National Regulatory Research Institute

Briefing Paper

Formula Rate Plans: Do They Promote the Public Interest?

Ken Costello, Principal

The National Regulatory Research Institute

August 2010

10-11

Acknowledgments

The author wishes to thank his colleague at NRRI, Mr. Scott Hempling; Dr. Christopher Garbacz of the Mississippi Public Service Commission; Ms. Donna Gray of the Arkansas Public Service Commission; Dr. Douglas Howe of IHS Cambridge Energy Research Associates; Dr. Mark Lowry of Pacific Economics Group Research; and Dr. Michael Schmidt of the Kansas Corporation Commission for their comments on an earlier draft of this paper. The author is responsible for any remaining errors in the document.

Online Access

The reader can find this paper on the Web at www.nrri.org/pubs/multi-utility/NRRI_formula_rate_plans_aug10-11.pdf.

Executive Summary

When dissatisfied with traditional rate-of-return regulation, public utilities propose new ratemaking concepts. Today's utilities complain about the need for frequent rate cases due to rises in the average cost of utility service. They also assert that the real-world applications of the test-year approach to ratemaking in today's environment can produce actual earnings below those authorized.

One category of utility responses is what some call formula rate plans ("FRPs"). As defined in this paper, an FRP is:

> *A ratemaking method in which the utility adjusts its base rates outside of a general rate case, usually annually, based on an actual or projected rate of return (ROR) on rate base or equity that falls outside some commission-defined band.*

Supporters argue that FRPs help stabilize a utility's rate of return without a full-blown rate case review—thus avoiding serious financial problems and preventing excess profits. Opponents argue that FRPs shift risk to customers and give utilities weak, or even distorted, incentives to control their costs.

This paper first summarizes, and compares, the major features of traditional ratemaking and FRPs in terms of their ability to ensure that rates satisfy the traditional objectives of "just and reasonable" ratemaking. What makes the job difficult for regulators is that some of these objectives conflict and regulators assign different weights to each one.

This paper should help regulators assess FRP proposals, especially in terms of how they affect different regulatory objectives and differ from traditional ratemaking. It advises regulators to have an open mind about FRPs. These rates do have some advantages over traditional ratemaking, but these advantages depend on details of design and execution. One important requisite for regulatory approval of an FRP, consistent with "just and reasonable" rates, is that the utility must demonstrate high performance in cost efficiency and non-cost areas of operation integral to consumer well-being. A badly structured FRP can produce poor incentives for a utility, causing customers to pay more for utility services than they would under traditional ratemaking and other mechanisms.

This paper makes the following specific recommendations:

1. ***Insufficiency of traditional ratemaking should be a pre-condition for adopting formula rates.*** If regulators find that traditional ratemaking does not provide compensatory rates to utilities, or does not carry out the remaining objectives, they should consider other approaches, such as multi-year price and revenue caps, FRPs, cost and revenue riders, and new rate designs. Regulators should review the merits and shortcomings of FRPs compared with other ratemaking mechanisms to determine which ones would best reflect "just and reasonable" rates and advance the public interest.

2. ***The regulator should condition any FRP on the utility meeting performance standards.*** The regulator and the utility have twin obligations: the rate regulator to set "just and reasonable" rates; the utility to perform with excellence. The utility's right to the former requires its compliance with the latter.

3. ***In calculating the utility's authorized ROR, regulators should account for the reduced business risk attributable to more timely and predictable cost recovery.*** An FRP reduces earnings volatility by shifting the risk of cost changes from shareholders to customers and reducing the risk of under-recovery. This shift in risk reduces the utility's cost of equity. Regulators should reflect this reduction in base rates.

4. ***The band of an FRP should be wide enough so that the utility can retain a higher ROR that could come from higher cost performance, or absorb a lower ROR that could come from lower cost performance.*** A wider band provides a utility with better incentives for cost performance. The incentives for a utility operating within the band are comparable to those incentives a utility faces between rate cases under traditional ratemaking.

5. ***The FRP should not guarantee earnings.*** Performance depends on risk of penalty for nonperformance. An earnings guarantee undermines this principle.

6. ***The targeted rate of return for rate adjustments should be beyond the boundary points of the band.*** To create good incentives and appropriate risk-sharing, when the actual ROR lies outside the band, any rate adjustment should result in the utility still earning below or above the "boundary point" ROR.

7. ***The process for rate adjustments should allow ample time and resources for the regulators and parties to assess whether the utility acted prudently during the evaluation period.*** FRPs call for the regulator to adjust rates when a utility's earned ROR falls outside a stated "band." No rate adjustment should occur without scrutinizing any cost increases that cause the need to adjust. Procedures should allow sufficient time for prudence investigations, to avoid the risk that rate increases become automatic. We cannot overstate the importance of this requirement.

8. ***Periodically, regulators should conduct a general rate case to examine the appropriateness of existing cost allocations, the authorized ROR, and rate designs.*** The regulator should also periodically evaluate an FRP plan to identify any problems or proposed changes that would make the plan operate more effectively. One criterion for a general rate review is whether annual rate adjustments have risen over time or involve large dollar amounts.

Table of Contents

Formula Rate Plans: Do They Promote the Public Interest?

I. Pressures on Traditional Ratemaking

When dissatisfied with traditional rate-of-return regulation, public utilities propose new ratemaking concepts. Today's utilities complain about the need for frequent rate cases due to rises in the average cost of utility service. They also assert that the real-world applications of the test-year approach to ratemaking in today's environment can produce actual earnings below those authorized.

Traditional ratemaking has dominated the landscape for decades. Regulators have a history of adapting to a changing environment. Take the example of rising average cost of utility service that started to emerge in the late 1960s. General inflation, oil price shocks, and stricter environmental standards led to increases in electricity generating costs in the late 1960s and early 1970s. These cost increases could not be reflected in rates fast enough to keep profits from falling. Concurrently, utilities' sales growth started to decline in response to rising electricity prices and a slowdown in economic activity. Overall, electric utilities' earnings were eroding because of regulatory lag.[1] Eventually many state commissions adopted fuel adjustments clauses (FACs),[2] future test years,[3] Construction Work in Progress (CWIP) in rate base,[4] and new rate designs (e.g., marginal-cost pricing)[5] to combat this problem.[6]

---

[1] "Regulatory lag" refers to the time gap between when a utility undergoes a change in cost or sales levels and when the utility can reflect these changes in new rates.

[2] Fuel adjustment clauses adjust rates outside of a general rate case in response to changes in the price of fuels used by generating facilities and other designated costs. State regulators base adoption of these mechanisms on three features of fuel costs: (1) fuel costs are substantial and recurring, (2) they are mostly beyond the control of utility management, and (3) they are unpredictable. The first fact means that mis-estimating fuel costs for a test period could have a large effect on a utility's rate of return.

[3] A future test year uses projections of costs and revenues usually over a twelve-month period during which new rates would apply, as the basis for determining the annual revenue requirement. If the projections are accurate, and if costs continue to rise, a future test year compared with an historical test year would increase the likelihood of a utility earning its authorized rate of return. It achieves this outcome by reducing regulatory lag.

[4] CWIP represents capital additions that a utility incurs but not yet used-and-useful in the provision of utility service. The allowance of CWIP in rate base, by reducing regulatory lag, improves a utility's cash flow and general financial condition.

[5] Marginal-cost rates correspond to the change in total cost from a utility providing an additional unit of service (i.e., marginal cost). It should give customers proper price signals. Marginal cost pricing takes a forward-looking perspective by accounting for prospective costs

Both electric and natural gas utilities have expanded their use of nontraditional ratemaking mechanisms, such as cost and revenue trackers, and multi-year price and revenue caps. Cost trackers, for example, are a general category of devices that allow current recovery of costs in specified categories;[7] revenue trackers compensate a utility for revenue losses between rate cases because of energy-efficiency programs and other factors (e.g., the price elasticity of demand).

One category of utility responses is what some call formula rate plans ("FRPs"). As defined in this paper, an FRP is:

> *A ratemaking method in which the utility adjusts its base rates outside of a general rate case, usually annually, based on an actual or projected rate of return (ROR) on rate base or equity that falls outside some commission-defined band.*[8]

Typically the midpoint of the band is the authorized rate of return in the last general rate case. Assume that the authorized return is 10 percent and the boundary points are 100 basis points above and below this level. Any actual return lying within the range of 9 to 11 percent would then require no rate adjustment. When the actual ROR lies outside the band, rate adjustments depend on a predefined targeted rate of return. If the actual return is 7 percent, the FRP might specify that the rate adjustment corresponds to raising the ROR: (1) to the midpoint of the band (10 percent), (2) to the lower boundary point of the band (9 percent), or (3) by some portion of the difference between the actual return and the boundary point (e.g., halfway, so that at an actual return of 7 percent, the rate adjustment would produce a return of 8 percent). The

---

rather than historical costs. The rate can discourage energy usage during times of scarce capacity (i.e., low reserve margins) and high peak demand.

[6] *See,* for example, Paul L. Joskow, "Inflation and Environmental Concern: Structural Changes in the Process of Public Utility Regulation," *Journal of Law and Economics*, Vol. 17 (1974): 291-327.

[7] *See* Ken Costello, *How Should Regulators View Cost Trackers?* NRRI 09-13, September 2009, at http://nrri.org/pubs/gas/NRRI_cost_trackers_sept09-13.pdf.

[8] In this paper, ROR refers to either the rate of return on rate base or on equity. Actual FRPs define ROR according to one of these two ways. When specifically referring to the rate of return on equity, the paper uses the acronym ROE. We express rate of return as a percentage. An ROR of 10 percent, for example, means that the return on rate base is 10 percent of the total dollar amount of the rate base.

[9] The FRPs in the first four states originated with commission action, while the South Carolina plan was a legislative mandate. For a description of four plans, with the first three for electric utilities and the last one for gas utilities, *see* http://www.alabamapower.com/pricing/pdf/rse.pdf., http://www.entergy-louisiana.com/content/price/tariffs/ell/ell_frp.pdf, http://www.mississippipower.com/pricing/pdf/pep-5.pdf, and http://www.scstatehouse.gov/sess116_2005-2006/bills/18.doc.

utility calculates rate adjustments based on the required change in revenues needed to move the ROR to the targeted level. As discussed in Part V below, what the FRP sets as the targeted rate of return affects both the utility's incentive for cost efficiency and the risk to customers.

The regulator might allow the utility to adjust rates under an FRP based on *pro forma* adjustments, which regulators commonly use to set rates in a general rate case: They adjust rates based on expected costs and revenues for a subsequent period. An alternative approach is simply to use actual historical costs and revenues, even when they reflect abnormal conditions and non-recurring costs, to determine a rate adjustment. The outcome has the same effect as compensating the utility for past deficient earnings and customers for past excess earnings.

Compared with a cost or revenue tracker, an FRP is a much more comprehensive ratemaking mechanism. A cost tracker allows a utility to recover its actual costs from customers for a specified function on a periodical basis outside of rate case. A revenue tracker allows a utility to periodically adjust its rates outside of a rate case when the actual revenues or the average revenue per customer deviate from the targeted level.

Specifically, whereas a cost tracker or revenue tracker address costs *or* revenues (and then, only those costs or revenues specified by the mechanism), an FRP accounts for all costs *and* revenues. The actual ROR earned by a utility directly relates to a utility's revenues and inversely relates to its costs. If costs, for example, exceed the test-year level, other things held constant, the utility's actual ROR would fall short of its authorized ROR.

Examples of formula rates are the plans under different labels for utilities in Alabama, Louisiana, Mississippi, Oklahoma and South Carolina.[9] The American Gas Association refers to these mechanisms as Rate Stabilization Plans.

Traditional ratemaking, as defined here, encompasses both rate-of-return regulation and fuel adjustment clauses (FACs) and purchased gas adjustment clauses (PGAs). Almost all U.S. utilities have used one or both of these mechanisms since the 1970s. The wide acceptance of FACs and PGAs by regulators reflects the view that these mechanisms are necessary to minimize the likelihood that a utility will earn a rate of return substantially below what was authorized. This perception stems from the magnitude of fuel and purchased gas costs relative to a utility's earnings. Other cost trackers, revenue trackers, multi-year price caps, multi-year revenue caps, and FRPs fall in the nontraditional category. These mechanisms share the feature of allowing the utility to recover its costs for predefined items outside of a general rate case.

As emphasized by their supporters, FRPs can help stabilize a utility's rate of return without a general rate case, thereby avoiding both financial difficulties and excess profits. The term "financial difficulties" has different interpretations; but no matter how it is defined, it has the potential to harm customers as well as the utility's shareholders. Financial difficulties could cause the deferment of needed capital investments to maintain reliable service, a downgrade of the utility's credit rating, and an increase in the utility's cost of capital. The time period over which these effects cause injury to utility shareholders generally would be more immediate than the injury to customers.

Part II summarizes the major features of traditional ratemaking. Part III describes the attributes of FRPs. Part IV compares the two ratemaking approaches in terms of setting "just and reasonable" rates. Part V offers regulators general advice on the acceptability of traditional ratemaking and FRPs.

This paper should help regulators assess FRP proposals, especially in terms of how they affect different regulatory objectives and differ from traditional ratemaking. It advises regulators to have an open mind about FRPs. These rates do have some advantages over traditional ratemaking, but these advantages depend on details of design and execution. One important requisite for regulatory approval of an FRP, consistent with "just and reasonable" rates, is that the utility must demonstrate high performance in cost efficiency and non-cost areas of operation integral to consumer well-being. A badly structured FRP can produce poor incentives for a utility, causing customers to pay more for utility services than what they would under traditional ratemaking and other mechanisms.

The Appendix lists questions that regulators should ask utilities and other parties about FRPs. This paper addresses some of these questions by offering recommendations.

II. Features of Traditional Ratemaking

A. Reasonable returns on prudent costs

As a general practice, regulators set rates so that utilities have the opportunity to recover prudently incurred costs plus a reasonable (or "fair") return on equity.[10] The common venue for setting rates is a general rate case. A general rate case involves the three major components of ratemaking: revenue requirements, cost allocation and rate design. *Revenue requirements* correspond to a utility's cost of service; *cost allocation* involves assigning cost responsibility to different customer classes and services; and *rate design* determines the actual prices charged to different customer classes and services at various quantities of consumption. A general rate case also typically covers a multi-month review period in which several parties participate. A general rate case normally initiates at the utility's request, involves large sums of dollars, involves all rates, and includes a thorough investigation of a utility's costs and revenues.

In a general rate case, the regulator determines what rates a utility could charge its customers for a future period. That determination is based on a "test year" estimate of future utility expenses, sales and investment, as well as the cost of debt (interest on loans) and the cost of equity (the cost of attracting shareholders), with debt and equity being the sources that fund the capital projects necessary to fulfill the utility's service obligation.

B. Rates fixed between rate cases

A second feature of traditional ratemaking is that base rates remain fixed until the regulator approves new ones in a rate case. One exception is when a utility requests a special rate or contract for customers between rate cases who, for competitive and other reasons, are unwilling to pay the standard rate.

C. No utility entitlement to the authorized rate of return

Under traditional ratemaking, the regulator does not guarantee that the utility earns its authorized rate of return. Actual results, in terms of costs and revenues, always vary from authorized. The regulatory obligation is to create a reasonable opportunity for the utility to earn the authorized level.

---

[10] The U.S. Supreme Court has stated: "The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties." (*See Bluefield Waterworks v. PSC of WV* 262 U.S. 679 [1923].)

D. Incentives for cost reduction between rate cases

A last feature of traditional ratemaking is that the utility has a strong incentive to control costs between rate cases. This effect derives from the mechanics of traditional ratemaking in setting the price, not the actual earnings of a utility. To the extent that the utility is able to hold down costs, its earnings and rate of return are higher. Customers do not receive the benefits of lower utility costs until regulators reflect them in new rates.

E. Summary of traditional ratemaking

In summary, traditional ratemaking involves an open and transparent process in which: (1) parties closely examine a utility's costs; (2) the regulator's intent is to give the utility an opportunity to recover its cost of capital; (3) the utility has a strong incentive for cost efficiency once the regulator sets new rates; and (4) rate changes require a utility to file a general rate case.

III. Formula Rate Plans

A. General information

An FRP allows for adjustments of the base rate outside of a general rate case. The periodic review under an FRP generally excludes cost allocation and rate design matters. It would include the regulator reviewing those costs not reflected in the rate established at the last general rate case. The reason for reviewing costs is that the proposed rate adjustment might reflect imprudent behavior by a utility in allowing certain costs to escalate. In other words, the ROR could fall outside the predefined band largely because of the utility's imprudence.

An FRP accounts for those revenues and costs not included in the test year used in the last rate case. If actual revenues and costs were equal to the test-year values, the utility would earn its authorized ROR and no rate adjustment would become necessary. Reasons for excess and deficient earnings include: (a) abnormal costs and revenues, which would have a temporary effect and might result from such factors as high inflation, a downturn in the economy, and weather; and (b) "normal" costs and revenues that differ systematically from levels used in setting base rates in the last general rate case, which would have more of a permanent effect and might result from the difficulty of projecting revenues and costs even under the "most likely" conditions. These costs can include, for example, capital costs for new projects previously approved by the regulator since the last general rate case.

Following is a description of one long-standing FRP, Alabama Power's Rate Stabilization and Equalization Factor (Rate RSE):

> It is the purpose of Rate RSE to lessen the impact, frequency and size of retail rate increase requests by permitting the Company, through the operation of a filed and approved rate, to adjust its charges more readily to achieve the rate of return allowed it in the rate order of the Commission. By provisions in the rate, the charges are increased if projections for the upcoming year show that the predefined rate of return range will not be met and are decreased if such projections show that the predefined rate of return range will be exceeded. Other provisions limit the impact of any one adjustment (as well as the impact of any consecutive increases), and also test whether actual results exceeded the equity return range.[11]

FRPs can act as a substitute for some cost and revenue trackers (e.g., revenue-decoupling trackers). They, in effect, consolidate different cost and revenue trackers. Cost trackers can diminish the positive effects of regulatory lag and retrospective reviews. They can also create

---

[11] *See* http://www.alabamapower.com/pricing/pdf/rse.pdf. The Alabama Public Service Commission first established an RSE plan for Alabama Power in 1982. This plan, unlike some FRPs, projects the utility's rate of return under existing rates for a subsequent period to determine whether the utility can change its rates so that it could earn a return within the predefined range.

distorted incentives because of dissimilar cost-recovery methods across a utility's functional areas.[12] With non-uniform treatment of different costs, for example, the utility might find it profitable *not* to pursue cost-minimizing objectives. Cost and revenue trackers have the major objective of preventing a utility from suffering serious financial problems between rate cases. A rate-of-return-driven mechanism such as an FRP can better achieve this objective than a number of cost and revenue trackers.

Under most applications, the utility adjusts its rates annually when its actual or projected ROR falls outside some specified band. The rate adjustment can come in different forms, including an adjustment that corresponds to the utility's projected revenue requirement for the following period. As an illustration, if the band encompasses a 9 to 13 percent ROR (with 11 percent as the utility's authorized ROR established in the last rate case) when the actual or projected return is 8 percent, the utility could adjust its rates upward to increase its return to, or bring it closer to, 9 percent or to the authorized ROR (11 percent).

B. Features of an FRP

1. Setting of the base rate

The starting rate is normally the rate set by the regulator in the last base rate case, reflecting the utility's revenue requirement, which in turn is based on the utility's prudent cost of service. Some FRPs update the authorized ROR to account for new energy usage and cost developments that affect a utility's cost of capital.

2. The band around the authorized rate of return

The band determines the range of ROR within which no rate adjustment takes place. It recognizes the effects of unexpected outside factors or random events on the actual ROR. Within this range, the utility has an incentive for excellent cost performance similar to that under traditional ratemaking. In theory, the range should include: (1) a lower value that does not place the utility in a "difficult" financial situation and (2) a higher value that does not reflect "unreasonable" earnings for the utility.

3. Sharing of the excess or deficient rate of return between shareholders and customers

Sharing of the earnings outside the band is another important component of an FRP. An FRP can include no sharing of earnings. For any ROR outside the band, for example, the utility might adjust rates to bring the ROR to either the "boundary point" or the authorized ROR (e.g., the midpoint of the band). These adjustments provide the utility with less desirable incentives for cost efficiency; they also shift risk to customers from poor utility-financial outcomes.

[12] *See* Ken Costello, *How Should Regulators View Cost Trackers?* NRRI 09-13, September 2009, at http://nrri.org/pubs/gas/NRRI_cost_trackers_sept09-13.pdf.

The approach to sharing should balance two factors: (a) the need to induce high cost performance by the utility and (b) the objective of returning to customers a "fair" share of a high ROR that the utility earned. The regulator would need to set a sharing ratio that reflects the relative importance it places on creating "high-powered" incentives for cost efficiency and the assurance of adequate benefits to customers. In the extreme case in which customers receive no compensation for "surplus" earnings, the utility has maximum incentive for cost cutting (since it keeps 100 percent of the incremental earnings from better cost performance). The outcome, however, may be deficient compensation to customers from the utility's efforts to control costs.

The sharing component might be nonlinear in the sense that it varies depending on the difference between the "boundary point" ROR and the actual ROR. For ROR increments far above the "boundary point," the plan might return a higher proportion to customers (e.g., 75 percent) than for increments closer to the "boundary" point (e.g., 50 percent). A symmetric FRP would allow for rate adjustments on both sides of the band in addition to having the same sharing arrangement on each side.

4. Prospective or retrospective perspective

Some FRPs project a utility's revenues and costs for the subsequent period to determine whether rates should change. In this instance, the regulator would adjust rates based on information that projects an ROR outside the predefined band. This approach is similar to a general rate-case review in which the regulator adjusts rates to allow the utility an opportunity to earn its authorized ROR or an ROR within a predefined band. Unlike one in which the FRP acts as a "true-up" mechanism, it does not compensate the utility for past deficient earnings and customers for excess earnings.

An alternative approach is for the FRP to act as a "true-up" mechanism. It would use the latest historical information to determine rate adjustments, which amounts to compensating the utility for past deficient earnings and customers from excess earnings. An FRP would achieve this outcome, for example, when it incorporates the most recent ROR, unadjusted for abnormal sales and nonrecurring costs and other factors, to compare with the targeted rate of return.

In sum, some regulators use strictly historical information to set new rates, while others use projections. Any rate adjustments are prospective in that they apply only to future periods; they also depend on a predefined methodology or formula.[13]

5. Performance standards

An FRP can include performance standards for certain functional areas. A utility has the legal obligation to perform well in return for more timely cost recovery and diminished utility risk. One utility with an FRP calculates a Company Performance Rating (CPR), which is a weighted indicator of customer price, customer satisfaction, and service reliability. The CPR affects both the range of authorized rate of return as well as the point of adjustment (i.e., the rate

[13] FRPs do not represent retroactive ratemaking because the regulator is not looking back to alter past rates, but is instead providing notice that future rates will be adjusted pursuant to a specific formula.

of return selected for rate adjustments within the confines of the allowed rates of return).[14] Regulators would want to assure the public that the utility does not underperform in any one area, especially if the outcome has a substantial effect on customer welfare.

6. Monitoring and other reporting requirements

Monitoring and reporting requirements include the regulator's verification of the utility's accounting filing and other information that allows the regulator to evaluate the utility's proposed rate adjustment. One important piece of accounting data is the actual net income to common stockholders, which the regulator can then compare with the net income allowed in the last rate case. Regulatory staff can conduct audits of the utility's ROR, operating costs, and rate base to determine compliance with regulatory rules and generally accepted accounting principles.

7. Process by which new rates go into effect

Any rate adjustment would occur prospectively—for example, over the next twelve months. As an alternative to adjusting the rates, the utility could increase or decrease its revenues through lump-sum surcharges or refunds. In these instances, the FRP compensates the utility or customers for past ROR shortfalls or excesses.

8. Method of cost review

FRPs involve not only whether the utility reported the correct costs but also whether those costs reflect prudent and efficient utility management. Regulators normally review cost-of-service information that the utility files to identify any imprudent costs

9. Frequency of rate adjustment

Rate adjustments usually take place annually. If regulators place importance on regulatory lag in promoting cost efficiency, they might want to adjust rates less frequently, say every two years.

10. Duration of the plan

Regulators can place a limit on the length of a plan. They might want to re-evaluate a plan—say, after three to five years—to determine whether it is operating as planned or requires some modifications. Consistently non-trivial annual rate adjustments might warrant a thorough rate-case review of the utility's cost of service and revenues.

11. Caps on adjustments

Regulators might place a limit on annual rate changes or average rate changes over a multi-year period. One possible exception is for *force majeure*.[15]

---

[14] *See* Mississippi Power Company, *Performance Evaluation Plan, Rate Schedule "PEP-5,"* at http://www.mississippipower.com/pricing/pdf/pep-5.pdf.

C. Benefits to a utility

Compared with traditional ratemaking, FRPs benefit utilities in several ways. First, they shorten the time between when a utility incurs a cost and recovers it in rates. With less regulatory lag, the utility facing increasing costs is in a better financial position than with a longer lag.[16] Second, the utility has more certainty in recovering its costs. This statement presumes that the regulator would more closely examine a utility's costs during well-publicized rate cases in which it has additional time and evidence to decide on the prudence of the utility's costs. It also presumes that a utility would incur costs between rate cases that were not included in the test year and that the utility would be unlikely to recover in the future. Third, over time it would likely file fewer general rate cases. These proceedings are time-consuming and absorb utility resources that have valuable alternative uses.

D. Potential benefits to customers

For customers, FRPs can offer benefits by reducing a utility's business risk, thereby reducing its cost of capital. ("Business risk" refers to the uncertainty associated with the operating cash flows of a business; it encompasses sales, cost and operating risks.) They can also allow the utility to share with customers prior to the next general rate case a portion of the benefits from cost efficiencies and favorable circumstances. High sales growth and productivity, for example, can produce unexpectedly high profits to a utility. Under traditional ratemaking, the utility would retain these profits until the next rate case. FRPs can distribute some of these profits to customers sooner. They can also moderate rate changes: Instead of a utility filing a rate case proposing a double-digit increase in rates, for example, an FRP could achieve the same increase more gradually over time. The adjustment of rates more frequently and at more moderate levels, however, might not necessarily benefit customers if a utility is able to pass through costs with less review by the regulator.

Customers could also receive better price signals under an FRP: Rate changes would tend to correspond to changes in the utility's costs.[17] FRPs can also reduce the cost of general rate cases, which customers ultimately pay. At least in theory, they also allow the regulator to review thoroughly a utility's financial condition every twelve months or less. (In practice,

---

[15] *Force majeure* is defined as an "act of God" or a natural and unavoidable event that substantially affects a utility's financial condition and performance in different functional areas.

[16] Regulatory lag can work to the advantage of a utility when the average cost of utility service declines. For electric utilities, this condition existed in the 1950s and most of the 1960s. During this time, many electric utilities earned returns far above their authorized returns (i.e., their cost of capital). The cost of generation declined and demand for electricity grew briskly. An FRP would have returned a portion of those high returns to customers more quickly. As it was, utilities retained these high returns for several years because of infrequent rate reviews.

[17] Under an FRP, rates can also change because of changes in sales not reflected in test-year revenues. It is, therefore, not always true that an FRP give customers better price signals in the sense that changes in rates correspond to changes in the utility's costs.

however, the period for reviews might be too short for the regulator and other parties to scrutinize adequately a utility's costs and the prudence of its actions.) Finally, the utility might have more motivation to advance social goals required by the regulator or state legislature (e.g., energy assistance to low-income households, energy efficiency) to the extent that an FRP allows quicker compensation to the utility for any earnings losses that might otherwise ensue.

E. Potential costs to customers

A potentially serious problem with FRPs is that they can mitigate regulatory lag and the effectiveness of cost reviews. These reviews can help regulators evaluate past costs in addition to projected costs that the utility reports in its annual filing for a rate adjustment.

The concern is that FRPs could increase the likelihood of a utility passing through excess and imprudent costs to customers. Proponents of FRPs contend that this ratemaking method prevents a utility from overcharging customers because of excess profits. What they fail to say is that overcharging can also result from the utility passing through *excess costs* to customers.

As mentioned earlier, FRPs would lead to less frequent general rate cases. The downside to fewer rate cases is conditions might warrant regulators to frequently revise cost allocation, the utility's cost of capital and rate design. A general rate case could benefit certain customers and improve a utility's pricing efficiency. The proper balancing of the various objectives of ratemaking might also require a general rate case; a limited annual FRP review would not address these objectives concurrently and holistically.

IV. The Regulatory Objective of Setting "Just and Reasonable" Rates

A. Conditions for "just and reasonable" rates

The acceptability of an FRP depends on it ability to produce outcomes that do not deviate substantially from the standards underlying "just and reasonable" rates. Such rates have the following characteristics:

1. Rates reflect the costs of an efficient and prudent utility.

2. Rates reflect the cost of serving different customers and providing different services and different levels of service.

3. Rates avoid undue price discrimination.

4. Rates allow a prudent utility a reasonable opportunity to receive sufficient revenues to attract new capital and not encounter serious financial problems.

5. As a recent phenomenon, rates should address policy objectives such as the promotion of energy efficiency and affordable energy to all customers.

B. Assessment

The first condition prevents customers from paying for costs that the utility could have avoided with efficient or prudent management. Regulators attempt to protect customers from excess utility costs by scrutinizing a utility's costs in a rate case or by applying an incentive mechanism (with explicit rewards and penalties) that motivates a utility to act efficiently. They sometimes establish standards for high performance.[18] Ratemaking practices can affect the propensity of a utility to act efficiently. Cost trackers for which relevant costs do not undergo a thorough review by the regulator, can weaken a utility's incentive to control those costs, all else being equal. They can also diminish the effect of regulatory lag on a utility's cost performance.

Traditional ratemaking provides a transparent process in which the regulator and parties can scrutinize a utility's costs and other information in support of a rate change. The FRP review process is shorter in duration, but it does not address such topics as cost allocation and rate design. Whether rates are more compatible with the costs of an efficient utility under one method is difficult to answer. Many industry experts would argue that traditional ratemaking does a better job of assuring that a utility recovers only prudent costs.

---

[18] For a discussion on how regulators can use performance measures and standards, *see* Ken Costello, *How Performance Measures Can Improve Regulation*, NRRI 10-09, June 2010, at http://www.nrri.org/pubs/multiutility/NRRI_utility_performance_measures_jun10-09.pdf.

On the other hand, an FRP is superior at updating rates in response to newly incurred costs between rate cases or costs not accounted for in the last rate case. Overall, traditional ratemaking seems to create a better environment for cost efficiency, while falling short in providing proper price signals to customers. The latter outcome results from the inability to change rates between rate cases.

The second and third conditions are not relevant. Under an FRP, cost allocation and rate design matters would still be addressed in a general rate case. For this reason, an FRP does not eliminate the need for rate cases. Regulators might also want to investigate whether revenues and costs are so out of line as to warrant a thorough review rather than a year-to-year adjustment. In fact, as recommended in Part V.H, regulators should mandate rate cases after a number of years, for example three to five years or even sooner, to address these essential aspects of ratemaking.

FRPs have a distinct advantage over traditional ratemaking in alleviating the possibility of the utility encountering financial difficulties. To the extent that the test-year concept of ratemaking is incapable of setting rates for a multi-year period, some alternative way for utilities to recover costs becomes necessary. The term "capable" here refers to the ability of test-year costs and revenues to reasonably reflect conditions during the effective periods of new rates. Piecemeal approaches such as cost trackers for individual cost items and revenue trackers can address some of these problems; an FRP arguably would more effectively and comprehensively overcome the problems derived from the "static" test-year concept underlying traditional ratemaking.

Regulators' efforts to promote social objectives might require changes in how utilities recover their costs. Regulators should consider different aspects of ratemaking as they relate to social-objective initiatives such as energy-efficiency and low-income programs. For energy efficiency, questions relate to: (1) cost recovery of utility energy-efficiency actions, (2) utility recovery of lost margins from energy efficiency, and (3) explicit utility-performance incentives for cost-effective actions. Regulators might contemplate a cost tracker for recovery of costs; revenues losses might justify a revenue tracker to compensate the utility for lost margins; an FRP could serve to compensate the utility implicitly for erosions in the ROR that might result from energy-efficiency initiatives.

FRPs can overcome some of the problems with cost trackers, namely, distorted incentives for cost control, the mismatching of a utility's total costs and revenues, and inadequate regulatory oversight of costs. The author uses the word "can" because addressing these problems requires a well-structured and executed FRP. That is, an FRP that has a wide band, a targeted rate of return that is at (or, preferably, beyond) the boundary points of the band, an adequate cost-review process, and performance standards.

An FRP can more directly achieve the major objective of cost trackers, which is to prevent a utility from suffering financial difficulties between rate cases. Regulators might want to modify traditional ratemaking if only to help advance social objectives. These objectives might require more timely recovery of costs and revenue losses that cannot be accountable for in a test year.

V. Advice to Regulators

Formula rates have advantages over traditional ratemaking in achieving some regulatory objectives. Parts III and IV point out that a formula rate has a number of attributes compatible with the term "just and reasonable." On the other hand, regulatory approval of formula rates should require certain conditions, with the major ones identified below.

A. Insufficiency of traditional ratemaking should be a pre-condition for adopting formula rates

The argument for FRPs is that traditional ratemaking is failing to produce "just and reasonable" rates. Regulators should start, therefore, with an investigation of current practices, to determine their precise shortcomings, if any way. With that knowledge, the regulator can shape any new plan to solve the specific problem. The question then becomes not a bipolar debate of "FRPs, yes or no," but instead what mix of methods—multi-year price and revenue caps, FRPs, cost and revenue riders, and new rate designs—produce the desired results.

This analysis allows the regulator to account for the different, and sometimes conflicting, regulatory objectives, such as public acceptability, efficient pricing, exceptional cost performance, gradualism, feasibility of implementation, and fairness among customers in a particular class.[19] New rate designs that place less risk on the utility for recovering its fixed costs can complement, and lessen the need for, an FRP.[20]

If regulators find that traditional ratemaking fails to provide compensatory rates to utilities, or does not carry out the remaining regulatory objectives, they should consider other approaches, such as multi-year price and revenue caps, FRPs, cost and revenue riders, and new rate designs. One alleged problem is the inability of traditional ratemaking to calculate test-year revenues and costs that accurately reflect the future. Another is the need to have frequent rate cases in an environment of rising utility costs and lower revenue growth.

---

[19] *See*, for example, Ken Costello, *Decision-Making Strategies for Assessing Ratemaking Methods: The Case of Natural Gas*, NRRI 07-10, September 2007, at http://nrri.org/pubs/gas/07-01.pdf.

[20] Most energy utilities recover some of their fixed costs in the volumetric charge. When electricity or natural gas usage falls, for example, because of factors such as abnormal weather, the business cycle, changes in customer behavior, and appliance and building characteristics, a utility's earnings also fall because the utility must pay the fixed costs regardless of the revenue level. Where recovery of a large percentage of the fixed costs depends upon energy usage, a small change in usage can have a large effect on a utility's earnings. Revenue-decoupling trackers and FRPs are alternative methods to deal with this problem.

One alternative mechanism, multi-year price caps, provides more robust incentives for cost efficiency than does an FRP. Some evidence exists showing a utility's performance in the form of total factor productivity improves over time as general rate cases become less frequent.[21] A reduction in the frequency of rate cases to increase regulatory lag, in other words, can positively affect a utility's long-term performance. This outcome implies that an FRP that adjusts rates on an annual basis for earnings deficiencies or surpluses have poor performance incentives compared with multi-year price and revenue cap mechanisms.

Multi-year mechanisms, however, intend to produce less stable profits, which regulators might find unpalatable. An FRP might appear to some regulators as more attractive in narrowing the range of profits that a utility can earn while at the same time providing reasonably good incentives for cost efficiency.[22] The last point depends, among other things, on the size of the band, the sharing arrangement of ROR outside the band, and the targeted ROR (e.g., the authorized ROR, the "boundary points" ROR, or an ROR outside the band). When structured badly, an FRP can produce "cost-plus" incentives that inevitably lead to poor utility performance. Under this scenario, regulators should assign a high negative aspect to FRPs and think seriously about disqualifying them as a desirable ratemaking mechanism.

---

[21] *See* Mark Lowry, "Incentive Plan Design for Ontario's Gas Utilities," presented before the Ontario Energy Board, November 3, 2006, slides 10-13.

[22] Under a price-cap mechanism, the maximum price that a utility can charge during a period *t* equals the base price plus the accumulated changes since the base period, determined by the change in the selected price index (e.g., GDP Implicit Price Deflator) minus the X-factor, which commonly relates to a measure of total factor productivity. Price caps have good incentives for high cost performance, but they can lead to a utility earning high profits without any guarantee of benefits to customers, at least until the next full rate case, from improved utility cost performance. In other words, a utility's actual rate of return could be much higher than the authorized rate of return. This possible outcome derives from periodic price adjustments based on parameters external to an individual utility's conditions.

As discussed in this paper, FRPs act as a safety net for regulators by preventing utilities from earning extremely high or low profits between formal rate reviews. FRPs also can allow customers to benefit visibly and directly when conditions favor a utility to earn high profits. Economic analyses have shown that compared to a pure price-cap regime, earnings-sharing-type mechanisms may better improve the long-term economic welfare of consumers. (*See*, for example, Richard Schmalensee, "Good Regulatory Regimes," *Rand Journal of Regulation* 20 (Autumn 1989): 417-36; and Thomas P. Lyon, "A Model of Sliding-Scale Regulation," *Journal of Regulatory Economics* 9 (May 1996): 227-47.) Taking everything into account, FRPs, at least in theory, can better satisfy both an economic and political test, at least compared with pure price-cap regulation. Some regulatory plans in the U.S. combine both price-cap and formula-rate-type plans to give utilities strong incentive for cost efficiency while placing bounds on their profits. These bounds recognize the possibility of a utility earning extreme profit that can violate both "equity" and political standards.

For the electric industry, increasing average cost of utility service is likely to magnify the negative consequences of traditional ratemaking. Options such as a future test year, cost trackers for individual functional areas, and revenue trackers can mitigate some of the problems. A thorough review of FRPs might show that it is a preferred approach that more directly and effectively addresses the potential problem of traditional ratemaking, which is that it does not give utilities a reasonable opportunity to earn their authorized ROR.[23] As implemented or proposed by some utilities, an FRP can coexist with cost and revenue trackers. One concern is that these mechanisms, taken as a whole, can place utilities in an "autopilot" mentality, blunting their incentives for, and disposition toward, excellent performance.

B. The regulator should condition any FRP on the utility meeting performance standards.

The regulator and the utility have twin obligations: the rate regulator to set just and reasonable rates; the utility to perform with excellence. To ensure compliance with the utility's obligation, the regulator should accompany any FRP with performance standards.

Regulators can establish performance standards for reliability, customer service, and other functional areas whose outcomes depend upon the actions of utility management.[24] Standards act to address the concern that an FRP might cause a utility to become more lax in its performance. One possible action is for the regulator to establish reliability/customer service standards and to review periodically whether the utility has complied with those standards. The regulator might want to consider whether the utility should receive a reward for surpassing the standards or should suffer a penalty if it falls short.[25]

[23] I made this argument in a previous paper. *See* Ken Costello, *How Should Regulators View Cost Trackers?* NRRI 09-13, September 2009, at http://nrri.org/pubs/gas/NRRI_cost_trackers_sept09-13.pdf.

[24] Over time, regulators have become more involved in addressing non-traditional utility activities such as the promotion of energy efficiency, renewable energy resources, and affordable energy. In achieving acceptable outcomes in these activities, regulators should consider performance standards.

[25] Many performance-based plans recognize the need to adequately monitor and enforce reliability/customer service standards. The primary reason for oversight is the widespread view of regulators and others that under performance-based ratemaking the utility would tend to cut costs, which could jeopardize its overall service quality to its customers. One policy calls for the regulators to penalize a utility for failing to meet prespecified standards, but not to reward it for superior performance. Regulators might rightly believe that a utility should not earn a reward for fulfilling a primary obligation, such as providing high overall service quality.

C. In calculating the utility's authorized ROR, regulators should account for the reduced business risk attributable to more timely and predictable cost recovery.

An FRP reduces earnings volatility by shifting the risk of cost changes from shareholders to customers and reducing the risk of under-recovery. This shift in risk reduces the utility's cost of capital. Specifically, with less volatility in earnings, an FRP should reduce the risk premium that prospective investors place on a utility. Regulators should reflect this reduction in base rates; in fact they should require the utility to accompany any FRP proposal with a calculation of the ROE effects.

A lower risk premium is warranted when annual rate adjustments guarantee zero gap between the authorized ROE and the actual ROE. According to the Capital Asset Pricing Model (CAPM) the lower the utility's expected earnings volatility, the lower the utility's risk relative to the market portfolio (i.e., beta). A downward adjustment of the utility's authorized rate of return would compensate customers for shouldering some of the risks the utility previously bore.

An offset to this adjustment might come from the utility bearing a higher risk because of performance standards that did not exist previously. Standards impose the risk that the utility would earn below-adequate profits.

D. The band of an FRP should be wide enough so that the utility can retain a higher ROR that could come from higher cost performance, or absorb a lower ROR that could come from lower cost performance.

A wider band provides a utility with better incentives for cost performance. The incentives for a utility operating within the band are comparable to those incentives that a utility faces between rate cases under traditional ratemaking. The band should be wide enough so that the rate adjustments do not occur within reasonable range of RORs. Most FRPs have boundary points at 50 to 100 basis points above and below the authorized ROR or the midpoint of the band.

E. The FRP should not guarantee earnings.

Performance depends on risk of penalty for nonperformance. An earnings guarantee undermines this principle. We have discussed the option of appending an ROR band to the FRP plan, with some cost recovery adjustments if results fall outside the band. These adjustments should leave the utility in a position of over- or under-recovering costs; otherwise the FRP becomes an entitlement to the authorized ROE. The author stated in a previous paper that:

> If a commission wants to guarantee that the utility will recover its authorized earnings, it would favor a rate design that allows the utility to recover all of its fixed costs in a monthly service charge or a customer charge. Since generally commissions do not, they implicitly recognize the positive incentive effect from allowing a utility's actual rate of return to deviate from the authorized level. Commissions also know that if a utility is continuously earning below its authorized rate of return, the utility has the right to file a general rate increase… If a commission wanted to assure the utility that it will always earn its authorized

> rate of return, it would allow the utility to recover all of its actual costs through trackers. Commissions generally do not allow the tracking of all costs because of incentive *and other problems*…[26] (Emphasis added)

A guaranteed ROR presumes that the regulator perceives the allowed rate of return as an entitlement that the utility should always receive except under extreme circumstances. The downside to this entitlement is that the FRP redistributes all the risk of utility operations to customers. This risk shifting appears unfair to customers, who would bear all the risk from utility-management actions as well as outside factors that affect the utility's ROR. Consequently, it also gives the utility poor or distorted incentives for cost efficiency.

The utility, for example, might have an incentive to increase its costs so that its actual ROE falls below the lower boundary and thereby trigger a rate increase commensurate with the authorized ROE. Assume that the authorized ROE is 11 percent and the lower boundary point is 9 percent. If the utility's actual ROE is 10 percent, it cannot adjust its rates upward. If, on the other hand, it achieves 8 percent, under our assumption it can increase rates so that its ROE becomes 11 percent. In this example, the utility might increase its costs so that its ROE falls from 10 percent to 8 percent. This distorted incentive hurts customers at the benefit of the utility's shareholders—an outcome that regulators would want to avoid.

F. The targeted rate of return should be beyond the boundary points of the band

When the actual ROR lies outside the band, any rate adjustment should result in the utility still earning a return outside the band. Adjustments back to the midpoint are equivalent to a guaranteed ROE at the authorized level.

To create good incentives and appropriate risk-sharing, when the actual ROR lies outside the band, any rate adjustment should result in the utility still earning below or above the "boundary point." Assume, for example, that the band is a 10 to 14 percent rate of return on equity. During the year the utility earns 15 percent; if the utility has to split the difference between the higher boundary of the band and the actual rate of return by adjusting its prices down, in the example the utility would realize a 14.5 percent rate of return. We assume that the mechanism is symmetrical, so if the utility earns below the lower boundary of the band—say, a 9 percent rate of return—it can adjust prices upward to realize a rate of return closer to the lower boundary. By sharing, rather than moving the targeted return to one of the boundary points, the utility has a stronger incentive to keep its costs down. With more potential benefits from better cost performance comes increased risk from subpar performance.

[26] Ken Costello, *How Should Regulators View Cost Trackers?* NRRI 09-13, September 2009, 11, at http://nrri.org/pubs/gas/NRRI_cost_trackers_sept09-13.pdf.

G. The process for rate adjustments should allow ample time and resources for the regulators and parties to assess whether the utility acted prudently during the evaluation period.

FRPs call for the regulator to adjust rates when a utility's earned ROR falls outside a stated "band." No rate adjustment should occur without prior regulatory scrutiny of cost increases causing the need to adjust. Procedures should allow sufficient time for prudence investigations, to avoid the risk that rate increases become automatic. We cannot overstate the importance of this requirement. Without regulatory vigilance, a utility can lose control of its costs and pass the risk to customers.

H. Periodically, regulators should conduct a general rate case to examine the appropriateness of existing cost allocations, the authorized ROR, and rate designs.

Before making a rate adjustment, the regulator should determine the cause. Periodically, regulators should conduct a general rate case to examine the appropriateness of existing cost allocations, the authorized ROR, and rate designs. One criterion for a general rate review is whether annual rate adjustments have risen over time or involve large dollar amounts. These outcomes would signal a growing or substantial mismatch between a utility's revenues and costs, resulting in large deviations between the earned and authorized ROR.

The regulator should also periodically evaluate an FRP plan to identify any problems or proposed changes that would make the plan operate more effectively. It is common for incentive-based plans and FRPs to undergo changes over time to alleviate previous problems and outcomes that violate regulatory objectives (e.g., the balancing of customer and utility interests).

Lastly, there is the question of whether the utility should have the right to file a general rate case during the effective period of the FRP. If, for example, the FRP is for a three-year period, could the utility file a general rate case in the interim? If a utility still files frequent rate filings, little rationale exists for an FRP. In this instance, the FRP benefits mostly the utility by diminishing regulatory lag with little benefits flowing to customers.

Appendix: Questions for Regulators to Ask Utilities and Other Parties in Consideration of a Formula Rate Plan

1. What special conditions warrant rate or revenue adjustments outside of a rate case?

2. In addition to an FRP, what other mechanisms exist to allow a utility to adjust rates between rate cases? What are the public-interest effects of these mechanisms relative to an FRP?

3. What evidence should a utility present to show the need for an FRP?

4. How should a regulator weigh the benefits of an FRP relative to its costs? Under what conditions would the benefits dominate the costs to justify an FRP?

5. How would an FRP affect the utility's incentive to improve its cost performance?

6. How can the regulator assure customers that they pay only for prudent and efficient costs? Specifically, how can the cost-review process assure that the utility does not recover excess costs from customers?

7. How would an FRP affect the utility's non-cost performance? Should an FRP include standards for utility performance?

8. If the concept of an FRP is reasonable, how can a regulator structure it to mitigate potential problems?

9. How long should an FRP operate before the utility has to file a general rate case?

10. What criteria should regulators use to determine the band (i.e., the range of RORs within which no rate adjustment occurs)?

11. How should regulators determine the sharing of excess or deficient ROR between shareholders and customers?

12. What should regulators determine as the utility's post-rate adjustment ROR (i.e., the targeted ROR)? Should it be:

    a. The authorized ROR established in, or updated since, the last rate case,

    b. The band's "boundary points" ROR, or

    c. Some portion of the difference between the actual ROR and the "boundary point" RORs?