the asymmetry of information and the differential political power of affected interests. In the discharge of their formidable duties, the compact presumes that regulators will be politically independent and uncaptured by regulated firms.⁹²

Ratebase/Rate-of-Return Regulation

Across the United States, regulatory theory and generally accepted regulatory principles established throughout the twentieth century are relatively consistent, despite the heterogeneity of market structures and policies and the diversity of state regulatory jurisdiction, authority, and methods. In accordance with the compact, ratebase/rate-of-return (RBROR)

⁸⁸ Beecher and Kihm (2016).

⁸⁹ In Wall Street terms, fear balances greed.

⁹⁰ See Kihm in this report.

⁹¹ Kerin (2012).

⁹² On the problem of regulatory capture, see Carpenter and Moss (2013) and Beecher (2008).



regulation serves as a conditional proxy for competition, providing incentives for efficiency while holding utilities accountable for meeting their obligations and taking equity into account.

As a core function under the regulatory compact, ratemaking “math” for utility monopolies takes the following general form:

$$RR = r(RB) + O\&M + D + T$$

where:

RR = test year (annualized) revenue requirements

r = authorized (not guaranteed) rate of return to compensate debt holders and equity shareholders

RB = ratebase (original cost of invested utility plant in service net of accumulated depreciation and adjustments)

O&M = operation and maintenance expenses (including administrative and general)

D = depreciation and amortization expense

T = income and other taxes

Revenue requirements (RR in the formula) are established in accordance with uniform systems of accounts and allocated across usage according to billing determinants, resulting in what are regarded as “cost-based rates.”⁹³ Every element of the ratemaking formula is subject to regulatory scrutiny. Although somewhat misleading, the RBROR model is sometimes referred to as “cost-plus” ratemaking, or even as a means of “guaranteed” profit. Assuming that the regulator is informed and independent, the allowance of any particular capital or operating expenditure or the granting of returns should *never* be automatic or formulaic. Utilities are expected to operate with “reasonable economies.” For each capital or operating expenditure, the utility bears the burden of proof to support its necessity, and the regulatory agency bears the responsibility to examine and evaluate the evidence brought before it. Each expenditure item and the performance associated with it is subject to audit, review, and approval.

Administrative procedures and legally established standards of review guide the process, but judicial deference enables regulators to operate with a zone of reasonableness, where they exercise considerable discretion and can make pragmatic adjustments in ratemaking. The rate case decision is the sum of many parts, supported by an evidentiary record, and regulators must consider this totality in terms of the package of incentives it represents.

Under the ratemaking model, as originally constituted, utilities file a general rate case affording the regulator review of each element of proposed revenue requirements. Over time the model has been modified. Sometimes through “legislative ratemaking,” utilities have won approval to use a myriad of cost trackers and adjustment mechanisms; these make for gradualism in rate changes based on incremental fluctuations in costs but shift revenue risk from the utility to the ratepayer. Initially, to be eligible for recovery under these mechanisms, a cost would have to be

⁹³ Billing determinants are the factors or drivers associated with usage by customers.



(1) substantial, (2) recurring, (3) volatile, and (4) largely outside of the utility's control. Fuel inputs (purchased gas or other energy) meet these criteria. However, the application of these mechanisms has been greatly expanded, even to include capital costs that might be substantial but do not comport with the other criteria. While cost review and reconciliation proceedings are required, the effect has been to largely automate the cost-recovery process and thus weaken associated efficiency incentives.

The monopolistic character of infrastructure-oriented enterprise is central to the compensation of utilities under the RBROR model. The most salient elements in terms of profit-centered incentives are the ratebase (RB) and the allowed "fair" return applied to it (r). The ratebase is comprised of prudent capital investment in utility plant in service and devoted to public use (that is, "used and useful" to the rate-paying public). The granting of a certificate of public convenience by regulators may establish need and potential merit, but its prudent fulfillment is a separate matter, and expenditures are generally not pre-approved. As utility services are highly capital intensive, the value of the ratebase can be an ample value to which the overall rate of return is applied.

The ratemaking formula provides both a return on (r) and a return of (D), the company's capital investments over time. Depreciation expense provides cash flow for possible reinvestment, and accumulated depreciation offsets the original value of assets in determining the ratebase. Returns on operating expenses are not consistent with economic or regulatory principles, which focus on the problem of recovering the monopoly's long-term capital costs for long-life assets over long time periods (formally, the problem of average cost exceeding the marginal cost of production). Though imprecise and a matter of judgment, amortization methods that help align cost recovery to expected service life comport with conceptions of intergenerational equity (that is, that idea that one generation of customers should not subsidize another).

Utilities finance capital through a combination of debt and equity. Revenues generated from the weighted return (r) are used to compensate the utility's debt holders (bonds and loans) and equity shareholders. The cost of debt is determined by the debt market; the cost of equity is based on a regulatory assessment of comparable risk. Authorized returns to shareholders will be somewhat higher than the cost of capital, reflecting both upside and downside risks, including the risk of losses. In the theoretic of perfectly competitive markets, returns are equal to the cost of capital and prices are equal to marginal costs.

For public utilities, setting returns equal to the cost of capital would make them indifferent to capital investment.⁹⁴ Regulators are pressed hard to give weight to financial considerations, although they should be circumspect with regard to assertions about riskiness and capital attraction.⁹⁵ By long-standing practice, regulators set a "fair" return to a level that is typically higher than the cost of capital, which is also reflective of imperfectly competitive markets.⁹⁶ The utility's actual cost of capital incorporates both a "risk premium" (above the rate of risk-free Treasury bonds) to provide compensation based on comparable risk and a "return premium" to

⁹⁴ See Gordon (1974), Kahn (1988), and Train (1991).

⁹⁵ See Kihm in this report.

⁹⁶ Beecher and Kihm (2016).



motivate the utility to pursue socially beneficial investment.⁹⁷ In many respects, a compensatory return sets a floor and a fair return sets a ceiling, creating an effective earnings band.

Returns authorized by regulators are *intentional* although still not guaranteed; utilities must reach for them and performance deficits and disallowances will make their achievement more difficult. Where there is opportunity for return, there also should be risk of loss. The goal of economic regulation is not to ensure profitability, but to provide fair compensation that will support the financial viability of firms providing essential utility services. Viability rests on fair returns to investors, but not all utility businesses will be profitable all the time, and the state does not render this promise. These distinctions are subtle but important in a context where much effort is devoted to the financial interests and incentives of regulated utilities under changing conditions.

Incentives under ratebase/rate-of-return regulation

Private ownership of monopolistic utilities allows not only for the deployment of private capital but also for the strategic use of economic incentives. Return on investment is a central incentive mechanism under the RBROR model. The potential for profitability is a mathematical function of ratebase value and authorized returns. However, the perceived advantage of the model in terms of motivating investment is simultaneously its perceived disadvantage if necessary checks on investment decisions to ensure protection of ratepayer interests are not in place.

Other things being equal, utilities operating under this model will have a propensity to invest, including a preference for capital over operating expenditures (known as the *Averch-Johnson* or *A-J effect*) and a temptation to “gold-plate” (overspend) to inflate the ratebase above an economically efficient level.⁹⁸ Historical and contemporary evidence suggests that utilities respond to the investment incentives provided by regulators. A prominent contemporary example is the effect of FERC’s compounding return incentives in terms of accelerating electricity transmission investment.⁹⁹

Regulated utilities must perform well under the RBROR model in order to realize their authorized returns. Both imprudence and inefficiency will be costly to utility shareholders, as excess expenditures between rate adjustments and disallowed expenditures during rate adjustments are effectively charged to them (“below the line”). It might appear controlling, but economic regulation provides but one set of incentives among other exogenous and endogenous factors affecting utility performance (Figure 2-1). Economic regulation is exercised within an expanse that includes other administrative and regulatory policy domains.

In fact, economic regulation can be understood as a constrained optimization problem, where various policies and mandates limit options and discretion. Arguably, regulators best serve

⁹⁷ Since 1990, as measured by the spread between authorized returns for the electricity industry and 10-year or 30-year treasuries, the aggregate premium for electric utilities has grown even as nominal authorized returns have declined. See UBS Global Research (January 11, 2017). <https://neo.ubs.com/shared/d1Ys5gA90c>.

⁹⁸ Averch and Johnson (1962). Empirical evidence of the AJ effect has been disputed; see S. Law (2014).

⁹⁹ Federal Energy Regulatory Commission Order No. 679 (July 2006). See Actual and Planned Transmission Investment 2006–2016 and EEI (2013),

www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/finreview/PublishingImages/bar_pln_trans.jpg and http://www.eei.org/issuesandpolicy/transmission/Documents/transmission_investment.pdf.



society by evaluating prudence and promoting economic efficiency within the constrained space. For their part, utilities will always have an information advantage over their regulators, which is why setting broadly effective regulatory incentives are so important and generally preferable to isolated incentives or micromanagement.

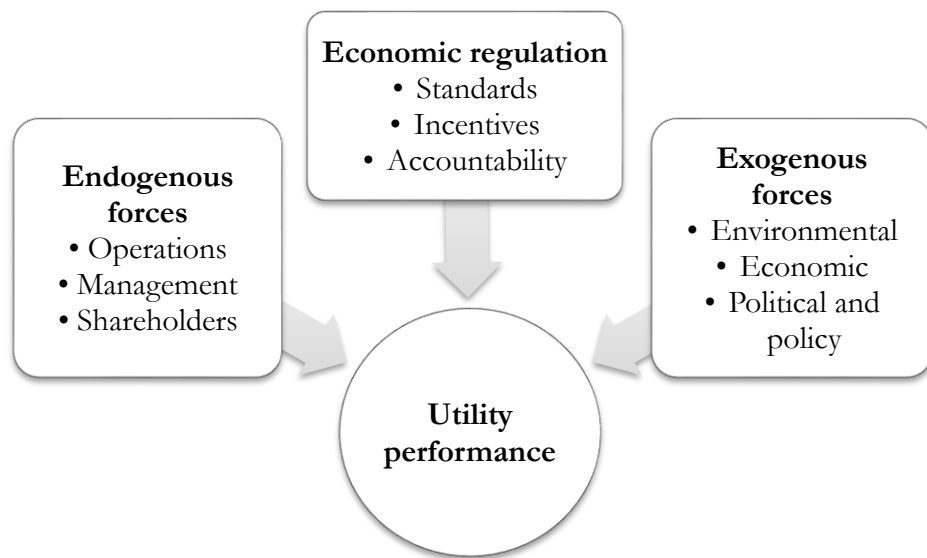


Figure 2-1. Factors affecting utility performance

Incentive-based tools under ratebase/rate-of-return regulation

A variety of incentive-oriented tools can be deployed under the traditional regulatory model as it approximates the forces that would shape performance in a competitive market. Three primary tools are regulatory lag, prudence reviews, and incentive returns.¹⁰⁰ Regulatory lag is a relatively passive tool, prudence reviews are largely reactive, and incentive returns are more proactive. Table 2-1 provides an expanded list of tools.

Rate cases are obviously central to economic regulatory incentives, as cost recovery is a function of rates under authorized tariffs. When costs are rising or sales are falling, utilities file rate cases on a regular basis. Although a blunt instrument and much maligned, regulatory lag under the

¹⁰⁰ Beecher and Kihm (2016).



Table 2-1. Incentive tools deployed under the traditional regulatory model

		Investment	Performance		
			Cost control	Efficiency	Innovation
Return on investment	Premium embedded in the fair return to promote infrastructure investment	☐			
Financial accounting and reporting	Transparency in capital and operating expenditures and performance		☐		
Cost recovery	Disallowance of imprudent capital or operating expenditures		☐		
Regulatory lag	Time period between cost incurrence and an authorized rate adjustment		☐		
Prudence reviews	Sound managerial decisions based on knowable information			☐	
Financial audits	Detailed review of general or project-specific financial indicators			☐	
Management audits	Detailed review of general or project-specific management practices			☐	☐
Price freezes or caps	Extension of regulatory lag to a multiyear rate period			☐	☐
Certificate of public convenience	Review of planned capital expenditure to ensure its necessity			☐	☐
Integrated resource planning	Balanced consideration of supply-side and demand-side management options			☐	☐
Performance standards	Specified terms of service to ensure acceptable performance			☐	☐
Incentive returns	Bonus above fair return tied to performance to promote innovation				☐



traditional model provides an intentional and salutary means by which regulators, substituting for markets, exert pressure on private monopolies to control costs.¹⁰¹ Whether by design or accident, lag should be “regarded as not a deplorable imperfection of regulation but as a positive advantage.”¹⁰² At the time of a rate case, the utility is strongly motivated to properly account for the cost of service and sales revenues anticipated for the rate “test year”; managers might even attempt to inflate costs to provide additional headroom to exploit after rates are set. Regardless, utilities that are able to control costs and find efficiencies between authorized rate adjustments are more likely to realize their allowed returns (Table 2-2).

Table 2-2. Regulatory lag: factors affecting achievement of returns between rate cases

		Efficiency trend between rate adjustments	
		Increasing operational efficiency	Decreasing operational efficiency
Cost and sales trends between rate adjustments	Falling costs and/or rising sales	Achieving authorized returns is likely	Achieving authorized returns is possible
	Rising costs and/or falling sales	Achieving authorized returns is possible	Achieving authorized returns is unlikely

At times, it can appear that utilities and their trade associations have put more effort into reducing regulatory lag than into reducing operating costs. The utility industries and credit rating agencies consistently identify methods to reduce lag as precedential “innovative” or “best” practices adopted by states with “constructive” regulatory environments.¹⁰³ In some cases, the problem may not be *regulatory lag* but *utility lag* in strategic management, including forecasting costs and sales revenues, accounting for price elasticities and other relevant factors in rate proposals, and making timely, complete, and convincing regulatory filings.

Risk-shifting cost-adjustment and revenue-assurance mechanisms have proliferated, although authorized returns have remained mostly intact. Although promoted to reduce regulatory

¹⁰¹ Describing the several different conceptions of lag is beyond the scope here. Some lag, such as administrative lag caused by under-resourcing regulatory agencies, can be deleterious.

¹⁰² Alfred Kahn (1971), Vol. 2, p. 48. Kahn continues to say, “Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their opposites.”

¹⁰³ For a survey of states, see Lowry, Makos, and Waschbusch (2015).



expense by reducing rate-case frequency, these methods can actually make regulation more costly and cumbersome by replacing a comprehensive rate case with multiple reconciliation cases, which might then be waived with desultory review. By shifting risk from investors to ratepayers, these mechanisms weaken incentives and distort behavior, including choices between capital and operating expenditures, and weaken regulatory oversight by making it more passive and automatic. The administrative savings could pale in comparison to the efficiency losses.

To their chagrin, utilities find that regulators “claw back” these savings in the subsequent rate case. Of course, the same phenomenon occurs in competitive markets, where firms must innovate continuously to maintain or grow revenues and market share. Regulators can impose price freezes for a multiyear period or adopt a price-cap regime to formalize or institutionalize regulatory lag.¹⁰⁴ However, utility acquiescence may hinge on whether various adjustment mechanisms or formulas are also put in place to shield them against rising costs or falling usage. Any ratemaking regime will not be tolerated for long if it results in insufficient or excessive returns.

Price-cap regulation has been implemented as an alternative to RBROR regulation and was the model of choice in the United Kingdom (UK) using the RPI-X formula,¹⁰⁵ even though the two methods actually have commonalities, including an initial assessment of revenue requirements and returns. Price caps typically are set for multiple years and include adjustments for anticipated productivity gains as well as inflation.¹⁰⁶ In reality, price caps will likely act not as a ceiling but a floor because monopolies by definition face no competitive pressure to price below allowed levels.¹⁰⁷

Understandably, utilities will be more amenable to price-cap regulation in a declining cost environment, as was the case when it was applied during the transition of the U.S. telecommunications sector to competition. Price caps are often supplemented by performance benchmarks to ensure that utilities do not degrade service to avoid costs and enhance earnings. Price caps make utilities price takers that can retain cost savings.¹⁰⁸ In theory, the extent to which price caps motivate utilities toward investment, such as grid modernization, depends on whether overall costs under the cap can be reduced by making selective capital or operating expenditures on the supply or demand sides.¹⁰⁹ With the RBROR framework, multiyear rate plans have been approved for some U.S. electricity and natural gas utilities, but typically are combined with adjustment factors and other mechanisms (including revenue decoupling) to limit shareholder risk.¹¹⁰

¹⁰⁴ Joskow (2008).

¹⁰⁵ RPI-X stands for Retail Price Index (RPI) less expected efficiency savings (X). See <https://www.ofgem.gov.uk/>.

¹⁰⁶ Italy has implemented a hybrid model of ratebase regulation for capital investments and price caps for operating expenditures. However, capital expenditures are essentially treated as a pass-through cost, suggesting potentially serious incentive issues related to prudence. See Lo Schiavo et al. (2013).

¹⁰⁷ On price caps and revenue caps, see Crew and Kleindorfer (1996).

¹⁰⁸ Brennan (1989).

¹⁰⁹ Lowry and Woolf (2016).

¹¹⁰ Costello (2016).



Regulators consider prudence in traditional rate cases as well as in focused prudence reviews of major and often complicated capital investment projects to ensure that expenditures are appropriate. Conventional utility projects can be compared to supply-side and demand-side investment and management alternatives that might avoid costs recoverable from ratepayers.¹¹¹ In the course of a rate review, imprudent expenditures can be disallowed, in which case prudent costs are imputed and equity shareholders absorb the difference. Utility managers will then face further accountability from their boards of directors. In this respect, incentives from public and private institutions of oversight can be synergistic. When these incentives fail, excess capacity, stranded investment, and financial losses may result.¹¹²

Allowing room for process improvement, the consistent application of generally accepted regulatory principles and standards of review can counterbalance the strong capital investment incentives embedded in the RBROR model. The risk of excessive investment and capacity applies to new technologies as well as old. No matter the promise or intent, not all expenditures related to infrastructure modernization will be beneficial. Prudence reviews can help ensure economic efficiency and ratepayer value. Regulators can step up their evaluation of prudence by conducting financial and management audits of utility practices. Certification, planning, and siting proceedings provide other venues for evaluating prudence.

Evolving technical standards are likely to play a key role in driving infrastructure modernization and may be as important as economic regulation. Regulators also set standards for both operational performance and the terms of service. Standards for utility performance have always been relevant to innovation. When standards are set, utilities and the industry at large will seek out methods of achieving them at the lowest cost if doing so will enhance the chance of realizing allowed returns. Performance standards may be established by regulators, but also by private organizations, sometimes rising to industry self-regulation, and adopted by regulators to the extent that the standards are consistent with public policy goals. Reliability and interoperability standards are exemplary. Once adopted, regulators can hold utilities accountable for compliant performance, assuming just compensation for the associated cost.

Given clear expectations and metrics, bonus returns can be used strategically to promote the achievement of specific performance targets. Importantly, prudent investment and efficient operations should be regarded as obligatory under the regulatory compact part and parcel of the job required of the sanctioned monopoly. The fair return allowed by regulators is actually more than compensatory by including a nominal return premium above the risk-based cost of capital. Extraordinary or bonus returns above the fair return should be allowed only for extraordinary performance consistent with efficiency criteria. An example would be accelerated adoption of technologies that confer clear benefits to ratepayers in terms of avoiding costs or enhancing service quality, subject to verification.

All regulatory incentives should have a clear purpose and measurable goals against which performance can be judged (more on incentive design later). As bonus returns constitute a transfer of value from utility ratepayers to utility shareholders they should also be used

¹¹¹ See PURPA and the evolution of purchase power agreements and demand-side management.

¹¹² Penn and Menezes (2017).



sparingly. Potential windfalls to shareholders should be compared to potentially less costly incentives, including managerial bonuses.¹¹³ Although positive performance incentives (carrots) may be appealing, the negative variety (sticks) may be easier for regulators to impose.

Incentives Under Traditional Regulation: Critique and Response

Critics of the RBROR model, and by extension the traditional regulatory paradigm, focus on what they see as embedded behavioral incentives that would appear to thwart expeditious progress toward achieving policy goals. Six distinct but interrelated incentives that for good reason have drawn considerable attention are:

1. Incentives that favor capital investment — the spending propensity;
2. Incentives that favor ratebase treatment — the technology neutrality issue;
3. Incentives that favor selling output — the throughput motive;
4. Incentives that favor high fixed charges — the rate-design dilemma;
5. Incentives that favor centralized technologies — the prosumer problem; and
6. Incentives that favor the status quo — the innovation challenge.

Each of these incentives is examined here with respect to their relevance to infrastructure modernization through an institutional lens and with an eye toward some parsing of regulatory fact and fiction.

1. Incentives that favor capital investment

Given the strong incentives for capital investment under the RBROR model, the insinuation that it may stand in the way of grid modernization by regulated utilities seems a bit disingenuous.¹¹⁴ It is unclear why today's grid investments, though "modern," would inherently be any less attractive to utility managers and investors than yesterday's grid investments. New technologies still tend to demonstrate the declining unit costs of production (scale economies) characteristic of utility monopolies. Indeed, grid modernization in the natural cycle of retiring and replacing aging infrastructure provides a tremendous capital investment opportunity (some would say a "golden" opportunity), particularly if public and regulatory policies shift risks from utility shareholders and managers to ratepayers.

Many managers will be drawn to the appeal of grid modernization projects, which can take the form of generation, transmission, and distribution upgrades; alternative power production and storage technologies; emissions controls; vehicle charging stations; advanced remote sensors; communications networks; smart meters; and more. A large advanced metering infrastructure (AMI) rollout, for example, can amount to hundreds of millions of dollars in expenditures, mostly by the utility, while also enhancing revenues from metered sales and even enabling prepayment.

The A-J effect further suggests that utilities of scale will tend to favor the inclusion of capital expenditures (capex) over operating expenditures (opex) in revenue requirements because the former will yield return potential, while the latter will not.¹¹⁵ In other words, tilting the mix

¹¹³ See Kihm in this report.

¹¹⁴ DeCotis (2016).

¹¹⁵ Smaller utilities may face constraints that alter economics and preferences.



toward capital investment can enhance profitability. The trend in electric utility ownership of upstream natural gas reserves, with regulatory consent, is illustrative.¹¹⁶ In some cases, it may be possible to lower revenue requirements and rates and maintain or increase earnings by trading a high-cost operating expenditure for a capital expenditure. Automation, for example, allows utilities to swap labor (an operating expenditure) for equipment (a capital expenditure). With grid modernization, advanced meters can displace meter readers and disconnection personnel, remote sensors can displace inspectors, security cameras can displace security guards, and so on.¹¹⁷

Modifications to ratemaking, including cost forecasting and “automatic” rate adjustments, can magnify incentives. Between rate cases, trackers provide a license to spend regardless of economic efficiency; not spending may be perceived as “leaving money on the table.” Recently popularized capital-cost surcharges may be problematic because the capex adder for infrastructure placed in service is not necessarily met by a capex offset for the infrastructure removed from service (that is, an adjustment to ratebase). The adjusted rates will capture for shareholders both the future returns on capex and the concurrent savings in opex. The extra cash flow to the utility can also be used to perpetuate capital spending. For these reasons, regulators should be vigilant about reviewing long-term capital asset investment and management plans generally and as part of certification, financing, and rate-case proceedings.

Thus, there is little reason to believe that under the RBROR model, utilities are somehow under-incented to invest in infrastructure modernization. In reality, the potential to make uneconomic investment choices, including gold plating, remains relevant. Asset retirements and expenditures related to modernization, or any other utility or policy objective, are not necessarily *prudent*. Regulatory checks are needed to ensure that utilities serve the public interest by deploying capital efficiently to achieve specified goals. Additional review and reporting processes might be needed in order for regulators to provide sufficient oversight. To the extent that some technologies carry additional risks, particularly the risk of obsolescence, regulators should also pay close attention to implications for the cost of capital.

“Death spiral” rhetoric aside, utilities may be able to withstand certain disruptive forces and might even embrace them.¹¹⁸ In fact, electricity industry capital expenditures continue to climb, consistent with investment cycle expectations (Figure 2-2).¹¹⁹ While revenues are relatively flat, operating expenses have declined, attributed to falling fuel costs. Growing capital intensity, measured by a ratio of assets to revenues, suggests an earnings opportunity for investors. Favorable returns and tax policies may provide additional incentives. The pessimism reflected by the industry in year-over-year investment forecasts, and echoed in rate hearings, appears belied by investment reality (Figure 2-3).

¹¹⁶ Walkup, Borison, Chamberlain, and Reed (2015).

¹¹⁷ Adoption of these technologies also has economic implications in terms of job losses for local economies and households, and the need for worker retraining.

¹¹⁸ See Graffy and Kihm (2014).

¹¹⁹ Edison Electric Institute. “Industry Capital Expenditures.” Various years, 2013 to 2016.



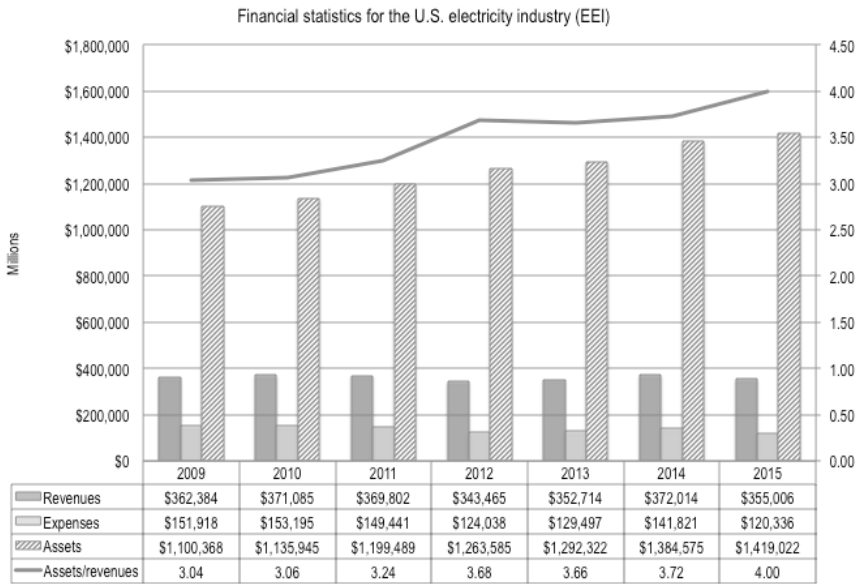


Figure 2-2. Financial statistics for the U.S. electricity industry

Data from EEI Financial Reviews various years; most recent data used to account for corrections. Available at www.eei.org.

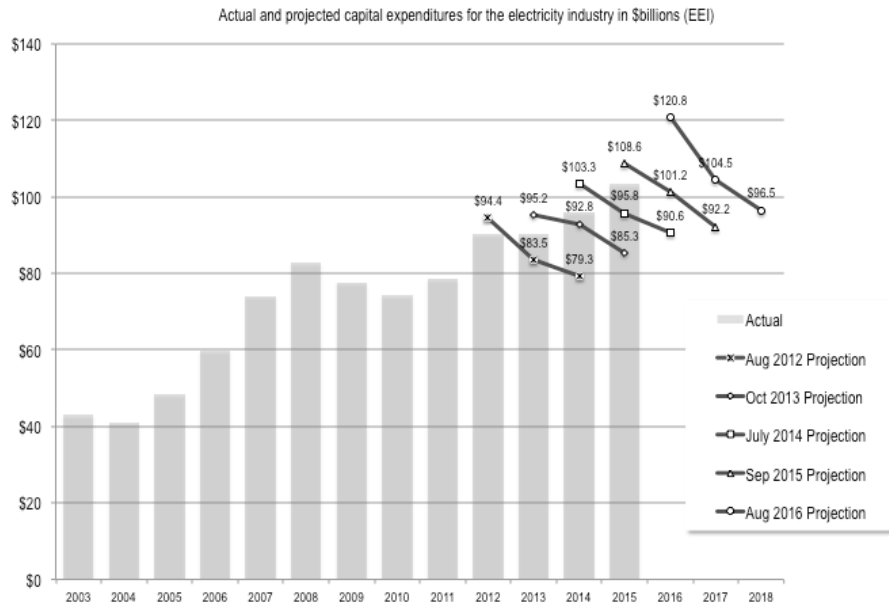


Figure 2-3. Actual and projected capital expenditures for the electricity industry

Data from EEI Industry Capital Expenditures, various years; most recent data used to account for corrections. Available at www.eei.org.



Some analysts urge the industry to prepare for an investment future more driven by modernization investment than growth in sales volume,¹²⁰ which might be especially welcome to utilities that no longer build generation. Though a motivation to managers, growth is not essential, and might even be detrimental, to ensuring shareholder value.¹²¹ Even less clear is that growth is needed by regulated monopolies that are given a clear path to profit. Others envision substantial growth in the form of electrification, particularly in transportation and heating.¹²² Building and operating industrial co-generation facilities, storage systems, and micro-grids may present potential opportunities as well.¹²³

Modernization also entails new services, such as vehicle charging, although these may or may not be provided by the regulated utility as a matter of policy. What these trends portend for sales, prices, and investment over the long run is unknown. For now, the advantages of scale and a more diverse portfolio (including distributed generation, demand response, storage, and wholesale power exchange) are consistent with the grid model and modernization.

2. Incentives that favor ratebase treatment

Under the RBROR model, ratebase treatment can naturally become the solution that looks to solve all problems.¹²⁴ Presumably, if regulators want to incent utilities to make any particular type of expenditure, they need only to characterize it as an asset to which an authorized return can be applied. Rate-basing makes for a durable earnings opportunity compared to the relatively short-lived premium companies enjoy for operational efficiency gains afforded by regulatory lag, given the claw-back of revenue requirements when rates are reset.

At the urging of various interests, regulators have sometimes allowed rate-basing of, or returns on, certain expenditures related to energy efficiency programs, regardless of the noncapital nature of these expenditures.¹²⁵ Incentives of this variety should require a clear demonstration of program effectiveness, as not all programs will yield sufficient benefits relative to costs or justify special ratemaking treatment, of course. Economists generally prefer pricing to programs for this reason; direct governmental subsidies to end-users are another option given potential social benefits. Extraordinary incentives likely constitute an unnecessary burden on ratepayers if cost-effective demand-side management is prudent relative to supply-side alternatives, in which case it should be mandated by regulators consistent with regulatory principles under the compact (more on the conception of prudence later).

Remarkable in the context of grid modernization is the counterclockwise case of cloud computing, which actually and atypically favors opex over capex. Cloud technology makes it possible to swap rate-based resident data centers, servers, and software, including related information-technology (IT) licensees, personnel, and support, for contracts, leases, or subscriptions with service providers. Proponents, including vendors, have raised the specter of

¹²⁰ Deloitte (2016).

¹²¹ See Kihm in this report.

¹²² Weiss et al. (2017).

¹²³ Asmus (2015).

¹²⁴ A related idea is the operating ratio method of ratemaking, which historically has been used to apply a return to operating expenditures when returns on depreciated assets would be insufficient to sustain operations.

¹²⁵ ACEEE (no date). Performance Incentives. <http://aceee.org/sector/state-policy/toolkit/utility-programs/performance-incentives>.



utility resistance and called for competitive or technological “neutrality,” invariably assured with incentives.¹²⁶ The National Association of Regulatory Utility Commissioners (NARUC) in turn passed a resolution that appears to support the concept of capitalization of cloud-based software, while acknowledging that software investments should best serve the needs of utilities and their customers and be subjected to regulatory evaluation of prudence.¹²⁷

Like other modernization technologies, the prudence of cloud computing is not generic and should be evaluated case by case in terms of relevant cost, risk, security, service quality, and other impacts. Some factors may favor some solutions, including hybrid solutions, over others. On the one hand, larger, integrated, and converged utilities may be able to capture internal scale or scope economies in IT. On the other hand, risk of obsolescence accompanies any IT capital investment. If cloud computing consistently lives up to its promises and is proven to be efficient and effective relative to in-house solutions, its wider adoption by regulated firms should be expected, as would be the case for competitive firms.

Utilities should be prepared to defend their choices directly, one way or another; third parties and regulators cannot make the case for them. The complexity of an issue makes prudence evaluation all the more important, particularly if dedicated incentives are involved, but regulators historically have not been strangers to complex issues. If a comprehensive analysis finds that benefits to ratepayers outweigh costs, but utilities remain recalcitrant, then regulators can impute costs accordingly, as they do for comparable prudence issues in ratemaking.¹²⁸ Regulators have considerable discretion with regard to the treatment of costs in accounting and ratemaking and need no permission from the national boards of accountancy.¹²⁹

The essence of prudence is that ratepayers should not cover the cost of an uneconomic choice, including the choice of capital over an operating expenditure. To be sure, regulators face information and knowledge disadvantage in these as in other areas, but this is why broad incentives under the traditional model are so important. Grid modernization calls for building evaluation capacity and establishing enforceable standards while preserving some level of competition among alternative technologies and providers, not limited to utilities themselves. Utilities could then be held accountable and rewarded under a performance-based regulatory scheme only when managerial or investor bonuses are tied to targets that benefit ratepayers.

The rationale for modifying accounting rules and capitalizing the cloud, then, is actually a bit hazy. Under the regulatory compact, prudence is expected and compensated accordingly. Moreover, any form of preapproval or revenue assurance to utilities amounts to a revenue assurance to cloud vendors, which could undermine efficiency and competitiveness in both

¹²⁶ See Trabish (2016). Logically, competitive neutrality would also call for rate-basing of meter readers as well as meters, and so on.

¹²⁷ NARUC Resolution Encouraging State Utility Commissions to Consider Improving the Regulatory Treatment of Cloud Computing Arrangements (Nov. 16, 2016). <http://pubs.naruc.org/pub/2E54C6FF-FEE9-5368-21AB-638C00554476>.

¹²⁸ In this case, reducing the ratebase and allowing an expense.

¹²⁹ Generally Accepted Accounting Principles (GAAP) are established by Financial Accounting Standards Board (FASB), a private nonprofit entity. When conflicts arise, “GAAP must yield” to regulatory accounting and reporting (FERC Order No. 552, 62 FERC 61, 299 (March 31, 1993)).



sectors. If cloud computing, or any other technology, is either advantaged or disadvantaged, it may be more a failure of regulatory implementation than a flaw in the regulatory model.

3. Incentives that favor selling output

One of the most frequently cited incentive problems is that the RBROR model by itself causes utilities to favor more sales over less sales, particularly in the short run, when a large share of costs is considered “fixed.”¹³⁰ This somewhat superficial logic, that utilities are driven to sell more of their core product, particularly to the neglect of demand-side opportunities, is the primary rationale for decoupling utility revenues (and thus profitability) from sales, one of the most actively promoted and well-diffused incentive mechanisms. Decoupling has been adopted for one or more electric or natural gas utilities in about half the U.S. states.

As popularized, decoupling and related methods for recouping “lost” revenues purport to neutralize the so-called “throughput” incentive that motivates utilities *between rate cases*. While it seems obvious that utilities with sufficient capacity *enjoy* higher sales, it is much less obvious or logical that they can do much of anything in the short term to *effect* higher sales except to underprice, which is atypical of monopolies.¹³¹ Utilities are not “maximizers” of authorized revenues or returns, as decoupling seems to presume. Neither the throughput incentive as a problem nor decoupling as a solution to it is well supported by economic theory or empirical evidence. The very idea of incentive regulation rests on a connection between conduct (output) and compensation (earnings).¹³² Prices that are not output-based for producers or usage-based for customers seem to subvert economic signals.¹³³

Monopoly outputs, whether commodities, conduits, or services, should be appropriately priced and subject to performance evaluation, whether or not dedicated incentives (specific to a project or target) apply. Despite an abundance of advocacy and gray literature, rigorous and impartial research in this area is sparse. The need is especially great for econometric analysis, with a focus on testing correlations with controls and estimating impacts. The water sector, where substantial and enduring efficiency gains are evident without decoupling for both publicly and privately owned utilities, provides a relevant counterfactual case.¹³⁴ Of course, in the wake of falling sales, some water utilities are embracing decoupling.¹³⁵

Although particular methods vary, decoupling is characterized as means of “revenue regulation”¹³⁶ and essentially provides utilities with revenue assurances by shifting revenue risk normally incurred between rate cases from shareholders to ratepayers. Decoupling shares many

¹³⁰ For an analysis, see Borenstein (2016). <https://ei.haas.berkeley.edu/research/papers/WP272.pdf>.

¹³¹ A rebate for fuel switching would be a form of price reduction, but would draw regulatory review if ratepayer-funded. Utilities can also advertise, but normally at shareholder expense, and non-price methods of influence may not be effective.

¹³² Brennan (2010).

¹³³ Noneconomic goals such as social equity are also relevant to pricing.

¹³⁴ Efficiency gains in water usage are attributed to the adoption of appliance and efficiency standards under the Energy Policy Act, but likely influenced by other factors as well. However, the water industry is dominated by municipal utilities that can adjust rates more frequently and usually without regulatory oversight.

¹³⁵ California regulators have authorized the use of a Water Revenue Adjustment Mechanism (WRAM) and Modified Cost Balancing Accounts (MCBA) for water utilities. www.ora.ca.gov/wram.aspx.

¹³⁶ RAP (2011).



of the theoretical and practical concerns associated with capping utility revenues, which has been more extensively analyzed.¹³⁷ The UK's RIIO model, though not necessarily characterized as decoupling, combines eight-year revenue caps for combined total expenditures (“totex”) and cost adjustments with a form of profit sharing.¹³⁸

How decoupling compares to other policy instruments along performance metrics important to regulators, particularly environmental compliance, should also be investigated. Because of the difficulty of isolating the factors affecting electricity usage and sales revenues, including concurrent policies, decoupling may actually reinforce the status quo by shielding utilities from the effects of changing weather patterns, consumer preferences, and economic conditions, as well as the effects of efficiency programs.

Advocates and analysts sometimes inadvertently imply that decoupling provides a positive incentive for utilities to embrace efficiency and conservation.¹³⁹ This is not actually the case in the absence of other incentives or requirements. In reality, regulatory lag will more likely focus managerial attention on costs, over which they have more control than sales. Utilities will be inclined to invest on the demand side if prices (or price caps) are below the cost of service¹⁴⁰ and efficiency programs are cost-effective. Of course, low prices will also disincline customers from investing in end-use efficiency on their own. With constant incremental adjustments, decoupling could also mute dynamic price signals.

Although the impact of these adjustments on utility ratepayers is diffuse and thus far appears to be nominal,¹⁴¹ the impact on the utility is appreciable. As a matter of public policy, then, decoupling seems grounded more in practical politics than welfare economics, because it keeps utilities whole and thus “defuses” opposition to energy efficiency based on the impact to their bottom lines.¹⁴² To what effect remains uncertain. Decoupling will be attractive to utilities until it is not, as when sales trend upward due to structural and economic forces.

Although decoupling might mitigate the sales incentives, it will not neutralize the choice between (usually smaller) demand-side and (usually larger) supply-side investments projects as long as regulators provide a return premium above the cost of capital.¹⁴³ Project scale and return premiums favor capital investment and, unsurprisingly, the investment community consistently lauds a “robust ratebase.”¹⁴⁴ In fact, gradual elimination of the return premium would more directly address the utility’s inclination toward the supply side, although it would also thwart capital investment for infrastructure modernization as well as have consequences for utility capital structures (lower debt) and stock prices (lower values).

¹³⁷ Stoft (1995); Crew and Kleindorfer (1996); Costello (1996); and Sotkiewicz (2007).

¹³⁸ Ofgem. Network regulation – the RIIO model. <https://www.ofgem.gov.uk/network-regulation-riio-model>

¹³⁹ National Renewable Energy Laboratory. Decoupling Policies: Options to Encourage Energy Efficiency Policies for Utilities. <http://www.nrel.gov/docs/fy10osti/46606.pdf>

¹⁴⁰ Brennan (2010).

¹⁴¹ Morgan (2013).

¹⁴² Brennan (2010), 49–69.

¹⁴³ See Kihm (2009) and Beecher and Kihm (2016).

¹⁴⁴ UBS, Public Service Enterprise Group: More Ratebase Please. <https://neo.ubs.com/shared/d1xOHcCaW6nf/>



4. Incentives that favor fixed charges

Rate design has always been politically challenging for utilities and their regulators, more so when costs are rising. The modernization context has invited more attention to a variety of rate design issues, in part because of technological advances that enable new models for classifying customers, characterizing costs, and designing rates.

In the context of flat or falling usage, many utilities have turned to the idea of raising fixed charges, which may seem logical given the capital intensity associated with substantial fixed infrastructure costs. Often considered variations of decoupling, approaches include straight fixed-variable (SFV) pricing as well as expanded use of demand or capacity charges. Monopolies may also be drawn to the idea of loading more costs on less price-elastic usage, and economic theory lends some support to this strategy (the *inverse elasticity rule* or *Ramsey pricing*). Fixed charges can be used to shift revenue risk from shareholders to ratepayers.

High fixed charges raise a number of issues related to both resource efficiency and ratepayer equity.¹⁴⁵ Rate design actually offers the chance to align the policy priorities of environmental and consumer advocates. On the efficiency side, variable rates refine price signals. While in the short run many system legacy costs are fixed, in the long run *all costs are variable*, and variable charges reflect this dynamic worldview. Price signals for infrastructure are more effective when the user bills reflect the full impact of their usage, not just the short-run marginal cost of commodities. A high fixed charge sends a weak price signal, as does a minimum bill with a usage allotment because it might induce usage. A variable charge can be designed to reflect long-run marginal costs, including those associated with environmental impacts.

On the equity side, as noted, all utility rates are regressive. A high fixed charge also takes away control from customers. Not all low-income households are low-use households and vice versa; however, on the whole, just as price is negatively related to usage, income is positively related and higher-income households tend to drive peak usage and capacity needs. The focus on fixed charges deflects from other potentially useful pricing reforms, including time-variant or dynamic pricing, that many consider superior means of achieving efficiency and equity.

Reliance on variable charges does not necessarily wreak revenue havoc. For essential services, the first blocks of consumption and the revenues they generate are likely quite stable and predictable, regardless of the pricing method. This especially holds true for energy-efficient households. System capacity costs are likely driven by the uses that are more discretionary and price responsive. Utilities should account for the repressive impact of prices, standards, and other factors on changing usage (elasticities) and work to drive down costly system peaks. In the context of rising costs and declining usage, rates and bills may rise but not as high as they would with uneconomic investment. Over time, improved efficiency will yield benefits to consumers in terms of these “lower highs” but also to utilities in terms of revenue stability.

Changes in usage may be durable, but raising fixed charges and variations of decoupling may be more reactive than proactive, and certainly are not the only policy response with regard to either revenue shortfalls or efficiency incentives. Consistent with the utility’s burden of proof,

¹⁴⁵ For a thorough critique, see Borenstein (2016).



more accurate forecasting of costs, sales, and revenues, and more frequent rate cases in which evidence is effectively presented to regulators, are responsive to the challenges of dynamic costs and usage. A variety of rate design alternatives can address both social goals and utility compensation within the accepted validity and principles of RBROR's cost-of-service framework.

5. Incentives that favor centralized technologies

Utilities traditionally invested in centralized technologies of scale. Both conventional and alternative technologies, including renewable energy resources, still demonstrate declining-unit costs. Utility-scale solar installations, for example, have cost advantages over residential and commercial installations.¹⁴⁶ Decentralized and distributed energy resources thus present a capital investment opportunity to utilities that own and operate generation or transmission facilities. Nonetheless, dynamic conditions call for continuous scrutiny of assumptions about scale. Many new technologies may be more “scalable” and “flexible” in order to better match supply to demand, both spatially and temporally.

Customer-premise power generation is growing. In the commercial and industrial sectors, this includes combined heat and power (CHP) and waste heat to power (WHP) systems. In the residential sector, some consumers (or “prosumers”) can generate electricity for themselves typically from solar installations and also sell the excess back to the utility. Prosumerism is made possible by advances in grids, metering, and pricing. Feed-in tariffs require a separate meter to measure the power sent to the grid. Net metering allows customers to net their energy consumption against their own energy production using a single meter.

High prices in some areas have increased interest in household options for energy generation and storage. The value of prosumer energy to the grid is time-of-use dependent; power generated during periods of peak usage or congestion will have more value. Whether and how this power should be compensated in terms of avoided system costs and broader social benefits are heavily debated. Notably, there is no analog in the water sector, where customers might also collect and store water; their compensation is limited to their marginal cost of usage.

The value of household solar and storage systems is generally grid dependent; in other words, the grid enhances the value of the household's investment.¹⁴⁷ Full grid defection is not an economic choice in most cases and customers continue to rely on grid resources for backup purposes. A long-term concern, however, is that wealthier customers will defect altogether and undermine grid economics, stability, and sustainability. On the other hand, not every consumer may prefer self-supply, and some economic projections suggest a gradual movement away from personal ownership models (for example, in housing and automotive transportation).

Both tax incentives and electricity rate policies, such as net metering, have been used to stimulate the market for distributed energy. Depending on rate-design methodologies, net metering can work to the advantage of some ratepayers (those with generation capacity) over other ratepayers (those without generation capacity). Net metering constitutes a quantifiable

¹⁴⁶ NREL (2016). NREL Report Shows U.S. Solar Photovoltaic Costs Continuing to Fall in 2016. <http://www.nrel.gov/news/press/2016/37745>.

¹⁴⁷ Hittinger and Siddiqui (2017).



form of cross subsidy if it allows participating customers to avoid paying for the fully accounted-for fixed costs of the grid that continues to serve them as both buyer and seller.¹⁴⁸ Some analysts are urging policymakers to revisit net metering in light of efficiency and equity concerns.¹⁴⁹ Although not prescriptive, NARUC recently issued general guidance to state regulators on issues related to rate compensation for distributed energy resources.¹⁵⁰

The debate over distributed resources is often framed as a conflict between solar and utility interests but also as a conflict between the interests of utilities and their ratepayers. Net metering and related rate-design challenges, such as establishing terms for stand-by service, provide some of the best illustrations of the efficiency and equity challenges brought by providing pricing incentives under generally accepted regulatory principles and ratemaking practices. Although the politics of cost allocation in this area can be intense, many promising new approaches can be readily subsumed under the prevailing regulatory paradigm, consistent with long-held ratemaking principles.¹⁵¹

6. Incentives that favor the status quo

Traditional utility investments are very technically specific, long-lived, and sunk, meaning that they are not fungible. Investors thus expect a return of and on their investment over a long time horizon. Promoting technological and managerial change under these circumstances is challenging partly because it is difficult to quantify, at least until it translates into measurable cost savings. Some would say that innovation is better advanced through policy instruments other than economic regulation, such as governmental grants for research and development.¹⁵²

One way that policymakers and regulators have sought to stimulate efficiency and innovation is through market restructuring to introduce some level of competitive discipline to utility monopolies. In the electricity sector, this was manifested by vertical separation of the generation, transmission, and distribution functions, in some cases structurally through divestiture of generation and transmission assets and the organization of wholesale power markets. Drawing from the experience in telecommunications, the idea was to open access to networks and negate incentives for utilities to discriminate in favor of themselves and their affiliates. Restructuring emphasizes the role of organized wholesale markets for electricity, with the addition of retail choice in 14 state jurisdictions. Although the promises of restructuring and choice were great, the market design challenges have been great and the results have been mixed.¹⁵³ At least some gains were offset by economies lost to vertical separation of utility functions along with added transaction and coordination costs.¹⁵⁴

Restructuring in some ways has actually complicated the achievement of grid modernization and associated goals, and led to rethinking of regulatory models and methods. The UK regulator's

¹⁴⁸ Picciariello et al. (2015).

¹⁴⁹ Alexander, Brown, and Faruqui (2016).

¹⁵⁰ NARUC Staff Subcommittee on Rate Design (2016).

¹⁵¹ Ibid.

¹⁵² The UK's Office of Gas and Electricity Markets (Ofgem) is tackling the innovation challenge by modifying its price-cap regime with the RIIO model (Revenue = Incentives + Innovation + Outputs). For more information, see <https://www.ofgem.gov.uk/network-regulation-riio-model>.

¹⁵³ See Rose (2012) and Caplan and Brobeck (2012).

¹⁵⁴ Kwoka (2005).



RIO formula for ratemaking, which is the successor to its price-cap formula, explicitly incorporates an expectation of innovation.¹⁵⁵ New York's Reforming the Energy Vision (REV) has become emblematic of the U.S. transformation effort in terms of not just accommodating but pushing innovation in the sector.¹⁵⁶ Other states, including California, Hawaii, and Minnesota, are also at the forefront on this issue.

Although widely assumed, their long history suggests that neither monopoly nor regulation is necessarily incompatible with efficiency or innovation and their translation to lower prices.¹⁵⁷ Assuming opportunities for returns, even monopolies will seek to minimize costs, maximize productivity, expand market presence, and develop new products and services on the supply and demand sides. Firms unencumbered by competition for market share might actually be able to devote more resources and effort to efficiency and innovation. Innovation can also allow for monopoly and monopoly rents, at least temporarily.¹⁵⁸ Moreover, technical standards and regulatory requirements can drive innovation within and outside regulated industries and firms.¹⁵⁹ With performance benchmarking, utilities may face comparative competition, if not direct competition, for service provision. Much innovation may come from the outside the utility sector and force change within the utility sector.

Finally, and logically, not an insignificant share of capital investment incented by the return premium under the RBROR model will be for newer technologies.¹⁶⁰ In reality, modernization and technological advancement provide utilities with a steady stream of capital investment opportunities, even for distribution-only utilities. The return premium might even induce utility managers to try to accelerate retirements, replacing assets prior to the end of their economic life, while still expecting recovery of any stranded costs. All of which suggests caution about assuming that incentives are misaligned or that extraordinary incentives are needed for grid modernization.

Of course, utilities are risk-aware and can be risk-averse, and will expect commensurate compensation for taking on risks associated with innovative but nontraditional technologies or practices. If regulators are inclined to respond with incentives of any kind, they should also impose performance requirements, monitor for gaming and abuse, and be vigilant to ensure that the nature and pace of capital turnover is beneficial to ratepayers. Investment decisions related to grid modernization, including those related to the priorities of reliability, security, and resilience, must still be demonstrably prudent. Regulators need capacity to evaluate grid investments, but the burden to prove benefits in absolute and relative terms should remain with the utility.

¹⁵⁵ See <https://www.ofgem.gov.uk/network-regulation-riio-model>.

¹⁵⁶ See New York State, Reforming the Energy Vision (REV). <https://rev.ny.gov/>

¹⁵⁷ On efficiency, see long-term inflation-adjusted price trends for electricity.

¹⁵⁸ Schumpeter (1934).

¹⁵⁹ Porter and van der Linde (1995).

¹⁶⁰ Kahn (1971) and Shepherd (1992).



Incentives as Wealth Transfer

Because someone must bear their cost, another term for incentives is *subsidies*, which implies wealth transfer and raises issues of economic as well as social equity.¹⁶¹ Society can and should subsidize many socially desirable investments, including infrastructure that serves essential social purposes and confers positive externalities. Whatever their form, all subsidies should be justified and subject to careful and objective evaluation to ensure that promises are delivered.¹⁶²

There is a substantial and consequential difference between subsidies coming from taxpayers (which can be more or less progressive depending on the instrument) or ratepayers (which are generally regressive). Tax subsidies are also more inclusive because ratepayers have different footprints and are only a subset of taxpayers. As a general proposition, costs that serve social purposes should be socialized and supported by the federal, state, or local tax base. These can support a variety of instruments, including tax incentives, grants, and loans (including Green Banks). Subsidization of particular technologies or production processes, however, is almost always problematic. Examples can be found in the subsidy schemes proposed to keep uneconomic or noncompetitive power plants in operation.

Subsidization through utility rates raises particular issues of efficiency (price distortion) and equity (cost allocation). Limiting transfers among ratepayers is important for preserving accurate price signals, particularly for price-inelastic and discretionary usage. Rates are never perfectly aligned with costs and rarely individualized, so some amount of inter-class and intra-class transfer is inevitable, but allocation of costs based on causation and marginal-cost pricing principles are widely accepted as fair in ratemaking.¹⁶³ Nonetheless, ratepayers still remain a tempting target for hidden taxation and wealth transfer. Indeed, a perennial criticism of the economic theory of regulation that regulators as politicians use ratemaking as a means of transferring wealth from some ratepayers to others. Allocating the cost of service is an admittedly imprecise and subjective process, but it is informed by generally accepted regulatory principles and practices. Incentive mechanisms invariably suggest a departure from cost-based rates and cross-subsidization.

In the reality of a zero-sum framework, which applies in the near term at least, regulatory decisions have distributional consequences (winners and losers). Utility rates and bills are considered regressive in the first place because in the aggregate they take a larger share of everyday expenditures from low-income households than from high-income households, even with assistance programs and pricing structures in place. The cost of incentives borne by ratepayers will thus have regressive effects. Another major challenge with all incentives is ensuring equity in the presence of program participants and nonparticipants, as well as free riders. In some cases, absent corrective policies, a high-income household could enjoy benefits

¹⁶¹ See opinion piece by Bryce (2017).

¹⁶² The considerable investments in advanced metering infrastructure (AMI) benefited from both taxpayer grants under the American Recovery and Reinvestment Act and ratepayer subsidies. Yet without concurrent implementation of dynamic pricing, outage management, and other AMI-enabled programs that help lower household costs and utility revenue requirements, the full benefits will be unrealized.

¹⁶³ As the short-run marginal cost of utility services is very low, incorporating long-run marginal costs in rate design will generally send better price signals for capital-intensive utilities with substantial environmental impacts.



at the expense of a low-income household. Finally, care must also be taken to ensure against incentives that result in intergenerational inequity as well as price distortion.

A clear distinction should also be made between subsidies for incentives intended to change the behavior of utilities, their investors, or their ratepayers, and subsidies to advance the goals of universal and affordable access to essential services (that is, the direction of wealth transfer matters). As both types of subsidies address market failures and social issues, both generally argue for tax support. Rate support can be justified if economic benefits to ratepayers clearly outweigh costs, taking equity impacts into account.

The economic case for ensuring affordability can be made in terms of maintaining the customer base and avoiding the disconnection and arrearage costs that must be borne by other ratepayers. Ratepayers support low-income ratepayers through payment plans, efficiency programs, and progressive rate structures. With exceptions, of course, usage by low-income households is less discretionary and has a lesser impact on system peaks.¹⁶⁴ Rate subsidies from any source can be limited to essential usage, above which cost-based price signals can still be implemented to influence economically relevant usage. A carefully designed and implemented lifeline rate is generally consistent with the efficiency and equity goals of regulation, and broader social objectives as well.

Incentives and Activism

The ability to transfer wealth through utility rates and the desire to bend the behavior of utilities or utility customers in a desired direction can invite legislative or regulatory activism, or mission creep. Regulation cannot be apolitical or exist in a vacuum. Governance theory, however, suggests that major public policies and mandates that typically have consequences for distributing or redistributing wealth are better left to institutions accountable to voters. In other words, the delegation of legislative and executive functions to regulatory agencies is not license to supplant democratic deliberation.

Although regulatory agencies act as an arm of the state, with quasi-legislative and quasi-administrative responsibilities, regulation is not a form of direct democracy and the conception of its policy role is relatively narrow, despite the election of commissioners in a dozen states. Regulatory independence and integrity emphasize a quasi-judicial role; that is, the commissioner as expert judge with a particular sphere of expertise.¹⁶⁵ The compact contemplates a regulator who is largely independent of the executive and legislative branches and avoids politicization.

Multiple policy domains affect the performance of utilities but also the performance of other regulators.¹⁶⁶ Essential rights and protections should be codified and enforced as a binding constraint. In many respects, the job of the economic regulator is to ensure the efficient and equitable achievement of social goals set by other institutions, which includes prudent compliance with environmental policies. Within its domain, economic regulatory authority has always been multi-faceted. Commissions oversee service safety, reliability, and quality because

¹⁶⁴ Faruqui, Sergici, and Palmer (2010).

¹⁶⁵ Beecher (2008).

¹⁶⁶ The Tinbergen Rule suggests that each policy target requires a dedicated policy tool.

<http://journals.sagepub.com/doi/abs/10.1177/0270467608325375>



these issues have direct implications for economic performance. According to this rationale, many commissions have extended authority in such areas as facility siting and security.

Activism, however, can take regulators beyond the relatively objective metrics of economics to more subjective territory, making regulatory decisions less defensible in economic and legal terms. Activism can morph into micromanagement, including interference with technological choices and market forces. An overarching fear is that some forms of activism will wield incentives in ways that inflate costs unnecessarily, and possibly to negligible or even negative effects relative to good intentions. In some cases, legislative mandates and limits to regulatory discretion may force economically inferior solutions, for which ratepayers pay the price.

Nonetheless, policymakers and regulators today are under some exogenous and endogenous pressure to expand the regulatory policy remit. The rationale for regulatory activism in the contemporary context often centers on the potentially dire consequences of externalities and the laxness of other institutions in addressing them. For many, rapid decarbonization is a social imperative and should be a fundamental policy priority. Of course not all forms of activism are politically progressive. Activism may pursue any policy value, including the development and use of fossil fuels.

The failures of other institutions should not be used as an excuse to distort or transform economic regulation. The convergence of environmental and economic regulation might seem to hold promise in terms of harmonizing and coordinating policies and aligning incentives; it might also lower the cost of regulation to regulated entities and the state. However, convergence also forgoes the complementarity of technical expertise, policy instruments, and the checks and balances that come with institutional separation. Convergence blurs boundaries. Logically, without boundaries, the regulator's reach could extend to an unlimited range of environmental impacts associated with utilities, from air and water quality to noise, odor, light, and other forms of pollution. Responsibility for these issues rests with federal and state public health and environmental agencies for good reasons.

Economic regulatory agencies are not designed as primary makers of public policy, and their authorities and capacities, while considerable, are still limited. When they do engage, they become vulnerable to the politics of special interests, including regulated utilities as well as a growing number of commercial interests seeking to advance particular technologies or methodologies. The ease with which regulators can be lobbied and influenced may induce and perpetuate activism. More deliberation about boundaries and the rules of engagement in this context is much needed.

Whether authorized or extra-statutory, assuming multiple regulatory roles in a single agency simply internalizes conflict, namely between ratemaking and other policy goals, and possibly compromising the achievement of both. If the economic regulator assumes responsibility for environmental impacts, this could also be an excuse to weaken environmental regulation as a separate institution. Society benefits when policymaking in both domains is sound, and some tension may even be valuable.



As manifestations of market failure, both negative and positive externalities are by definition public problems that call for public solutions through democratic policymaking.¹⁶⁷ Externalities can be approximated and priced, but only “real” costs should flow to ratepayers.¹⁶⁸ Arbitrary adders that are unconnected to actual accounting costs and have no particular destination (such as a tax obligation) will violate cost-based ratemaking, enrich the utility monopoly, and harm ratepayers by inflating prices for essential services. Economists have long argued for pricing externalities through Pigovian taxes and cap-and-trade regimes that would allow market forces to drive production and consumption decisions toward efficient solutions. Given political will, pricing carbon would help achieve emission goals by expanding deployment of demand-side and renewable resources more efficiently and effectively than other policies, including portfolio requirements.

Neither legislation nor regulation should assign to ratepayers costs or risks associated with externalities that should rightfully be borne by taxpayers. These issues arise whenever ratepayers are asked to pay for public-benefits programs, economic-development discounts, system-support resources, nuclear power subsidies, and so on. Economic regulatory consideration of externalities is generally confined to compliance with standards, consideration of avoided costs, and rate design. Legislatively, the Public Utility Regulatory Policy Act (PURPA) has been useful in this regard because of its congruence with economic regulation.

In the context of grid modernization, vehicle-charging stations provide a relevant case. Advocates may want to advance clean energy goals by promoting electrification of the vehicle fleet, requiring the expeditious rollout of charging stations. Regulated utilities may need to establish a charging station tariff, but authorizing them to build and ratebase the stations is another matter.¹⁶⁹ The cost will likely be borne by all ratepayers, most of whom do not drive electric vehicles and some of whom do not drive at all. Unregulated competitors in that area will be disadvantaged, which would likely sacrifice efficiency. One option is for utilities to enter this market through unregulated affiliates, so that shareholders bear all risks, but affiliated businesses raise other concerns for regulators.

None of this is to say that economic regulators should be entirely passive, reacting only on a case-by-case basis. Even as they navigate within their lane, regulators should advance the goals of efficiency and equity. Regulators can pursue their policy responsibilities actively by initiating rulemakings and other proceedings, but also by informing policymaking in other realms, including testimony before legislative bodies and information sharing with other agencies. Nor should regulators ignore context. When choices present comparable economic profiles, regulators should take other policy considerations and community preferences into account.

¹⁶⁷ Excluded from this conception are costs that can be rightfully assigned and internalized, such as costs associated with power-plant decommissioning.

¹⁶⁸ See 133 FERC ¶ 61,059, Docket EL10-64-001 (California Public Utility Commission) and Docket EL10-66-001 (Southern California Edison, Pacific Gas and Electric Company, and San Diego Gas & Electric Company), Issued Oct. 21, 2010.

¹⁶⁹ See Missouri Public Service Commission decision in Ameren Missouri tariff filing 2016-246 (April 19, 2017). https://www.efis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=ET-2016-0246&attach_id=2017016053.



New Paradigm or New Prudence?

Despite the considerable rhetoric and occasional hyperbole demanding a “new paradigm” for economic regulation, what actually might be needed is a “new prudence.”¹⁷⁰ Like the regulatory compact, prudence is a living and adaptable concept, so the idea of an obligatory new prudence can be understood as radically conservative. In other words, meaningful regulatory reform does not necessarily require paradigmatic change. Without a doubt, what might have been considered prudent even a decade ago would not be considered prudent today, let alone for a utility of the future. Embedded in an outdated conception of prudence are substantial opportunity costs in term of efficiency and innovation.

A new prudence might be labeled incentive-based or performance-based regulation, but it is essentially a logical evolution of the economic regulatory paradigm and consistent with its core principles. With an updated prudence for today’s network industries, the traditional regulatory model and the incentives provided within it might actually be well suited to the demands of contemporary policy goals including, if not especially, infrastructure modernization. At a minimum, prudence should be defined in terms of enforceable standards and generally accepted utility practices, both of which can be substantially strengthened in light of technological advances and opportunities as well as dynamic supply and demand conditions. Regulators should make their expectations about prudence clear and update their practices accordingly.

Economic regulation should remain focused on economic objectives. In essence, however, prudence can no longer be judged in the simple binary terms of *efficiency* but in the multi-dimensional terms of spatial, temporal, and technological *optimization*. Prudence calls not just for compliance with enforceable standards and generally accepted utility practices but optimized compliance that results in the lowest feasible cost to ratepayers. As with efficiency, the expectation is not to arrive at an elusive equilibrium or “optimum” but rather to make continuous improvements toward an optimal solution set, constrained by policy mandates.¹⁷¹

The concept of a new prudence can easily accommodate alternative business and pricing models. Whether or not they operate in restructured or retail-access states, local electric utilities are integrating information and operational technologies (IT/OT) and evolving to become full-service providers of grid-based services, perhaps as optimizing distribution system operators (DSOs) that may or may not own and operate centralized or decentralized technologies on the supply and demand sides.¹⁷²

The prudence of the past would simply guide utilities to build out a system to meet demand, including a reserve margin to ensure a high level of reliability. The built capacity would be large, lumpy, long-lived, and centralized. The utility would be a “demand taker,” and both costs and prices would simply flow from the utility’s capital investment and operating choices. Under this typical scenario, a good portion of the built capacity would go unutilized for much of the time due to average and peak load patterns. As in the past, utilities remain accountable for ensuring

¹⁷⁰ Consistent with this concept, Schiavo et al. (2013) suggest that transformation and innovation call for “more sophisticated regulatory instruments.”

¹⁷¹ Some argue that the puzzle of reliable, affordable, and clean energy is not solvable with today’s technologies.

¹⁷² For the purposes of this analysis, it is not presumed that grid modernization requires retail choice or “transactive energy,” even though this might be implied by many conceptions.



the safety, reliability and quality of service, and the legal standard for prudence based on the “known and knowable” at the time of key decisions remains core.

Today’s prudence commands that utilities recognize the dynamic and interrelated nature of demand and supply. They now have a number of tools to inform key decisions (Table 2-3). A prime example of new prudence would be cost-effective load shifting and load reduction through dynamic pricing and demand management, as enabled by smart meters, grid intelligence, and real-time information. Nothing in the prevailing regulatory paradigm prevents the deployment of these strategies and tools. Not every tool will be appropriate or cost-effective for any utility at any given time. However, in a data-driven world, more information is now *knowable* by utilities as well as their regulators. If utilities are not availing themselves of generally accepted practices to optimize their operations, lower the cost of service to ratepayers, and fulfill all other obligations, economic regulators should ask, why not? One of the most salient regulatory powers is to compel the production of information from regulated firms. The burden of proof should remain on utilities to make their case, one way or another. If the answer is unsatisfactory to the detriment of performance, consequences should follow.

Prudence calls for technological neutrality with regard to resource and operational choices among supply-side and demand-side options. The potential for energy efficiency and waste reduction to improve system operations, avoid capital costs, and lower revenue risk associated with volatile and unpredictable usage is apparent. Performance and outcome standards should thus make implementing the tools of end-use efficiency, such as integrated resource management and dynamic pricing, a matter of prudence. With or without added bonuses, any compensation related to efficiency efforts should be tied to performance, which of course requires a systematic evaluation scheme. Regulators should also be cognizant of the potential trade-offs and ratepayer impacts associated with alternative models for delivering of efficiency services, including competitive procurement.

A contemporary conception of prudence also calls on utilities to embrace a new grid architecture and principles of flexible infrastructure design to accommodate evolving technologies and manage associated risks.¹⁷³ Technologies that meet these new standards for infrastructure design may be far less capital-intensive and centralized. Some may be provided through new utility business models and some by other service providers in the space. Utilities will evolve in this landscape and expand their focus from delivering volumetric commodities to providing technology-driven services, but they will remain central as long as scale, aggregation, integration, and coordination matter and grids bring value to achieving social goals, such as environmentally responsible, universally accessible, and reliable service.¹⁷⁴ Although it shares many ideas associated with the UK’s RIIO, New York’s REV, and other state initiatives, a new prudence as outlined here is actually a less complicated and less hands-on approach.

No manner of incentive regulation is guaranteed to produce desired outcomes. Regulating to a new prudence and relying on clear and proven methods, including allowed returns under the

¹⁷³ De Neufville and Scholtes (2011). Along these lines, researchers at Next Generation Infrastructures at the Delft University of Technology have coined the concept of F.R.A.M.E. to refer to infrastructure that is flexible, reliable, available, maintainable, and economic. <http://www.nextgenerationinfrastructures.eu/>

¹⁷⁴ See Corneli and Kihm (2015).



RBROR model, could be simpler to implement, less prone to conflicts and gaming, and more effective than intricate incentive schemes. A new prudence can and should be enforced under the traditional regulatory paradigm and by traditional means, including state conditions on the compact, but through a variety of new tools at the disposal of economic regulators (also included in Table 2-3). These tools are meant to improve the efficiency and effectiveness of regulatory agencies and their processes.

Updated regulatory tools should be promoted through research and education, professional regulatory networks, and the diffusion of proven practices in accordance with generally accepted regulatory principles. Reticence about their adoption could suggest problems of regulatory capacity, conservatism, or possible corruption by interests that stand to lose from change. Problems of capacity may be a function of agency size and budget, making it even more important to lower information costs. Regulatory agencies may need to invest more in analytical capabilities, particularly in the areas of economics, finance, and accounting.

Importantly, under the regulatory paradigm, prudence does not define *what* goals are to be achieved but provides a framework within which these goals should be pursued. It remains for policymakers to make these goals clear, demand prudent approaches to their achievement, and provide or withhold compensation in accordance with outcomes. Under long-standing regulatory law and practice, prudent performance should earn nothing more than a fair return. Fair returns are already calibrated to exceed the risk-based cost of capital in order to motivate beneficial investment as defined by public policy. The return premium on the capital side compensates utilities in total, and thus might also be understood to recognize that certain operating expenditures may be required under the terms of the regulatory compact.

Implementing a new prudence comes with its own challenges, but these should be no more arduous than other conceptions of incentive-based regulation. Although this model fits within the regulatory paradigm, legislatures may need to reinstate for regulators the powers, resources, and discretion needed for implementation. It would also call for political will on the part of regulators, particularly in the face of political pressure from utilities and special interests. Successful implementation would require overcoming the risk aversion of utilities and the conflict aversion of regulators. It is far easier politically to give positive incentives than to exercise powers of enforcement, which may account for current policies and practices. Utilities and their industry associations might embrace some measures, such as uniform standards, but shun others, such as benchmarking. Performance benchmarking is essential under this scheme and methodological techniques can overcome assertions of firm uniqueness. Finally, if some jurisdictions implement the model and others do not, the playing field and rules of regulation will remain uneven.



Table 2-3. New tools for a new prudence

Tools for enhancing utility performance

- Real-time digital intelligence and communication platforms, big-data storage, and analytics
- Decision support (e.g., construction, supply-chain, project, and risk management)
- Comprehensive and integrated resource planning and portfolio diversification
- Capital asset and ecological planning, management, and control systems
- Contingency planning and security protocols for physical and cyber threats
- Optimization modeling for capital and operating options
- Dynamic load and congestion management technologies and controls
- Spatial imaging, mapping, forecasting, and analysis (e.g., RS, GIS, and SCADA)
- Market mechanisms (e.g., competitive bidding and time-variant pricing)
- Consumer information, services, outreach, and engagement
- Research and development and pilot studies (firm and industry)
- Flexible, adaptive, modular, and resilient infrastructure design

Tools for enhancing regulatory enforcement

- Uniform technical standards, codes, and rules (e.g., franchising, siting, sizing, interconnection, interoperability, and so on)
 - Statistical benchmarking and comparative competition with metrics and targets
 - Certification of alternative service providers and model contracts
 - Informed and consistent rules for cost and risk allocation and rate design
 - Technological, structural, and market neutrality in planning and approval
 - Empirical analysis of cost-effectiveness, productivity and other performance metrics
 - Outcome-based compensation mechanisms (e.g., management or investor bonuses)
 - Comprehensive empirical evaluation of programs, services, and customer satisfaction
 - Management and performance audits and improvement plans
 - Transparent and data-driven compliance monitoring and reporting systems
 - Consumer protection rules, procedures, and penalties (e.g., fraud prevention)
 - Process improvement, organizational development, research, and professional education
-



Incentive Design Considerations

As a general proposition, incentives should be used only if they promote economic efficiency consistent with the core goal of economic regulation, constrained as appropriate by other values and objectives expressed through democratic institutions. The purpose of regulation is not to ensure competitive neutrality among a utility's options, maintain the value of the utility's ratebase, or to soften the impact of technological change on the utility sector and its investors. Regulation should ensure prudence, namely efficient compliance with prevailing performance standards and service policies, by providing an effective but conditional proxy for competition. However, if competition would force technological advancement, then so too should the regulator. True competitors would not be able to inflate prices by inflating returns through rate-basing or return premiums without risking market share and financial viability.

As already discussed, just because an investment is associated with infrastructure modernization is not sufficient proof of system, ratepayer, or societal benefits; nor is it sufficient proof of either prudence (fair returns) or the need for special incentives (bonus returns). Investments that present a cost advantage should be regarded as the prudent option in the first place and merit no additional reward. Special incentives will magnify traditional incentives already regarded as problematic, including the potential for uneconomic investment or operational choices.

When they are implemented, an incentive should translate into economic benefits for ratepayers that could not be achieved without the incentive. Incentives that substantially and demonstrably drive costs and prices downward will be more politically palatable. Incentives that simply drive costs and prices *upward* are more difficult to justify, even with the promise of future benefits to ratepayers or society; that is, lower costs and prices (lower highs) than would have been realized without the intervention.¹⁷⁵ Incentives that might yield economic benefits include those that will accelerate the verifiable achievement of efficiency targets that will avoid costs or enhance service reliability or security in the face of an urgent need. Incentives that simply penalize or reward a particular type of investment violate criteria related to efficiency and neutrality.

While the regulatory model is reasonably well suited to imposing discipline and promoting efficiency, motivating innovation has always been a greater challenge. For one thing, innovation may not be readily identified. Incentives for innovation should also be scrutinized carefully in terms of value to ratepayers in lowering costs and prices. Innovation also presents additional issues in terms of maintaining the risk-reward relationship. Ratepayers should not bear all of the risk when it comes to unproven technologies or practices. If a proposal convincingly passes a ratepayer benefit test, regulators can attempt to motivate innovation by various means, including possible ratemaking allowances for pilot and demonstration programs, research and development, managerial performance, and profit sharing.¹⁷⁶

¹⁷⁵ Beecher and Chesnutt (2012).

¹⁷⁶ The UK's RIIO model gives explicit attention to incentives for innovation.



Utilities and other parties are free to propose incentive mechanisms, but their implementation and evaluation should be guided by principles consistent with economic regulatory theory in order to maximize efficacy and minimize deleterious impacts:

- Incentive-oriented regulation should be purposeful, targeted, and consistent with policy mandates and measurable performance criteria.
- The use of incentives should be limited in time and scope, with the ultimate goal of letting market forces and prices work as soon as practical.
- Incentive mechanisms should be symmetrical, presenting the potential for both upside (rewards) and downside (penalties) consequences.
- Incentives should be closely monitored and rigorously evaluated in terms of intended and unintended consequences as well as interactive effects.
- Evaluation methods should disentangle the effects of incentives from other endogenous or exogenous factors affecting utility performance.
- The regressive impacts of rate-supported incentives should be considered, as well as taxpayer subsidies or corrective rate design, to protect disadvantaged households.

Over time, with the benefit of new information and objective evaluation, regulators may find that some incentives work as planned and others do not. In some cases, other policy instruments may be more effective or efficient. Finally, changing conditions and policy priorities may call for evaluating incentives, both old and new.

Concluding Observations

From an institutional perspective, the focus on regulatory incentives can be somewhat myopic. Incentive problems are often perceived but their presence is not always clear. Incentive solutions often seen as effective are not necessarily well supported by rigorous evaluation. When a problem is perceived, some thought should be given to which institutions of governance, democratic or regulatory, are rightfully responsible for taking action, what alternative actions might be taken, and what additional measures might be needed.

When new paradigms and incentive “fixes” are advocated, policymaking should be informed by the answers to a series of questions (4 2-4). In particular:

- Is there a clean and demonstrable incentive or disincentive problem as defined in terms of a market or regulatory failure, and what is its empirical nature and extent?
- Will an incentive mechanism be efficient and effective in addressing the problem it is meant to address, or should other policy instruments be considered?
- Who will benefit from implementation of the incentive, society at large or utility ratepayers, and who should bear the cost of subsidization?
- Does the problem warrant extraordinary incentives beyond conditions of the regulatory compact, expectations of prudence, and the fair rate of return?
- Are monitoring and evaluation systems in place to ensure that incentives achieve desired outcomes, taking all relevant performance factors into account?
- Are adequate measures in place to mitigate adverse effects in terms of economic efficiency and ratepayer equity?



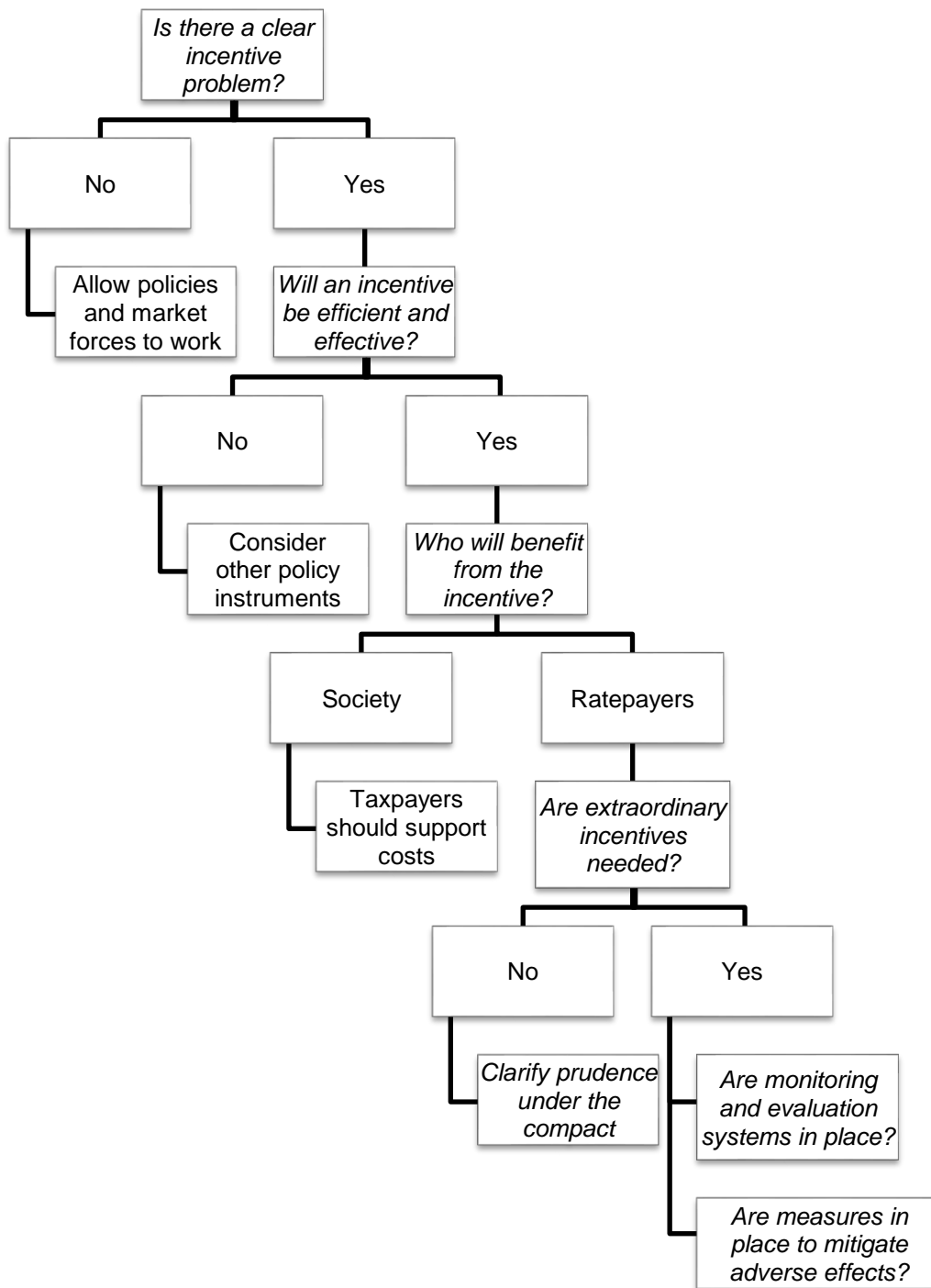


Figure 2-4. Conceptual framework for considering incentives



In the context of energy policy imperatives, aging energy infrastructure in the United States should be modernized and optimized in accordance with prudence. If grid modernization is meritorious, then so is identifying and addressing obstacles to it. The dominant means has been to recast the lack of prudence as a problem of incentives and devise intricate schemes to entice utilities to behave in desirable ways. Under this conception, utilities must be positively rewarded, even for performing as should be expected.

A simpler, though not simple, means is to articulate an obligatory new prudence consistent with modernization and other social goals, and to hold utilities accountable for the choices they make. In other words, regulators should regulate to enforceable standards and accepted practices and provide for compensation accordingly. Armed with new toolsets, utilities and their regulators can become optimizers within the constraints of their respective roles and relevant mandates. The radically conservative idea of a new prudence is clearly compatible with new business and pricing models, as well as performance-based regulation, while remaining true to the economic regulatory paradigm.¹⁷⁷

The rush to replace the paradigm may be partly a function of institutional memory loss that may or may not be recoverable. As an institution, the economic regulation of utilities seemed relatively effective through the 1970s, when it seemed to operate closer to its theoretical ideal, enjoying considerable technical capacity and political independence. Pressure on costs and prices, emergent ratemaking mechanisms, and a growing emphasis on restructuring and deregulation across the sectors were among the disruptive forces contributing to a sense of regulatory failure. Ongoing federal preemption and legislative intervention have resulted in a loss of jurisdiction, authority, and discretion reducing the scope and strength of state regulation and in some cases resulting in regulatory vacuums.¹⁷⁸ Still, the apparent “failure” of the paradigm may be less a failure of theory than a failure of implementation. Although many regulators remain true to the traditional ideals, their job has become more difficult.

One reason may be that utilities appear to have become more risk-averse, which with regulatory reinforcement can become a self-fulfilling tendency. A manifestation of this mindset is their success in winning a variety of risk-shifting measures from conflict-averse legislators and regulators, although not necessarily with commensurate reductions in authorized returns. The effect, if not the objective, is to socialize risk while privatizing returns. Some mechanisms seem to suggest not just a reduction of regulatory lag but all possibility of loss. Return without risk, of course, is both antithetical to the regulatory compact and even suggestive of regulatory capture. Contrary to the prevailing narrative, and given the desire for innovation and transformation, utilities today might actually face not too much risk, but too little.

The real incentive problem, then, might actually lie not with traditional regulation but with its greatly modified form, altered so extensively that it is barely recognizable. So-called “best practices” are only best depending on perspective, which is why they should always be understood in terms of the interests behind them. Many of these practices, even those ostensibly designed to address or align incentives, may actually mute the incentives for

¹⁷⁷ Aggarwal and O’Boyle (2017).

¹⁷⁸ See California oversight of PG&E transmission spending (Baker 2017).



efficiency and innovation that can be effectively provided under a more robust and uncluttered risk-return formula. Performance incentives do not work well when muffled by the noise of so many signals, some of which are likely to compete.

Incentives and the subsidies on which they rely might actually have the paradoxical effect of making the utility complacent about innovation and slowing its pace. Rather than shielding utilities from all forms of risk by shifting it to ratepayers, regulators should harness the power of risk-based incentives to focus utilities on performance. Good companies can take good regulation and deliver performance consistent with expectations and obligations of prudence. Taking a long-term view, but contrary to common rhetoric, economic regulation has actually proven to be a remarkably adaptive policy instrument. Regulatory methods can be fine-tuned toward new purposes. However, the regulatory framework can be adapted to evolving conditions without adapting away from core principles related to efficiency and equity. In some respects, over-adaptation has weakened regulatory oversight. In some cases, legislative or regulatory activism has played a role.

Ironically, in a contest to design from scratch a system of incentives for infrastructure modernization, the winner might actually look a lot like the model under which that infrastructure was built in the first place. Thus, one policy option is to return the economic regulatory model to its unadulterated form in order to connect compensation to conduct, restore the rightful balance of risk and reward, and put the forces of proxy competition to work.

The opportunity for infrastructure modernization *is itself an incentive*, particularly when conjoined with the traditional regulatory model. Assuming that modernization is consistent with an updated conception of prudence, extraordinary incentives should not be needed. The benefits to utilities in terms of investment opportunity are obvious; the benefits to ratepayers are contingent on sound regulation to ensure that technologies and practices enhance the quality and lower the cost of service, consistent with preferences. Realizing these promises depends on whether regulators are willing and able to respect the social compact and let the powerful economic incentives at their disposal work to serve the public interest.

Defense of economic regulation in its traditional form should not be construed as acceptance of the status quo or recalcitrance about reform. Regulatory processes and practices have much room for improvement. If in the face of persistent market failure regulators are unable or unwilling to regulate consistent with the paradigm, then strategies for building regulatory capacity or alternative structural models will be needed. If for whatever reason regulation no longer serves the public interest, its institutional time may be up.



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3. Public Policy Perspective: Regulatory Incentives to Support Grid Modernization

By Ronald L. Lehr

Introduction

Traditional cost of service regulation, as typically practiced by state utility commissions that oversee investor-owned utilities, is unlikely by itself in most cases to respond sufficiently and quickly enough to capture potential benefits from grid modernization for consumers and society. There are at least three reasons:

1. Financial incentives for regulated utilities are misaligned with public policies. Current incentives do not support the increased pace and variety of investments (capex) to respond to industry challenges, including updating systems and technologies at the distribution and transmission levels. Changes to utility operations are needed to support new utility roles, and these may require new streams of utility expenses (opex). While cost of service regulation provides capex incentives, although sometimes not well targeted, opex incentives are lacking.
2. New information from applications of new communications technologies enables consumers to become energy producers and to take more responsibility for their energy use. But traditional regulation doesn't incent utilities to support increased consumer sovereignty.
3. A variety of factors stand in the way of creating well targeted and well aligned utility incentives, including litigated processes, poor communications, relationships that do not build trust, and lack of consensus about outcomes.

For these reasons, additional attention to regulatory incentives is required.

Traditional cost of service regulation is based on cost accounting that defines both expenses that can be recovered in rates and investments on which earnings are allowed.¹⁷⁹ Financial results of utility operations, in terms of earnings per share that are of great interest to utility managers and investors, are the usual focus of discussions about utility incentives. This chapter of the report explores other sources and kinds of incentives, in addition to financial incentives, recognizing that a variety of incentives gives a better chance for successful outcomes for grid modernization.

Alternatives and reforms to traditional cost of service regulation can improve the pace, process and outcomes in utility regulation. Given the wide variety of circumstances in which states regulate utilities, there is no uniform or single approach that will serve every requirement in every situation. But some common threads apply.

In the context of grid modernization, this chapter explores earning on equity investment that provides the main financial incentive for investor-owned electric utilities, as well as several

¹⁷⁹ Cost of service regulation and a proposal for "new prudence" to address current challenges are well described in Janice Beecher's chapter of this report. Steve Kihm's chapter describes how utility managers can create value for shareholders when returns (r) exceed the cost of capital (k).



regulatory disincentives. Next are practical implementation and timing questions that both regulators and industry investors face.

Following that is a description of variations on basic financial incentives that are in common use. These include differential investment returns, formula ratemaking, and performance incentive measures. Given their monopoly, single-provider status as sole suppliers of services that depend on a wires network, utilities also enjoy monopsony power as single buyers in markets for electric power produced by other firms. These incentives are little understood and often ignored. Monopsony incentives are analyzed with examples.

At both transmission and distribution levels, planning can provide incentives for investment if it illuminates options, addresses logical pathways for implementation, and helps stakeholders achieve consensus about which investments to make, how to pay for them, and how system benefits that are achieved can be equitably shared. Planning helps develop information that both public and private decision-makers can use to justify approvals and investments. Decisions about both short term options and their long term implications can be improved. Planning can elucidate risks, providing incentives for taking manageable risks related to investing in grid facilities and capabilities. Examples in the paper of planning that informs decision-making about grid modernization options illuminate its potential benefits.

In contrast to conventional approaches, performance incentive regulation, coupled with creative, informal and effective due process, offers solutions that can allow state utility regulators to effectively align utility financial incentives with desirable grid modernization investments and related program expenditures. Such solutions can improve uptake of new grid technologies and speed the pace of regulation to better match the speed of changes facing the electric power industry.

Process issues must be addressed, since regulatory due process itself can be an impediment to progress, or, if due process can be achieved in more informal and constructive ways than those typically practiced, creative regulatory process itself can be an important contribution to progress.

Finally, this chapter posits a number of questions for utility regulators and executives. These questions are based on the author's experience making both public approval and policy decisions as well as utility budget and investment decisions. Tasks facing both public and private decision-makers are very similar: ask questions until a "yes" or "no" vote on propositions that require exercise of the decision-maker's judgment can be justified.

Grid Modernization Outcomes

Given DOE's grid modernization goals explained in this report's introduction, a modern grid must achieve:

- greater resilience to all types of hazards;
- improved reliability for everyday operations;
- enhanced security from an increasing and evolving number of threats;
- additional affordability to maintain economic prosperity;



- superior flexibility to respond to variability and uncertainty; and
- increased sustainability through additional clean energy and energy-efficient resources.

For the purposes of this chapter, I assume that sustainability includes utilities' and other firms' financial sustainability.¹⁸⁰ Attention to incentives will likely be required to engage utilities, and other firms that either compete with utilities or supply them with goods and services, to deliver these grid modernization outcomes. Regulatory incentive options discussed here can support both investment risk assessments and management of investments made by these firms, as well as proper alignment of regulations and public policies with firms' financial incentives, to achieve these grid modernization outcomes.

Rapid Electric Industry Changes

Among many forces driving electric industry changes, information enabled by computing power and available software is one of the most important. Rapid technology improvements flowing from research and development, followed by demonstration and deployment to take advantage of improved information, have resulted in many more choices for consumers. Hardware available to consumers at ever-lower prices challenges previously dominant utility control. What was an industry where one size, at one price, fit all, at least within broad residential, commercial and industrial rate classes, is changing rapidly in the direction of mass customization, where many more consumers will expect energy solutions that are tailored to their particular situation and requirements. In these circumstances, the electric energy commodity, still a dominant industry product, will likely be delivered in the future in new forms, with more service content to meet changing consumer demands.

Another force driving change flows from consumer demands and public policy that require environmental costs, particularly air pollutants from fossil-fuel combustion, but also impacting water and land, to be incorporated into industry costs, rather than imposed on others as costs "external" to the power system. Customers, including many major corporations, have their own requirements for how clean their electric power should be and are acting to meet their own goals. Technology improvements allow them to do so in increasing numbers. Individual as well as corporate and institutional goals can be reached at a savings, rather than costing extra.¹⁸¹ When customer efficiency can be coupled with clean energy at low cost from solar, wind and other non-combustion resources, customers can internalize their own previously external costs. As more efficiency and clean energy options are used, their costs can also drop, due to market improvements and scale economies. This virtuous cycle is having noticeable impacts on fossil generation.

These technology, consumer and environmental drivers suggest that current levels of industry change may be unprecedented, similar to the 1990s when many states restructured their electric systems. They are at least noteworthy enough to raise serious questions for state and

¹⁸⁰ While it is not the federal government's responsibility to assure utility financial success, many other stakeholders addressing grid modernization challenges will be interested in the financial sustainability of utilities, including utilities themselves and their investors.

¹⁸¹ See Lehr (2016a) and Lehr (2016b).



federal regulators about the need to examine whether their business as usual will continue to achieve the best possible public interest outcomes.¹⁸²

Traditional Regulatory Approaches: Questions for Regulators

Rapid electric industry changes suggest that traditional regulatory approaches should be reviewed. Some of the questions that regulators could ask are:

- Should regulators consider how to pick up the pace of their regulation to better match the pace of changes facing the industry?
- Could a variety of regulatory incentives be better aligned with both traditional and emerging public interest values?
- Should discussion of incentives start with financial incentives, but also include those related to the pace and timing of regulatory interventions, planning that results in risk management for investment purposes, and emerging impacts due to increased consumer choices?
- Are better defined outcomes and improved metrics and measurements for progress possible or required?
- Are incentives and disincentives that regulators currently apply in regulating utilities sufficient to support investment in, and utility expense budget support for, state and federal grid modernization goals in the face of rapid changes in the electric industry?

Incentives That Utilities Face

Generally, regulated utilities have incentives that are allowed by their regulators, who control rates utilities charge consumers and what can be included in those charges. But utilities have many incentives that go beyond financial incentives, and beyond what regulators control directly — for example, the following:

- **Cost accounting and cost allocation.** At the base of cost of service regulation are two opportunities that present incentives for investor-owned utilities to manipulate cost results to achieve favorable outcomes for shareholders:
 - *Assignment of costs to accounting categories.* Cost assignments for utility expenses and investment are made to cost categories in the Uniform System of Accounts¹⁸³ based on accounting conventions. Accounting categories are used to divide costs up among different customer classes (for example, residential, commercial, industrial) in order to set rates. These cost assignments are not automatic. Rather, they involve judgment. A good example is assignment of

¹⁸² For more on this topic from the author's perspective, see Lehr (2014), Lehr (no date), and Zinaman et al. (2015).

¹⁸³ FERC also mandates the USOA used by all electric utilities: Uniform System of Accounts.

<https://www.ferc.gov/enforcement/acct-matts/usofa.asp>.



costs to “fixed” and “variable” categories in ratemaking. Fixed investments are generally those lasting longer than a year, while variable costs are consumed within a year. In reality, all costs are variable in the long term. So accounting conventions and judgments used in assigning costs become the focus for contests among those who have conflicting interests and values.

- *Allocation of joint costs of service.* It is widely accepted that there are no precise mathematical or exact methods for allocating joint costs of production.¹⁸⁴ In electricity regulation, costs for generation, transmission and distribution must be assigned to wholesale and retail service, and then to classes of customers. Since there is no precise way to allocate these costs, and allocations result from judgments and approximations, allocation processes provide incentives for disputes and conflicts among contending interests.
- **Regulatory lag, process and rules.** Regulatory incentives include time taken by regulators to act, costs and risks of regulatory processes, and costs and risks related to rules of prospective application and various other forms of regulatory guidance with which regulators require utilities to comply. Such rules and guidance are put in place for a variety of good reasons, including risk reductions achieved with planning certainty, reliability, and a variety of engineering and service standards; consumer service and service quality requirements; disaster responses; enabling safe and reliable interconnections with electric systems; and financial standards and filings. All of these create incentives, impacting consumer rates eventually and more or less directly.
- **Market incentives.** Market structures, market development and market choices all affect utilities, providing them with incentives to respond to markets in which they participate or to resist market choices. Particularly as new technology becomes more available to more interested consumers, utilities have to respond to additional choices consumers might make, such as investing in end-use efficiency, buying green power from utilities or third party providers, or putting solar panels on their roof and adding storage or backup generation.
- **Increased consumer sovereignty.** New technology and information revolutions vastly expand consumer choices. In turn, utilities and their regulators face new incentives and challenges to which they must respond. As technology enables consumers to make additional energy choices, utilities have new facts to confront and new incentives to which they respond.
- **Information, privacy and security.** Information, and information access and flows, change relationships between consumers and utilities, as some consumers use their own computing power to take control of their energy use. Information privacy and cyber security raise many challenging issues and incentives that accrue to various players that must be considered. As technology change accelerates, new incentives arise for utilities that call for regulatory engagement.
- **Financial relationships with consumers.** With changes in access to information and technology, financial relationships and the economics on which they are based change relationships between consumers and utilities, as consumers have new choices about whether and how much to invest or spend on their new “prosumer” roles.¹⁸⁵ Utilities

¹⁸⁴ See, for example, Bailey (2009).

¹⁸⁵ Consumers can be producers as well as consumers, hence “prosumers.”



also must change their planning and investment outlooks to accommodate more of their prosumers' desired distributed generation resources. If enough consumers make choices that lead to drastically less than anticipated use of utility power, utilities face the dreaded "death spiral" as remaining customers have to pick up stranded utility investments.¹⁸⁶

- **Electric industry economics.** Fundamental industry economics are changing. In many instances, new utility-scale wind and solar projects are more cost-effective than continuing to run old fossil generation. Such economics provide new incentives for both utilities and alternative electricity providers that sell directly to consumers in markets restructured to allow consumer choice. All investors in new generation have changing incentives due to changing economics. They must decide what resource investments to consider, and whether and how much of these new technologies to own themselves. These choices, in turn, raise questions about how to carry financial burdens of stranded utility assets. Here, again, incentive questions are at the heart of the matter. In vertically integrated states, utility monopsony incentives — as single buyers in the market for bulk power from new renewable resource projects — become acute regulatory concerns in these circumstances.
- **Utility managerial incentives.** More service orientation could elevate utility marketing departments, long thought oxymoronic functions inside monopolies, above their historic position of about tenth on the utilities' top list of internal functions, following several engineering categories and possibly accounting, law and finance.¹⁸⁷ How all these changes in utility business models work out will depend in large measure on how utility managers respond to the incentives they face and how and at what pace regulators are responding.

Utility Incentives for Grid Modernization

State regulators typically allow utilities to earn up to an authorized return on the equity portion of their investments in facilities that are "used and useful" for providing retail customer services. Grid modernization investments fall into the class of facilities on which utilities can earn up to the authorized rate of return. This incentive predisposes utilities to favor investments over expenses, since they earn on investments but not on expenses. The incentive also acts to keep investments on utility books and earning revenue, rather than to retire or refinance them, since utilities face risks that their regulators (or state law) might not allow the utility to collect on plant investments that are not in service. Likewise, utilities are not incented to spend money that falls in expense categories, like running programs that provide new services to consumers, since, typically, they do not make profits on expenses. So, for example, animating customers to take advantage of grid modernization investments through such programs would not be in the utilities' financial interests, while making grid investments that are included in the utility's rate base would be.

¹⁸⁶ See, for example, Kind (2013) and Kind (2015). For evidence that the death spiral may be overstated, see Darghouth et al. (2015). Time-varying rates may offset cost recovery issues caused by deployment of solar photovoltaic (PV) technology. As solar PV deployment rises, it will shift a utility's peak system demand to times when solar PV output is lower, thus dampening impacts of solar deployment on utility cost recovery.

¹⁸⁷ E Source Blog. May 4, 2017. Did You Miss the 2017 California Emerging Technologies Summit? We've Got Your Top Takeaways. <https://www.esource.com/Blog/ESource/8-10-13-Forum-Utility-Innovation>.



Given that utilities can earn on equity invested in grid modernization, we can expect and we have observed that utilities will make proposals to invest in new grid equipment. Utilities are less likely to propose new grid services that require them to budget for and expend funds that fall into expense categories. However, a significant body of work has created incentives for these classes of utility expenses for the purpose of energy efficiency and demand response.

Federal Transmission Investment Incentives

The Federal Energy Regulatory Commission (FERC) has jurisdiction over interstate and wholesale electric power markets and has put incentives in place that foster transmission investments.¹⁸⁸ FERC's incentives aim to benefit consumers by ensuring reliability and reducing power costs as new power lines reduce transmission congestion. FERC also granted transmission incentives to encourage utilities to join Regional Transmission Organizations, to compensate utilities for using new technologies, and for building lines in critical transmission corridors.

Utility Disincentives for Grid Modernization

Disincentives for grid investment include the difficulty of having adequate foresight to specify the right kind and pace of grid investments, since both technology and consumer expectations are in rapid flux. Since technical standards for a fully integrated, modern grid are just emerging, this disincentive is tied to a real problem — not all gizmos that could be included in a modern grid will work together seamlessly in the absence of a complete pattern of standards, so it is hard to know when to invest in some or all of them.¹⁸⁹

Regulatory punishment can be an important disincentive. Some utilities have tried to make grid investments despite the incomplete pattern of standards for the technologies, information and data collection, and communications that a modern grid suggests, and had their investments disallowed in whole or part by regulators.¹⁹⁰ Such utilities will have second thoughts about making similar investments in the future.

Demonstrations and Deployments

Focused demonstrations could pull together many of the elements of a grid modernization strategy for investment, build out, and operations, and provide the right incentives for

¹⁸⁸ In 2005, the Energy Policy Act added a new Section 219 to the Federal Power Act that required FERC to offer incentives for grid modernization. FERC implemented section 219 by issuing Order 679, establishing by rule incentive rates for transmission investments. Since Order 679, FERC has evaluated more than 85 applications for over \$60 billion in potential transmission investments. For an overview, see:

<https://www.ferc.gov/industries/electric/indus-act/trans-invest.asp>. A November 12, 2012, FERC Order, "Promoting Transmission Investment Through Pricing Reform," 18 CFR Parts 2 and 35, Docket No. RM11-26-000, discusses how FERC will evaluate proposed transmission incentives. <https://www.ferc.gov/whats-new/comm-meet/2012/111512/E-3.pdf>. See also Transmission Investment. <https://www.ferc.gov/industries/electric/indus-act/trans-invest.asp>

¹⁸⁹ NIST. Smart Grid. <https://www.nist.gov/engineering-laboratory/smart-grid>.

¹⁹⁰ See, for example, Jaffe (2016). See also Nowicki (2013).



consumers, utilities and other service providers to engage in their various roles. Demonstrations can test potential solutions and generate data and information needed for results to be analyzed and reviewed. Pilot programs can have the benefit of lower investment risk due to smaller scale. If carefully set up and monitored, they can justify mass deployment if they succeed.

For example, utility plans now underway as a result of New York’s Reforming the Energy Vision (REV) proceedings are taking this approach.¹⁹¹ More demonstrations appear to be required before it will be clear just what packages of technologies can best work together effectively to meet consumer expectations. Demonstrations now starting could show how utilities can make money without doing competitive harm to third party providers of similar goods and services.

Another open question is how regulation will protect the large numbers of consumers who will not be early adopters of new technologies and services, while allowing those consumers who want to take advantage of a more modern grid to do so. Since some of these consumers will be investing their own capital in facilities that ease burdens on the utility system — for example, adding storage that reduces overall utility costs — valuation and cost and benefit allocations will need to be further developed.¹⁹²

Planning

Planning appears to be a prerequisite for working through many of these issues. Planning spans integrated resource planning (in vertically integrated states), transmission planning and distribution planning.¹⁹³

Planning provides incentives for both public and private decision-makers to collaborate as they answer the fundamental question, “compared to what?” Planning can set up expectations and help form consensus among various views about what the future holds and what investments might produce the best results. Planning produces information on which both public and private decision makers can exercise their talents for using good judgment. Planning can lead to avoiding expensive mistakes if exercised in a “risk-aware” fashion, as well as leading to lower investment risks and costs as risks are identified and avoided.¹⁹⁴ Planning includes cost and benefit studies that inform decisions about expanding transmission systems or joining markets.

While utilities have a long history of in-house distribution planning to meet service requirements, it is an emerging area for regulator engagement. In some states, the impetus is higher penetration levels of distributed solar photovoltaic (PV) systems at customer sites. Deriving locational benefits from distributed energy resource investments is of particular interest. But it is challenging to nail these benefits down in the face of changing consumer expectations about the value of their energy investment and use patterns, advances in distribution technologies (like smart inverters for rooftop PV or smart control technologies for

¹⁹¹ See, for example, Gahran (2016).

¹⁹² Valuation is part of DOE’s Grid Modernization Initiative. See <https://energy.gov/under-secretary-science-and-energy/doe-grid-modernization-laboratory-consortium-gmlc-awards>.

¹⁹³ See Kahrl et al. (2016). Also see ICF International (2016).

¹⁹⁴ Binz et al. 2012.



end uses),¹⁹⁵ and emerging relationships between aggregated consumer demand response and needs of regional grids and their market operators.¹⁹⁶

Similar issues arise when planning for replacing old distribution equipment, or responding to systems damaged or destroyed by natural disasters. In both cases, utilities have financial incentives to invest in the grid, but they face regulators and stakeholders who have very different visions of how and how much to modernize the grid. Again, planning, followed by pilots and demonstrations, seems to provide the best approach to work out these complexities, including how to provide the right kinds and levels of incentives while eliminating disincentives. Planning can both reduce confusion about the direction and pace to take and limit possibilities for regulatory second-guessing. A solid planning effort can reduce the mystery of utility investments and reduce utility disincentives.

Illinois Grid Modernization Statute and Implementation

A recent assessment of progress on implementation of the Illinois “Energy Infrastructure Modernization Act” highlighted:¹⁹⁷

- \$3.2 billion in grid hardening and smart meter investments authorized
- An annual formula rate process for electric delivery charges that has led to shorter, more routine rate cases and fewer disputed issues among parties
- Installation of more than 2 million advanced meters, about half the goal
- More confidence among utilities that regulators will determine their capital investments were prudently incurred and faster returns on these investments through delivery charges reset annually
- Fewer truck rolls and outages as a result of distributed automation investments
- Rate increases that have outpaced inflation¹⁹⁸
- Performance goals for reliability, consumer benefits and diversity are enforced with penalties (basis point deductions on return on equity)
- Questions remain about whether performance standards are too severe or not difficult enough and aimed at the right outcomes, whether superior performance should be rewarded, and about potential benefits of multiyear rate plans.
- Full technology benefits remain to be realized, particularly consumer education and empowerment to achieve more consumer adoption of dynamic pricing and peak shifting programs.

¹⁹⁵ The Western Interstate Energy Board has addressed DER Interconnections and advanced inverter deployment in a paper: see McAllister (2016).

¹⁹⁶ Mills et al. (2016).

¹⁹⁷ McCabe, Ghoshal, and Peters (2016). See also Hemphill and Jensen (2016).

¹⁹⁸ From a consumer perspective, this level of rate increases is not necessarily a good result.



Alternative Regulatory Approaches for Utility Financial Incentives

Earning a return on invested equity

The primary financial incentive for utilities that regulation provides today is profits allowed as percentage returns (“rate of return”) on invested equity.¹⁹⁹ These profits create incentives for utilities to choose capital investment to respond to most problems and opportunities they face, so long as they can invest within the “r-k” constraints that Steve Kihm points out in this report — adding value for existing shareholders with investments that return more than the capital costs required. Utility profitability depends on investing equity to gain returns within the level authorized by regulators.

Correspondingly, utilities have less (or no) financial incentive to employ expense-based solutions, since they do not earn profits on expenses. Instead, expenses are covered in rates, but without a profit. So in the case of grid modernization, utilities have financial incentives to make grid investments, but without adding an additional source of profits, they have no (or few) incentives to build up consumer services like education that are expenses that could enable customers to understand and take advantage of the services and efficiencies that more modern and intelligent grids can offer.²⁰⁰

While earning on invested equity provides a useful incentive to invest in the business to provide plant and equipment to serve consumers, it also leads to lack of attention to non-capital-based options and less use of expense-based solutions than may be justified. The equity incentive also can prevent change because, once made, capital investments are more difficult to adjust than expense budgets are to amend. Utilities are also incented to over-weight “make” (or “build”) options versus “buy” options in sourcing decisions, to the detriment of striking, growing and maintaining partnerships with third party vendors of goods and services. A more modern grid suggests that utilities that are more able to respond flexibly to changing technology and consumer requirements, using deals with partners to provide responses to changes in their business environment, might be better off than utilities whose only response is a capital investment.²⁰¹ Since utilities earn on investments they own, they will prefer “make” over “buy.”

Further, if a utility has a choice between making an investment it can own and on which it can earn, as opposed to acquiring goods or services from another provider — which will be treated as an expense on which the utility does not earn a return — it will favor its own investment. This incentive is related to and supportive of utility monopsony power.

¹⁹⁹ Any call recording of a utility’s quarterly investment report to analysts will reveal utility executives promising analysts to invest capital in the business, and analysts questioning how executives will get regulators to allow investments to be placed in rate base, leading to earnings for shareholders. Utilities usually post these analysts call recordings on their web pages under headings like “investor relations.”

²⁰⁰ Third parties can provide these services, instead of utilities bearing these expenses. Access to customers and to their energy use information are issues that regulators are beginning to address.

²⁰¹ If your only tool is a hammer, every problem is a nail. Changing this incentive has been central to the efforts of the New York Public Service Commission to create its REV model. See State of New York Public Service Commission, Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, “ORDER ADOPTING A RATEMAKING AND UTILITY REVENUE MODEL POLICY FRAMEWORK,” Issued and Effective May 19, 2016. Also see Pyper (2016) and Trabish (2017a).



Adjusting utility monopsony incentives

Utilities are monopolies under law and their state-granted franchise when they are sole suppliers of electric utility services. Given their monopoly, single-provider status as sole suppliers of services that depend on wires networks, utilities in vertically integrated states also enjoy monopsony power as single buyers in the market for electric power produced by other firms. If another firm produces electricity, outside of merchant markets, there is generally only one place to sell it — to a utility. While regulators have been dealing with utility monopoly power over consumers for a century or more, monopsony incentives only started to be felt when PURPA opened the utility market to competitive generators in 1978.²⁰² Where markets for competitive generation were deregulated, as in the restructuring that encompassed about half the U.S. electric markets in the 1990s and early 2000s, the theory is that competition among generation owners will be sufficiently robust to protect consumers from generator owners seeking excessive rents.

Where utilities that own wires systems can use their ownership of those systems to either favor their own generation or discriminate among other firms' generation offerings, monopsony incentives will be present. Regulators will need to apply vigilance and expend efforts to protect consumers and the public interest. The monopsonist's incentives are to squeeze suppliers so that most of the benefits of their contract arrangements accrue to the monopsony, to negotiate terms that result in most risks falling on suppliers, and to insist on contract protections that require suppliers to indemnify the monopsony, but not to be indemnified in turn. In the short term, utilities squeezing third party providers might be considered to be in consumers' interests. But in the long term, too much utility monopsony pressure on third party providers could eliminate competitive pressures they bring and lead to higher, not lower, rates.

Performance standards, timing of performance, liquefied damages, choice and location of dispute resolution, notice responsibilities, ability to cure defects – almost every conceivable term addressed in a contract with a monopsonist – can be impacted by monopsony power, since the supplier has no other buyer in the market for its goods and services. Where regulators set up utilities as “platform providers” for grid modernization as in New York's REV proceeding, or engage their monopoly ownership of delivery wires and position as sole providers of frequency control operations, regulators will need to be fully aware of monopsony incentives and actively regulate them in the public and consumers' interests.

Applying differential investment returns

Another way that regulators have adjusted utility incentives is by allowing different returns for certain types of investments. There are a number of examples.²⁰³ Among them is a California proceeding on a pilot incentive program for distributed energy resources (DERs). Initially, the assigned Commissioner proposed a differential investment return for DER investments that substitute for utility distribution equipment investments based on the difference between the

²⁰² The Public Utility Regulatory Policies Act (PURPA, Pub.L. 95–617, 92 Stat. 3117, enacted Nov. 9, 1978) promotes energy conservation, efficient use of domestic energy and renewable energy.

²⁰³ See, for example, ACEEE. Performance Incentives. <http://aceee.org/sector/state-policy/toolkit/utility-programs/performance-incentives> and Kihm et al. (2015).



utility's cost of capital (k) and return on capital (r), pegged at about 3.5 percent given conditions in California.²⁰⁴

The utilities' expressed view is that regulation sets authorized rates of return equal to the cost of capital. As Kihm explains in this report, there must be a difference between the two to allow utility managers to add value for shareholders. If $r = k$, no value can be added. A pilot performance incentive mechanism for DERs under development in California would include a management fee of 4 percent of yearly DER provider payments paid as an incentive to utilities where DERs save money by substituting for, or deferring, conventional distribution investments. To win this incentive, utilities' net market value calculations for potential DER pilot projects would need to include analysis of capacity; energy; ancillary grid services; and grid integration, deferred distribution and transmission system, and DER procurement contract costs. Each of the three California utilities would test a different market value method to justify their performance incentive and to make sure pilot program DERs included were incremental to existing efforts.²⁰⁵

The California commission has released a "roadmap" that puts the incentive proposal and pilot DER acquisitions in context with other DER initiatives.²⁰⁶ The roadmap includes the incentive and pilot docket with other dockets as part of distribution planning, infrastructure, interconnection and procurement.

Using alternative ratemaking approaches

Some state regulatory commissions have implemented alternatives to traditional ratemaking that address utility incentives and regulatory costs. These ratemaking alternatives provide a variety of incentives and disincentives that can impact whether utilities will want to invest in grid modernization and whether consumers will want to avail themselves of benefits grid modernization might bring them.

For example, formula rates change customers' charges if utility earnings are outside predefined levels, either too high or too low. True-up mechanisms often accompany rate formulae. True-ups adjust rates in response to changes in external factors that can cause costs that are outside utilities' control, such as interest rates, inflation or unusual weather. Formula ratemaking can save regulatory costs by providing a predictable, scheduled approach to ratemaking.

Potential incentives for utilities with formula rate approaches are that utility management can apply themselves to running their business efficiently between scheduled formula reviews, earnings are more constant and less likely to under or over return, and consumers can expect more stable rates and fewer rate shocks giving them better certainty with which to plan their own energy use alternatives and investments. However, establishing formulae can be challenging and provides incentives for building in utility bias. Likewise, values subject to true-up and interim reviews require definition, data collection and reporting, and these factors can be controversial. Setting rates with formulas provides incentives for utilities to cut costs, but cost-

²⁰⁴ See Florio (2014).

²⁰⁵ See <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M169/K669/169669077.PDF>. Also see Lowry, Makos, and Deason (forthcoming).

²⁰⁶ Trabish (2017b).



cutting can be done at the expense of service quality and reliability, so performance standards for service quality and reliability should be considered.²⁰⁷

The Texas Legislature, concerned about increasing costs for transmission and distribution, recently asked the Public Utility Commission of Texas to report on alternative ratemaking mechanisms.²⁰⁸ The commission's consulting report discusses alternatives to an existing rate adjustment mechanism that allows utilities to propose new rates twice a year. In addition to formula rate plans, ratemaking alternatives discussed are:

- *Straight fixed-variable (SFV) rates.* SFV rates attempt to recover most utility fixed costs by imposing very high fixed charges unrelated to amounts of electricity consumed. Advocates of SFV rates claim they better align fixed charges with fixed costs, make utility cash flows more certain, avoid rate changes when loads change, mitigate (but do not eliminate) utility disincentives to promote energy efficiency,²⁰⁹ and provide an incentive for customers to lower peak demands.
- *Decoupling.* Decoupling utility revenues sets rates based on sales per customer estimated for a test year. Energy prices are adjusted if actual sales are different than test year estimates. Decoupling revenues from sales removes utility incentives to resist spending on programs to encourage consumer energy efficiency and to increase energy sales, but does not address incentives to add investment to rate base. (See text box on next page.)
- *Lost revenue adjustment mechanisms.* These mechanisms provide for rate adjustments between rate cases to hold utilities' cost recovery levels constant when consumers employ more efficiency (and, depending on design, other types of DERs) than was assumed when rates were set in a rate case. Since these mechanisms allow constant cost recovery levels for utilities, they reduce utility disincentives to support consumer efficiency programs and investments.
- *Multiyear rate plans.* These plans keep rates constant for the plan term, subject only to predetermined adjustments during the plan period, typically three to five years. Adjustments are based on defined cost impacts, like inflation, that are either beyond utility control, or that recognize general cost impacts, like overall economy productivity gains. In the plan's defined time frame, utilities have incentives to control costs, since cost savings can add to utility profitability. But service quality could be impacted by cost-cutting, so regulatory attention must be paid to service levels. Performance standards for service quality and reliability can accompany multiyear rate plans, along with tracking and reporting and financial consequences — penalties or rewards, or both. Fewer and more predictable rate cases under these plans can make regulation less costly.
- *Price caps.* Price caps set prices or unit revenues on factors other than utility costs. They typically use inflation, less productivity improvements, to set rates that better reflect prices that would be charged in competitive markets while providing incentives for utility managers to create higher profit levels resulting from cutting costs. Cutting costs could affect consumers by leading to lower service quality, so regulatory vigilance must be exercised if price caps are implemented.

²⁰⁷ See formula ratemaking discussions in *Recovery of Utility Fixed Costs: Utility, Consumer, Environmental and Economist Perspectives* by Wood et al. (2016). See also Lowry, Makos and Deason (forthcoming).

²⁰⁸ Kirsch and Morey (2016).

²⁰⁹ Like decoupling, SFV rates retain utilities' incentives to increase sales and add to rate base.



Decoupling

Among alternative ratemaking approaches, decoupling addresses utility financial incentives to increase energy use. Decoupling can reduce utility revenue loss risks due to rate designs that encourage energy efficiency and peak load management, consumer on-site generation, and use of non-utility energy services. By reducing these risks, utilities have better incentives to adopt new rate designs that encourage efficiency or shift loads away from peak demand, support rather than oppose consumer generation options, and encourage efficient alternatives provided by third parties.²¹⁰

Decoupling can help reduce rate case frequency and rate case controversies since energy prices will change based on actual utility sales. Now widely used for both electric and gas utilities, decoupling has been encouraged in states where efficiency and demand management are policy priorities.²¹¹

Decoupling is consistent with utility investment in grid modernization that provides platforms for consumer alternatives, along with communications, information flows, and data management that enable consumer alternatives to be more broadly used.²¹²

The Texas consultant report also addresses alternative ratemaking approaches that it characterizes as more “incremental revisions,” including the following:

- *Future test years.* Projecting cost data can result in setting rates that better match actual costs when the rates are implemented. Conversely, use of historical test years can lead to rates that are based on “stale” data.²¹³
- *Earnings sharing mechanisms.* Sharing earnings between consumers and shareholders can be used in a variety of applications, including earnings tests, wholesale market sales, efficiency investments and others, to incent utilities to undertake efforts that produce revenues or benefits which, if not shared, might not be undertaken.²¹⁴
- *Cost trackers.* Trackers adjust rates to follow certain costs, like fuel costs, between rate cases. Based on a specified formula, trackers allow costs to be recovered that utilities otherwise cannot control, provide for costs during construction to be recovered, or require costs to be tracked for other purposes, such as allowing timely recovery of capital investments.

As the Texas consultant report points out, all these alternatives require some form of periodic review by regulators to make sure that they are producing intended results. Procedural costs

²¹⁰ Morgan (2012).

²¹¹ Lowry, Makos, and Waschbusch (2015).

²¹² Initially used in UK regulation, revenue caps with correction factors charged or refunded to consumers that reflected variations between allowed and actual utility revenue resulted in increased revenue when sales volume and numbers of customers increased. More recently, the UK regulator OFGEM reformed its approach, breaking these links, so its current RIIO program results in revenue decoupling.

²¹³ Other alternatives include partial future test years, in which some historical and some future data can be included, and true-ups can address certain rate data elements that can change while rates are under regulatory consideration.

²¹⁴ Aggarwal and Burgess (2014).



can be reduced by using scheduled, periodic reviews, in hopes that agreed on and familiar data requirements, analysis methods and review procedures will result. To varying extents, these alternatives can help to move regulation from relying mainly on backward-looking accounting methods toward more forward-looking economic analyses. An appropriate balance must be maintained, as both disciplines have benefits.

The argument here is that more attention to looking forward, and using more time in planning and in economic analysis, should replace some of the time and effort otherwise poured into regulatory efforts aimed at accounting for costs that are already sunk, both in operations and investments. The current pace of industry change demands more regulatory attention to the future. As the pace of change picks up, what happened in the past becomes a less useful guide to the future.²¹⁵

Performance incentive regulation

Performance measures can help to focus utility attention on outcomes that need improvement, cause regulators and stakeholders to provide better definition of outcomes they seek, and tie utility financial results to measured performance on outcomes that consumers want. Under the rubric “better value for money,” the United Kingdom’s electric wires company regulator, Ofgem, has moved regulation there toward performance outcomes and has most closely tied performance to utility financial results in its RIIO regulation.²¹⁶ Setting up such a process requires a lot of work, but results seem to justify these efforts.²¹⁷

Performance regulation has a history of being applied to a range of issues by U.S. regulators. Commonly used to support utility improvements in their consumer interactions, with regard to outages and repairs and for power plant operations, it has accompanied rate and price cap plans to mitigate against cost-cutting that impacts consumer service levels. Performance regulation has more recently been applied to energy efficiency outcomes and is in active consideration for application to capital investments like grid modernization.

A handbook prepared for Western utility regulators details how to set expectations in the form of performance outcomes, what metrics and measurements can track progress toward defined outcomes, and how to associate revenues with quantified utility performance. The handbook also discusses examples of the use of performance regulation, how to avoid unintended consequences as well as gaming and manipulating performance incentives, and the benefits of starting by tracking and reporting.²¹⁸

²¹⁵ Lehr and Binz (no date). Also see Tweed (2012) and Lehr (2014).

²¹⁶ “RIIO” stands for Revenue=Incentives+Innovation+Outputs. See <https://www.ofgem.gov.uk/network-regulation-riio-model>

²¹⁷ For example, an Ofgem official recently told a Denver audience that UK wires company outlooks toward DERs and DER providers had been changed “by 180 degrees” toward supporting DERs and working effectively with DER providers while less than 5 percent of their total wires revenues was impacted by RIIO incentives. Maxine Frerk, Denver Public Meeting, Feb. 18, 2016.

²¹⁸ Woolf, Whited, and Napoleon. 2015. A useful bibliography is included in the handbook. Also see Lowry and Woolf (2016).



An important consideration in setting up performance incentives is clear outcomes or objectives that are to be achieved. For example, the UK Ofgem RIIO strategy states:²¹⁹

“Through our regulation, we aim to deliver these five outcomes for consumers:

1. Lower bills than would otherwise have been the case.
2. Reduced environmental damage both now and in the future.
3. Improved reliability and safety.
4. Better quality of service, appropriate for an essential service.
5. Benefits for society as a whole including support for those struggling to pay their bills.”

The important activity in defining outcomes is to engage all stakeholders in their definition. Likewise, multiparty discussions can help inform what performance is within utilities’ control to advance progress toward outcomes. Such discussions need to be based on broad understanding of all relevant considerations and general acceptance that performance associated with each outcome represents rational relationships between outcomes sought and means to achieve them. These are not trivial matters and they deserve careful attention. They are also unlikely to be accomplished in a trial hearing setting, so regulatory process alternatives are usually employed to generate stakeholder consensus.²²⁰

Another key consideration concerns measurements and metrics for judging performance to determine if desired outcomes are being reached. Multiparty stakeholder discussions can consider what data and information are already being maintained, what data could be generated at minimal or reasonable cost, and how data could be arrayed to provide useful information. Minimizing disputes about data and its use is an important task during development of performance incentives. Periodic reporting of chosen performance metrics and measurements is a useful first step. Financial incentives, and possibly symmetric financial penalties, can be considered after data gathering, measurement, analysis and reporting issues have been resolved. It is easier to start financial consequences at modest levels and increase them if they are not high enough, than to cut them back if they turn out to be too generous.

Initial incentives established are unlikely to be perfect, and adjustments will need to be made. But even a flawed performance standard is likely to be an improvement over blanket financial incentives now commonly in place: invest equity to earn returns. Certainly there is an opportunity to put emphasis in a performance incentive regime on particular investments, like grid modernization, that have large potential benefits with good prospects for success.

²¹⁹ Ofgem (No date).

²²⁰ See, for example, the process underway in Minnesota’s e21 Initiative: <http://www.betterenergy.org/projects/e21-initiative>.



Top 10 Reasons for Performance-Based Regulation

There are a number of reasons that performance-based regulation might be desirable. A recent editorial²²¹ contains 10 reasons why utilities should consider it:

1. To reduce regulatory burdens
2. To clarify what is expected
3. To change how they do business and make money
4. To motivate more efficient operations
5. To reduce investment risks and costs
6. To gain allies to support policy changes
7. To involve legislators and commissions and staff in constructive dialogue
8. To pressure critics to become positive contributors
9. To create more value for money
10. To better satisfy customers

Pace and Process in Regulation

Challenges facing the electric industry suggest that regulatory business as usual is unlikely to achieve the pace and depth of change that current circumstances require. If that is the case, then the process of regulation, as well as its substance — such as utility incentives and disincentives regulation creates — should also be subject to careful scrutiny. There is a case that regulatory processes will need to change for incentives to be better aligned with desired current and future outcomes, such as grid modernization.

The predominant decision-making process for many U.S. state regulatory commissions is much like trial litigation. Utilities in “file and suspend” regulatory proceedings make an application for regulatory approval, and the commission gives notice of the utility’s application. Interested parties request to intervene to take part in the proceeding. A procedural order lays out a step-wise march through what amounts to a bench trial featuring discovery, dueling expert witnesses, introduction of testimony and exhibits, cross examination in a public hearing, summary briefs, and eventually a commission order.

While trial litigation can be a powerful process for finding facts based on expert opinion, regulation by trial may be a poor process for finding the right balance among competing interests, for establishing rules of prospective application, for justifying demonstrations of new technologies and approaches to meeting emerging consumer demands, and for keeping pace with rapid change. Trial-type regulation provides incentives for parties to take starkly opposite positions to make their case as clear and exclusive as possible, rather than seek consensus and incremental progress in the middle ground. Open communications and extending relationships of trust are typically difficult or impossible while the trial is being held.

Is regulation by trial the only or best procedural option? Not really, particularly for determining rules of prospective application — what is needed to develop new regulations required to

²²¹ Lehr and O’Boyle (2015).



respond to information revolution impacts, changing technologies and consumer expectations. A number of procedural alternatives that comport with legal due process requirements are available. Many commissions make use of them to develop and implement new policies. The argument here is that they need to be used more if regulation is to keep better pace with the speed of electric industry changes.

One important issue in developing alternative procedures that can speed progress toward grid modernization is how regulation meets legal due process requirements. Alternatives to standard regulatory practice depend on careful attention to notice — how interested persons or firms find out that a regulatory action will be taken and are given a chance to participate. Notice is the key element in administrative due process.²²² Following on creative use of notice to gather stakeholders into fair and open procedures, there are a number of processes regulators can use that can be added to, or substituted for, trial-type litigation that is so common in state regulatory proceedings. These processes can address needs to pick up the pace of regulation and define and better implement both traditional and emerging public interest values.

Alternatives to depending solely on trial-type hearings for moving regulation forward have been extensively discussed elsewhere.²²³ They include policy dialogues, informational meetings, regulatory negotiations, settlements, rulemaking in quasi-legislative formats, facilitation and mediation, and “drive-by regulation.” Improved alignment of utility incentives to achieve responses to current industry challenges is more likely to be accomplished using some, or many, of these procedural options than addressing them only through trials.

²²² Five elements in administrative due process must be observed in regulation to produce regulatory decisions that will withstand judicial scrutiny on appeal. In the simplest terms they are notice, a hearing, a record, a fair decision maker, and an opportunity to appeal. Notice is the part of fair and adequate procedure that lays out what is at stake and gathers interested parties into the process. Without adequate notice, those who have a stake in the outcome do not have a chance to be heard. Inadequate notice is also the easiest flaw for a reviewing court to find deficient. Creative use of notice is the key to moving toward more efficient regulation and does a better job on both substance and process.

²²³ Trabish (2016).



Questions for Policymakers,²²⁴ Utility Regulators, and Executives and for Investment Due Diligence

- Have we used options that increase and improve communications to arrive at consensus on objectives and incentive measures, or do we rely mainly on litigation-type processes to get regulatory decisions?
- Are we using most of our regulatory time and resources in quasi-judicial settings, or are we making good use of quasi-legislative proceedings, addressing rules for future application and other forms of regulatory guidance?
- Do we have consensus on outcomes we are seeking that responds to all stakeholders' interests, including profitability required for utilities to have their financial interests aligned with public interests?
- Do we use planning effectively to generate needed information about options, fully answering the question "compared to what?"
- Does our planning support both regulators balancing interests and achieving public interests and investors making due diligence-based investment decisions?
- Are there sufficient pilot and demonstration projects to help us determine which grid modernization investments can be broadly deployed?
- Are we aware of and addressing all incentives and disincentives for grid modernization investments?
- Do we have measures and metrics that can track progress toward outcomes we have defined?
- Do we report on utility progress toward outcomes, as determined by measures and metrics we have chosen?
- Are utility financial incentives aligned with public interest outcomes that regulators are seeking in grid modernization?²²⁵

Conclusion

Forces driving electric industry change and the rate and extent of changes now apparent require reevaluation of whether traditional utility regulation is adequate to meet electric industry challenges. Broad consideration of both financial and other incentives that impact grid modernization suggests that many alternatives and reforms are being explored and many of these could be more widely adopted. Among these alternatives are regulatory options that put relatively less regulatory time and effort into addressing the question "did we pay the right

²²⁴ The author's experience includes making public utility regulatory decisions as a commissioner and chairman of the Colorado Public Utilities Commission. It also includes making utility business decisions, including capital and operating budget decisions, as president and commissioner of the Denver Board of Water Commissioners, the water utility for 1.4 million customers. In both these decision-making roles, the work was the same: keep asking the hardest questions possible until reaching a decision to vote "yes" or "no." The questions here suggest what information might be required to support decisionmaking about utility incentives in regulation, with a focus on some of the key issues that decisionmakers should keep in mind.

²²⁵ Also refer to the questions posed by Janice Beecher in this report.



amount for what we got” and more regulatory time and effort into anticipating the future, asking “what do we want, and how do we pay for that?”

Clear and widely shared understanding of desired outcomes, specification of utility performance that leads toward those outcomes, and metrics and measurements of performance that quantify progress toward desired outcomes are basic features that could allow utility incentives to be better aligned with society’s goals, expressed in electric utility regulation. A trial-type regulatory process is unlikely to be the only or best means for consumers to achieve better value for their money as change sweeps through the electric service industry. Decision-makers, both public and private, have critical roles in animating improved results. They must ask their toughest questions, and keep asking them, until they can exercise their decision-making judgments with confidence that their public approvals and private investments produce the best outcomes possible.



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Appendix. Dividend Discount Model

Figure 1-2 in Chapter 1 provides cost of equity estimates for the 40 or so electric investor-owned utilities that the *Value Line Investment Survey* follows. This appendix provides the details of the model used to develop those estimates.

Given a current stock price and a projected future dividend stream, the Dividend Discount Model finds the implied investor discount rate (cost of equity)—the one that equates the present value of the dividend stream and the current stock price.²²⁶ This version allows for varying dividend growth rates in the near term (2017–2020) and the long term (2021 and beyond). The following equation represents the functional form of the model:

$$P_0 = \frac{DPS_{2017}}{(1+k)} + \frac{DPS_{2018}}{(1+k)^2} + \frac{DPS_{2019}}{(1+k)^3} + \frac{DPS_{2020} + \frac{DPS_{2021}}{(k-g)}}{(1+k)^4}$$

Where:

P_0 = current stock price

DPS_i = dividends per share in period i

k = investors' expected return (cost of equity)

g = long-term sustainable dividend growth rate

Value Line²²⁷ provides most of the information needed to make this estimate, including (1) an estimate of a company's 2017 dividend per share and (2) an estimate of dividend per share for the 2019–2021 period. We assume that estimate applies to the mid-point date in that range (2020). Given these end points we can interpolate the dividends-per-share figures for the intervening years. For years 2021 and beyond we assume that dividend-per-share growth for all utilities will converge to the rate that is sustainable based on industry average returns on equity and dividend payout rates.

²²⁶ For a full exposition of the model, see Gordon, M. 1974. *The Cost of Capital to a Public Utility*. Michigan State University Press.

²²⁷ The *Value Line Investment Survey* is widely cited in regulatory proceedings.

