Incentive-based ratemaking:

Recommendations to the Hawaiian Electric Companies

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Executive Summary

The Hawaiian Electric Companies ("the Companies") have asked us to provide advice on improving the incentive arrangements in their ratemaking procedures in connection with the Hawai'i Public Utilities Commission re-examination of decoupling in Docket No. 2013-0141. The Companies also asked us to provide an overview of the theory and practice of incentive-based ratemaking ("IBR") in energy regulation and to make recommendations as to how the Companies' RAM, RBA and other aspects of ratemaking could be improved. The Companies also asked us to comment on various rate of return issues raised in Docket No. 2013-0141.

Incentive-Based Ratemaking

Incentive-based ratemaking ("IBR") is an extension to or adaptation of traditional "cost-of-service" ratemaking, rather than a fundamentally new concept. Traditional cost-of-service ratemaking provides a financial incentive to control costs[1] because rates do not change between rate cases. As a result, the benefits of cost savings achieved between rate cases accrue in part to the utility. Traditional ratemaking also has a set of approval, reporting and oversight requirements centered on the GRC to set base rates periodically.[2] These requirements encourage a utility to avoid unnecessary costs by providing an opportunity for the Commission and other stakeholders to review utility actions and test for prudence. Even where there are multi-year rate case cycles and revenue adjustment mechanisms with true-ups that flow the plant additions through to rates, standard regulatory practice contains an important constraint. In the next GRC, there is the opportunity for a detailed prudence review of any item in the test-year revenue requirement, including return on a rate base for which authorization for including the post-test year plant additions from the prior rate case is being requested. The opportunity for review (and potential disallowance in case of imprudence) provides an incentive for the utility to avoid unnecessary costs.

Traditional ratemaking was developed in the last century in an environment of growing sales, both in terms of customers and usage per customer. Growth provided a growing revenue stream that, in many cases, covered rising costs and supported investment even without increasing rates.

More recently, growth has stopped or has even reversed. In an environment of rising costs, this means that rates have to increase in order to support necessary investment, implying frequent rate cases (with the attendant administrative costs). Even if sales decoupling is implemented, so

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1 In this report we use "control costs" as shorthand for efforts on the part of utility management to reduce costs by finding ways of operating more efficiently.

2 The setting of rates to recover changing fuel and purchased power costs, which are not in the control of a utility, are in most states determined outside the GRC in separate balancing accounts or riders. These are largely outside the discussion of this report.

that declining volumes do not mean that revenues also fall, rates may still need to rise if costs are also rising. Frequent rate cases have two disadvantages: first, rate cases are costly; second, if rates are frequently updated to reflect changes in cost, the utility has a limited incentive to control costs and improve efficiency, because the utility foresees that a successful effort to reduce costs will quickly result in a reduction in the authorized revenue requirement. IBR is employed in many jurisdictions to address these issues: IBR determines rates for several years at a time, so that rate cases are less frequent, and changes in actual cost are reflected in rates less frequently, so the utility has an incentive to control costs.

In many cases, the challenge in implementing an IBR plan is to determine authorized revenues for a sufficiently long period in advance to provide strengthened incentives, while at the same time ensuring that revenues do not stray too far from the revenues required to support actual costs over the course of the plan, so that achieved returns are neither unsustainably high nor unsustainably low.

Designing an IBR Plan

The report sets out five high-level principles to guide the design of an IBR plan.

- The IBR plan should provide a financial incentive to deliver desired outcomes.
- Both customers and investors should see benefits from increased efficiency.
- The utility should bear risk from factors that are within management control but should not bear the risk from factors that are outside management control.
- The IBR plan should permit necessary commission oversight and scrutiny, while minimizing the administrative burden on all participants in the rate-setting process where possible.
- The IBR plan must provide the utility with a reasonable opportunity to earn a fair rate of return.

One caveat is important to recognize at the outset: broad-based IBR plans that determine revenues for significant periods of time are not appropriate in all circumstances. In some situations, more narrowly targeted IBR plans may be more likely to succeed. In particular, if the requirements of the utility's system and/or the relevant policy objectives of the regulator and stakeholders are such that rapid investment is needed, especially if the precise scope and timing of the investment is not clear, then broad-based IBR may not perform well. The reason is that under such circumstances delivering the investment program and building new assets may be a higher priority than improving the cost-effectiveness of existing operations. IBR is good at providing incentives for improving efficiency, and IBR plans can be designed to deliver new outputs requiring investment, but only if those outputs can be clearly defined.

A particular challenge in designing an IBR plan for energy utilities is the treatment of plant additions. The energy sector is characterized by large investments in long-lived capital assets that are not always scalable. As a result, the pattern of investment over time may not be a smooth trend, making it difficult to predict future investment needs by simply extrapolating a historical trend. Different IBR plans have evolved different mechanisms for dealing with plant additions. Some plans do not cover plant additions, so that the revenue requirement associated with O&M expenses are treated within the IBR plan, while the capital-related revenue requirement is addressed through separate rate-making mechanisms that provide additional revenue corresponding to capital recovery, but which do not provide the same efficiency incentives. Other plans may include plant additions via a contingent mechanism, so that the amount of revenue collected under the plan increases if the amount of plant additions increases. Although there are many examples of jurisdictions in which service quality incentives have been implemented alongside broad-based IBR plans that provide utilities with strengthened incentives to control costs, service quality incentives are not an essential component of IBR plans. There are also jurisdictions that require utilities to report their performance.

Where targeted incentives are implemented, such as reliability, service quality or some of the changes outlined in *Exhibit A: Commission's Inclinations on the Future of Hawaii's Electric Utilities: Aligning the Utility Business Model with Customer Interests and Public Policy Goals ("Exhibit A: Commission's Inclinations")*,[3] the design of the incentives should follow the principles for IBR plans laid out above. In particular, performance on the relevant metrics has to be objectively measureable, targets should be realistic, and rewards and penalties should be symmetric.

Current Ratemaking Approach of Hawaiian Electric Companies: RBA and RAM

The current ratemaking approach is not traditional ratemaking but a new system put in place to accommodate and guide the sweeping changes required to meet the goals of the Hawaiian renewable portfolio and energy efficiency standards. These path-breaking policies require that the Companies help facilitate a third party energy efficiency provider to achieve by 2030 at least a 30% reduction in delivered electricity. The Companies must implement a long term resource plan that provides 40% of the generation from renewable sources. Already electricity sales have been falling every year since 2004 at an average rate of over 1% per year. The renewable production is about 18%, ahead of the 2015 target of 15%. Thus, Hawai'i's leading green energy policies have changed the Companies' business model in two specific ways. First, there was a deliberate emphasis on energy efficiency and distributed generation, which along with the high price of electricity generated by imported fossil fuels, have resulted in sales declining. Simultaneously, the Companies are tasked to design, invest in and operate a generation, transmission and distribution grid system that can reliably handle a very large growth of intermittent renewable generation sources, both utility-scale and distributed.

The twin pressures of falling sales and increasing investment resulted in two significant changes to the ratemaking approach for the Companies: the Revenue Balancing Account (RBA)

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[3] Exhibit A to Decision and Order No. 32052, Docket No. 2012-0036, Integrated Resource Planning, April 29, 2014.

mechanism to decouple revenues from sales, and the Revenue Adjustment Mechanism (RAM) to adjust revenues for changing costs associated with needed investments for the time period between rate cases.

The RBA in Hawai'i is an example of a ratemaking mechanism typically described as "sales decoupling" that is increasingly common in North American jurisdictions. In Hawai'i, the RBA has the effect of allowing the Companies to collect the authorized revenue requirement, excluding the portion that represents fuel and purchased power costs, irrespective of volume sold. As such, the RBA is an essential component of the framework that permits the Companies to facilitate energy conservation and distributed energy generation between rate cases, while maintaining the financial strength to make necessary investments. Without the RBA, the Companies would either have to file more frequent rate cases or have to reduce investment.

The purpose of the RAM is to allow revenues to change in the post-test years to reflect the cost of necessary investments and expenses between rate cases.

The Commission suggested that an indication of a possible problem may be the recent overall increase in the revenue requirement, especially resulting from the rapid increase in baseline plant additions. The RAM mechanism does not result in cost shifting or recovery of imprudent costs from customers.

Under the current RAM, there is a possibility for investments to be made earlier than they may be without a RAM, but that is both a potential benefit and a source of increased costs to customers. Without the RAM, some investments would likely be delayed. Moreover, the Commission recently laid out in the *Exhibit A: Commission's Inclinations* many new systems and changes in operating procedures that it is looking for. The RAM will be essential to keep in place to facilitate these changes.

Recommendations for Improving the RBA and the RAM

Our recommendation is that the RBA, or a mechanism like it, continues to be necessary given the circumstances of the Companies, and the likely continued mismatch between needed investment and falling sales.

Our understanding of the rate-base RAM is that it was designed to allow earlier recovery of necessary investments in the period between rate cases, and therefore realize the benefits of reduced administrative costs from a three-year rate cycle without prejudicing the investment. Recent Commission statements[4] indicate that there continues to be policy drivers for increased investment. As a result, a mechanism like the rate base RAM will continue to be needed if a three-year rate cycle is to be maintained, but it can be improved.

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4 See *Exhibit A: Commission's Inclinations,* esp. Section 1 Creating a 21st Century Generation System and Section 2 Creating Modern Transmission & Distribution Grids.

The treatment of investment and capital additions under a comprehensive IBR plan is a challenging issue, particularly if the utility is not at a "steady state" and if significant investment plans are being proposed. It seems to us that the Companies are in just such a position, and that it would be difficult to design a successful comprehensive IBR plan that would *simultaneously* strengthen financial incentives to control costs and also facilitate needed investment to deliver the Commission's policy goals. Furthermore, in our experience a transition from traditional cost-of-service to IBR can take several years of detailed design work, and may still require that capital additions be treated outside the IBR plan.[5]

Designing a comprehensive IBR mechanism for the Companies is likely to be a challenging task because of the uncertainties and risks associated with a major transformation of the Companies' systems.

We note that the Companies have started to develop two conceptual IBR approaches.[6] However, we note that these two conceptual approaches are at an early stage of development. Implementation would be likely to involve significant work and might require additional design work to incentivize delivery of the investment programs.

A targeted financial incentive can be added to the Baseline RAM to strengthen incentives for the Companies to control costs. The Companies have developed two alternatives for modifying the existing RAM mechanism to reflect the Commission's concerns. We understand that these alternatives would include new mechanisms for providing information to the Commission on capital addition plans, as well as on variances between actual additions and prior year forecasts. In addition, the Companies are proposing that financial incentives could be included within either of the two alternatives being proposed. Alternative 1 includes an annual rate-base RAM target, and alternative 2 includes a rate-base RAM cap determined as part of the GRC.

In our view, both alternatives represent an improvement over the current RAM mechanism. Importantly, they both have improved reporting arrangements. Both alternatives conform with the principles we have laid out. In particular, unlike the current RAM arrangements[7] both alternatives provide the Companies with a reasonable opportunity to earn a fair return on investments made between test years. We recommend alternative 1 over alternative 2 because alternative 1 has a consistent financial incentive to control costs, whereas alternative 2 has a financial incentive only if additions are expected to be above the level of the cap. It might be argued that alternative 2 could provide an element of "rate certainty" not provided by

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5 See the approach in Alberta, described below.

6 See Hawaiian Electric Companies, *Initial Statement of Position for Schedule B Specific Issues*, Docket No. 2013-0141, Issue 5. Use of economic incentives/penalties to reward significant, accelerated efforts to reduce costs and improve customer service, subsection on IBR Plan Concepts, May 20, 2014.

7 The current arrangements do not provide a reasonable opportunity to earn a fair rate of return on investment because the current arrangements for calculating rate base RAM revenues incorporate a delay and recover only 90% of incremental revenues, irrespective of Company performance.

alternative 1, because the capped level of RAM revenue requirement is known in advance for three years. However, we would expect that to be of very limited benefit to customers because the level of RAM revenue requirement is a very small component of changes in rates. Alternative 2 also has the disadvantage, in our view, that significant weight is put on the level of capital additions in the test year. If the Companies are restricted to investing only at the level of the test year additions, that may constitute an inappropriate constraint on their ability to invest and to respond to changing priorities during the three year cycle.

Rate Stabilization and Securitization

While the main subject of this paper is IBR and closely-related topics, there are two ratemaking issues which are unrelated to IBR but which could be effective in mitigating revenue requirements increases in Hawai'i: rate stabilization through "alternative cost recovery" approaches to plant additions, and securitization as means to reduce the cost of recovering the rate-based costs of older fossil generation plants shut down before they are fully depreciated. While these mechanisms are unrelated to IBR, we recommend that they be considered because they could help to address the problem of high and increasing rates in Hawai'i.

Cost of Capital Issues

The decoupling policy in Hawai'i, through the RBA and the RAM, is similar to the decoupling policies studied in a recently-published Brattle paper on decoupling and the cost of capital.[8] We are aware that the authorized ROE was reduced by 50 bps in conjunction with the adoption of the RBA and RAM in Hawai'i, but that decision was made in the absence of empirical analysis, because at the time there were no studies available. Based upon our empirical analyses, which found no statistically significant decrease in the estimated cost of capital, we recommend that the Commission reverse the decision to reduce the allowed ROE because of the adoption of decoupling.

If the Commission were to eliminate or substantially modify the RBA policies, which we would not recommend, it would expose the Companies to the problem of falling sales resulting from energy efficiency and distributed generation policies. In that case the Commission should reverse the 50 bps reduction in the allowed ROE previously imposed. In addition, we expect that the cost of capital would be likely to increase further because the Companies would face the dilemma of having incompatible motivations to both increase sales to increase profit and to facilitate distributed generation (which decreases sales). Eliminating the RBA/RAM is unlikely to be optimal from the point of view of the customers, the Commission or the Companies, because these policies provide benefits to both the Companies and their customers.

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[8] Michael J. Vilbert, Joseph B. Wharton, Charles Gibbons, Melanie Rosenberg, and Yang Wei Neo, *The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation*, Prepared for The Energy Foundation, March 20, 2014.

If the RBA were left in place, but the RAM were to be substantially modified or eliminated, the likely effect on the cost of capital would depend upon how the RAM were modified and what, if any, policy were to replace it. The RAM primarily serves to recover changes in costs between rate cases. Unless the risk of cost recovery as opposed to the timing of recovery were to increase without the RAM, the cost of capital is unlikely to be substantially affected. However, in a situation in which the Companies were investing heavily to meet reliability and RPS goals, the Companies would be forced to file more frequent rate cases if operating without the RAM. We recommend that both the RBA and the RAM remain in place.

I. Introduction

A. Our Assignment

The Hawaiian Electric Companies ("the Companies") have asked us to advise on improving the incentive arrangements in their ratemaking procedures in connection with the Hawai'i Public Utilities Commission re-examination of decoupling in Docket No. 2013-0141. We were asked to review the Commission's February 7, 2014 decision and order in Docket No. 2013-0141[9] and the Companies' current decoupling mechanism, i.e., the rate adjustment mechanism ("RAM") and revenue balancing account ("RBA"). The Companies asked us to provide an overview of the theory and practice of incentive-based ratemaking ("IBR") in energy regulation, and to make recommendations as to how the Companies' RAM, RBA and other aspects of ratemaking could be improved. The Companies also asked us to comment on various rate of return issues raised in Docket No. 2013-0141. We have also been asked to review *Exhibit A: Commission's Inclinations on the Future of Hawaii's Electric Utilities: Aligning the Utility Business Model with Customer Interests and Public Policy Goals* ("*Exhibit A: Commission's Inclinations*"). Appendix A to this Report contains brief biographies of the authors.

B. Introduction to Incentive-Based Ratemaking

In "traditional" ratemaking, the utility revenue requirement is determined by looking at costs in a defined 12-month period, known as the "test year". Originally test years were historical, so costs were known by the time that the rate case was filed. During periods of rapid inflation this approach meant that historical test-year costs were quickly out of date, and "forecast" test years became more common,[10] with the test period typically beginning around or shortly after the filing date.[11,12] An advantage of the traditional approach is that because it uses historical data, or

9 *Decision and Order No. 31908*, Docket No. 2013-0141, (Haw. P.U.C. 7 February 2014).

10 "For many years, commissions have adjusted test-year data for "known changes;" *i.e.*, a change that actually took place during or after the test period (such as a new wage agreement that occurred toward the end of the year). More recently, due largely to inflation, a few commissions have modified the traditional historic test-year approach by using a forward-looking test year (either a partial or a full forecast) [f/n omitted] or by permitting pro forma expense and revenue adjustments." *The Regulation of Public Utilities*, Philips, Public Utilities Reports, 1984, p. 182.

11 In many states, including Hawai'i, commissions have moved to a forecast test year. A forecast test year reduces the time-lag between changes in rates and costs but does not update rates for further changes in costs after the test year.

a short-term forecast, it should be relatively straightforward to determine the revenue requirement: it is either certain what the costs were or uncontroversial to develop a short-term cost forecast. One disadvantage with the traditional approach is that if costs are increasing more rapidly over time than revenues, rate cases will need to be frequent so that the authorized revenue can "keep up" with changes in costs. Electric sales growth has slowed across the U.S., and has even fallen in Hawai'i. Furthermore, if costs are persistently changing in the same direction, rates determined in the traditional way will lag behind and will either be too high or too low to meet the fair return standard.[13]

A second disadvantage with the traditional approach is that if the authorized revenue requirement is frequently adjusted (in a rate case) to reflect changes in costs, the financial incentives a utility has to maintain or improve the efficiency of its operations is weakened. In this case, the utility realizes that its share of any efficiency improvements will be small because the benefits will quickly be transferred to customers at the next rate case. The financial incentive for the utility to invest management effort, innovate and take risks in order to find efficiencies is therefore weaker.

Nevertheless, approaches in which revenues are updated relatively frequently for changes in incurred costs can have important advantages in some circumstances, even if they are not creating financial incentives for improving efficiency. In particular, if rapid investment is needed, approaches that allow revenues to increase as investment is made provide comfort to investors (and analysts) that cost recovery will be timely. If new investment is risky, for example because it includes new technologies or new operating procedures that are relatively untested, the utility may be reluctant to invest because of the risk that the technology may not "work" correctly or may be judged, in hindsight, to have been imprudent. In these circumstances, if policy considerations dictate that the utility should be encouraged to invest in new and innovative technology, further modifications to the regulatory framework may be required to clarify whether technical risks are to be borne by the utility or by customers.

Standard approval, reporting and oversight requirements encourage a utility to avoid inefficiency because they provide an opportunity for the Commission and other stakeholders to review utility actions and test for prudence. Approvals could include the requirement to obtain prior approval for commitments to major capital expenditures, fuel contracts, and power purchase agreements. Where there are rate case cycles and revenue adjustment mechanisms with true-ups that flow the plant additions through to the customers, standard regulatory practice contains an important

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12 A recent survey found that about one third of U.S. jurisdictions use historical test years, one third use future test years, and one third are intermediate or not easy to classify. (See *Forward Test Years for US Electric Utilities*, Pacific Economics Group Research paper for the Edison Electric Institute, August 2010, Table 2.

13 See the U.S. Supreme Court's opinions in *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923), *and Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

contingency. In the next general rate case ("GRC"), there is the possibility of a detailed prudence review of any item in the revenue requirement, especially the post-test year plant additions. The possibility of review (and potential disallowance) operates as a check on the expenditures. The distinction between these incentives and the incentives created by an incentive-based ratemaking ("IBR") plan (described below) is that the IBR plan can be structured to provide the utility with a share of realized cost savings. A well-structured IBR plan provides a financial incentive to encourage the utility to find ways of operating more efficiently

IBR[14] refers to different ways in which regulators have modified their approach in an attempt to strengthen financial incentives for utilities to control costs.[15] The economic literature[16] on IBR characterizes the design of regulatory schemes as being on a range between two extremes: at one extreme, rates are set to recover costs, including a normal return on investment ("cost plus" or "rate of return" regulation); at the other extreme, rates are fixed and are independent of costs. IBR refers to schemes that fall towards the fixed-price end of the scale, because these schemes allow the utility to keep part of the benefits of reducing costs. In this report we discuss financial incentives in some detail. Although we recognize that there are other incentives which influence utility decision-making, we mostly discuss *financial* incentives: mechanisms which provide an opportunity for the utility to earn a financial reward (or suffer a financial penalty), through the income earned from utility operations. IBR plans can also be designed to provide financial incentives for achieving other outputs besides increased efficiency.

In discussing IBR plans, it is important not to confuse inefficiency and imprudence. The standards are different. An inefficient utility is not imprudent (otherwise there would be no point in IBR). The goal of IBR is to provide the utility an incentive to find and eliminate inefficiencies. Imprudent costs are those that should not have been expended at all.

With only the normal approval and oversight requirements and no financial incentives to reward improvement, there is no strong reason for a hypothetical utility to invest effort (which may or may not pay off) in trying to be more efficient. If the utility knows that an effort to reduce costs, if successful, will quickly result in a reduction in the authorized revenue requirement, the utility has a limited incentive to make the effort to reduce costs.

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14 Other terms are performance-based ratemaking (PBR), formula-based ratemaking (FBR), "RPI–X" (which usually refers to the approach taken in the UK where the authorized revenue requirement increases with the retail price index measure of inflation, plus or minus a real-terms trend). All of these terms broadly refer to the same concept of extending the period between rate cases and allowing the authorized revenue requirement to change between rate cases according to a pre-determined formula. The term "alternative regulation" is also sometimes used.

15 In this report we use "control costs" as shorthand for efforts on the part of utility management to reduce costs by finding ways of operating more efficiently.

16 A good overview of the literature is in Paul L. Joskow, "Incentive Regulation and Its Application to Electricity Networks", *Review of Network Economics,* 7(4) December 2008.

A well-designed IBR plan is an extension to traditional ratemaking methodologies that provides stronger financial incentives to the utility to encourage delivery of desirable outcomes such as greater cost-effectiveness (and hence slower growth in revenue requirements). IBR schemes are designed so that if, over time, desirable outcomes are achieved, the utility will earn a greater return than it would have done under traditional ratemaking. Conversely, if the desirable outcome is not achieved, the utility will earn a smaller return than it would have done under traditional ratemaking. If a utility has relatively stable costs, a straightforward way to strengthen incentives for improving cost-effectiveness is to lengthen the period of time between rate cases. Incentives to reduce costs are strengthened in this case because, between rate cases, reduced costs result in increased returns to the utility (whereas when rates are reset in the rate case, the benefits of reduced costs go to customers in the form of rates lower than they would otherwise have been). Lengthening the time between rate cases thus increases the returns available from a given reduction in costs, thereby strengthening the incentive. Of course, lengthening the time between rate cases also has the advantage of reducing the administrative costs of regulation for the utility, the Commission, and interveners. Unfortunately, the option of simply increasing the period between rate cases—i.e., a rate freeze—is frequently not available. If costs are changing rapidly, holding the revenue requirement constant for an extended period of time would not be consistent with the fair return standard, because the company will not have fair opportunity to earn its cost of capital. This is particularly the case when there is a need for significant capital investment.

The challenge, then, in designing a ratemaking scheme with strengthened incentives to control costs is to adjust the authorized revenue requirement *between rate cases* so that the framework as a whole provides the utility with a reasonable opportunity to earn a fair rate of return. We note that the existing RBA and RAM arrangements were designed, in part, to permit a longer period between rate cases.[17]

The discussion above relates to incentives that come from the way in which the overall revenue requirement is determined and focuses on incentives to reduce costs. There are also more "targeted" incentives which operate as an add-on to the usual rate-making process, and these targeted incentives can be designed to deliver a wide range of desirable outcomes, often related to service quality. For example, a targeted incentive scheme could focus on reducing service interruptions. Such a scheme would operate by providing an additional payment (or a penalty) according to performance relative to a target level of interruptions.

[17] The next Hawaiian Electric rate case in the cycle is scheduled to be a 2014 test year rate case. Maui Electric's case is 2015, and Hawai'i Electric Light's case is 2016.

C. MYTHS ABOUT IBR

In our experience stakeholders may sometimes have unrealistic expectations of what IBR is and what it can achieve. This is unfortunate because, as we elaborate below, IBR plans are most effective when they can operate for an extended period of time (several years at least) without risk of "re-opening". It is therefore important that the plan has widespread support from the parties at the outset, and that there is a shared understanding of what the plan is capable of achieving. In the following paragraphs we discuss briefly some of the misperceptions or unrealistic expectations that parties may hold about IBR plans.

An IBR plan has to be *consistent* with the overall policy goals of the Commission and other stakeholders. For example, a plan designed to encourage the utility to reduce costs may not be consistent with a policy objective of interconnecting large amounts of renewable energy, if interconnecting renewables requires the utility to invest in upgrading its network.

As the discussion above suggests, IBR is best considered as an adaptation to traditional rate-making rather than a completely new and different approach. Many IBR plans will borrow features of traditional regulation, and in any case all IBR plans will be founded on cost-based rates determined in the same way as a traditional GRC. It is therefore not reasonable to expect IBR to be completely different from traditional cost-of-service regulation, nor can traditional concepts such as a reasonable opportunity to earn a fair rate of return be abandoned under IBR. Furthermore, IBR will not be appropriate in all circumstances. IBR is easier to apply when a utility is in a "steady-state", but is much harder to apply (or may be inappropriate) if the utility is undergoing rapid change. If there is rapid investment in new assets or new technologies, the size and timing of necessary investment may be uncertain. In such circumstances, particularly where rapid investment may be required, a significant element of cost pass through may be needed in order to provide a reasonable expectation of cost recovery. For this reason, IBR is often applied to distribution-only utilities but is rarely applied to transmission utilities or vertically-integrated utilities.

A second misconception is that IBR amounts to paying utilities extra returns for doing what they should have been doing anyway under traditional regulation. A well designed IBR plan will only provide increased returns if performance is better than a fair and reasonable estimate of what the performance would have been under a traditional approach. Finding ways of becoming more efficient and implementing more effective cost control is difficult, takes additional effort on the part of utility management, and may involve taking on additional risks and uncertainties. Not all attempts to improve efficiency will be effective. Thus it is appropriate to offer an incentive to reward success (as well as a penalty for poor performance). A necessary condition is that it is possible for the regulators, in consultation with the utility and interested parties, to make a reasonable estimate of a performance target under traditional ratemaking and utility practices. The target must be consistent with the circumstances of the particular situation. In the current case of Hawai‘i, we understand but have not specifically reviewed the aggressive goals of the renewable portfolio standards ("RPS") and energy efficiency portfolio standards ("EEPS") (discussed below) that tend to increase costs and bills in the short and medium run. Any performance target aimed at reducing costs should be developed with recognition of the new factors that are driving cost increases.

A third misconception is that a reward paid to the utility under an IBR plan because of good performance (for example, for reducing costs or increasing service quality) harms customers because rates are higher than they would have been if the reward had not been paid. A well-designed IBR plan offers a "win-win" outcome. Customers and the utility both benefit if operating efficiency is improved. The "reward" under the IBR plan represents the utility's share of the benefit. If the reward was not available to the utility, the efficiency gains would not have been made and there would have been no benefits to share. Equally, if a reward is paid because of improved service quality, customers benefit from improved quality. If the plan is well designed, outcomes that can be achieved because of the plan, such as significant efficiency improvements, would likely not to have been achieved without the plan.

Finally, it is not realistic to describe an "optimal" IBR plan because the design of a good IBR plan will depend on the specific circumstances facing an individual utility, and may also depend on the preferences of commissions and customers as to the various tradeoffs involved in designing the plan. Therefore, designing an IBR plan for a specific utility should not involve selecting from a menu of plans in operation elsewhere. Lessons can be learned from experience, but the main benefit of looking at what has been implemented elsewhere is to illustrate the range of approaches that are possible.

In our view, the best starting point for designing an IBR plan is to agree on some high-level principles that can be used to guide the design. We offer some suggestions below.

II. Designing an IBR Plan

A. PRINCIPLES

It may be helpful to set out some high-level principles to guide the design of an IBR plan before considering the elements of the plan and the options available. In this section we offer some suggestions for principles that could be adopted in this case, based on our experience with IBR design efforts in other jurisdictions and our review of the record in Docket No. 2013-0141.[18]

It is important to recognize at the outset that broad-based IBR plans that determine revenues for significant periods of time are not appropriate in all circumstances. In particular, if the requirements of the utility's system and/or the relevant policy objectives of the regulator and stakeholders are such that rapid investment is needed, especially if the precise scope and timing of the investment is not clear, then IBR may not perform as well as traditional cost-of-service

[18] See, for example, presentations at the Alberta Utilities Commission Performance Based Ratemaking workshop, the Van Horne Institute, May 26 2010.

regulation. The reason is that under such circumstances managing the investment program and building new assets is likely to be a higher priority than improving the cost-effectiveness of existing operations. IBR is good at providing incentives for improving efficiency, and IBR plans can be designed to deliver new outputs requiring investment, but only if those outputs can be clearly defined. Not all investment programs will be amenable to being incorporated in an IBR plan because it will be difficult to specify precisely what the program is expected to deliver.

The IBR plan should provide a financial incentive to deliver desired outcomes. If the utility performs well, it should earn a financial reward in the form of increased net income. Conversely, if the utility performs poorly, it should expect to earn less net income. For example, if the utility is able to deliver good-quality service at lower cost by becoming more efficient, it should be able to keep some of the savings in the form of increased income. If the utility is unable to keep costs under control and operates inefficiently, it should not be able to pass the inefficient costs on to customers, and should therefore earn a lower return. The nature of the desired outcome, and how performance is to be measured, must be clearly set out in advance if the incentive is to be effective:

- There should be the ability to measure performance under the plan objectively and unambiguously;
- The nature of the desired (and measurable) outcomes should reflect the policy priorities of the Commission and the concerns of interveners and other stakeholders; and
- There should be a realistic opportunity for the utility to meet the plan goals and earn a fair return.

Both customers and investors should see benefits from increased efficiency. If the utility is successful in improving the efficiency of its operations, the benefits should be shared between customers and investors. The share of the benefits of increased efficiency that accrue to investors provides the financial incentive encouraging the utility to improve. If a plan design sought to give all or almost all of the benefits to customers, the plan would be ineffective because the utility would not have an incentive to improve. Conversely, a plan which allowed investors to keep the benefits of improved efficiency for an extended period would probably not be supported by customers. One way in which the benefits can be shared is to allow investors to keep all of the benefits for a certain period of time, with customers receiving all of the benefits after that through "re-basing" of rates at the next GRC. Alternatively, customers can start to share in the benefits earlier using an explicit earnings-sharing mechanism. One of the fundamental tradeoffs in designing an IBR plan is that the larger the customer share of benefits from improved efficiency, the weaker the incentive for the utility to achieve efficiency improvements.

The utility should bear risk from factors that are within management control but should not bear the risk from factors that are outside management control. Management controls the operations of the utility. It makes sense that the utility should benefit if it is able to reduce the cost of its operations by becoming more efficient, because management has direct control over the efficiency of operations. However, if fuel purchase costs fall because it happens to be a particularly cool summer with lower demand, the utility should not receive a windfall benefit as a result. There is no point exposing the utility to risks in relation to factors that it cannot control, and there may be a cost if the risk is large enough that it contributes to an increase in the cost of capital or requires the utility to hold more working capital. It is for this reason that IBR plans frequently incorporate a mechanism to pass through changes in elements of cost that are outside management control, such as fuel prices or changes in taxation. IBR plans also frequently incorporate sales decoupling so that management does not have the conflict between the policy goals of energy conservation and promoting distributed energy resources and the fact that lower retail sales reduces profits.[19]

The IBR plan should permit necessary commission oversight and scrutiny, while minimizing the administrative burden on all participants in the rate-setting process where possible. Often an objective of designing an IBR plan is to reduce the frequency of GRCs and thereby reduce the "cost" of regulation for the Commission, the utility and all other stakeholders. Lengthening the period between rate cases can strengthen incentives, as discussed above, and may also reduce the costs of the regulatory process. Matters which have been addressed in the GRC (or proceeding to adopt an IBR plan) should not be re-litigated in subsequent filings during the IBR plan term, because the effectiveness of the IBR plan may be undermined, and the costs of the regulatory process unnecessarily increased for all parties. Such disputes should be addressed in the next GRC. Furthermore, once the plan has been implemented, utility management should be permitted to operate the utility (including adjusting priorities and spending plans as appropriate) within the terms of the plan. If management discretion is unduly limited, the benefits of the IBR plan may be achieved more slowly or not at all.

The IBR plan must provide the utility with a reasonable opportunity to earn a fair rate of return. Moving away from the traditional approach to utility regulation and employing an IBR plan does not change the applicable regulatory standards and protections associated with determining the authorized rate of return. Investors must have the opportunity to earn the same return as they would have from investing in a different investment with similar risk. The operation of an IBR plan means that *achieved* rates of return may vary more over time or between utilities than they would have done under traditional regulation, because under IBR there is an opportunity to earn increased returns for good performance, as well as the chance that returns will be lower if performance is poor. However, at the start of the IBR plan, the utility must *expect* to be able to

19 Decoupling policies come in several forms. Sales decoupling breaks the direct link between fixed cost recovery and unit sales (as does the Companies' RBA). The majority of sales decoupling policies in electric and gas delivery industries also include a revenue adjustment or attrition mechanism (like the Companies' RAM) because over time sales decoupling eliminates growth as a revenue source. In a minority of jurisdictions, sales decoupling is instead linked to broad capital expenditures riders that supply funds for net new investments. This is discussed further in this Report in Chapter IV. In Hawai'i decoupling is also used to refer to the total ratemaking policy of RBA and RAM within the 3-year rate case cycle.

earn its cost of capital (and the authorized ROE should be set equal to the cost of equity capital).[20] In practice, this means that incentive mechanisms that are added to an IBR plan should be *symmetrical*, in the sense that the risk of a financial penalty for poor performance should be balanced by the opportunity for a financial reward if performance is good.

B. ATTRIBUTES OF A WELL-DESIGNED IBR PLAN

A well-designed IBR plan should reflect the principles described above. However, the final form of the plan will depend on factors that are specific to a particular utility, jurisdiction and operating environment. For example, a plan used to set rates for a distribution-only utility might look very different from a plan covering the full revenue requirement of a vertically-integrated utility. Some plan designs might rely on a time-series of detailed regulatory accounting data that may not be available in all jurisdictions. Nevertheless, we think that it is possible to identify some desirable attributes of IBR plans which, while they may not be achievable to the same extent in all circumstances, could be a useful cross check for options under consideration. The following describes many of the characteristics of a well-designed IBR plan.

Simplicity—regulatory processes tend to become more complicated over time as refinements are added to an existing design. However, there are benefits from keeping an IBR plan simple, or at least starting out with a simple plan. If a plan is complicated, unintended outcomes may be more likely. Complexity could also undermine the strength of incentives: if it is difficult to work out in advance the financial consequences of various different outcomes under a plan, it will be harder for management to make an optimal allocation of effort. A simple plan will also be easier to explain, and therefore easier to gain support from all interested parties. A simple plan should also reduce the cost of the regulatory process, which is often one of the motivations behind designing the IBR plan.

Fairness—a well-designed IBR plan should be attractive to all sides. For the utility, the plan should offer the chance for increased returns if performance is good; for customers, it should offer the prospect of greater cost-effectiveness and/or improved service quality and the protection that performance payments will only be made if performance is good. For all sides the administrative cost of regulation can be reduced. An IBR plan should not offer increased returns unless performance is good. Equally, the plan should not penalize the utility unless performance is poor. Performance targets should be achievable and should be *symmetric* about the expected

[20] In general, regulators attempt to set the allowed ROE equal to the cost of equity capital, but occasionally the allowed ROE may need to be set higher than the cost of equity capital. This situation arises when the utility cannot expect to earn the allowed return because of some other aspect of the regulatory system. An example is when the utility faces asymmetric risk, meaning that the utility faces the possibility of a large loss without the corresponding possibility of large gain. When facing asymmetric risk, setting the allowed ROE higher than the cost of equity capital restores the expectation that the utility can earn its cost of capital.

outcome, so that a penalty is paid if performance is worse than expected, but the utility is rewarded if performance is better than expected. A fair plan needs to provide revenues sufficient to cover the cost of service at the start of the plan, as determined in an opening cost-of-service proceeding; and it needs to provide increased revenue over the plan term if the cost of service is expected to increase. However, the plan is not a blank check: the design of the plan should be supported by evidence as to the change in costs and cost-effectiveness that can reasonably be expected over the plan term.

Clear motivation—a successful IBR plan will have a design that clearly relates to the policy objectives underlying its adoption. If a primary motivation is to reduce regulatory burden by reducing the frequency of rate cases, the IBR plan needs to provide revenues that change during the plan term if costs are expected to change. If a primary motivation is to strengthen incentives to improve efficiency, the plan should offer significant financial incentives for controlling costs. If a primary motivation is to encourage action to promote renewable generation, the plan should offer financial incentives around a renewable energy target.

Staying power—many utility investments are long-lived, and actions taken to improve efficiency may have multi-year payback periods. As a result, financial incentives in an IBR plan can only be fully effective if the utility is confident that the plan has staying power, and will operate for its full term without re-opening (except as provided for by the terms of the plan itself, for example via an "off-ramp" type mechanism).[21] Staying power requires avoiding unworkable plan outcomes, for example through a sharing mechanism to temper very high or very low achieved ROE, and requires up-front commitment from the commission and customer groups. How the plan is to operate must be clearly specified to minimize the risk of ambiguities and misunderstandings that could lead to re-opening the plan part way through.

C. TREATMENT OF PLANT ADDITIONS UNDER IBR

A particular challenge in designing an IBR plan for energy utilities is the treatment of plant additions. The energy sector is characterized by large investments in long-lived capital assets that are not always scalable. Additions or replacement of capacity (either generating capacity or transmission network capacity) are often "lumpy" because of economies of scale. As a result, the pattern of investment over time may not be a smooth trend, making it difficult to predict future investment needs by simply extrapolating a historical trend. Some categories of investment require permitting and siting procedures that can be time-consuming and can introduce delays that are hard to predict. Some investment is driven by load growth, and can therefore be considered "revenue generating", in the sense that the need to invest is naturally coincident with

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21 An "off ramp" or similar mechanism acts to terminate the IBR plan early and reset rates if certain pre-defined trigger-points are reached, typically as a result of achieved ROE either being too far above or below the authorized ROE.

increased revenue.[22] However, other kinds of investment are driven more by the need to replace aging assets and thus are uncorrelated with changes in revenue.

The factors described above mean that the revenue requirement associated with the capital invested in a utility's system may not follow a smooth path over time. After an initial build out, utility rate base could decline over time with depreciation, such that the associated revenue requirement declines in nominal terms. When load grows sufficiently to require investment in incremental (but lumpy) capacity, there could be a corresponding jump in the revenue requirement. Similarly, replacement capital expenditure could also give rise to a sudden jump in the capital-related revenue requirement because the cost to replace a long-lived asset is almost always much greater than the original cost. It can be difficult to accommodate such changes in the revenue requirement under an IBR plan because, as discussed above, for the plan to provide effective incentives, it has to operate for several years without re-basing. Capital expenditure can be hard to predict by extrapolating a historical trend, and even if a multi-year forecast of capital expenditure is available, factors such as permitting that are largely outside the control of the utility could easily introduce delays. In contrast, O&M expenses typically show a smoother pattern over time and are therefore easier to accommodate within an IBR plan.

Different IBR plans have evolved different mechanisms for dealing with plant additions. Some plans do not cover plant additions, so that the revenue requirement associated with O&M expenses are treated within the IBR plan, while the capital-related revenue requirement is addressed through separate rate-making mechanisms that provide additional revenue corresponding to capital recovery, but which do not provide the same efficiency incentives. Other plans may include plant additions via a contingent mechanism, so that the amount of revenue collected under the plan increases if the amount of plant additions increases. Such a "plant additions driver" needs to be expressed in terms of units of work, such as MW of new generation connections, rather than in dollar units, in order to preserve the incentive properties of the IBR plan. We discuss specific examples of plant additions mechanisms below.

D. TARGETED INCENTIVES ON RELIABILITY AND CUSTOMER SERVICE

IBR plans strengthen incentives to control costs. Since improving service quality implies increasing costs, regulators may be concerned about an incompatibility between incentives to control costs and maintaining or improving service quality. If there is insufficient revenue to support necessary investment, service quality will decline over time. Targeted incentives to maintain or improve service quality are one possible response to this concern. Service quality

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[22] Sales decoupling means that revenue is independent of sales volume, such as in the Companies' RBA. Some utilities have sales decoupling mechanisms or rate structures that decouple revenue from changes in sales per customer, but changes the revenue requirement proportionate to the number of customers.

incentive plans take a set of service quality metrics (such as the frequency and duration of interruptions) and provide a financial reward or penalty according to how the utility performs against targets set for each metric.

Although there are many examples of jurisdictions in which service quality incentives have been implemented alongside broad-based IBR plans that provide utilities with strengthened incentives to control costs, service quality incentives are not an essential component of IBR plans. There are also jurisdictions that require utilities to report their performance.

Where service quality incentives are implemented, the design of the incentives should follow the principles for IBR plans discussed above. In particular, performance on service quality metrics has to be objectively measureable, targets should be realistic, and rewards and penalties should be symmetric. It is also very important that the service quality metrics are closely connected to the attributes of good service quality that customers care about. Unfortunately, it is not always easy to determine what aspects of quality customers care about, or to measure those aspects in an objective way. For example, it may be important to customers that a utility's call-center staff performs "well". However, it is easy to measure statistics such as the percentage of calls answered within a certain period of time, but it is less easy to measure whether customers are satisfied with the outcome of a call. Some customers may care a lot about power quality or momentary interruptions, whereas other customers may be relatively unaffected by these issues.

In relation to network reliability, there are some commonly-used methods based on the Institute of Electrical and Electronics Engineers ("IEEE") standards for measuring indices of average frequency and duration of interruptions.[23] Many utilities are required to report these reliability metrics, and in some cases financial incentives linked to these metrics.[24]

Where financial incentives are linked to service quality metrics, other parameters that have to be defined in the scheme include the target level of performance and an overall cap on the dollar amount of penalty and reward. In many cases, the target level of performance is based on a historical average (for example, the average of the last five years). The cap on reward or penalty is usually expressed as an aggregate across all of the service quality metrics.

Service quality incentives of this kind are suitable for driving gradual improvements in service quality or for encouraging utilities to maintain existing levels of (good) performance. They are not suitable for driving step changes in performance, because a step change will typically require significant amounts of investment. If a step change is required, a business case for the investment would be brought forward by the utility in a GRC rather than funded via the service quality incentive.

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23 IEEE standard 1366-2003.

24 Examples include utilities in California and New York, as well as in Australia. See, for example, *Approaches to Setting Electric Distribution Reliability Standards and Outcomes*, Serena Hesmondhalgh, William P. Zarakas, and Toby Brown, Brattle paper for the Australian Energy Markets Commission, January 2012.

III. Examples of IBR Plans

In this section we give some examples of IBR plans that have been implemented by energy regulators in various jurisdictions. We are not suggesting that these examples offer a "template" that could be applied in Hawai'i: in every case, IBR plans have evolved over time to meet the specific needs of the particular utility, commission, other stakeholders and operating environment in which the plan was applied. However, we suggest that these examples are useful because they can illustrate a range of different approaches to the same basic problem of providing recovery of efficiently-incurred costs while reducing the frequency of GRCs. We begin our brief description of each example with a list of high-level "takeaway" points that we believe are illustrated by the example.

We give three examples of IBR plans that determine overall revenue requirements, as well as some examples of targeted incentive schemes that are aimed at improving reliability and customer service. An IBR plan is often characterized by a formula used to determine the revenue requirement (or, sometimes, the rates). Frequently this takes the form:

$$RRQ_{t+1} = RRQ_t \times (1 + I - X) + K + Y +/- Z$$

In this formula: I is an inflation factor; X is an offset (which can be positive or negative) representing the real-terms trend in base revenue requirements; Y is a flow-through factor that passes through elements of the revenue requirement which are outside the utility's control, such as fuel costs; Z is a factor to cover "exogenous events", unexpected changes in costs that may be addressed through one-off filings during the plan term; and K is a factor to provide incremental revenue requirement for needed capital additions that cannot be funded within the main I – X component of the revenue requirement.

One of the issues raised by the Commission in this docket is the relationship between IBR and strategic planning.[25] We are not aware of any examples of Commissions or other regulatory authorities designing an IBR plan to promote a major change of utility strategy. Rather, as we discussed above, an attribute of a well-designed plan is that it should have a clear motivation related to the underlying policy objectives of the Commission. Once the underlying policy objectives have been clearly set out, the IBR plan can contribute to successfully achieving the objectives by providing a financial incentive for delivering outputs related to the policy objectives. However, it is unlikely that a well-designed IBR plan will be sufficient to deliver all policy objectives because it will not always be possible to find objectively-measurable outputs that are relevant to each policy objective. Rather, the policy objectives are decided first, from which flows both the utility strategy and the design of the IBR. The design of the IBR may well influence the utility strategy, and how quickly it is delivered, but many aspects of the utility strategy will have to be agreed outside the framework of the IBR plan itself. In particular, the

[25] Schedule B issue 3d is "What modifications can be made to the RAM and/or RBA provisions that would provide appropriate incentives/penalties for the Hawaiian Electric Companies to make major adjustments to utility strategies and action plans that are in the public interest?".

level of investment required to deliver the utility strategy is likely to be approved in a GRC or proceeding specifically addressing investment rather than in the design of an IBR plan.

In the examples which follow we review the incentive properties of the regulatory framework in California, Alberta and the United Kingdom. These are just three illustrative examples of how different regulatory frameworks provide incentives. It is important to note, as discussed above, that *all* regulatory frameworks provide incentives of one kind or another. The approach in Alberta is labeled "performance-based ratemaking" while the general ratemaking approach in California has evolved over time to acquire important incentive properties, but has not been given a "performance" or "incentive" label. We have not attempted a full description of all the details of the approach in each case, but we have described the key features relating to the incentives provided by the approach. We describe the incentive to control costs, to undertake necessary investment, and to deliver specific outputs such as service quality.

In describing these examples of IBR plans we also highlight other features of the regulatory framework in each jurisdiction which could be relevant to this proceeding. One example is the fact that Alberta distribution utilities are subject to IBR but Alberta transmission utilities are not.

A. California

General form of the plan

The approach to regulating the state's gas and electric utilities has evolved over time, and the details are different for the different utilities. We are not attempting a comprehensive description, but we would like to highlight what we see as some important themes.

The GRCs are on multi-year cycles. For example, Southern California Edison's last GRC covered a 2012 test year plus "post-test year ratemaking" for 2013 and 2014;[26] and Pacific Gas and Electric's last GRC covered a 2011 test year plus 2012 and 2013.[27] The test year revenue requirement is based on a detailed (forecast) cost of service, where the authorized revenue requirement is based on a detailed buildup of operating expenses, depreciation and return on rate base.[28] The revenue requirement for the post test years (sometimes called the "attrition" years) is usually not determined by building up a detailed forecast cost of service as is done for the test year. Although detailed cost forecasts are usually presented in evidence, the final decision is usually based on a more simplified approach. For example, a trend or escalation rate can be

[26] See CPUC Decision D.12-11-051.

[27] See CPUC Decision D.11-05-018.

[28] If the rate case is settled rather than fully litigated, the settlement itself usually specifies only the agreed revenue requirement, without a corresponding set of agreed detailed costs that build up to the agreed revenue requirement.

applied to expenses and to capital additions in order to determine the revenue requirement,[29] or the revenue requirement increases can be determined in a top down fashion without tying back to detailed assumptions about changes in underlying costs.[30] The key point is that the GRC authorizes revenue for the test year and revenue increases for the subsequent years.

For the California utilities, the GRC authorizes revenues for the distribution function.[31] The distribution revenue requirement is decoupled from sales (or throughput) risk because there is a balancing account treatment to ensure that any shortfall/excess in collections in one year is made up/returned in the next. As a result, the distribution revenue recognized by the utility will be equal to the authorized revenue, irrespective of the number of kWh distributed or new customers connected. This arrangement is similar to the RBA in Hawaiʻi.

Incentives to control costs

For the duration of a rate case cycle, the authorized revenue for each year of the rate cycle is determined in advance in the GRC and is not subsequently updated[32] until the next rate case. If costs in the test year turn out to be higher than the forecasts on which the authorized revenue was determined, the utility will by definition earn less than the authorized rate of return. If the utility is able to reduce costs relative to the forecasts, it will earn more than the authorized rate of return. As a result, the utility has a financial incentive to control costs. Similarly, because revenues for the post test years are also determined in advance and are not adjusted if actual costs turn out to be higher or lower than forecast, the utility also has a financial incentive to control costs in the years between test years.

Investment

In general, capital additions are funded through the revenue requirement determined in the GRC, and there is no additional mechanism for funding investment. However, mechanisms targeting specific investments have been implemented on occasion. One example is the "adder project" arrangement. This has been implemented for specific projects on Pacific Gas and Electric's gas transmission network, which has its own rate case cycle, also typically three years.[33] The adder project mechanism works by determining a revenue requirement for a specific project.

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29 See the Southern California Edison general rate case (D.12-11-051), at pp. 606–9.

30 The latter approach is more typical when the rate case is settled.

31 Electric transmission is subject to FERC jurisdiction; utility generation revenue requirements are covered by the GRC, but power procurement and other elements of customer rates are determined in other proceedings.

32 There are cases in which the revenue requirement in the post-test years is a function of inflation, so the revenue requirement would be updated in light of new inflation data, but it would only be updated within the parameters determined in the GRC.

33 The rate cases for PG&E's gas transmission and storage business have also often been referred to as the "gas accords".

The utility is allowed to collect the adder project revenue requirement only once the project is actually in service.[34] The adder project mechanism has the advantage that the revenues are contingent on the project being in service, so the utility has a strong incentive to deliver the project on time. At the same time, the revenue requirement is determined in advance, so the utility also has an incentive to control project costs (since it is not simply trued-up after the fact for the revenue requirement implications of actual costs).

A second targeted mechanism we have seen in California is the "Reliability Investment Incentive Mechanism" or "RIIM".[35] The RIIM mechanism has not been applied uniformly to all California utilities. The RIIM functions somewhat like a "one-way balancing account". If the utility invests less than the authorized amount, the amount of the underinvestment is returned to customers; if the utility spends more than the authorized amount, it is not able to collect additional revenues. In the most recent Southern California Edison rate case, the RIIM accounted for more than $4 billion of investment over three years,[36] in expenditure categories "particularly related to long-term electric reliability".[37] CPUC has said that "[t]he purpose of RIIM is to provide SCE with an incentive to spend funds for reliability-related activities and not divert them to other activities or short-term profits" and that the RIIM "served the interests of ratepayers by requiring SCE to spend the funds consistent with their authorized reliability purpose."[38]

Reliability incentives

At certain times some California utilities have been subject to targeted incentive mechanisms aimed at improving reliability. For example, in the 2012 rate case for San Diego Gas and Electric, the CPUC adopted performance incentives for the length of interruptions (SAIDI and SAIDET),[39] the number of interruptions (SAIFI) and providing customers with an accurate estimated restoration time (ERT).[40] Under these measures, a target level of performance is set on each of the four reliability measures. If the utility performs better than the target, it is able to collect a "reward", and if it misses the target, it is penalized. In addition to defining the targets and a formula for calculating the rewards / penalties, the CPUC also determined an overall "cap" on the maximum amount of penalty and reward that could apply in each year.

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34 See, for example, the CPUC's decision on PG&E's 2008 GT&S rate case (D.07-09-045), p. 7.

35 The RIIM has one component targeting reliability investment and a second component which sets a hiring target for field personnel directly working on reliability-related projects. We concentrate on the investment component.

36 CPUC D.12-11-051 at p. 696.

37 *Ibid.*, at p. 693.

38 *Ibid.*, at pp. 692–4.

39 SADI is the average total time off supply in minutes per customer per year for all interruptions longer than 5 minutes, and SAIDET is the average taking into account only extended outages.

40 See CPUC decision on the 2012 GRC for San Diego Gas and Electric (D.13-05-010), pp. 204-8.

In other cases, the CPUC has not implemented reliability performance incentives. For example, neither PG&E's 2011 rate case nor SCE's 2012 rate case includes such incentives.[41]

Key points

High level takeaways from the California approach are as follows.

- While the GRC has a single test year for which a revenue requirement is determined (on a forecast basis), the utility is able to present evidence of its expenditure plans and the drivers of increased cost in the post test years and to apply for "attrition" increases in revenue requirement. The interval between rate cases and test years is usually three or four years. The period between GRCs provides an incentive to control costs.
- Post-test year "attrition" increases in revenue requirement may be determined in a top-down fashion without building up from a detailed set of cost forecasts, or may be determined from expenditure trends.
- Various approaches for funding certain programs outside the main part of the plan have been used in different circumstances, including a "use it or lose it" allowance for reliability spending, and an "adder" approach whereby an additional revenue requirement is determined for specific projects but can only be collected if and when the project is built.
- Reliability incentive schemes have been used for some utilities in some rate cases, but not comprehensively.

B. ALBERTA

General form of the plan

In 2010 the Alberta Utilities Commission ("AUC") launched an initiative to require the gas and electric distribution utilities[42] in the province to move away from "traditional cost of service" regulation to performance-based regulation. The "traditional" approach in Alberta had been a GRC every two or three years, on a forecast basis. However, unlike other jurisdictions where a multi-year rate case cycle consists of a test year plus broad or top-down adjustments to reflect changes in the revenue requirements in the subsequent years, the traditional approach in Alberta was a "multi-test year" approach. A detailed cost forecast covering each year of the cycle was prepared and assessed in the rate case. The AUC decided to shift to a IBR approach with a five-

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41 See D.11-05-018 and D.12-11-051.

42 In Alberta there is some common ownership of distribution and transmission businesses, but the regulated distribution and transmission utilities do not own generation, and they do not sell electricity to end customers. There is retail competition, and there is an independent system operator.

year cycle, in part to provide stronger incentives for the utilities to be efficient, and in part to reduce the regulatory burden of frequent rate cases. It initiated a generic proceeding in 2010, commissioned expert advice, and reviewed the utilities' proposals in a comprehensive generic proceeding that ran for over two years.[43]

The new approach consists of "going-in" rates and revenue requirements determined in the traditional way for a single test year on a forecast basis. In the years following the test year, rates are adjusted by an inflation index (I), a fixed productivity factor (X), a capital factor (K, discussed further below), flow through items (Y), and exogenous items (Z). Thus the form of the plan is $R_{t+1} = R_t \times (1 + I - X) + K + Y +/- Z$. There is no earnings sharing, but the plans can be re-opened if circumstances warrant (for example, if the achieved ROE is more than 500 basis points above or below the authorized ROE, or more than 300 basis points above or below for two consecutive years).

The IBR formula applies to *rates* rather than the revenue requirement. As a result, the utilities are exposed to revenue uncertainty associated with changes in throughput (and changes in the number of customers). Alberta is somewhat unusual, however, in that per customer electricity consumption and the number of customers served are generally increasing. There is no sales decoupling, although the distribution tariff for residential customers is two-part, with a fixed charge on the order of $40 per month.[44]

It is important to note that the IBR plan in Alberta only applies to distribution revenue requirements. Transmission revenue requirements (for the transmission function of the combined distribution utilities and for the stand-alone transmission utilities) are set using the traditional approach. For transmission, the AUC took the view that it was not appropriate to apply IBR in part because "[t]he electricity transmission system is entering a period of significant change with substantial planned expansions".[45] Transmission revenue requirements are set by a rate case process similar to the "traditional" approach for distribution revenue requirements prior to the implementation of IBR. Revenue requirements use a forecast of costs for each of two test years. However, there are a few differences between how transmission revenue requirements are currently set and how distribution revenue requirements were traditionally set:

- Transmission has full sales decoupling;[46]

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43 See *Rate Regulation Initiative, Distribution Performance-Based Regulation, Decision 2012-237*, Alberta Utilities Commission, September 2012. The proceeding had been launched in February 2010, and some aspects of the plans for some of the utilities have not yet been finalized.

44 See, for example, ATCO Electric price schedule D11 which shows a fixed charge of CAN$1.21/day (*ATCO Electric 2014 Annual PBR Rate Adjustment (Interim Rates) Approved in Decision 2013-461 (Dated: December 20, 2013)*).

45 See AUC letter of February 26, 2010, quoted in Decision 2013-237, paragraph 59.

46 The transmission revenue requirement is billed directly to the Alberta Electric System Operator; there are no "rates" as such for the transmission utilities.

- Most transmission capital expenditures are eligible to earn a return immediately while an asset is under construction (i.e., construction work in progress can be included in rate base); and
- The revenue requirements associated with most new transmission assets are trued-up according to actual capital expenditures through a balancing account process.

Thus revenue recovery for transmission investment is subject to considerably less uncertainty. This reflects the significant investment in new transmission assets currently being undertaken, in part, in response to a large increase in renewables interconnection. It also reflects the difficulty in forecasting the scope, cost and timing of transmission projects.

Incentives to control costs

As with any multi-year rate cycle, the incentive to control costs on the distribution network comes from the fact that rates (or revenues) are determined in advance and are not updated, except with certain exceptions if costs turn out to be higher or lower than expected. Incentives to control costs on some items of capital expenditure are reduced because of the K-factor mechanism, discussed below. The AUC rejected suggestions that an earnings sharing mechanism should be included because it would act to weaken incentives to control costs.[47] The Alberta IBR plans are to run for five years and, other things equal, a longer plan would be expected to have stronger efficiency incentives.

Unlike distribution, the form of the transmission revenue control itself does not provide incentives to control costs. For transmission investments, the incentive to control costs comes from regulatory oversight, cost reporting, and the risk of disallowance if investments are judged to have been imprudent.

Investment

A very important feature of the Alberta IBR plans is the capital or K factor. The companies presented evidence on the expected amount of investment over the term of the IBR plan, and argued that adjusting going-in rates by I minus X each year would not provide sufficient revenue to support the needed investment. The AUC agreed that the I minus X trend would not provide sufficient revenue, and it therefore accepted the concept of a K factor to provide additional revenue to support needed investment.

The AUC said: “A capital tracker mechanism in a PBR plan is warranted in circumstances where the company can demonstrate that a necessary capital replacement project or capital project

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[47] See Decision 2013-237, pp. 178-9.

required by an external party cannot reasonably be expected to be recovered through the I-X mechanism."[48]

In some respects the K factor is performing a similar job to the "attrition rate relief" in California, in that both result from the need for additional revenue to support needed investment. However, distinguishing features of the Alberta K factor is that the K factor amounts for each year of the plan are approved in separate annual filings; revenue requirements are determined on a forecast basis; and there is a subsequent true-up to reflect actual investment (subject to a prudence review). The AUC acknowledged that efficiency incentives would be weakened because of the true-up process, but it said: "The company will only be permitted to collect the forecast amounts for the capital tracker on an interim basis, and a true-up to the actual amount of the capital tracker will occur after the capital expenditures have been made. As a result, these companies will still have some efficiency incentives due to the risk of regulatory disallowances in the true-up process if expenditures are not prudently incurred."[49] The Alberta K factor thus operates in a similar fashion to the rate base RAM mechanism in Hawaiʻi.

The mechanism for cost recovery of transmission investment was described above. The AUC made a number of changes to the way in which transmission costs were recovered in order to facilitate rapid investment.

Reliability incentives

The generic IBR proceeding in Alberta considered whether a "quality" or reliability measure should be implemented as part of the IBR plan to provide an automatic penalty for poor reliability and an automatic reward for improved reliability. The AUC ultimately decided to continue to rely on existing mechanisms: utilities are required to report quarterly on various reliability and service quality metrics, and the AUC has the ability to impose penalties if performance standards are not met.[50]

Key points

High-level takeaways from the Alberta approach are as follows.

- Transmission revenue requirements are set on a traditional cost-of-service basis and are not subject to IBR. Transmission has full sales decoupling, and revenue requirements are set on the basis of forecast costs and forecast capital

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48 Decision 2012-237, paragraph 587.

49 *Ibid.*, paragraph 615.

50 The reporting requirements and quality standards are set out in *Rule 002: Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and Gas Distribution Systems*, AUC, December 2013. The AUC is able to levy penalties of up to $1m per day or the economic benefit derived from contravening the rules (see Decision 2012-237, paragraph 897).

expenditures. Most transmission investments are eligible for construction work-in-progress in rate base treatment, and for revenue requirements to be trued-up according to actual investments.

- Distribution revenue requirements are determined under an IBR plan. The overall approach is to determine the revenue requirement and rates for a single forecast test year, then to escalate rates for the four subsequent years. The IBR plan applies to distribution rates only (with no transmission, generation or power supply costs) and the Alberta electric utilities benefit from a two-part tariff with a fixed charge and growing throughput.
- Capital expenditures on distribution programs or projects where the capital-related revenue requirement is growing faster than the IBR plan trend can attract additional funding by means of a separate annual application process. This mechanism provides an additional revenue requirement which is trued-up on the basis of actual investment, subject to prudence review.
- In Alberta, the Commission considered whether a targeted incentive scheme addressing distribution reliability was required but ultimately decided that existing reporting arrangements were sufficient.
- The different treatment of transmission and distribution reflects the rapid changes underway on the transmission system, in part driven by a significant increase in renewables penetration.

C. UK

General form of the plan

UK distribution utilities[51] have been regulated under an "RPI – X" approach[52] since privatization 25 years ago. The general form of the plan is similar to Alberta: $R_{t+1} = R_t \times (1 + I - X)$. There are several important differences, however:

- revenue requirements are calculated on the basis of "trended original cost", with the value of the rate base increasing each year with inflation;
- the IBR is applied to revenues rather than rates;
- there is no re-opener mechanism; and

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51 Distribution utilities in the UK are regulated separately from transmission utilities (there is some common ownership). Generation and retail supply are not subject to price regulation.

52 The IBR plan in the UK is referred to as "RPI – X" because the inflation index used in the plan is the Retail Price Index.

- rather than a "test year plus trend", the plan revenue is designed in light of a full forecast of expenses and investment for each year of the plan term.

As the IBR plans have been in place for many years, a number of refinements have been developed over time. For example, the term of the plan has been extended and now runs for eight years rather than five,[53] reducing the regulatory burden of the review process, and strengthening efficiency incentives. A second innovation has been to introduce a "revenue driver" for interconnecting additional renewable generation at distribution voltage (discussed further below). A third change is that, in response to concerns that under the IBR regime utilities had limited ability and/or incentive to invest in innovation that could facilitate renewable integration, energy efficiency and other desirable changes, the regulator introduced specific measures aimed at supporting innovation (also discussed below).

In some respects, the UK approach is similar to a traditional North American cost-of-service approach with a forecast test year. However, in place of a single (forecast) test year, the UK utilities are required to prepare a business plan and associated detailed forecasts of costs that cover the entire IBR period, now eight years. During the rate case proceeding, these cost forecasts are extensively tested by staff and technical consultants. Ultimately, the IBR plan is designed so that the net present value of the revenue requirement produced by the IBR is equal to the net present value of the forecast costs. Under the UK approach, the X factor in the plan is unconnected with productivity improvements or trends in cost: it is a parameter which, together with an initial change in the first year of the plan,[54] smooths the profile of the revenue requirement over the plan term.

UK distribution utilities are separate legal entities from the retailers that sell electricity to end customers (although a retailer and a distributor can be owned by the same holding company). End customers have a contractual relationship with the retailer only, and the retailer purchases distribution services from the distributors on behalf of its customers. Distributors bill retailers on an aggregated basis, and volumetric rates are a relatively small part of the distribution charge. The IBR plan applies to distribution revenues rather than rates: the distributor is free to adjust its rates as long as the rates conform to principles laid out in a charging methodology statement approved by the regulator. The constraint is that revenues collected should not exceed the results of the IBR formula, and any variances are passed on in the following year (the system is similar to the sales decoupling mechanism in California).

Transmission utilities are regulated under a similar system, although there are separate mechanisms for funding major capital investment projects.

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53 The current electricity distribution price controls run from April 2010 to March 2015. A proceeding is underway that will cover the period April 2015 to March 2023.

54 Traditionally, the plan is defined by the initial change, known as "P_0", and the annual real terms change, "X". By convention, positive values of P_0 or X represent reductions in revenue requirement.

Incentives to control costs

As with other IBR plans, the length of the plan is a key influence on the strength of incentives to control costs. Over time, various developments have been added to the basic form of the plan to improve the incentive properties.

- The term of the plan has been increased from five to eight years.
- A "carry over" mechanism was developed to strengthen incentives for capital expenditure efficiency towards the end of the plan term. Differences between authorized and actual capital-related revenue requirements were carried over into the next plan term, so that the proportion of the efficiency savings accruing to the utility would not depend on which year in the plan the saving was made.
- A "menu" approach was developed to address the problem of over-forecasting. The utilities are allowed to choose from a menu of plans which range from relatively higher revenue requirements and an earnings-sharing mechanism that gives most savings to customers, to a relatively lower revenue requirement with an earnings-sharing mechanism that allows the utility to keep a larger proportion of the savings. The purpose of the menu approach is to encourage each utility to choose an option that best reflects the utility's own unbiased estimate of future costs, thereby avoiding the over-forecasting problem.
- There are fourteen regionally-based distribution utilities, all of which are on similar IBR plans with the same start and end dates. As a result, the regulator is able to benchmark aspects of utility performance across the fourteen regions.
- A twin-track approach for reviewing business plans and cost forecasts has been implemented. Utilities which are judged to have developed particularly impressive business plans, and which have been diligent in engaging with stakeholders in developing their plans, are eligible for a fast-track decision with less in-depth scrutiny.

These refinements are the result of continuous evolution of the IBR plans over time, and have resulted in significant complexity.

Investment

The basic premise of the UK type of IBR plan is that investment is forecast for the entire period of the plan. For example, this means that the utility business plans published in March 2014 contain detailed forecasts of costs for each year for 2015 to 2023.[55] Over time various

[55] Business plans are published by the utilities as part of the rate case proceeding. See, for example, business plan documentation for UK Power Networks, available at: http://library.ukpowernetworks.co.uk/library/en/RIIO/Main_Business_Plan_Documents_and_Annexes/

mechanisms have been added to the basic RPI – X approach to recognize that the basic framework may not support timely delivery of needed investment in all circumstances.

One such circumstance is that over time it became clear that very large amounts of renewable generators would be seeking to interconnect at distribution voltages, potentially requiring significant investment by the utilities. It was difficult to forecast with any degree of precision how much generation would connect and when, so it was difficult to provide an adequate revenue requirement on a forecast basis. Furthermore, if the revenue requirement associated with the cost of interconnecting generation was fixed in advance, the utility could be reluctant to engage with prospective generators in a timely fashion since interconnection would not provide the utility with additional revenue but would cause it to incur additional costs. This issue has been resolved by providing a "revenue driver": the authorized revenue increases automatically by a certain amount for every MW of generation capacity that is interconnected. The revenue increment is set equal to 80% of actual costs, plus a fixed per MW allowance, with a backstop so that the revenue allowance must at least cover funding the interconnection costs at the authorized cost of debt.[56] The mechanism is designed to provide an incentive to encourage the utility to be responsive to interconnection requests, while also providing an incentive to control costs.

A second circumstance is major upgrades to the transmission networks. Transmission network projects are frequently controversial because of "siting" issues. The time required to obtain the necessary permits can be hard to predict, and siting issues can result in route changes that make predicting costs difficult also. In consequence, in the UK (as also described in Alberta), mechanisms have been designed to provide cost recovery for major transmission projects outside the usual IBR mechanism. For example, in 2004 the regulator implemented a mechanism known as TIRG (Transmission Investment for Renewable Generation). TIRG was implemented outside the regular IBR framework for the transmission utilities in order to minimize delays in developing the deep reinforcement projects necessary to bring significant quantities of power from proposed renewable projects in Scotland down to major load centers in England. Other mechanisms were developed later (Transmission Investment Incentives, and Strategic Wider Works).[57] The common features of these mechanisms are that they are outside the regular rate case process; they provide funding for specific projects on a case-by-case basis; and they allow an element of cost pass-through. The mechanisms reflect the necessary trade-off that, in order to allow transmission projects of uncertain scope, timing, and cost to proceed in a timely fashion, it is necessary to allow some cost pass through even though this may weaken incentives to control costs.

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[56] See *Electricity Distribution Price Control Review Final Proposals – Incentives and Obligations* (Ofgem, December 2009), chapter 3.

[57] Details of these programs can be found at https://www.ofgem.gov.uk/electricity/transmission-networks/critical-investments

The third important circumstance where specific mechanisms have been implemented to encourage investment relates to “innovation”. The regulator has designed several mechanisms to fund innovative projects undertaken by distribution and transmission utilities. These mechanisms involve utilities (and, in some circumstances, third parties) submitting funding requests to the regulator. The requests are judged by an independent panel against a set of criteria, and the successful projects will be funded out of additional authorized revenues collected by the utilities. In part, these mechanisms reflect a concern that regulated utilities may under-invest in innovative projects, for example because regulated utilities are unable to capture the “upside” benefits of successful innovation, and because there may be a “first mover disadvantage”.

- The “Network Innovation Competition” provides up to around $50m per annum of funding to support trials of new technology on the transmission networks.[58] In the first year of operation, it supported two projects, one to use new sources of data and methods of analysis to optimize use of capacity on the Anglo-Scottish interconnector, and a second to establish a collaborative test and development facility for HVDC systems. Criteria for funding are
  - contributing to a low-carbon energy sector, or other environmental benefits, while providing net financial benefits to customers;
  - generating knowledge that can be shared amongst all transmission utilities;
  - innovative (i.e., not ‘business as usual’) and has an unproven business case where the innovation risk warrants a limited development or demonstration project to demonstrate its effectiveness;
  - robust and can be implemented quickly; and
  - involves other partners and external funding.
- The Low Carbon Networks fund provides a similar level of funding (and has similar funding criteria) for projects on distribution networks. Projects that have been funded include using new technology to manage the low voltage parts of the network in real time, thereby releasing additional capacity. Customer-side projects have also been funded, for example where customer-side energy efficiency measures have been targeted to locations that have allowed network upgrades to be avoided.[59]

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[58] See *Innovation in networks – Ofgem’s Electricity Network Innovation Competition: Decision on first year of competition* (Ofgem, November 2013).

[59] See, for example, *Creating Britain’s Low Carbon Future Today – Innovation and Competition Brochure* (Ofgem 2013).

Reliability incentives

The UK distribution IBR plans include a set of targeted incentives on service quality and reliability. Incentives are applied to measures of interruption frequency and duration, as well as on call center call handling performance (based on interview scores).[60]

Also included are targeted incentives on other outputs. For example, there is an incentive mechanism to encourage (and provide funding for) replacement of overhead wires with underground cables in areas of conservation interest. There is also a "shared savings" mechanism to encourage the utilities to reduce the costs of losses on the system.[61]

Key points

High-level takeaways from the UK approach are as follows:

- The approach in the UK has been in place for 25 years and has been refined over time. For electric distribution utilities, the revenue requirement is set on a forecast basis for the whole of the IBR period (8 years). Significant effort goes into reviewing the utilities' business plans and cost forecasts over the two years prior to the start of the IBR period.
- A variety of tools have been used to address capital expenditures, plant additions and plant additions uncertainty. Some large transmission projects have been treated outside the regular IBR framework because timing and cost were too uncertain. For the distribution utilities, a "menu" approach has been used to give utilities the choice between a higher revenue requirement with less scope for incentive rewards or a lower revenue requirement with greater incentive rewards.
- The regulator has designed a number of mechanisms to enable the utilities to respond effectively to a low-carbon policy agenda. Targeted schemes make funding available for network innovation: large-scale demonstration projects aimed at proof-of-concept implementation of new technology, for example in advanced control systems to facilitate renewables integration within the distribution grid. Transmission network upgrades driven primarily by the need to interconnect significant quantities of renewable generation far from load centers are funded outside the main IBR proceeding on an as-needed basis.
- In addition to cost-control incentives from the form of the IBR plan, the distribution utilities also have targeted incentive schemes for improving reliability and customer service.

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60 The details of the service quality mechanism are described in *Electricity Distribution Price Control Review Final Proposals – Incentives and Obligations* (Ofgem, December 2009).

61 *Ibid.*

IV. Current Ratemaking Approach for the Hawaiian Electric Companies

A. Introduction

We have been asked to recommend how the current ratemaking approach could be modified to improve the incentives provided to the Companies and thus lead to the improved progress toward the goals that the Commission has set out. Recognizing that the Commission posed several questions in Docket No. 2013-0141 about the operation of the current arrangements, we have first considered what incentives are provided under the current operation of the revenue balancing account ("RBA") and the revenue adjustment mechanism ("RAM").

Other non-financial regulatory mechanisms that provide incentives to avoid excessive costs are formal and informal reporting requirements, including the requirement that the Companies obtain prior approvals for major capital expenditures, fuel contracts and power purchase agreements. Most important is the detailed review of operations in rate case proceedings.

We have focused on the incentive properties of the existing arrangements, and in particular the incentives to

- increase efficiency and reduce costs, and
- make investments necessary to deliver policy goals of the Commission and the Legislature.

B. Key policy objectives of the Commission and Legislature

The binding Hawai'i Renewable Portfolio Standards (RPS) and Energy-Efficiency Portfolio Standards (EEPS)[62] brought about a dramatic change in the business climate and strategy. The specific requirements for the Companies going forward have been considerably amplified by the release of the *Exhibit A: Commission's Inclinations on the Future of Hawaii's Electric Utilities*. The Companies' business model changed in two specific ways: there was a deliberate emphasis on renewable energy integration and energy efficiency, which along with the high price of electricity generated with fossil fuels, has resulted in the reduction and effective end to MWh sales growth.[63] Simultaneously, there was a requirement to create and invest in a modernized grid that can reliably handle a very large growth of renewable, intermittent generation sources,

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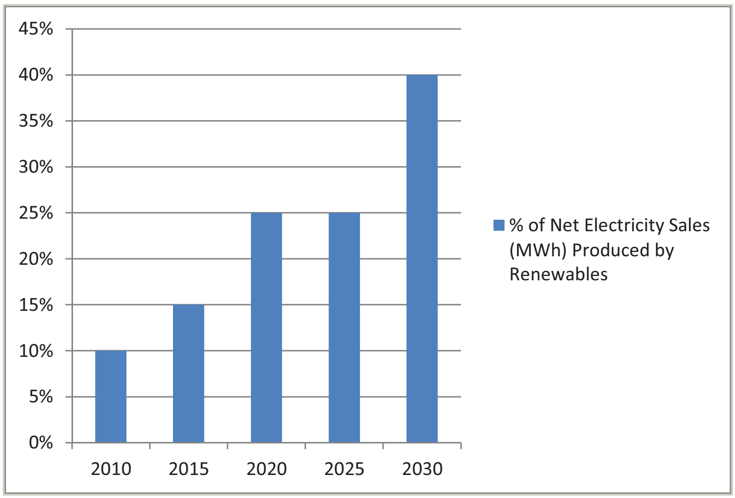
[62] Hawai'i Revised Statutes, Chapter 269, Part V Renewable Portfolio Standards, Sections 269-91 to 269-96.

[63] The EEPS energy usage reduction goal is 4,300 GWh in 2030, which represents 45% of the 2011 retail GWh sales.

both utility-scale and distributed.[64] High levels of penetration of distributed generation, principally rooftop solar, present a set of new operational and system investment issues to integrate this important resource that are facing utilities across the world.

The current RPS went into effect July 1, 2009. The minimum levels of net energy to be produced from renewable sources are shown in Figure 1.

Figure 1 Goals of the Hawaiʻi Renewable Portfolio Standards



The scope of this undertaking is indicated by the annual report that the Companies file with the Commission.[65]

Simultaneously with the need to plan and to invest to create the utility of the future, the Companies sales are lower as a result of the EEPS policy mandates and the rapid development of distributed generation, particularly photo voltaic systems subsidized with the Net Energy Metering retail rate policy. Total retail electric sales have declined every year since 2004 and are now at a level comparable to that of 1998-99, as shown in Figure 2.

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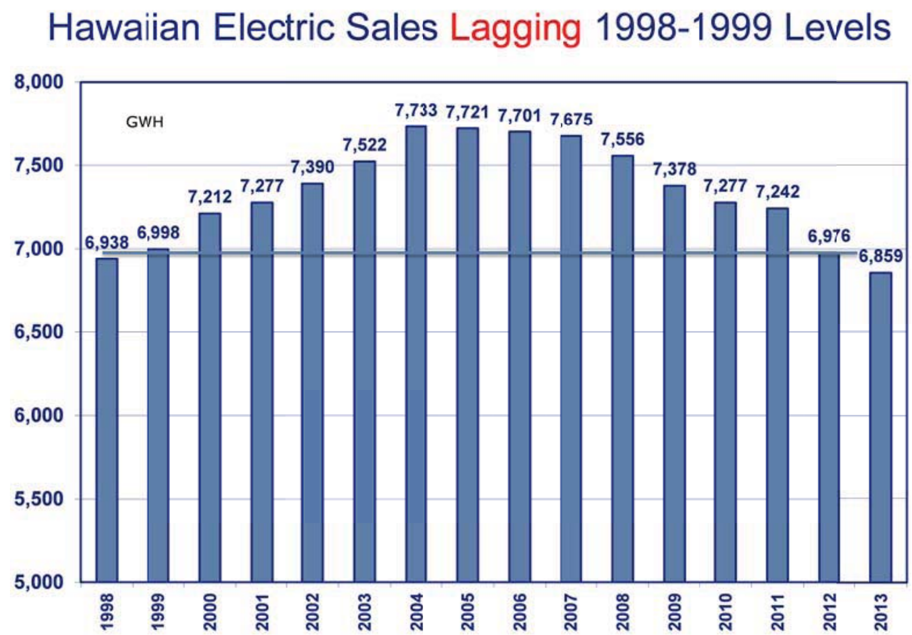
64 The RPS renewable energy goal is to provide at least 40% of retail usage by 2030.

65 Hawaiian Electric Companies, *2013 Renewable Portfolio Standard Status Report, For the Year Ended December 31*, 2013, Docket No. 2007-0008, March 31, 2014. For 2013, the electrical energy generated by renewable sources, electrical energy savings using renewable displacement technologies, and electrical energy savings using energy efficiency technologies totaled 34.4% of total sales. The report also noted that using the post-2015 separation of the energy efficiency saving goal, the current renewable generation technology percentage is 18.2%, which is above the 2020 goal.

Figure 2: Hawaiian Electric Company (Oahu) Retail Sales Trends[66]



Even with low growth in new customers and the reduction in usage per customer, there remains the requirement to invest in a depreciating electrical system. We understand that the pursuit of the State's clean energy goals and service reliability and the resulting twin pressures of falling sales and increasing investment resulted in two significant changes to the ratemaking approach for the Companies: the RBA mechanism to decouple revenues from sales, and the RAM mechanism to adjust revenues for increased costs associated with needed investments for the time period between rate cases.

C. THE REVENUE BALANCING ACCOUNT

The effect of the RBA is to allow the Companies to recover the authorized revenue requirement (excluding the portion that represents fuel and purchased power costs), including adjustments that flow from the RAM (as discussed below), regardless of whether actual sales differ from the sales forecasts used to determine rates. Under the traditional approach to utility ratemaking, base rates[67] are determined in a GRC and generally do not change until the next GRC. Thus, if actual sales kWh change over time and are thus different from the estimates on which rates were set,

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66 Hawaiian Electric Companies information.

67 Base rates generally cover operations and maintenance expenses, depreciation, fuel and purchased energy costs at assumed rate case prices, return on investment and other fixed costs, but exclude changes to fuel and purchased energy prices, non-energy purchased power costs, and smaller program costs collected through riders and balancing accounts.

the utility will recover more or less revenue than that authorized in the rate case. Before 2005 in the U.S., sales growth (connecting new customers and increasing sales per customer) generally provided additional revenue which would support necessary infrastructure investments and sometimes allow the utility to continue operating without a rate case for several years, even though costs were increasing. However, for many utilities, and for the Companies in particular, in recent years sales have been declining. As a result, it would have been very difficult for the Companies to make needed investments without requesting frequent rate increases. In recognition of this situation and because of the administrative cost of frequent rate cases, the Commission authorized a RBA to shield the Companies from the reduction in revenue that would otherwise result from declining sales.

The RBA is an example of an innovative ratemaking mechanism typically described as "sales decoupling" (or more technically sales decoupling with a true-up).[68] Such mechanisms are increasingly common in North American jurisdictions. To show this, we provide a count of both the narrower sales decoupling with true-up (such as the RBA) and a broader set of decoupling policies that include first, straight fixed-variable ("SFV") rates, a rate design with higher fixed cost-lower variable costs and, second, lost revenue adjustments mechanisms (LRAMs), which are specifically for energy efficiency reductions. For sales decoupling with true-up, only California had electric utilities operating under this decoupling approach in 2005, although it had been used and then abandoned in the 1990s for electric utilities in the states of Florida, Maine, Montana, and Washington. By 2013, 13 states, including Hawai'i, employed sales decoupling for electric utilities. The natural gas local delivery companies ("gas LDCs") have also adjusted to falling sales from long run conservation. In 2013, there were 22 states that allowed gas LDCs to use sales decoupling with true-up. Table 1 below shows the states using the various forms of these ratemaking policies that break the link between revenues and unit sales. The grand totals at the bottom come from different sources but are generally comparable to the Report of Steve Fetter.[69]

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[68] Edison Electric Institute (EEI), *Alternative Regulation for Evolving Utility Challenges: An Updated Survey*, Pacific Economics Group Research LLC, Jan. 2013.

[69] Steve Fetter in his report to the Companies cites the Regulatory Research Associates (RRA) survey. Brattle uses EEI, as indicated in footnote above, and adds some changes that have occurred recently. The two sources have slightly different definitions and total numbers, but they agree that the majority of U.S. states use one of the forms of decoupling for both the electric and natural gas delivery utilities.

Table 1: States that Use Specific Decoupling Policies

	Regulated Electric Companies		Regulated Gas Delivery Companies	
Policies	**No. of States**	**States with Policy**	**No. of States**	**States with Policy**
Decoupling with True Up	13	CA, CT, DC, HI, ID, MA, MD, NY, OH, OR, RI, WA, WI	22	AR, AZ, CA, GA, IL, IN, MA, MD, MI, MN, NC, NJ, NV, NY, OR, RI, TN, UT, VA, WA, WI, WY
With RAM	9	CA, DC, HI, ID, MD, NY, OH, OR, WA	18	AZ, CA, IN, MA, MD, MI, MN, NC, NJ, NV, NY, OR, RI, TN, UT, VA, WA, WY
Without RAM	5	CT, MA, NY, RI, WI	5	AR, GA, IL, MI, WI
Fixed Variable Rates	4	CT, IL, MS, NV	9	CT, FL, GA, IL, KY, MO, ND, OH, OK
LRAM just for EE and DSM impacts	17	AR, AZ, IN, KS, KY, LA, MA, MT, NY, NC, NH, NV, OH, OK, OR, SC, WY	9	AR, AZ, CT, KY, MA, MT, NY, OR, WY
Total (no double counting)	28	AR, AZ, CA, CT, DC, HI, ID, IL, IN,KS, KY, LA, MA, MD, MS, MT, NC, NH, NV, NY, OH, OK, OR, RI, SC, WA, WI, WY	30	AR, AZ, CA, CT, FL, GA, IL, IN, KY, MA, MD, MI, MN, MO, MT, NC, ND, NJ, NV, NY, OH, OK, OR, RI, TN, UT, VA, WA, WI, WY

Note: Policies of states are not mutually exclusive. States can have more than one policy. There are 51 jurisdictions, including DC.
Source: EEI, *Alternative Regulation for Evolving Utility Challenges: An Updated Survey* , January 2013, and Brattle updates.

Table 2 below shows 28 electric utilities located in the 13 states listed in row 1, col [2] that now have the decoupling with true-up ratemaking policy. This also lists in column [3] whether according to the EEI alternative rate survey they also have a RAM-like mechanism. In column [4] the table shows the most recent allowed return on equity. In section V below, we discuss the impact of sales decoupling on the cost of capital.

Table 2: Ratemaking Approach and Authorized ROE Among State Regulated Electric Subsidiaries

	State	State-Regulated Electric Subsidiary	Decoupling (YES/NO)	Attrition Adjustment (Like RAM)	Current Authorized ROE (%)
		[1]	[2]	[3]	[4]
1	California	Pacific Gas and Electric Company	YES	YES	10.40
		San Diego Gas & Electric Co.	YES	YES	10.30
		Southern California Edison Company	YES	YES	10.45
2	Connecticut	United Illuminating Company	YES		9.15
3	District of Columbia	Potomac Electric Power Company	YES	Per Cust	9.40
4	Hawaii	Hawaii Electric Light Company, Inc.	YES	YES	10.00
		Hawaiian Electric Company, Inc.	YES	YES	10.00
		Maui Electric Company, Limited	YES	YES	9.00
5	Idaho	Idaho Power Co.	YES	Per Cust	10.50
6	Maryland	Baltimore Gas and Electric Company	YES	Per Cust	9.75
		Delmarva Power & Light Company	YES	Per Cust	9.81
		Potomac Electric Power Company	YES	Per Cust	9.36
7	Massachusetts	Fitchburg Gas and Electric Light Company	YES		9.20
		Massachusetts Electric Company	YES		10.35
		Western Massachusetts Electric Company	YES		9.60
8	New York	Central Hudson Gas & Electric Corporation	YES	YES	10.00
		Consolidated Edison Company of New York, Inc.	YES	YES	9.20
		New York State Electric & Gas Corporation	YES	YES	10.00
		Niagara Mohawk Power Corporation	YES		9.30
		Orange and Rockland Utilities, Inc.	YES	YES	9.40
		Rochester Gas and Electric Corporation	YES	YES	10.00
9	Ohio	Duke Energy Ohio, Inc.	YES	Per Cust	9.84
		Ohio Power Company	YES	Per Cust	10.30
10	Oregon	PacifiCorp	YES		9.80
		Portland General Electric Company	YES	Per Cust	9.75
11	Rhode Island	Narragansett Electric Company	YES		9.50
12	Washington	Puget Sound Energy, Inc.	YES	YES	9.80
13	Wisconsin	Wisconsin Public Service Corporation	YES		10.20

Notes and Sources:
"Per Cust" in [3]: Revenue Requirement is changed periodically in proportion to change in number of customers.
[1]: The Brattle Group, Paper on Decoupling and COC of Electric Utilities.
[2]-[3]: EEI, *Alternative Regulation for Evolving Utility Challenges: An Updated Survey* , January 2013.
[4]: SNL, Rate Case Profiles.

In Hawaiʻi the RBA is an essential component of the framework that permits the Companies to maintain the financial strength to make necessary investments between rate cases, while at the same time to pursue conservation and distributed energy goals which would otherwise have severe adverse consequences for the Companies, and would be incompatible with a three-year rate cycle. A mechanism like the RBA is an essential component of a framework that affords the Companies a reasonable opportunity to earn a fair rate of return. Without the RBA, the Companies would either have to file more frequent rate cases or have to reduce investment if revenues were inadequate to recover costs. The RBA also has the effect of allowing the Companies to collect any increased revenue requirements of net plant additions from the RAM. The incentive issues with the RAM will be discussed next.

The EEPS goal for 2030 implies that there will be a long-term downward trend in sales. In this situation, it is essential that a sales-decoupling mechanism like the RBA or a similar mechanism be maintained.

D. The Revenue Adjustment Mechanism

While the purpose of the RBA is to decouple revenues from sales, the purpose of the RAM is to allow revenues to change in the post-test years to reflect the cost of necessary investments and expenses between rate cases.

The existing RAM has three major components: O&M, rate base and depreciation/amortization. The RAM allows revenues associated with plant in service[70] to change as the Companies make needed investments. Without the RAM, the Companies' ability to invest between rate cases could be significantly reduced, because capital recovery of new investments could not begin until the next GRC. Absent the RAM, substantial capital investment would make it difficult or impossible for the Company to earn its authorized rate of return between GRCs. The Companies have needed to make significant investments in their systems in recent years for various reasons including policy priorities to connect significant renewable generation, and the need to replace ageing infrastructure. A mechanism like the RAM is beneficial in a situation in which rapid investment is required because it permits timely recovery of costs associated with necessary investments. Without the RAM, there is a risk that investments would have been delayed, and/or it would not have been possible to move to a three-year rate cycle.

In addition to the benefits described above, an issue raised in Docket No. 2013-0141 is the question of whether the introduction of the RAM could have had the unintended consequence of shifting financial or operational risk from the utility to customers, or shifting costs that may have been imprudent or otherwise inappropriate.[71] We explain below (section V) that neither the RBA nor the RAM shift financial risk from the Companies to customers. We also see no likelihood that operational risk would be shifted. These mechanisms also do not allow the Companies to shift inappropriately-incurred costs to customers because, as we explain further below, costs remain subject to Commission review. The Commission suggests that a possible indication of a problem may be the recent overall increase in the revenue requirement, especially resulting from the rapid increase in baseline plant additions. Figure 3 shows the time profile of ratebase growth for the three Companies.

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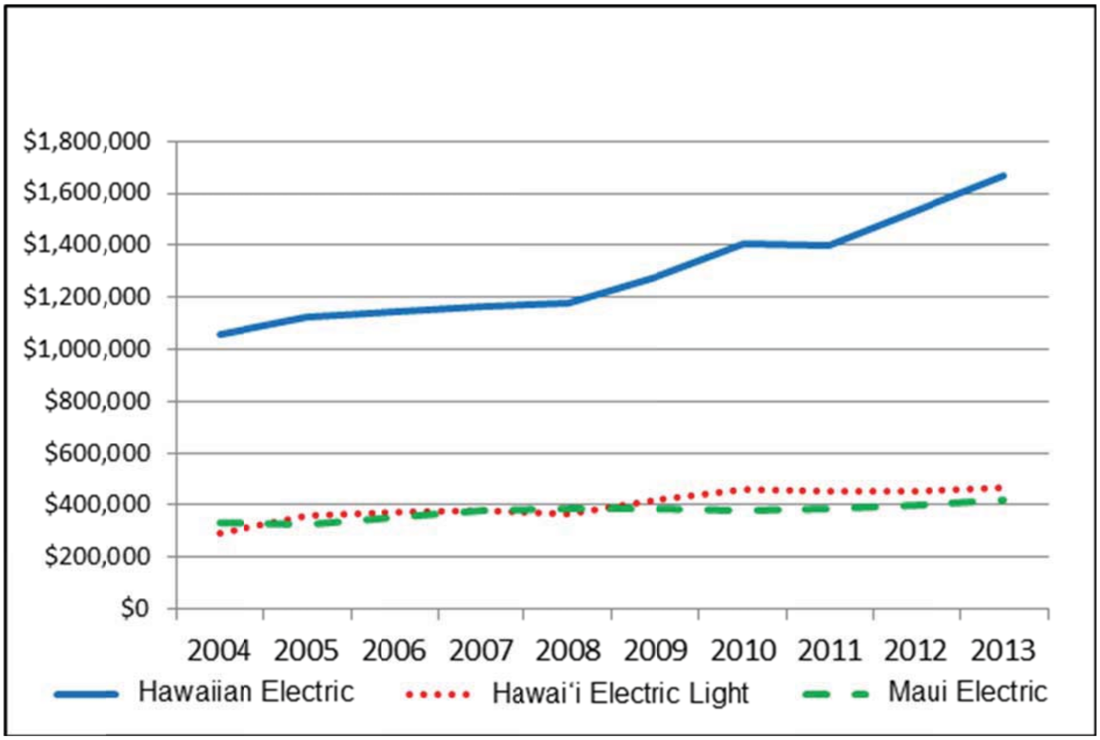
70 These revenues consist principally of return on invested capital, including an allowance for income taxes, and depreciation. Broadly speaking, if rate base increases over time (for example, because plant additions are greater than retirements and depreciation) then these revenue requirements will increase over time.

71 Schedule B, issues 3a and 4a.

Figure 3: Time Profile of the Ratebase of the Companies 2004-2013 ($000s)[72]



The Commission raised this broad issue in Decision and Order No. 31908, Section C, Issue 2, Finding and Conclusions, p. 42:

> Issue No. 2 - Findings and Conclusions
>
> Based on its review of the entire record and the recommendations of the parties, the commission finds and concludes as follows with respect to Issue No. 2: As discussed in Order No. 31289, the commission has serious concerns regarding the recent trend of HECO's increasing expenditures for utility plant.

The Companies have a set of regulatory approval and reporting requirements, mentioned above in section IV.A, which provide an incentive to avoid excessive costs.

An important principle of cost-of-service ratemaking is that all prudent costs of providing reliable electric service including developing new renewable resources, modernizing grid systems, and maintaining safe and reliable service are appropriately allocated and ultimately born by the customers. During a GRC, the Commission has the opportunity to review plant additions since the last GRC. If any of the plant additions are determined to be imprudent, recovery of those costs can be denied, including refunding any associated amounts of recovery already

72 Hawaiian Electric Companies information.

collected. The RAM mechanism does not automatically result in ultimate shifting or recovery of imprudent costs from customers. Costs found to be imprudent could only be temporarily shifted to customers and would ultimately be borne by the Companies.

The RAM-allowed revenue requirement increases are also partially penalized in two ways.

1. For Maui Electric and Hawai'i Electric Light, there is a lag of five months from the beginning of the RAM period before they are able to record revenues for the RAM. (Pursuant to the Stipulated Settlement approved by Order No. 31126, Hawaiian Electric is able to record RAM revenues for the January through December calendar year through 2016 but will revert back to the five month lag thereafter.)
2. Under the Schedule A Decision of February 2014, 90% rather than 100% of the incremental Rate Base RAM—Return on Investment adjustment is allowed to be recovered through rates.

We recommend that these provisions be modified because they do not meet the general standards of symmetry and providing a reasonable opportunity to earn a fair rate of return on investment. These provisions seem undesirable for two reasons: first, they are inconsistent with the objective of the RAM, which is to facilitate needed investments in the years between rate cases; second, they constitute a guaranteed under-recovery on investment, irrespective of whether that investment was appropriate or not.

The RAM allows investments to be made earlier than without the RAM because cost recovery is not delayed to the following GRC. The Companies must invest in their systems to ensure highly reliable service and to meet the goals of the RPS and EEPS. Since Hawai'i has set goals for 2030 that are more ambitious than any other state in the U.S., this is a difficult task that requires the Companies to innovate and to develop their systems accordingly. The RAM permits the Companies to contribute to achieving these policy goals. Since these policy goals remain in place and, if anything, are becoming more ambitious,[73] a mechanism such as the RAM continues to be necessary.

Without the RAM, some investments would likely be delayed. Under the RAM, customers pay for needed investments earlier than they would do in the absence of the RAM, but they also receive the benefits earlier as well (because the investments, which provide benefits by contributing to the various policy goals described above, are made sooner). In our view, this does not constitute a transfer of risk. Rather it is one of the timing of needed investments. There are substantial and unavoidable costs to meet the goal of providing reliable service and moving toward the goals of RPS and EEPS.

[73] For example, the importation of LNG into Hawai'i in the new container ship technology, with necessary onshore modifications to infrastructure.

Fulfilling the guidance recently provided by the Commission[74] means that the need for a mechanism like the RAM will be even greater than before. Creating the "utility of the future" will require investment in new distribution and transmission infrastructure to integrate fully the portfolio of renewal resources. Replacing fossil fueled "must-run" generation will also require investment. Achieving some of the goals envisioned more than likely will require steps that are both innovative and untried, but some steps may not succeed as fully as expected. In such an environment, uncertainty regarding cost recovery will increase unless there is a mechanism such as the RAM in place. Even with the RAM, uncertainty is likely to increase because some of the actions taken may not be judged in hindsight to have been wise.

There is a risk that the Companies might not manage new investments as cost effectively as they could have. This is a risk that is present in all capital investments by all companies and is not a result of the RAM.

There is an issue of whether additional, financial incentives can and should be crafted to provide incentives to build the utility of the future as efficiently as possible. We agree that modifying the RAM to provide strengthened financial incentives for the Companies to control costs going forward would be possible and may be warranted. Alternatives 1 and 2 proposed by the Companies provide a strengthened incentive, as will be discussed below.

E. RECOMMENDATIONS FOR IMPROVING THE RAM AND RBA

We discussed above our understanding of the main features of the RBA and why it was implemented. Our recommendation is that the RBA, or a mechanism like it, continues to be necessary.

As we discussed above, our understanding of the rate-base RAM is that it was designed to allow earlier recovery of necessary investments in the period between rate cases, and therefore realize the benefits of reduced administrative costs from a three-year rate cycle without prejudicing the investment. Recent Commission statements[75] indicate that there continue to be policy drivers for increased investment. As a result, a mechanism like the rate base RAM will continue to be needed if a three-year rate cycle is to be maintained.

In our view, recent Commission documents contain policy goals which could conflict with one another, such that the detailed design of an optimal RAM mechanism may depend on the relative priorities attached to different policy goals. On the one hand, the Commission is concerned about increasing costs and has raised the possibility that IBR-type mechanisms could be used to strengthen incentives to control costs. On the other hand, the Commission wants the Companies to make significant changes to their systems, requiring investment. We explained above that the

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74 See *Exhibit A: Commission's Inclinations.*

75 See *Exhibit A: Commission's Inclinations,* esp. Section 1 Creating a 21st Century Generation System and Section 2 Creating Modern Transmission & Distribution Grids.

treatment of investment and capital additions under an IBR plan is a challenging issue, particularly if the utility is not at a "steady state" and if significant investment plans are being proposed. It seems to us that the Companies are in just such a position, and that it would be difficult to design a successful IBR plan that would *simultaneously* strengthen financial incentives to control costs and also facilitate needed investment to deliver the Commission's policy goals. Furthermore, in our experience a transition from traditional cost-of-service to IBR can take several years of detailed design work, and may still require that capital additions be treated outside the IBR plan.[76]

The document *Exhibit A: Commission's Inclinations* provides a vision of a future 21st Century generation and delivery system for Hawai'i. However, since no such system has yet been built, outcomes may vary from the vision. The language in the document recognizes this. The actual system must be accomplished through good planning, careful investments, learning by doing, and incorporating further development of many new technologies.

The policy priorities we describe above suggest that continued rapid investment may be needed, and that costs and optimal technology choice are uncertain. To design a comprehensive IBR plan where the revenue requirement is determined for several years in advance (as is done in California or the UK) would start from a forecast of capital additions over at least a three-year period, and would require the Commission to authorize recovery of three years' worth of revenue requirements. At the same time, it might be necessary to define one or more output measures related to the investment programs in order to provide an incentive for the programs to be delivered on time. This is likely to be a very challenging task because of the uncertainties and risks associated with a major transformation of the Companies' systems. We noted above that designing a comprehensive IBR plan is a significant effort. IBR is often applied to distribution-only utilities but is rarely applied to transmission utilities or vertically-integrated utilities.

We note that the Companies have started to develop two conceptual IBR approaches along these lines.[77] An IBR plan of this type would provide a financial incentive for the company to control costs associated with capital additions as well as O&M expenditures, because under such a plan the authorized revenues would be determined in advance. In fact, such a plan would in some respects be similar to the existing O&M RAM component, and, like the O&M RAM currently in place, would provide a financial incentive because cost savings accrue to the company in the years between rate cases. However, we note that these two conceptual approaches are at an early stage of development. Implementation would be likely to involve significant work and might require additional design work to incentivize delivery of the investment programs.

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[76] See the approach in Alberta, described above.

[77] See Hawaiian Electric Companies, *Initial Statement of Position with Respect to Schedule B Specific Issues*, Docket No. 2013-0141, Issue 5. Use of economic incentives/penalties to reward significant, accelerated efforts to reduce costs and improve customer service, subsection on IBR Plan Concepts, May 20, 2014.

The Companies have also developed two alternatives for modifying the existing RAM mechanism to reflect the Commission's concerns. We understand that these alternatives would include new mechanisms for providing information to the Commission on capital addition plans, as well as on variances between actual additions and prior year forecasts. In addition, the Companies are proposing that financial incentives could be included within either of the two alternatives being proposed.

Under alternative 1, annual capital additions forecasts would be submitted. Because the forecasts would be annual, the difficulty of forecasting three years out (as would be required for a full IBR plan) is avoided. The Companies are proposing that an incentive mechanism could be designed to provide a financial reward to the Company if actual additions are below forecast (and a corresponding penalty if the additions are greater than the forecast). This mechanism would provide a financial incentive to control costs that was not present in the current ratebase RAM mechanism. The financial incentive is smaller than would be provided in a comprehensive multi-year IBR, for example because the incentive is effectively "reset" each year. However, strengthening the incentive by extending the period would be problematic, as explained above. The incentive proposed is a reasonable trade-off: it provides some financial incentive but avoids the difficulty of forecasting additions for multiple years and the need for output measures to incentivize delivery.

Under alternative 2, capital additions forecasts would be capped at the test year level. The difficulty of forecasting additions for multiple years is avoided, to an extent, by assuming that additions can be held to the test year amount. Under a full three-year IBR plan there could be a risk that investment would be delayed. Alternative 2 avoids this risk because the Companies would be trued-up if actual additions are below the cap. Thus there is no financial incentive to delay investment (but also no financial incentive to control costs if additions are below the level of the cap). Alternative 2 also provides that the cost of additions above the cap would be borne by the Companies, until the next GRC. This feature provides a financial incentive for the Companies not to exceed the cap.

In our view, both alternatives represent an improvement over the current RAM mechanism. Importantly, they both have improved reporting arrangements. Both alternatives conform with the principles we have laid out, and, in particular, unlike the current RAM arrangements[78] both alternatives provide the Companies with a reasonable opportunity to earn a fair return on investments made between test years. We would recommend alternative 1 over alternative 2 because alternative 1 has a consistent financial incentive to control costs, whereas alternative 2 has a financial incentive only if additions are running above the level of the cap. It might be argued that alternative 2 could provide an element of "rate certainty" not provided by alternative 1, because the capped level of RAM revenue requirement is known in advance for three years.

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[78] The current arrangements do not provide a reasonable opportunity to earn a fair rate of return on investment because the current arrangements for calculating rate base RAM revenues incorporate a delay and recover only 90% of incremental revenues, irrespective of Company performance.

However, we would expect that to be of very limited benefit to customers because the level of RAM revenue requirement is a very small component of changes in rates. Alternative 2 also has the disadvantage, in our view, that significant weight is put on the level of capital additions in the test year. If the Companies are restricted to investing only at the level of the test year additions, that may constitute an inappropriate constraint on their ability to invest and to respond to changing priorities during the three year cycle.

V. Rate of Return Issues

A. Impact of Decoupling on the Cost of Capital

The Brattle Group has performed one of the only empirical studies on the electric industry of the effect of the adoption of decoupling mechanisms on the cost of capital.[79] The conclusion from the study was that there was no statistically significant decrease in the estimated cost of capital resulting from the adoption of decoupling.

Brattle study of decoupling and the cost of capital

Traditional cost-of-service ratemaking collects a utility's total costs, fixed and variable, largely through volumetric rates. Successful energy efficiency (EE) and distributed generation (DG) programs will reduce the volume of kWh sales, and thus will simultaneously reduce the recovery of fixed costs, making it more difficult to fully recover the authorized fixed-cost revenue requirement. In a 2013 survey of new, alternative ratemaking policies, the Brattle study found 13 states and 21 state-regulated electric utilities had decoupling. There were 22 states that allowed gas industry decoupling. Decoupling here means the use of a ratemaking mechanism like the RBA, which trues up the revenues actually collected to a target level. Many of the RBA mechanisms also have a RAM-like mechanism, but not all. Many of those that do not have a RAM have a capital additions recovery mechanism that has a similar effect. Most of these decoupling policies were implemented since 2005, including Hawai'i's implementation for the Companies in 2011.

The implementation of a decoupling policy is regularly contested by some interveners, who generally argue that the allowed return on equity (ROE) should be reduced because decoupling, by design, reduces the variability of revenues, which they believe translates directly into reduced business risk and hence reduced cost of capital. The paper cited above reports the results of an empirical study of the period 2005 to 2012 to determine whether there are statistically verifiable

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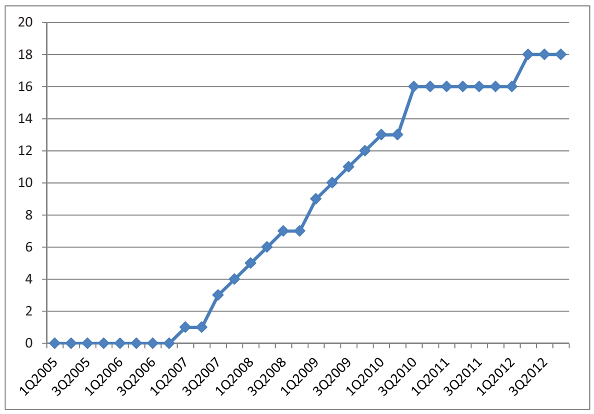
[79] Michael J. Vilbert, Joseph B. Wharton, Charles Gibbons, Melanie Rosenberg, and Yang Wei Neo, *The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation*, Prepared for The Energy Foundation, March 20, 2014.

effects of decoupling ratemaking on electric utilities' cost of capital. The sample consisted of 21 state-regulated electric subsidiaries operating in 11 states.[80] Figure 4 below shows the substantial growth in the number of electric companies that changed to decoupling during the study period.[81] This growth drove the decoupling index in the study.

Figure 4: Substantial Growth in the Number of State-Regulated Electric Subsidiaries With Decoupling Ratemaking over the Study Period



A decoupling index was created for each holding company based on the share of assets in the subsidiaries having decoupling. We test the effect of the Decoupling Index on the overall after-tax weighted-average cost of capital (ATWACC) by regression analysis on the time series of quarterly ATWACC values for the each holding company. We know that financial markets are forward looking since information becomes available to the market when a company files for decoupling, on the ongoing status of the hearings, and when decisions are expected. To test whether these expectations led the markets to adjust the cost of capital before the decision was released, we consider four alternative periods for when financial markets might react to the possibility that decoupling being implemented. First is the date (quarter of year) when the state Commission approves decoupling in a decision. Three other periods are one, two or three quarters before the quarter of the decision.

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80 Some states that have decoupling were omitted because of the research design. These include California where the utilities had decoupling during the entire study period, whereas we were looking for companies that changed to decoupling during the study period. Washington adopted decoupling after the study period ended. Rhode Island's utility is owned by a British company whose shares are traded differently on stock exchanges.

81 In our study, we focused on decoupling policies that true up for differences in actual sales compared to forecast sales. We did not explicitly consider the presence of revenue adjustment style mechanisms as an additional variable in our analyses. However, a review of our sources indicates that approximately ¾ of the companies with sales true-up decoupling also had some form of revenue adjustment mechanism to deal with cost increases between rate cases.

The results of our test for each of the four models with varying financial market anticipation are all in general agreement and fail to reject the claim that decoupling does not lower the cost of capital. Although the coefficient on the decoupling index is negative, the null hypothesis that the coefficient is zero or positive (i.e., not negative) cannot be rejected at the 5% level. Hence, there is no statistical support for the claim that decoupling leads to a decrease in the cost of capital.

B. DECOUPLING IN HAWAIʻI

The decoupling policy in Hawaiʻi, through the RBA/RAM, is similar to the decoupling policies we studied in our paper.[82] We are aware that the authorized ROE was reduced by 50 bps in conjunction with the adoption of the RBA and RAM in Hawaiʻi, but that decision was made in the absence of empirical analysis, because at the time there were no studies available. Intuitively, a reduction in the allowed ROE would seem to be justified because decoupling reduces the variability of revenues, but that is too narrow a view. It is important to also consider the context in which decoupling has been adopted. The purpose of decoupling is to remove the utility's throughput incentive that conflicts with the goal of energy conservation. As long as significant fixed costs are recovered in volumetric rates, falling sales that the Companies are experiencing from energy conservation and distributed generation would cause earnings attrition. This would drive the need for frequent rate cases. Based upon our empirical analyses, we recommend that the Commission reverse the decision to reduce the allowed ROE because of the adoption of decoupling.

The conclusion that decoupling does not result in a statistically significant decrease in the cost of capital raises several questions.

1. If decoupling reduces the variability of revenues, what is the explanation for the failure to detect a reduction in the estimated cost of capital?
2. If decoupling does not reduce the cost of capital, why do the credit ratings say that it does?
3. Does this mean that decoupling is not a valuable regulatory policy?
4. If Hawaiʻi were to eliminate the RBA mechanism, would the cost of capital for the Companies increase?

The discussion below addresses these questions.

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[82] All of the 21 companies in the Brattle study had RBA mechanisms. The majority had RAM mechanisms as well. Note that the 21 companies in the decoupling study are fewer than the 28 companies listed in Table 2 above. The number was reduced by requirements we imposed on companies for inclusion in the study, including change of decoupling status during study period and ownership by a NY Stock Exchange traded holding company.

First, for a reduction in the cost of capital to be justified, the adoption of a decoupling policy would have to reduce the type of risk that affects the cost of capital. That risk is called systematic risk or market risk. Systematic risk is the risk remaining in a fully diversified portfolio of investments. An individual company's total risk includes both systematic and diversifiable risk. Diversifiable risk is the risk that can be eliminated by investing in a portfolio of assets in different industries. Because diversifiable risk can be eliminated, diversifiable risk does not affect the cost of capital, because investors do not have to bear that risk. If adoption of decoupling mostly reduces diversifiable risk there would be no reduction in the company's cost of capital.

Second, decoupling has generally been adopted as a policy to remove the throughput incentive for regulated companies. The throughput incentive results from the recognition that a regulated company recovers a large portion of its fixed costs (including the ROE) through a variable charge based upon volume of consumption. The more electricity that a company sells, the higher the profit will be. The desire to sell more directly conflicts with conservation, energy efficiency and the encouragement of customer-sited distributed generation as policy goals. Decoupling removes the throughput incentive by severing the link between sales volume and recovery of fixed costs. If renewable energy and conservation policies are imposed upon a utility without simultaneously adopting a decoupling mechanism, it is highly likely that the systematic risk of the company would be increased. Systematic risk is the risk associated with developments in the economy. Absent decoupling but with energy conservation and DG policies, a utility's sales (and its profit) are likely to be lower than forecast when the economy is in decline and higher than forecast during economic boom times.

In addition to the reduction in diversifiable risk, a well-designed RBA type policy should merely remove the increased systematic risk that resulted from the adoption of policies that promote renewable energy and conservation. Recognition of the increase in systematic risk from the policy and the corresponding reduction of that risk from adoption of a RBA should result in no net change in risk for the utility for a well-designed RBA. Therefore, no cost of capital adjustment is warranted.

If the RBA were determined to more than offset the level of risk of the renewable energy and conservation policy, there should be a policy debate about whether this is a desirable outcome, because such a result could lead to inefficiency in the provision of electrical service. It would also be necessary to determine the type of risk being reduced. If the RBA affects only diversifiable risk, such as weather related volume risk, no cost of capital adjustment is warranted. Only in the case that the net effect of the RBA is determined to reduce the risk that affects the cost of capital, i.e., systematic risk, would it be necessary to determine the magnitude of the effect on the cost of capital.

Credit rating agencies regard decoupling favorably because decoupling reduces diversifiable risk. The type of risk important to investors in a company's debt is different from the type of risk important to equity investors, because payments to debt investors are made prior to any payments to equity investors. Debt investors are concerned with the total risk (i.e., the sum of systematic and diversifiable risk) of the company whereas equity investors are concerned with systematic risk, i.e., how their returns change with the economy. Debt holders are concerned that there is adequate revenue to make the required payments. If company revenue is exceptionally high, debt holders do not benefit, but they may not be paid if revenue is exceptionally low. Consequently, debt holders value consistent revenue streams more than highly variable streams. Debt holders prefer a lower, but relatively certain cash flow stream (if sufficient to make the debt payments) to one that is higher on average, but is highly variable so that in some periods, debt payments would be at risk. Decoupling policies provide the lower total risk that debt holders value.

Decoupling then provides at least two benefits. First, it removes the throughput incentive that a regulated company would otherwise have, contrary to the goals of renewable energy integration and conservation. Second, it is valuable to debt investors and is likely to result in a lower cost of debt which provides a benefit to both customers and the company. Although decoupling may reduce the cost of debt, there generally is a long delay before the credit rating agencies will adjust the credit rating. In addition, any change in the market cost of debt already outstanding would be reflected in the market price of debt. Debt ratings change infrequently and any reduction in debt costs only show up the next time a company issues debt. It would potentially show up immediately in the market cost of debt, but cost-of-capital studies typically don't try to capture changes in the market value of debt.

If the RBA/RAM were modified

If the Commission were to eliminate or substantially modify the RBA/RAM policies, would that increase the Companies' cost of capital? Elimination of the RBA would expose the Companies to falling sales resulting from energy efficiency and distributed generation policies. The Commission should reverse the 50 bps reduction in the allowed ROE previously imposed for the simple reason that the Commission's original decision to reduce the ROE was a direct result of the adoption of the RBA/RAM.

In addition, we expect that the cost of capital is likely to increase because the Companies would face the dilemma of having incompatible motivations to both increase sales to increase profit and to facilitate distributed generation (which decreases sales). However, consistent with our recommendation that the cost of capital not be reduced without empirical evidence when decoupling was adopted, if decoupling were eliminated we would not recommend an increase in the allowed ROE (additional to reversing the 50 bps) without empirical evidence. In any case, the result is unlikely to be optimal from the point of view of the customers, the Commission or the Companies. Moreover, it is likely to be disruptive to regulatory proceedings because forecast sales volume becomes much more important. Full cost recovery for the companies will depend upon an accurate forecast of expected sales. More importantly, to the extent that decoupling offsets the systematic risk associated with adoption of renewable energy, DG and conservation policies, reversing decoupling would remove the balance achieved that allowed the cost of capital to be unaffected. Removing that balance would likely increase the cost of capital.

If the RBA were left in place, but the RAM were to be substantially modified or eliminated, what would be the likely effect on the cost of capital? The answer, of course, depends upon how the RAM were modified and what, if any, policy were to replace it. The RAM primarily serves to recover changes in costs between rate cases. Unless the risk of cost recovery as opposed to the timing of recovery were to increase without the RAM, the cost of capital is unlikely to be substantially affected. However, in a situation in which the Companies were investing heavily to meet reliability and RPS and related utility of the future goals, the Companies would be forced to file more frequent rate cases if operating without the RAM. Alternatively, the allowed ROE would have to be set above the cost of capital so that the Companies could expect to earn their cost of capital without frequent rate cases or the Companies would be forced to delay needed capital investments. Although delaying investment would reduce the rate of increase in the revenue requirement, it would also delay the customer benefits that will result from meeting the RPS and EEPS goals or from maintaining reliability on the system.

The RBA/RAM policies provide benefits to both the Companies and their customers. The Companies are able to facilitate policy goals of energy efficiency and distributed generation, and to build the utility of the future without also facing conflicting incentives to sell more or to limit investment until the next GRC. In addition, the administrative burden and costs of frequent rate cases are reduced on all parties. In our view, the RBA and the RAM should continue.

Can the Risk/Benefits of the RBA be Calculated Separately from the RAM?

Determining the magnitude of the effect on the cost of capital from individual policy decisions is likely to be very difficult if not impossible to accomplish accurately for a variety of reasons. Estimating the cost of capital with the precision necessary to estimate the effect of the adoption of the RBA is likely to exceed the accuracy of the models, because cost of capital estimation models estimate the cost of capital for a sample company as a whole. Any estimate of the cost of capital from the sample must consider any differences in the regulatory environment, business and financial risk of that sample company compared to the companies with decoupling in order to interpret the results accurately.

Overestimating the effect on the cost of capital could handicap the Companies in acquiring the capital necessary to meet the demands for reliable electric service. Underestimating the effect on the cost of capital means that customers pay somewhat more for service, but that increased cost is likely to be far less expensive to customers in the long run than the costs from under investment in the electric infrastructure.

Attempting to adjust the allowed return for one regulatory provision is inadvisable because it inevitably leads to debates about whether other regulatory provisions have been accurately considered in the allowed cost of capital. Estimating the cost of capital is controversial enough without trying to estimate it policy by policy.

C. IMPACT OF STRENGTHENING IBR INCENTIVES ON THE RATE OF RETURN

If an IBR plan were adopted for the Companies, the question arises as to whether there would there be an effect on the Companies' cost of capital. We are not aware of any reliable empirical work on this issue, but we have some observations. First, an IBR plan increases the uncertainty in returns on utility investment, because relative to more traditional approaches there is a weaker link between revenues and costs. This is true, in part, because a well-designed IBR plan does this explicitly as a means of providing a financial incentive to the utility. Second, if an IBR plan is "biased", in the sense that unfavorable outcomes are more likely than favorable ones (such as would be the case with an incentive mechanism providing for penalties but no rewards), the authorized rate of return would have to be increased to compensate for the asymmetry in the plan even if the cost of capital did not increase. Unless the allowed ROE is greater than the cost of equity capital, the company will not be offered a fair opportunity to earn its cost of capital, because there is no upside to offset the downside of a penalty in some situations.

A well-designed IBR plan would be unbiased in that that potential for a penalty is matched by an opportunity of a comparable expected reward, but an unbiased plan *could* increase the cost of capital if the resulting additional uncertainty in returns was positively correlated with returns in the market. Whether any such positive correlation exists, depends upon the design of the IBR plan and its administration.

Because of the increased volatility of a utility's returns when operating under an IBR plan, the utility may need to adopt a more conservative capital structure, i.e., increasing the percentage of equity and decreasing the percentage of debt in the capital structure. A more conservative capital structure would allow the company to absorb variations in annual cash flow more easily, because debt payments must be made whereas payments to equity investors do not. Theoretically, changing the capital structure due to an increase in diversifiable risk is a wise policy but would not change the overall cost of capital because the cost of equity would decrease as the financial risk decreased. In other words, the cost of equity is a function of the amount of equity in the capital structure. The more equity in the capital structure, the lower is the financial risk that is borne by the equity investors. Ultimately, the effect on the overall cost of capital depends upon whether the increased variability in returns due to the IBR plan is related to the market. If so, the utility's cost of capital would increase. If not, then no there would be no increase.

D. RETURN ON RBA BALANCES

In Decision and Order 31908 the Commission stated the following:

> 3. Most parties supported the use of the same interest rate for both over- and under-collections of the RBA balances. While the commission does not agree that it is necessarily appropriate that these interest rates be the same for surpluses owed to ratepayers and for balances owed to the company, for purposes of this

> *Order,* the commission is authorizing use of the same interest rate for both surpluses and under recoveries. However, this issue is specifically subject to later review and adjustment by the commission in the Schedule B proceedings or a future docket. (p. 25)
>
> The Commission finds that an under-collected RBA balance is essentially a risk-free loan to the utility from the ratepayers, and, as noted by COH [County of Hawai'i] is guaranteed to be repaid by a commission approved adjustment of rates from one year to the next. In such circumstances, there is simply no merit to an argument that the risk of recovering this shortfall is equal to the overall risk facing the company's equity investors as reflected in the authorized rate of return. (p. 26)[83]

There are two questions to be addressed here:

1. What is the appropriate interest rate to be paid on the balance?
2. Should the interest rate be different if the balance is owed to customers by the utility as opposed to if customers owe the utility?

In Decision and Order 31908, the Commission ordered the Companies to use the short term debt rate as established in deriving the consolidated cost of capital in each company's last full rate case in computing interest on the outstanding RBA balance. This is not an attempt to re-litigate this issue, but if the Commission decides to consider differential interest rates for customers and the Companies, the following should also be considered. Although the interest rate is applied to the RBA on a monthly basis, at the end of the year, the RBA will generally have a non-zero balance if the adjustment factor is set appropriately.

The RBA balance is expected to be recovered over a 5-17 month period, and the Commission has the authority to change rates through the RBA adjustment factor in order to amortize the RBA balance. In financial theory, the rate of return appropriate for an investment is a function of its risk. Under the assumption that the Commission will alter the RBA adjustment factor as necessary to amortize the RBA balance within a 5 to 17 month period, the initial conclusion is that the investment in the RBA balance is of low risk. It is equivalent to a short-term loan with an average maturity of about 12 months.

However, there are some factors that would change that initial conclusion. For example, if there were always a RBA net balance outstanding, either owed to customers or to the company, it would no longer be equivalent to a short-term loan. The net balance would become part long term capital of the firm that should be included in the rate base. In that case, the balance should receive a long-term interest rate and be a portion of the capital structure. .

[83] There seems to be a slight error in the quotation. Specifically, an under-collected RBA balance would be a loan *from* the utility to the customers, not the other way around.

The next question is "Whether the risk of the RBA balance would differ depending upon whether customers or the utility were owed money?" There are likely to be small risk differences but it is probably simplest to treat the balances of equivalent risk. In either case, the Commission can change rates to amortize the balance, but the risk depends upon the use of the money not the source of the funds. The classic principle of "sources and uses" instructs that the source of funds for an investment is irrelevant to the expected return of the investment. It is the use of the funds that determines the risk. For example, U.S. government bonds are low risk and get a low rate of return. The expected return on government bonds does not depend upon the source of the funds used to buy the bonds.

In the case of a RBA balance owed by the Company to customers, the risk of that loan does not depend upon the customers' sources of funds. Nor is the Company's source of funds relevant.

If any difference in risk were considered, the risk of the balances owed to the Company is higher risk than the risk of balances owed to customers. Although the Commission can change rates to amortize the RBA balances, the Commission cannot make individual customers pay because they can default or move away. However, the Commission can always make the Company repay any RBA balance. Some of the balances not paid by customers may be collected in the allowance for uncollectible accounts, but probably not all. For example, credit card companies recognize that small loans to individuals are of high risk. Of course, the need for electric service provides a method of recovery not available to credit card companies, but the fact remains that loans to individuals are often risky. It is for this reason that the risk of balances owed by customers are of slightly higher risk.

E. Differentiated rates of return to incentivize grid modernization

We note that Senate Bill 120 requires the Commission to consider whether implementation of a number of incentives and cost-recovery mechanisms would be in the public interest, and that one of these is the use of differentiated authorized rates of return on equity to encourage grid modernization. Specifically, HRS 269-6(d)4 suggests:[84]

> The establishment of differentiated authorized rates of return on common equity to encourage increased utility investments in transmission and distribution infrastructure, discourage an electric utility investment in fossil fuel electric generation plants to incentivize grid modernization, and disincentivize fossil generation, respectively.

Before discussing the effect of a differentiated ROE policy, it is necessary to outline the potential characteristics of such a policy. To provide an incentive to invest in transmission and distribution infrastructure ("T&D"), the policy envisions a higher ROE for T&D than for fossil electric generation. However, implementation would still require setting the differentiated

[84] Senate Bill 120, Session Laws of Hawaiʻi 2013

ROEs in a manner that would allow the Companies to expect to earn their cost of capital on average. If the allowed ROE for fossil generation was lower than the cost of capital, then the allowed ROE for T&D would need to be higher than the cost of capital. A policy that violated that expectation would either be costly to customers or violate the standards established by the U.S. Supreme Court in the *Hope* and *Bluefield* decisions requiring an allowed return equal to that of alternatives investments of comparable risk. In principle, setting the differentiated ROEs to meet this standard is a matter of calculation but in practice would be difficult because the appropriate differentiated ROEs would depend upon the type of investments made.

There are two possible justifications for a policy setting differentiated ROEs by type of investment. First, there is an underlying assumption that the utility has the ability to meet customers' needs by substituting investment in T&D for investment in fossil electric generation. In other words, in deciding how to configure their systems to meet customer demands, the Companies would have the choice between at least two configurations, one with relatively more fossil generation and one with less. For this assumption to be true, inadequate T&D must be the cause of not being able to utilize the full production of renewable generation. Whether transmission is a bottleneck or not is a factual question. The second justification is that investment in T&D is difficult in Hawai'i for some reason. Therefore, the Commission may want to provide a premium ROE as an incentive for the Companies to overcome any obstacles to siting and/or constructing new T&D. Providing an incentive ROE to promote investment in transmission is a policy pursued by the FERC for exactly this reason.

For most sources of renewable generation, output is variable because output depends upon either wind velocity or solar radiation. Fossil fuel electric generation serves as an essential back up generation source when sufficient renewable generation is not available. Currently, there is no alternative available to the Companies. If the Companies do not have a meaningful tradeoff between investing in T&D and fossil generation, differentiated ROEs would not be good regulatory policy because it would potentially increase the cost of providing service to customers. With a premium ROE, investment in T&D would be preferred even if the investment were not strictly necessary, but the investment choices of the Companies with regard to fossil fuel generation would not be affected. In addition, the Commission already has the tools to monitor investment in new fossil fuel generation through the requirement to preapprove investments larger than $2 million. Such a limit would normally include any new fossil fuel electric generation investment.

However, if there is a tradeoff, differentiated ROEs may still not be a good regulatory policy if it would encourage the Companies to pursue investment that does not provide the "least cost" method of providing service. Of course, one reason supporting differentiated ROEs is the recognition that not all costs may be reflected in market prices. This is the problem of externalities, which are costs not reflected in the market prices faced by decision makers. One such externality is the cost of carbon dioxide on the environment from the use of fossil fuels. In a situation in which T&D is a constraint preventing the full utilization of non-fossil fuel sources of generation, the use of differentiated ROEs would be one way to address cost externalities. If addressing externalities were the goal of the differentiated ROEs, there still remains the issue of setting the differentiated ROE appropriately because it would require estimating the cost of the externalities. For example, if the estimated cost were too high, it would induce economically inefficient investment in T&D, needlessly increasing costs to customers. In the final analysis, the wisdom of such a differentiated ROE policy depends critically on there being a constraint that can be alleviated by additional investment in T&D.

VI. Recommendations for improving other aspects of ratemaking

We understand that one of the concerns of the Commission and interveners, and one of the motivations behind Docket No. 2013-0141, is that the Companies' rates are high relative to rates in other jurisdictions, and have been increasing. While the main subject of this paper is IBR and closely-related topics, we think that there could be merit in considering two ratemaking issues which are unrelated to IBR but which could be effective in mitigating rate increases in Hawai‘i: rate stabilization through "alternative cost recovery," and securitization. The first alters the time-pattern of capital recovery for new investments, and the second, securitization, could lower the unrecovered costs associated with the accelerated retirement of older fossil plants.[85]

A. Rate Stabilization

Under original cost ("OC") ratemaking, the capital charges (return and depreciation) for a new asset are highest when the asset is initially placed into service. This is one reason that rates in Hawai‘i are increasing rapidly. Depreciation reduces the investment on which a return is earned, so capital charges decline over time as the asset depreciates. The goal of alternative recovery methods is to address this problem by altering the pattern of recovery for new investments. Specifically, rates are lower initially than under OC rate making, which addresses, in part, the Commission's concern about the rate of increase in electric rates. The alternative patterns do not change the present value of the recovery, just the pattern.

Perhaps the easiest example of an alternative cost recovery model is to consider a fixed-rate 30-year mortgage. The mortgage payments for principle and interest are constant over the 30 year period, but the amount of the principle repaid with each payment increases over time. In the case of a mortgage, payments are constant in nominal terms, but there are an infinite number of other patterns. For example, payments could be level in real terms which means that they increase in nominal terms over time. One pattern is sometimes called Trended Original Cost (TOC), which is distinguished by the attempt to match the cost recovery pattern that would result if the utility were in a perfectly competitive environment. Figure 4 shows four alternative ways of recovering the same investment, which have the same present value to customers, even though the pattern of rate impacts over time is quite different.

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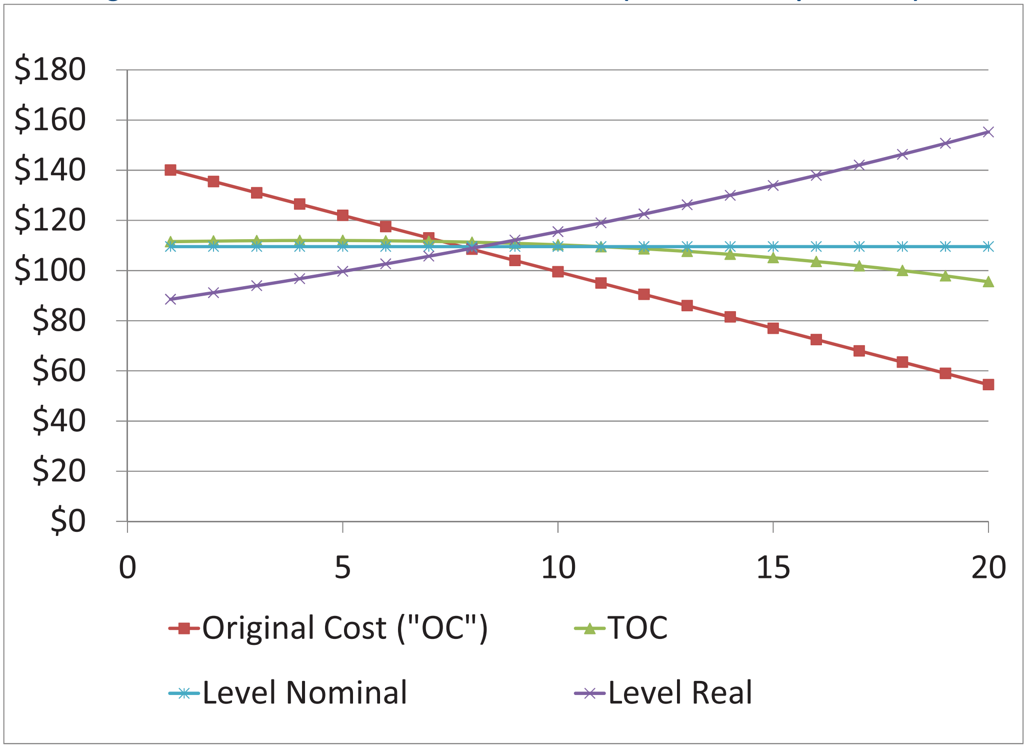
85 See *Exhibit A: Commissions' Inclination*, p. 25.

Figure 5: Four Patterns of After-Tax Cash Flow (Return and Depreciation)[86]



In the U.S., Kern River, a natural gas pipeline regulated by the FERC, uses a level nominal recovery pattern. The FERC regulates oil pipelines through use of TOC. In the U.K. and New Zealand, alternative cost recovery is standard.

Alternative cost recovery works this way:

1. GAAP depreciation and tax depreciation are unchanged.
2. The difference between the after-tax earnings under OC and the alternative cost recovery pattern is a regulatory asset that is added to the rate base for future recovery. Initial recovery under OC is higher than under the alternative recovery mechanism, but this is the reason to propose an alternative recovery mechanism. However, at some point in the future, OC recovery will be less than recovery under the alternative recovery mechanism so that the regulatory asset will decrease. At the end of the expected life of the asset, the full investment in the asset will be recovered including any delayed recovery.

Implementing alternative cost recovery could give rise to three issues aside from the desired mitigation of rate increases.

86 Note: in these examples, inflation is 3%.

Credit rating and cash flow

Actual cash flow with alternative cost recovery is lower than under OC recovery, which has an adverse effect on the company's credit ratios. Net Income is lower, but the debt ratio declines because the regulatory asset is effectively an equity investment. For a company whose credit ratios are near the bottom of the range for a particular rating, a credit downgrade could result.

If the amount of investment recovered under alternative cost recovery is a relatively small portion of the total rate base, the negative effect on the credit ratios is not likely to be material. If used in conjunction with securitization of assets removed from service, the credit impact can be lessened further.

Regulatory asset

Although GAAP and tax depreciation are unaffected, there is a "balancing" asset added to the rate base in the regulatory accounts. The regulatory asset is the difference between what would have been recovered under OC cost recovery and what is authorized for recovery under the alternative recovery method.

The existence of a regulatory asset creates risk not present for OC recovery. If a future regulator decides to deny recovery of the regulatory asset, the company would have to write it off. The severity of this risk depends upon the strength of the regulator's promises.

Uncompensated switch from OC to alternative recovery

For assets already in service, switching from OC to an alternative recovery method could result in a windfall for either customers or shareholders. For example, capital charges are higher initially for OC recovery so switching to an alternative recovery method requires an adjustment so that both customers and the company are treated fairly. It is for this reason that alternative cost recovery is best implemented for new investments as opposed to the full amount of the current rate base.

B. SECURITIZATION

In the Commission' *Exhibit A: Commission's Inclinations of the Future of Hawaii's Electric Utilities*, there is a section "New Regulatory Incentives to Achieve Hawaii's Clean Energy Future." It lists five potential regulatory solutions to incentivize utilities. On page 25, one solution is described as:

> "Fossil generation retirement incentives mechanism to encourage acceleration of utility generating unit retirements, including potential use of securitization to allow the utilities to exit the generation business financially;"

When retirement takes the form of shutdown, the Companies would have unrecovered costs related to such a plant that they could reasonably expect to fully recover. In the mid to late 1990s, the similar policy of stranded cost recovery was the most important issue that had to be solved in any state that wanted to move to the policy of "retail access and competition at wholesale". While the technique was developed in many states for this purpose, it has subsequently been expanded to meet several other applications. These included financing mandatory pollution-control equipment and catastrophic storm reconstruction expenditures. Securitization involves pooling loans to create consolidated securities that investors can purchase. Organizations have begun to securitize solar and energy efficiency loans to produce greater levels of investment. Recently, Solar City securitized $54.4 million in loans for solar photovoltaic installations.[87]

The idea behind securitization is a lower-cost mechanism to recover the remaining investment in the unrecovered costs of early-retired fossil plants that are or will be taken out of rate base because they are no longer used and useful.

Under the policy of restructuring, the utilities' generation assets had to be sold or transferred to an unregulated subsidiary. Market prices, determined by competitive auction or regulatory proceeding, were almost always lower than the undepreciated balance of the generating assets. The unrecovered balance on the plants that were sold was put in a regulatory asset to be recovered over a reasonable period of years. Many states, like Pennsylvania and New York, utilized a specific way to recover the investment at a lower cost to customers - the process of securitization.

Technically, securitization is a debt financing structure that relies on the use of government-sponsored debt as a substitute for the mix of traditional debt and equity typically used to finance utility capital expenditures. The fundamental purpose of securitization is to achieve a lower cost of capital through the use of very highly-rated debt for 100% of the financing requirements of a utility project. The high debt rating (and lower cost of debt) is achieved through the use of a set of "credit enhancements" that are initiated by governmental action. Three primary credit enhancement features that are employed as part of the transaction are 1) a financing act (from the government), 2) a financing order (from the regulatory agency) and 3) a true-up mechanism (administered by the regulatory agency and the utility).

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87 J. Paul Forrester, "Green investments require bulletproof financing," *Public Utilities Fortnightly*, 2008. Kat Friedrich, "Solar and Energy Efficiency Securitization Emerge," Clean Energy Finance Center, November 15, 2013. http://www.cleanenergyfinancecenter.org/2013/11/solar-and-energy-efficiency-securitization-emerge.

Securitization first requires Legislative action. The required legislation establishes the legal basis for several key elements of securitization for the duration of the securitization period. First, the act establishes the right of the utility regulator to impose a securitization charge, which is a separate itemized charge on a customer's bill. Second, the legislation also recognizes that the ability to impose such a charge creates a financial asset, in which the entity entitled to the revenues from the charge has a property right. This right serves as the primary collateral for the bonds. The charge is explicitly deemed to be irrevocable and non-bypassable in an attempt to ensure that any future efforts to rescind or circumvent this obligation will be unsuccessful (both by future legislatures, regulatory agencies or customers). Third, the utility needs to obtain a regulatory order authorizing the establishment of a Special Purpose Entity (SPE) that issues the securitization bonds, the proceeds of which are used to pay the specific utility stranded costs that are to be securitized.

Finally, securitization is likely to significantly lower the cost to the customers of paying for stranded costs. When done with the full support of the legislature and the regulatory commission, this can support 100% debt financing – potentially providing relatively lower rates in the short run to utility customers. The securitization framework removes uncertainty surrounding the recovery of the regulatory asset and transfers recovery of the regulatory (non-performing) assets, such as stranded costs, from the utility to an independent entity. Many of the securitizations in the United States in the past 15 years have been used to finance stranded costs related to electric restructuring.

For the Companies, securitization could be used to recover the remaining investment in fossil fuel generating plants or other assets removed from service.

1. The Companies would receive the remaining unrecovered investment immediately which provides the capital necessary for alternative investment.
2. The Companies' revenue requirement is reduced by the removal of the assets from its rate base.
3. Customers pay the principle and interest on the bonds through a dedicated surcharge, but the payments are much lower than if the assets were in the rate base.

For example, consider an investment with $100 million remaining and a 10 year expected life. Normally, the revenue requirement for that asset would be about $20 million with straight-line depreciation ($10 million/year assuming a 10 year remaining life) and a pretax return of about 10% or $10 million. If financed with A-rated bonds with a coupon of 4% (or perhaps lower), the customer charge would be $4 million compared to $10 million and potentially the amortization period for the securitized bonds could be 30 years instead of 10 year, further reducing the charge to customers. The total charge in the first year would be $20 million ($10 million return and $10 million in depreciation) if in the rate base compared to about $7.3 million ($4 million in interest and $3.3 million in amortization of principle) if securitized for a savings of about $13.7 million.

The Companies would serve as "collection" agent for the bonds by simply adding a surcharge to all customers' bills. The proceeds would be sent to the bankruptcy remote entity for payment to bond holders. The securitized debt would not be on the Companies' books so there is likely to be no negative effect on the Companies' credit metrics. I t may, in fact, be credit enhancing because an older asset has been sold.

Customers also save the fuel and O&M expenses on the assets, but the Companies will generally have to replace the generating capacity with some other resources, which will add some costs to the system. If the new assets are more efficient than the assets being replaced, the net costs to customers could be lower than not securitizing the assets.

Implementing securitization would likely require the assistance of an investment bank to insure that all legal and regulatory requirements were satisfied.

Appendix A: Biographies

Michael J. Vilbert
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Dr. Michael J. Vilbert is Office Director of The Brattle Group's San Francisco office and has 20 years of experience as an economic consultant. He is an expert in cost of capital, financial planning and valuation who has advised clients on these matters in the context of a wide variety of investment and regulatory decisions. In the area of regulatory economics, he has testified or submitted testimony on the cost of capital for regulated companies in the water, electric, natural gas and petroleum industries in the U.S. and Canada. His testimony has addressed the effect of regulatory policies such as decoupling or must-run generation on a regulated company's cost of capital and the appropriate way to estimate the cost of capital for companies organized as Master Limited Partnerships. He analyzed issues associated with situations imposing asymmetric risk on utilities, the prudence of purchased power contracts, the economics of energy conservation programs, the appropriate incentives for investment in electric transmission assets and the effect of long-term purchased power agreements on the financial risk of a company. He has served as a neutral arbitrator in a contract dispute and analyzed the effectiveness of a company's electric power supply auction. He has also estimated economic damages and analyzed the business purpose and economic substance of tax related transactions, valued assets in arbitration for purchase at the end of the contract, estimated the stranded costs of resulting from the deregulation of electric generation and from the municipalization of an electric utility's distribution assets and addressed the appropriate regulatory accounting for depreciation and goodwill.

He received his Ph.D. in Financial Economics from the Wharton School of the University of Pennsylvania, an MBA from the University of Utah, an M.S. from the Fletcher School of Law and Diplomacy, Tufts University, and a B.S. degree from the United States Air Force Academy. He joined The Brattle Group in 1994 after a career as an Air Force officer, where he served as a fighter pilot, intelligence officer, and professor of finance at the Air Force Academy.

JOSEPH B. WHARTON
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Dr. Joseph B. Wharton is a Principal in The Brattle Group's San Francisco office and has 30 years of experience as an economic consultant and utility executive focusing on innovative regulatory approaches and incentive ratemaking. He has done assignments in electric, natural gas delivery and water industries and is an expert in renewable energy, energy efficiency, demand response, and alternative ratemaking. Dr. Wharton recently led a team that prepared filings in the California Public Utilities Commission's rulemaking regarding the Self Generation Incentive Program and Other Distributed Generation Issues (R. 12-11-005). This is the first step under new state law to find a long term policy for distributed generation and the current Net Energy Metering (NEM) policy to go into effect in July 2017. Dr. Wharton and co-authors conducted an empirical analysis of decoupling ratemaking for electric utilities, which is a growing form of regulated ratemaking that facilities a variety of current policy developments like energy efficiency, lower load growth and distributed generation penetration.

Dr. Wharton has provided expert testimony in California, Delaware, Kansas, Massachusetts, New Hampshire, New Mexico, Nevada, Rhode Island, Texas, and before the FERC. Dr. Wharton began his career at the Southern California Edison Company where he was liaison to the California Energy Commission, when California began to aggressively pursue its state energy policy. He helped develop state of the art forecasting and business models at the Electric Power Research Institute (EPRI) and then at Dun and Bradstreet in Cambridge, MA. He worked at the New England Electric System (now National Grid USA) as the Assistant to the President and CEO. There he also held management positions in rates, forecasting and integrated resource planning. Dr. Wharton is a Past President of the New England Economic Partnership, a Boston-based, nonprofit organization for regional economic forecasting and policy discussion. He belongs to the National Association of Business Economists.
Dr. Wharton received his A.B. in economics from Occidental College and his M.A. and Ph.D. in economics from the University of California at Los Angeles.

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Dr. Toby Brown specializes in the regulation and economics of the gas and electricity sectors. He has consulted for pipelines, utilities, and regulators in the U.S., Canada, Europe, and Australia, and he has particular expertise in incentive-based regulation in the energy sector. In Alberta, he participated in the generic proceeding to develop incentive-based regulation for the Alberta distribution utilities, and helped one of the major utilities in the province to develop an incentive-based rates proposal. In Australia Dr. Brown has advised the regulator on various aspects of the incentive-based ratemaking approach applied to distribution utilities. He has also been involved in pipeline and utility rate cases in several jurisdictions in the U.S. and Canada.

Dr. Brown's project experience at The Brattle Group also includes analyzing business risk in pipeline rate cases, assessing the economic impacts of alternative regulatory frameworks and competitive structures in the energy sector, and advising on regulatory best practices based on experience in different jurisdictions worldwide.

Dr. Brown also provides litigation support in a wide range of areas, including damages estimations, competition assessments, gas contract arbitrations, and utility and pipeline rate cases.

Dr. Brown was previously part of Brattle's European practice before relocating to San Francisco to join the firm's energy practice. Prior to joining Brattle he worked at the UK energy regulator, Ofgem. He holds a D.Phil. in chemistry from the University of Oxford.

THE Brattle GROUP

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ABOUT US

The Brattle Group provides consulting and expert testimony in economics, finance, and regulation to corporations, law firms, and governments around the world. We combine in-depth industry experience and rigorous analyses to help clients answer complex economic and financial questions in litigation and regulation, develop strategies for changing markets, and make critical business decisions.

We are distinguished by:

- Thoughtful, timely, and transparent analyses of industries and issues
- Affiliations with leading international academics and highly credentialed industry specialists
- Clearly presented results that withstand critical review

HISTORY

The Brattle Group was founded in 1990 by five principals dedicated to integrity and excellence in economic and financial consulting.

Since opening our first office in Cambridge, we have expanded throughout the United States and Europe to more than 200 people. We opened in Washington, DC in 1996 with a focus on regulation, antitrust, and public policy. In 1997, we entered Europe with an office in London. In 2002, we opened our San Francisco office with Nobel laureate Dan McFadden to be closer to our litigation and utility clients on the west coast and in the Pacific Rim.

We expanded into Madrid and Rome starting in 2009, and we are now recognized as a top consultancy on energy, finance, and competition throughout the European Union.

Most recently, we opened a New York office, providing a home base in one of the most important financial and legal markets.

Throughout this growth, our goal has remained to serve clients with thoughtful and analytically rigorous work in an atmosphere that values excellence, teamwork, and dedication.

CLIENTS

Our clients rank among the world's best performing and most admired public and privately held companies, law firms, and industry organizations, and we have worked for more than 80 of the *AM LAW 100* and more than 100 of the *Fortune Global 500*. We also advise U.S. and international regulatory and government agencies.

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