RETAIL ENERGY
PRACTICE BRIEFING SERIES

Compensating Risk in Evolving Utility Business Models

August 2017

THE Brattle GROUP

RETAIL PRACTICE BRIEFING SERIES

This brief is the second in a series that analyzes potential utility responses to challenges and trends related to the "Utility of the Future" (UoF). A new UoF paradigm is emerging as utilities rethink their future business models in response to the expansion of distributed energy resources (DERs), decarbonization goals, declining sales growth, and technological developments. While each of these developments has the potential to disrupt the status quo, they may also provide growth opportunities to utilities and new market entrants. They also raise complex questions concerning how and when to modify, or even completely change, long-standing regulatory practices. Much has already been written on these topics, but, more often than not, each issue is examined in relative isolation. Our briefing series examines the UoF from an integrated perspective by examining linkages among the financial, technological, strategic, and regulatory dimensions.

This brief focuses on how the overall risk of a utility, especially as measured in its cost of capital, may be impacted by UoF developments. Other briefs in the series look at the viability of the traditional regulatory compact, evaluation of DERs, rate innovations coordinated with service design updates and other system modernizations, and long-term growth opportunities.

For many regulated industries, accelerating trends that are challenging their business models may also be causing heightened business and financial risk. The electric utility industry in particular is confronting unprecedented challenges due to waning demand and technological change.

For the past several decades, economic growth has steadily decoupled from energy use. Today, growth in electric demand is barely a fraction of gross domestic product (GDP) growth, whereas 50 years ago it was much higher. Separately, demand for electricity *delivered by traditional utilities* has also been eroded by technology developments that enable end-users to serve some or all of their own needs (or potentially even to supply some of the needs of other customers) via distributed energy resources (DERs), such as solar panels and smart appliances. Meanwhile, regulated utility revenues are mostly collected traditionally through volumetric charges for actual energy delivered, leaving utilities vulnerable to revenue and fixed cost recovery erosion as net demand falls.

At the same time, the industry faces the potential need for significant investments in new, low-voltage infrastructure, information systems, and controls in order to reconfigure their systems for a platform-based, transaction-driven future that integrates many DERs.[1] This is a recipe for regulatory and financial tension, with the possibility of stranded costs or foreshortened useful lives of existing assets, inefficient power consumption, inefficient DER development that does not correspond to avoidable costs, and the need to allocate growing system costs to a shrinking base of net demand. The pace and depth of these changes will depend on how fast technology evolves, as well as how strong the policy mandates and regulatory adjustments are made for encouraging a new paradigm.

This heightened risk can be expected to have an effect on the cost of capital, both increasing it and making it more complicated to measure. As business strategies and accompanying regulation evolve to accommodate these new technologies and investment requirements, risk burdens may increase in absolute terms and may also shift between utilities and customers, or between subgroups of customers (such as those who participate in DERs versus those who do not). Redefining customer classes with greater differentiation, or other approaches to address this risk, will almost certainly diverge across regulatory jurisdictions since the demographics, average costs, and geographies vary enough across regions that the pace and consequences of adopting new technologies differ markedly. This will pose challenges to the traditional approaches to cost of capital determination, which involve measuring returns expected

1. These industry developments are covered in more detail in our first brief, "Evolving Business and Regulatory Models in a Utility of the Future World."

by the investing public for comparable companies based on the behavior of stock prices (and other financial data).[2] As the pool of comparable companies shrinks, other mechanisms for identifying greater or lesser risk will have to be developed.

Importantly, in a regulated setting much of the increasing risk is *asymmetrical*. That is, these DER technologies will increase the propensity of utilities to face downside risks if market conditions or technologies move against them without enjoying much opportunity for compensatory, upside gains if and when their assets and services should become more attractive than average. This asymmetry was also present under traditional regulatory regimes where the regulator's mandate has been to mitigate the pricing power of "natural monopolies" while assuring adequate returns to the required investments (while pursuing a standard that utility assets must be "used and useful"). Thus, the traditional utility bargain is that utility investors have an opportunity, but not a guarantee, to earn their administratively-determined return, provided that realized market conditions correspond roughly to test year expectations. Any "upside" garnered beyond that has had to be carefully crafted as transitional (e.g., due to efficiency improvements between rate cases) and limited (e.g., via modest incentive mechanisms). Meanwhile, the downside risks are potentially unbounded, if rare (e.g., should assets become impaired by unexpected extreme market conditions). For example, the strains from the failure of the California wholesale electricity market in the early 2000s created huge losses for utilities, despite them having no real role in, or allowed alternatives to deal with, those adverse conditions. The traditional asymmetrical risks arising from bad luck in the market are amplified by rapid technological and commercial change. Such circumstances create more downside exposure than upside potential because they disrupt the value of the assets serving with the traditional approach. They may also induce new patterns of demand in customers that are adverse to prior ratemaking expectations.

An additional feature of asymmetric risk affecting utilities is that it can reasonably be expected to be more idiosyncratic than systematic. That is, it is most commonly rooted in unique local economic circumstances facing a given company or project, or arising from technological change that has little connection to broader economic forces. However, absent a regulatory mechanism to remove the asymmetric risk, the cost of capital is not accurately measured by traditional methods.

Of course, technological change can be painful and disruptive to competitive businesses as well, but unlike competitive businesses, utilities cannot pursue the opportunities from the new technologies in a way that captures much or sometimes any of their high value. In particular, utilities cannot selectively choose when and where to enter or leave a market segment and what prices to charge. Instead, if they can participate at all in these new technologies, utilities can only do so with prices that provide expected cost recovery and nothing more (no higher profits when assets are "in the money" because the allowed rates are cost-based), and they must provide non-discriminatory, equivalent service for all customers. On the other hand, when technology and customer behavior shift against them, utilities are vulnerable to losses due to under-recovery from falling revenues or regulatory cost disallowances.

2. Specifically, the Capital Asset Pricing Model (CAPM) and Discounted Cash Flow Analysis (DCF).

The current shift towards DERs and smart energy usage behind the meter is creating a new suite of such asymmetric risks. The key questions posed by this changing business environment that utility managers and regulators will need to consider include the following:

- Will traditional approaches to measuring the cost of capital continue to serve their intended purpose? If not, what other methods can inform the proper rate of return allowances?
- Should the observed cost of capital be augmented by additional risk premia for asymmetry?
- What other adaptations to ratemaking, rate design, or allowed returns on capital are appropriate to address changing risks?

In this brief, we offer some additional perspective on cost of capital measurement and asymmetric risk as well as consider the implications of regulatory responses to date for handling shifting risk profiles. We conclude by returning to the key questions posed. While this brief focuses on risk and the financial aspects of the UoF transition, consideration of these issues should ultimately be integrated with other elements, such as appropriate rate design, changes to sales growth forecasting, new methods for sizing and timing of infrastructure improvements, and the system integration impacts of DERs, which will be addressed in future briefs. Those factors can both increase or mitigate risk, depending on how they are adjusted for the UoF environment.

PRICING OF ASYMMETRIC RISK

The asymmetric risk facing an investor in a regulated utility can be analogized to the risk facing an investor in corporate bonds: although they both have the opportunity to earn a stipulated return,[3] there is no guarantee and not much upside (though bonds can appreciate if interest rates fall after they are issued), while there is unbounded downside (albeit with low probability). For example, a corporate bond default can wipe out the entire value of the bond. Similarly, a utility investment is exposed to adverse "black swan" events that, while rare by definition, have the potential to severely handicap or even bankrupt the company and similarly wipe out much of its value.[4]

3. In the case of the bond, this is the yield to maturity (and assumes the bond is held to maturity).

4. The term in this sense is from Nassim Nicholas Taleb. See, for example, *The Black Swan: The Impact of the Highly Improbable*, 2nd edition, (New York: Random House 2010). As noted previously, outright bankruptcy of a utility is quite rare, because usually the regulatory process will provide enough ad hoc adjustments for even a severely strained utility to remain viable, but it is not unheard of. More common, but problematic, for investors and eventually customers is a badly-impaired utility that cannot afford to make valuable improvements and maintain its system optimally.

By the nature of the utility business, these adverse events tend to have a strong regulatory flavor, such as:

- The natural gas price deregulation in the 1980s, which pushed two natural gas pipelines into bankruptcy, largely because they held bypassable long-term supply purchase contracts (for resale to distribution customers) that were well above spot market prices (which itself was created by the deregulation).
- The mid-1990s' vertical unbundling and wholesale deregulation of generation in the electric industry, which created significant stranded costs that were not always reliably or fully compensated.
- The California Energy Crisis of 2001, in which anticompetitive behavior in the poorly designed, newly-formed competitive wholesale market, combined with strict constraints on hedging imposed on the utilities, caused runaway spikes in power prices, leading to financial disaster for utilities.[5]

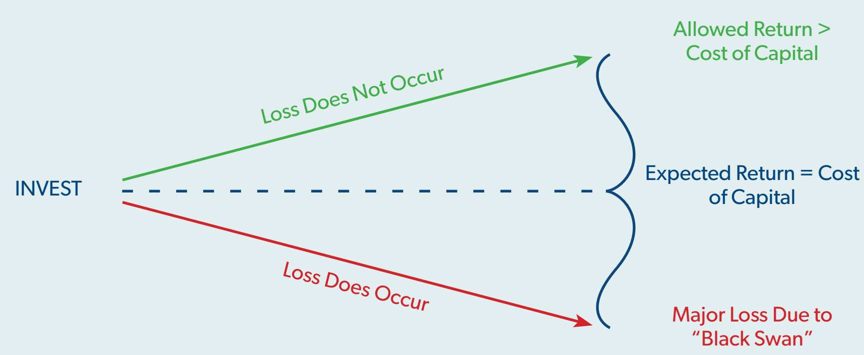
A more recent and less dramatic, but still widespread, example of asymmetric risk is the regulatory disallowances of utility gas hedging costs in forward contracts that were struck when natural gas wellhead prices were high (2007-2009). These positions became rapidly and significantly "out of the money" as gas prices fell dramatically due to technological advances in shale gas development.

> These examples show that an asymmetric, black swan situation does not have to be a sudden, discrete event (like a hurricane or a technical failure at a large asset, though those can also cause significant cost recovery shortfalls). Rather, it can be any change in policy or market environment that is significant, disruptive, and persistent enough to evolve more rapidly (or simply differently and worse) than regulatory mechanisms can fully and properly anticipate and react. The foreseeable, but rapid changes in the utility business model noted earlier have this attribute and similar, emerging changes are likely to contribute to asymmetric risk going forward.

5. For a full discussion of the California Energy Crisis, see Gary Taylor, Peter Fox-Penner, Romkaew Broehm, and Shaun D. Ledgerwood, *Market Power and Market Manipulation in Energy Markets: From the California Crisis to the Present*, Public Utilities Reports, Inc. 2015.

In order for investors to be comfortable with funding an entity facing substantial asymmetric risk, stipulated or "promised" returns must exceed the cost of capital. Again, the example of corporate bonds helps to show why this is the case. The best a bondholder can hope for is that the bond pays off in full and on time at its promised coupon rate of return.[6] However, the bond might instead default, in which case the bondholder will receive something less than the promised coupon return. The *expected* return, the probability-weighted average of returns in scenarios ranging from the best (i.e., no default) to the worst (i.e., receipt of less than the promised payments) outcomes, will be below the promised return, and equal to the actual cost of capital. This is illustrated in Figure 1.

FIGURE 1: REGULATION WITH COMPENSATED RISK OF MAJOR LOSS[7]



CONCLUSION: If allowed return is greater than cost of capital, expected return on rate base can equal the cost of capital even with a risk of major loss.

Allowed Return = cost of capital + asymmetry risk premium can compensate investors for the risk of major losses due to "black swans."

6. Again, if held to maturity.

7. Bente Villadsen, Michael J. Vilbert, Dan Harris, and A. Lawrence Kolbe. *Risk and Return for Regulated Industries*, Chapter 10. Academic Press, April 19, 2017.

To remedy the possibility of loss relative to the promised payments, investors will bid bond prices down to a level where the yield to maturity compensates for the perceived likelihood of downside outcomes; that is, to where the prevailing yield times (1-probability of default) equals the true cost of capital. This is why bonds with poorer ratings have progressively higher yields compared to U.S. Treasury bonds of comparable maturity.

Notably, while investment in regulated utilities resembles investment in corporate bonds from the perspective of facing asymmetric risk (in that many investors turn to utilities for relatively steady, likely cash flows), utility investments differ in that it is not clear they are similarly compensated for "default" (asymmetric) type risks in their allowed levels of return. This is because regulators have traditionally adopted the academic definition of cost of capital—on which allowed returns are based—as equal to expected returns. This is a correct understanding of the cost of capital, but if it is awarded as if there is no chance of an asymmetric loss (i.e., as if the factors of future costs and loads used in setting rates are the expected values), the actual expected return for the utility will be below the cost of capital.

Correspondingly, the financial economic models used to estimate the cost of capital reflect the expected outcome, not some analogue to the "promised" outcome. The Capital Asset Pricing Model (CAPM), for example, commonly relies on historical data to estimate betas and the market risk premium, and those historical data include bad outcomes as well as good ones.[8] Similarly, the Discounted Cash Flow model (DCF) uses forecasts of dividend or earnings' growth rates. Properly developed, those forecasts should take the possibility of bad, asymmetric outcomes into account, but so does the stock price against which the Internal Rate of Return (IRR) of the projected cash flows is determined, so again there is no net revelation of the cost of these downsides.[9] In neither case can we observe what the return would be that is equivalent to a corporate bond's "in full and on time" outcome and then adjust it to being a default-weighted yield. Thus, an allowed rate of return equal to the cost of capital does not provide an adequate rate of return for a regulated company faced with substantial loss from asymmetric risk, even when the cost of capital is estimated perfectly and the market is fully aware of the risks facing the regulated company.

This result might seem paradoxical, because the cost of capital is also deemed by financial economists to be the required return for the underlying risks. Stock prices in an efficient market should rise or fall to a level where the expected return is also the required return. However, not all risks require a return, if they can be diversified away. This is often the case for asymmetric risks, to the extent they arise for idiosyncratic reasons unrelated to financial markets or the economy as a whole but instead are peculiar to the luck and specific circumstances of the company in question. At the extreme, consider a utility whose disallowance risk, or failed cost recovery risk from unforeseen market or regulatory

8. Additionally, to the extent that the bad outcomes are uncorrelated with the rest of the market, they will have zero impact on the measured beta.

9. There are some differences in how leading or lagging the CAPM and DCF may be in reflecting information about asymmetric risk, depending on when they are measured relative to news that reveals the downside risk. For instance, it is possible that the stock price could change before the earnings forecasts are adjusted, at least as used in a rate case.

conditions, is equivalent to flipping a coin and getting tails instead of heads. Such random risks have nothing to do with the economy, so they are deemed "nonsystematic" and are generally diversifiable (if held in a portfolio of many other securities in the market, some of which might benefit from the same problem).[10]

This is not to say that such risks do not matter to investors or to the management of the affected companies. To the contrary, those asymmetric exposures reduce expected future cash flows and so reduce the value of the stock, but once that is reflected in the price, there is no additional premium for the problem. As an analogy, you could not expect to earn more on a home you bought in a region with hurricane risks than one in a region without that problem. Instead, the home in the hurricane region should sell for less, everything else being equal, and then appreciate comparably to elsewhere. To offset the hurricane risk, you need insurance, not a higher appreciation rate for the house.

Importantly, asymmetric risk cannot be ignored by regulators simply because it is not priced by traditional models, such as the CAPM or DCF models used to estimate the cost of capital. Under long-received and uncontroversial legal decisions and regulatory conventions, utilities must be entitled to a fair (i.e., unbiased) opportunity to earn their cost of capital against their prudently invested capital. This assures they will be cost-based and adequately compensated compared to unregulated investments of similar risk. (Recall that unregulated investors can pick and choose their targets to achieve their expected return, while utility managers and their investors cannot.) Thus, if regulatory allowances for revenue requirements and the associated return components are not somehow marked up to offset the black swan possibility of adverse events asymmetrically undermining cost recovery, this goal of risk parity with other financial investments will not be achieved. For utilities, the "promised return" is just the allowed cost of capital, which, unlike the bond yield, does not include a markup for default risk.

In principle, you could solve this by assessing the asymmetric downside exposure and adding a sweetener to the allowed return on equity (RoE) (above the measured cost) to make a utility revenue allowance more like a bond yield, probabilistically scaled up for "default" risk; however, it is generally not appropriate to do this for utilities because by providing compensation for an asymmetric risk that is within the control of the regulator to impose, the regulator may be tempted to later impose the loss on the utility, reasoning that the utility had already received compensation for the expected risk. The latter will necessarily be below the true cost of the risk, once fulfilled, if the premium gives the regulator license to penalize. Under these moral hazard conditions, adequate compensation for the risk of disallowance would have to be equal to the full amount of the investment that could be disallowed.

Later in this brief, we discuss ways around this measurement and compensation conundrum. Broadly speaking, the answer is to try to mitigate the asymmetry, not pay for it in advance. There are many ways to do this for the DER risks created by new customer control over portions of their supply and energy management.

---

10. A portion of asymmetric risk affecting utilities may be "systematic" in the sense that broad economic trends can amplify exposure to this kind of utility risk (e.g., disallowances being more likely in a recession), and that portion of the risk would be reflected in the estimated cost of capital.

REGULATORY RESPONSES TO NEW BUSINESS RISKS

Utility and regulatory responses to the emerging business environment are developing along an evolutionary, interdependent path, with different incentives to customers and the utility as well as implications for risk and return, service design, and investment opportunities at each stage.

DECOUPLING

To date, most of the responses from many utilities and their regulators to the disruptive risks of DERs and more customer empowerment have been *reactive* in nature, with the basic goals of restoring revenues lost to reduced demand and distributed resources, while still fostering ongoing penetration of new technologies. Such reactive responses have adopted a variety of mechanisms, but they can be grouped under the general designation of "decoupling" of revenues from energy delivery volumes. According to SNL, more than 14 states have allowed full decoupling for an electric utility, while 42 states have allowed some form of decoupling, lost revenue recovery, or fixed variable rate design for a utility in their jurisdiction. Such mechanisms allow the utilities to better track revenue shortfalls arising from certain technology, weather, and policy outcomes (especially energy efficiency, but also other DERs) and to true up those lost revenues with reallocation of the unrecovered amounts to other customers in future periods.[11] This (temporarily) disconnects the amount of revenue collected from actual billing unit sales.[12]

Because decoupling is designed to improve fixed cost recovery while allowing the utility to pursue energy conservation programs, in essence stabilizing revenues, it might be expected that it would also create a reduction in risk and the cost of capital. This issue has been the subject of vigorous debate. For example, regulators sometimes have been asked to, or have chosen to, reduce the allowed ROE for utilities in conjunction with the approval of new decoupling programs. These regulators have assumed that the reduction in the volatility of a utility's revenues from adoption of decoupling reduces the utility's risk and therefore its cost of capital. Taken by itself, this is a plausible expectation, because volatility is a source of risk and decoupling dampens that. However, decoupling is not introduced except in contexts where

11. See Regulatory Research Associates, "Adjustment Clauses – A State-by-State Overview," August 22, 2016.

12. If a trend requiring decoupling is very persistent, it is likely to eventually become infeasible to keep reallocating the costs to non-participants at some point.

cost recovery risk is otherwise increasing. As a result, the *net* risk effect in the broader context appears to be neutral, as several empirical studies have confirmed.[13] That is, the decrease in risk from decoupling appears to be balanced by the increase in risk associated with the regulatory and technological changes that call for decoupling in the first place.

> Therefore, at its core, decoupling is a mitigation measure, intended to equilibrate the terms on which utilities rely when providing service in traditional versus non-traditional ways.

Conversely, it has also been suggested that decoupling or any similar risk-equilibration measure alone is not enough to make utilities indifferent between traditional and non-traditional service approaches. Instead, it is argued that utilities are foregoing other kinds of profitable investments when they encourage conservation or DERs, and so they should be given an additional incentive payment (such as an ROE sweetener for success) to make them indifferent between their conventional solution and the new approach. This is a valid observation, but it can be a subtle problem to calibrate the value, size, or risk of the foregone investment and resulting profit opportunities, so such appeals tend to be quite controversial. Some have even argued that utilities routinely earn materially more than their cost of capital on traditional investments, so they need to earn at least an equivalent amount of excess returns on non-traditional service methods in order to be truly indifferent. Our opinion is that the evidence offered to support this view of excess returns does not actually succeed.[14]

Another viewpoint holds that utilities are in essence only pursuing a customer solution (instead of developing their own resources) as a sort of favor to their customers. Since the utilities have no financial "skin in the game," they may not pursue the customer approach as fully as it might be worth. To offset this, they need a management fee or some kind of profit on the service itself. (This issue also arises when older assets become fully depreciated, but still have value in use.) However, there is no ready agreement on the right size or incentive from such fees, but the argument is plausible and it is likely to be an increasingly relevant discussion in the future, because if the utility distribution system evolves towards being a "platform" for DER and informational transactions, the utility may deserve some payment as

13. To review Brattle's most recent analysis of this subject, see Michael J. Vilbert, Joseph B. Wharton, Shirley Zhang, and James Hall, "Effect on the Cost of Capital of Ratemaking that Relaxes the Linkage between Revenue and kWh Sales: An Updated Empirical Investigation of the Electric Industry," November 2016. Available at brattle.com.

14. A view recently presented to the California Public Utilities Commission (CPUC) started from an observation that utility market-to-book ratios for common equity were about 1.7. (See CPUC, *Assigned Commissioner's Ruling Introducing a Draft Regulatory Incentives Proposal for Discussion and Comment*, Rulemaking 14-10-003, April 4, 2016.) Based on that, it was inferred that regulators were implicitly allowing utilities to earn about 3.5 percentage points in excess of their cost of capital, but that this served as a positive incentive for utility capital expenditures to improve the system. By extension, if DERs are an alternative means to those improvements, a payment to offset this 3.5 percentage point profit return on capital they displace was needed to induce utilities to accommodate DERs. This view of incentives has some qualitative merit, but its analytics rely on assuming that the market-to-book ratio signals reliably whether a utility earns more or less than its cost of capital, which is not the case. See the presentation, "Moving Toward Value in Utility Compensation Shareholder Value Concept," by Brattle Principals A. Lawrence Kolbe and Michael J. Vilbert on the assumptions underlying this incorrect view. Available at brattle.com.

the facilitating intermediary. If the grid is an essential facility for the intermediation, then it should be compensated to assure adequate interest in fostering the intermediation capability, even if there are few direct costs involved. For the moment, that idea is more conceptual than proven, but it is often being anticipated with performance-based rates, discussed next.[15]

PERFORMANCE-BASED RATEMAKING

A more active and behaviorally-targeted form of regulatory response than decoupling takes the form of performance-based ratemaking (PBR) mechanisms, discussed in more detail later. PBR is intended to reduce the frequency and scope of regulatory intervention or oversight in utility pricing, while motivating sustained or even improved utility performance in a number of potential dimensions, ranging from cost savings to improved reliability to encouraged adoption of new technologies. Diverse performance incentive mechanisms have been deployed in numerous regulatory jurisdictions in the U.S. In the context of the evolving political interest in innovative, smarter infrastructure, some states are considering PBR incentive mechanisms for utilities to find more opportunities to deploy distributed, customer-centric energy technologies.[16]

> From a risk perspective, the essence of PBR mechanisms is that utilities may earn more than their normal cost of capital for achieving or exceeding performance targets and less for failing to achieve them. While this may cause shareholder incentives to be better aligned with the interests of other stakeholders, it also means that the range (or uncertainty) of possible return outcomes is likely to increase.

Depending on the specifics of the mechanism, performance-based mechanisms taken in isolation might be expected to introduce more risk to utilities, because they sometimes allow greater financial dispersion around traditional target return levels for the sake of the performance incentives that it entails. Additionally, they may also be inadvertently or intentionally asymmetric, if the targets are set too high to be achievable or if there are only penalties and no rewards.[17]

15. For more discussion, see William Zarakas, "Two-Sided Markets and the Utility of the Future: How Services and Transactions Will Shape the Utility Platform," forthcoming 2017.

16. For example, a variety of Earnings Adjustment Mechanisms (EAMs) have been proposed in the context of New York State's Reforming the Energy Vision (REV) program to reward desired utility policies.

17. For example, the Alabama Power Rate Stabilization and Equalization framework includes a sharing mechanism for actual returns above a threshold, but no true-up is made for actual returns below the allowed return. Alabama Public Service Commission, Report and Order, Dockets 18117 and 18416, August 21, 2013.

In practice, these concerns may be tempered by earnings sharing mechanisms in which the incentivized earnings outcomes above or below predetermined ROE thresholds are shared between shareholders and ratepayers. Also, again depending on specifics, a PBR mechanism may offer the opportunity to mitigate the asymmetric risk faced by utilities. For instance, the Earnings Adjustment Mechanisms (EAMs) in New York offer an upside-only benefit of up to 100 basis points for success on some DER-preparatory practices and performance targets by utilities. In this case, rather than being a generalized reward for utility stewardship of the distribution sector, these EAMs are directed at specific, measurable goals. As with decoupling, the risk and cost of capital implications of PBR mechanisms will form a compelling question for future inquiry.

UTILITY OF THE FUTURE (UoF) EFFORTS

The most evolved approaches to new business objectives and resulting risks have consisted of initiatives to reevaluate and possibly revise the entire business model of utilities, instead of making small adjustments to new pressures in a compartmentalized fashion as they arise. One example is the ongoing UoF dialogue, which considers a comprehensive overhaul of the utility business model.[18] To date, this has been considered only in a few states, particularly California and New York, which are examining new business models that involve adjustments in ratemaking to reduce business risks while also making long-term policy decisions about the roles of utilities in either owning or managing new resources, what new products and services they will provide, how to structure new revenue streams, and other concerns. Performance-based mechanisms assembled in a coordinated fashion (the EAMs mentioned previously) are core tools for accelerating a hoped-for transition to a new technology platform and its associated business model.

It remains to be seen what the aggregate risk implications of broad UoF initiatives like this will be, but it is almost certain that the net effect will be an increase in utility risk. Besides introducing additional asymmetric risk and more regulatory policy uncertainty into the cost of capital determination, the new technologies will affect (likely shorten) the useful lives of some of the existing infrastructure and may even result in some stranding. For instance, in wholesale markets where many renewable resources are being added to the supply mix under long-term power purchase agreements with utility buyers, the marginal cost (and wholesale market price) of energy in wind- and solar-intensive hours is falling, while the need for rapid ramping capability from peakers as backup is increasing. This tends to make large baseload power plants less valuable or even economically obsolete, well before their engineering (or expected regulatory) lives have ended. In contrast, peakers and flexible resources may be more valuable, but are (where regulated) not allowed to charge or collect more for their service benefits.

18. This is reflected in the work of the Lawrence Berkeley National Laboratory's (LBNL) Future Electric Utility Regulation Series, America's Power Plan, the Smart Electric Power Alliance's (SEPA) 51st State Initiative, and the More Than Smart Initiative.

DERs may have a similar impact on upstream plants as well as on some low voltage equipment. Depreciation lives for assets may need to be shortened, and decision rules for when to install new assets may have to be based on more uncertainty about their avoided costs or risks. DERs also make load forecasting for designing test year costs and rate design factors (capacity and energy) more difficult, and they increase volatility or uncertainty on the system with respect to cash flow collection, system upgrade requirements, and ratemaking design volumes. At deep penetration levels, they may even impose significant new control and integration costs on the system at the same time as they are reducing net utility demand, making the cost recovery for those new infrastructure investments more difficult. The future extent and pace of regulatory change for incentivizing and coping with these changes (i.e., the activity of reevaluating the traditional regulatory compact between utilities and their customers) is itself a source of risk.

KEY QUESTIONS TO CONSIDER FOR COMPENSATING NEW UoF RISKS

Will traditional approaches to measuring the cost of capital continue to serve their intended purpose?

Both the CAPM and DCF methods of estimating the cost of capital rely on data from a pool of comparable companies.[19] In the past, regulators had the ability to compare the cost of capital for integrated electric utilities across wide geographies and regulatory jurisdictions. However, regulators also had to adapt these techniques to changing industry circumstances. For example, industry consolidation and other ownership changes among electric and gas utilities, as well as oil and gas pipelines, have meant that criteria for assembling a pool of comparable companies had to evolve, and frequently had been made less stringent (and, as a result, potentially less reliable statistically) to maintain a material pool.

The industry changes now on the horizon will be far more radical, with more profound implications for assembling comparable companies. This is because these changes and accompanying shifts in risk will not affect utilities uniformly or all at once, for at least three reasons. First, some areas are naturally more amenable to the penetration of new, renewable technologies. Second, some regions have relatively high average costs and associated rates (and therefore, correspondingly high avoidable costs to their customers), while others are inexpensive and less attractive environments for DER use. Third, some regions have political or regulatory enthusiasm for the new business imperatives and are

19. This discussion would also apply to less commonly used models, such as the Fama-French and APT models.

providing incentives and mandates, while others are more skeptical or cautious. This heterogeneity may create challenges for regulators in benchmarking fair returns.

> Soon, utilities may vary more widely in terms of risk profile as challenges to the traditional business model and associated regulatory responses progress unevenly across states.

It may become increasingly necessary to use supplemental conventional measures of risk with more qualitative ranking mechanisms in order to determine how a particular company deviates from the pool of comparable companies. For instance, rate design, such as the degree to which fixed costs are recovered in fixed charges, is a big determinant of risk, so that measures of operating leverage become important (especially due to mismatches between the use of fixed and variable charges in rates versus having a cost structure with similar fixed and variable proportions). Further, a close review of the regulatory regime (including the adoption rate of DER, the risk of stranded assets, etc.) is becoming increasingly important.[20]

Should the observed cost of capital be augmented for UoF considerations by additional risk premia (or other adjustments)?

Like the issue of how to identify a relevant group of peer companies for cost of capital benchmarking, the question about whether or when to add a risk premium to the observed cost of capital for new risk factors is not new, but this question may become more acute under new utility business models because of the magnitude of change likely to occur. In the past, proposed adjustments to the cost of capital generated by traditional methods have been motivated by diverse considerations. For example, it has become routine to stipulate adjustments to the CAPM to capture persistent (or to exclude transitory) sources of systematic risk. The right level of adjustments can be estimated based on observable market data, such as the yield spread of corporate bonds relative to government bonds.

As briefly described earlier, one of several possible ways to compensate a utility for the asymmetric risk is by adding an asymmetry risk premium to the allowed rate of return, so the promised rate has an expected rate equal to the true cost of capital. In this approach, the utility gets an asymmetry risk premium on top of its measured cost of capital in its

20. It is likely to be impossible as well as unproductive to attempt to screen a potential cost of capital sample for all differences in regulatory policies (i.e., decoupling, fuel adjustment clauses, forward test year) because there are a large number of possible policy combinations relative to the sample size of relatively "pure play" companies with traded equity.

allowed rate of return whether or not the loss occurs. In essence, it is an insurance premium built into the rate of return rather than purchased directly and passed through as an operating cost. If the asymmetry risk premium is set at the right level—and the probability of a disallowance is independent of the fact that an allowance premium has been granted—the average of the allowed rate of return above the cost of capital and the outcome if the loss occurs will equal the cost of capital. The regulated company again has an overall expected rate of return equal to the cost of capital, akin to the type of payoff facing a corporate bond holder.

However, as explained earlier in regard to the difficulties of measuring asymmetric risk, unlike adjustments to the CAPM for persistent systematic risk, estimating an appropriate asymmetric risk premium based on idiosyncratic risk cannot, by definition, be based on observed market data, and therefore faces substantial computational hurdles. The likelihood, timing, and magnitude of downside outcomes must all be estimated. Another possible complication arises when the asymmetry risk arises from potential changes in the legal or regulatory standards governing the company, which creates a danger of circularity. That is, the disallowance risk after an allowance may be no longer just a random, actuarial risk exposure to the same risk that was originally intended to be insured.

Even if there is no moral hazard, it is not clear that asymmetric risks arise in a geometric compounding fashion. (This is the implicit assumption of conventional discount rates, which because they compound over time, are assumed to be offsetting risk whose variance increases linearly over time.) Some asymmetric risks may be more episodic, transitory, or conditional, in that there may be a window of time when they either discreetly arise or not. This is particularly true if they depend on some major public policy resolution, such as whether or not we have a national climate mitigation rule. It is not clear, therefore, that simple add-ons to the cost of capital will be a fitting or even a tractable solution to asymmetric risk. In such cases, it is preferable for the regulator to adopt policies that mitigate the asymmetric risk itself. Some possible mechanisms for doing this are discussed next.

What other adaptations to allowed returns on capital are appropriate to address changing business risks?

Experience to date suggests that it may be harder to meaningfully adapt cost of capital measures to dynamic, asymmetric risk patterns than to define and bound the underlying risks themselves through new regulatory paradigms. For instance, decoupling, or even better, more efficient rate designs that reflect underlying fixed costs in fixed charges, largely dissipate the asymmetric risk that arises from lost volume of net sales due to DERs.[21] (This does not address other UoF problems, such as asset obsolescence or shorter lives, but it is a useful improvement.) Incentive mechanisms can also be targeted at underlying risk issues, thereby at least making their outcomes more palatable to the host utility.

21. In practice, decoupling is more of a short-term palliative than a long-term solution to the DER adoption issues facing utilities, because at some point transferring under-recovered costs to other customers becomes inequitable and intractable. However, it is very useful when DER penetration is low.

For protecting new technology investment risks (recognizing that investments in new technologies may prove less successful than hoped, or may be supplanted by even better technology later that was not initially foreseen), strong *ex ante* prudence standards assuring ongoing cost recovery, even if they later prove less successful than anticipated, can also mitigate regulatory and technological asymmetry.[22]

Broadly speaking, there may be advantages to mitigating utility risk exposures rather than contorting analytically (and somewhat necessarily, subjectively) to capture novel risks in new risk-pricing measures. Alternatively, downside risk could be managed via obtaining actual, customized business-risk insurance, the cost of which would be recoverable in rates. For instance, some utilities already buy extreme weather insurance, which may become more important as more renewables (which are themselves weather sensitive) become a larger part of their supply portfolios.

This is not to say that cost of capital measures should not evolve with UoF developments. It is very likely that the new technologies themselves lead to increased, un-diversifiable (systematic) market risk for utilities, because the rate of DER adoption will itself be somewhat market sensitive. To be sure, it will become both more important and more difficult to measure a compensatory allowed rate of return, which may call for a more refined set of metrics. For example, as noted previously, with changes in technology and customer behavior taking place at different rates, in different ways, and in different jurisdictions, it may become difficult to identify a comparable risk sample.[23] It may also turn out that some types of customers, perhaps those most active in pursuing new technologies, contribute more to utility risk than others who continue to consume a more traditional service from the utility, and so risk pricing itself may have to be allocated differently across customer segments. Also, it would be wrong to categorically rule out adjustments to traditional cost of capital estimation parameters, some of which are already modified to address changing market conditions, or even *ex-post* adjustments. For instance, it would be fine to add a cost of capital premium if the conditions for triggering a future disallowance were specified in terms that are exogenous to the regulatory decision making process.

---

22. For example, the U.S. Federal Energy Regulatory Commission (FERC) provides some transmission investments with full recovery of capital expenditures regardless of whether the project is completed.

23. Given the fast-paced changes in the industry, a traditional 2-5 year measurement of beta, for example, may not fully reflect the current environment in which electric utilities operate.

CONCLUSION

Utility cost of capital estimation for regulated industries is likely to face increased need for innovation in both the short and long term. This is being driven by accelerating trends in the business models of regulated electric utilities.

Specifically, utilities are being affected both by slowing electricity demand and cost increases or cost transfers by the sometimes inefficient bypassing of their systems by DERs and kindred technologies (due to outdated rates that do not reflect costs or sufficient differences in customer characteristics). Risk is likely to increase as a general matter due to the regulatory process uncertainty, as the terms of the utility "compact" with its customers is being rewritten gradually. Risk changes will not occur uniformly across the industry, instead arising on a more fragmented basis in terms of geographic regions and customer classes. It will take a while for the evidence to stabilize about what the risk conditions have become and for experiments in compensation to be tested for the efficacy.

> Regulators are actively developing responses that range from focused revenue supports to comprehensive industry reorganization. The new risks need to be compensated or mitigated so that utility costs can be recovered and investors can continue to have an unbiased opportunity to earn their cost of capital.

Cost of capital measures will have to evolve in parallel with innovations in service design, pricing, and utility infrastructure, recognizing that it often may be easier to mitigate a risk directly rather than to measure its marginal effects on the cost of capital. Such adjustments will be critical for utilities to have the financial strength and incentives to support the many changes the UoF environment will require.

ABOUT BRATTLE'S RETAIL ENERGY PRACTICE

As distributed energy resources (DERs) become more widespread and utility managers and regulators look toward incorporating new business models, the "retail" side of the electric utility industry is receiving increased attention. The Brattle Group's Retail Energy Practice helps clients address the critical issues that impact the utility industry at both the distribution system and retail service levels.

Brattle's Retail Energy team has extensive experience developing benefit-cost analyses for next generation investments in smart grid, system reliability and resilience, and overall grid modernization, as well as for investments at the system edge, such as electrification opportunities. We have also worked extensively on assessing business and financial models applicable to the evolving electricity market ecosystem, and are at the forefront of marginal cost and benefit analyses that are becoming increasingly important in determining efficient and equitable pricing constructs and incentives for DER compensation. Our expertise is grounded in foundational principles of economics and finance, in order to better align load forecasting, rate design, and risk management with industry trends and developments.

For more information on our expertise and services, please contact:

BILL ZARAKAS

Retail Energy Practice Leader
+1.617.864.7900 | Bill.Zarakas@brattle.com

» brattle.com

Brattle

THE POWER OF ECONOMICS