Alternative Utility Ratemaking Policies

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Alternative Utility Ratemaking Policies

Overview

Utility rate regulation is often one of the most litigated, lobbied, and arcane topics of state law and policy. Each year, the General Assembly, the Maryland Public Service Commission (PSC), and the state court system – with the active intervention of a wide array of interested stakeholders – collectively grapple with various aspects of how utilities should provide and recover the costs of utility service to Maryland customers, or "ratepayers." Distributed utility services have traditionally been regulated through a "cost of service regulation" model. Gas and electric distribution services remain under that model, while telephone companies have been legislatively authorized to use an alternative form of regulation since 1995. This document provides a high-level overview of how traditional regulatory ratemaking works, common alternatives to that approach, how Maryland's recent regulatory practices may interact with the various policy options, and how PSC has chosen to move forward.

Recent Consideration of Alternative Forms of Regulation

In the 2019 session, the General Assembly considered, but did not pass, Senate Bill 572 and House Bill 653, which had the potential to prompt significant changes in Maryland's approach to ratemaking as it relates to gas and electric utilities. The bills would have required PSC to give heightened consideration to various types of alternative ratemaking. As introduced, an "alternative rate plan" meant a plan to establish new base rates for an electric company or a gas company that includes the use of (1) a fully forecasted test year; (2) multiyear rates; (3) formula rates; (4) rate designs that reflect fixed and variable costs; (5) other rate plans; or (6) a combination of rate plans that meet the requirements of the bill. The bills also allowed utilities to include performance standards along with their alternative rate plans, which would provide incentives for favorable utility performance in reliability or customer satisfaction. Although the Senate did not pass any version of the bill, the House passed an amended version limiting the forms of alternative ratemaking to fully forecasted test years and formula rates, along with other changes.

On the regulatory front, in recent years and in response to various requests for alternative ratemaking approaches, PSC has alluded in various rate case opinions to the need for a more holistic review of alternative rate plans before authorizing a more significant departure in rate setting practices. On February 14, 2019, shortly after Senate Bill 572 and House Bill 653 were introduced, PSC launched Public Conference 51 (PC 51), a Technical Conference on Alternative Forms of Rate Regulation (AFORs). As part of that conference, PSC received 38 sets of written comments and held two days of hearings.

Subsequently, on August 9, 2019, based on the record in PC 51, PSC issued Order No. 89226, establishing Case No. 9618, to facilitate the implementation of multiyear rate plans (MRPs). In its order, PSC endorsed the use of a historical test year to develop any MRPs[1], which would be able to last up to three years, as well as the incorporation of performance-based goals to provide incentives for optimal utility performance and public policy outcomes. Utilities would also retain the right to file traditional rate cases. Although this document discusses PSC's endorsement of MRPs in greater detail below, in summary PSC found that MRPs could limit the frequency of rate cases and provide customers with greater certainty about changes in rates, as well as reduce the administrative burden for regulators as compared to other alternative rate plans. PSC further found that MRPs would reduce delays in cost recovery and allow utilities to operate their businesses in a more predictable regulatory environment, as well as provide more transparency and insight into utility planning processes.

To implement MRPs, PSC directed its Public Utility Law Division to convene a working group to propose details by December 1, 2019, on which PSC would rule by January 30, 2020, and after which utilities could begin to file MRPs. The working group will also explore how to incorporate performance-based measures into MRPs, and provide recommendations to PSC by April 1, 2020.

Cost of Service Regulation

Federal, state, and local governments subject electric and natural gas utilities that deliver services to consumers to "cost of service regulation" because the services are essential to society and because one entity may provide the services at a lower cost than a combination of smaller entities. Without regulation, as a natural monopoly, a single utility would have the power to restrict services and set prices outside of market forces. Therefore, cost of service regulation aims to achieve public benefits, including safe, adequate, and reliable services, and even environmental attributes, that the market may not achieve on its own.

The principles of cost of service regulation have evolved since states began to adopt them at the turn of the twentieth century. From a strict legal standpoint, state regulation of public utilities is the exercise of a state's police powers, inasmuch as the industry affects the public interest, whether it is a monopoly or not. Public utility theory, doctrine, and case law, however, also refer to a "regulatory compact" between a utility and the government under which the utility accepts the duty to serve the customers in its territory in exchange for the government's promise to approve rates that make the utility whole. Thus, cost of service regulation requires a regulator to determine a utility's revenue requirement – that is, the cost of service – which reflects the total amount a utility must collect in rates to recover its costs and a reasonable return.

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[1] It is worth noting that the historical test year will be used as a basis to develop forecasted test years for up to three years. MRPs by definition require forecasted revenue requirements and rates, because the commission will set rates for a future period based on projected costs. The historic test year creates a baseline from which those projections can be made.

Regulatory Lag

Although cost of service regulation and its accompanying traditional forms of ratemaking have remained relatively stable over time, various alternative forms of ratemaking have also emerged. The principal benefit sought by utilities through alternative forms of ratemaking is the reduction of regulatory lag – the period of time that the regulatory process takes to reflect a utility's actual costs. Depending on fluctuations in costs and revenues, regulatory lag may inhibit the ability of a utility to earn its authorized rate of return, or may allow a utility to earn above its rate of return.

Several utilities have maintained that PSC's reluctance to make a more significant departure from traditional ratemaking practices has prevented them from earning their authorized rates of return. On the other hand, PSC and several other parties maintain that regulatory lag encourages utilities to act in an efficient, cost-conscious manner. Others may also note that PSC has approved contemporary cost recovery with gas surcharges under the Strategic Infrastructure Development and Enhancement Infrastructure Replacement Program (STRIDE) as well as with electric surcharges for Baltimore Gas and Electric (BGE) and Potomac Electric Power Company (Pepco) for accelerated reliability investments.

Deregulation

Roughly 80% of Maryland electricity ratepayers receive their distribution service from investor-owned utilities (IOUs),[2] while the remainder receive service from member-owned, nonprofit electric cooperatives or municipally owned utilities. The vast majority of gas ratepayers also receive distribution service from IOUs.[3]

As in many other states, Maryland has unbundled its regulation of (or "deregulated") the electric supply function from distribution functions. Under this industry restructuring, electric utilities divested themselves of power plant ownership while retaining ownership of distribution and transmission facilities. Before restructuring, PSC regulated electric utilities that were "vertically integrated" and responsible for generation, transmission, and distribution of power to retail customers, but now PSC regulates companies that do not own any generation resources, and has less insight into their investment decisions. As a result, PSC only sets the rates that distribution utilities charge for distribution service, and PSC no longer has an integrated resource planning division to review utility investments in generation and other assets.

Today, ratepayers no longer receive their electric supply from the same vertically integrated company. Instead, ratepayers may choose to either (1) receive "Standard Offer Service"

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[2] The four investor-owned electric utilities in Maryland are The Potomac Edison Company, Baltimore Gas and Electric, Potomac Electric Power Company, and Delmarva Power and Light Company.

[3] The seven investor-owned gas utilities in Maryland are Baltimore Gas and Electric, Washington Gas Light Company, Columbia Gas of Maryland, Inc., UGI Utilities, Inc., Chesapeake Utilities, Sandpiper Energy, and Elkton Gas.

electric supply from their distribution company, which procures the energy from generators through a competitive auction process overseen by PSC[4] or (2) shop for their supply under terms offered directly from a competitive retail supplier. Similarly, gas customers served by regulated distribution companies, such as Washington Gas or BGE, may purchase their gas supply through a competitive gas supplier as an alternative to the default gas commodity service procurement overseen by PSC. Ultimately, both regulated distribution utilities and third-party suppliers acquire electricity and natural gas through interstate wholesale electricity and gas markets, which are governed by the Federal Energy Regulatory Commission (FERC).

Maryland Public Service Commission Rate Proceedings

Generally, PSC conducts a formal rate case proceeding after a utility applies for a significant change in its rates. Rate cases are extensive, fully litigated proceedings that afford certain parties designated by statute, such as PSC's technical staff, the Office of People's Counsel, the utility, and other intervening parties the ability to participate in extensive discovery, briefing, and evidentiary hearings, as well as opportunities for less formal public comment. During a rate case, the participants examine and argue the merits of the various components that determine a utility's revenue requirement. After PSC renders a final decision on a rate application, the utility is able to reflect the new rate and any associated changes in its tariff, which functions as a contractual document containing the terms that govern the utility's service to its ratepayers.

Basic Ratemaking

A utility's revenue requirement, its cost of service, consists of its rate base multiplied by its allowed rate of return, plus its operating expenses.

Revenue Requirement (Cost of Service) Formula

(Rate base x Rate of return) + Operating Expenses = Revenue Requirement

Rate Base

A utility's rate base includes the net amount of investment, funded by investors, in utility equipment and facilities[5] used to furnish utility service. The rate of return is the percentage rate that a utility's regulator determines a utility may earn on its rate base to cover the cost of capital, which is the compensation that investors require for exposing their capital to risk. Operating expenses include operation and maintenance costs (O&M), depreciation, and taxes.

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[4] Choptank Electric Cooperative purchases power through long-term wholesale contracts. Southern Maryland Electric Cooperative (SMECO) uses a managed supply portfolio to procure power.

[5] Utility equipment and facilities are commonly referred to as "plant" in utility regulation.

Rate Base and Test Year

A utility's rate base is the total of all long-lived investments made by the utility to serve consumers, minus accumulated depreciation. Long-lived investments include buildings, fleet vehicles, office furniture, poles, wires, transformers, pipes, computers, and computer software, and may also include adjustments for capital that a utility must maintain (to pay its bills), deferred taxes, and deferred costs incurred by the utility in furtherance of regulatory or policy objectives.

Like other state utility commissions, Maryland's PSC uses the concept of a test year to determine a utility's rate base and revenue requirement. Under a test year framework, a utility presents its costs and revenues on an annual basis, which, depending on state law and practice, may represent a recently completed or historical year, a future estimated year, or a hybrid of the two approaches. In Maryland, PSC has traditionally favored a historical test year, but more recently has accepted hybrid approaches, especially when anticipated future costs are more certain, or known and measurable[6].

A historical test year approach uses actual investments, expenses, and sales, to which the utility proposes adjustments, in accordance with known and measurable changes that have occurred or are reasonably expected to occur before new rates take effect. A future or forecasted test year involves an estimate of the same data, typically subject to examination by the regulator.

Under each approach, major additions to a rate base may be reflected, and the goal is to have revenues, expenses, and rate base reflect their authorized relationships. In reality, and by definition, however, variables are likely to change. Historical test years tend to work best during periods of stable costs, and when productivity offsets inflation. Future test years, however, are often most advantageous in more dynamic economic conditions, as well as during periods of greater customer growth or large capital investments, and may show more effectiveness when combined with ongoing regulatory scrutiny.

Rate of Return

Setting a utility's rate of return is another critical component of a utility's revenue requirement and the underlying rate case. Utilities may earn a regulated annual rate of return on their rate base, and the rate must allow the utility to attract appropriate amounts of capital relative to the risk that the utility's business faces. Utilities use various sources of capital, principally

[6] The commission has a significant amount of flexibility to establish alternative rates. As PSC technical staff states on pages two through three of its May 21, 2019 comments in PC 51, "[t]he commission's enabling legislation affords it broad authority which is liberally construed. In setting rates, the commission may use any alternative form of regulation for an electric company that the commission finds, after notice and hearing, '… protects consumers, ensures the quality, availability, and reliability of regulated electric services; and is in the interest of the public, including shareholders of the electric company.' There is no similar provision for gas companies; however, the commission's broad authority may allow it to use the same principles in establishing an alternative form of regulation for gas companies in the event the commission finds that such a change is merited." (internal citations omitted)

including various types of shareholder equity and bondholder debt, and in theory, the relative combined cost rates of each source produce a utility's rate of return. Neither shareholder equity nor bondholder debt typically comprises more than 60% of a utility's capital structure.

Hypothetical Rate of Return Calculation[7]

	% of Capital Structure	**Cost of Capital for Element**	**Weighted Cost of Capital**
Common Equity	45%	10%	4.5%
Preferred Equity	5%	8%	0.4%
Long Term Debt	45%	7%	3.15%
Short Term Debt	5%	5%	0.25%
Rate of Return			**8.3%**

Although the cost of debt is relatively easy to ascertain, a utility's cost of equity (or return on equity, "ROE") is typically one of the most contentious matters in a rate case, with a slew of experts employing various economic models to argue which return a utility must offer in order to attract investors. Ultimately, regulators may use their own judgment to sift through a variety of models, as well as other considerations such as avoiding large rate changes ("gradualism"), utility performance, regulatory risks, and ROEs authorized for comparable utilities in comparable regulatory environments.

Operating Expenses

Operating expenses include regularly occurring expenses such as labor, fees for consultants and attorneys, maintenance services, insurance, taxes, and depreciation expense, as well as sporadic expenses such as storm damage and rate cases expenses that are typically subject to multiyear averaging.

Electric Cooperatives and Municipal Utilities

Notwithstanding the same ratemaking process, there are a few key distinctions when setting rates for IOUs as compared to cooperatives and municipal utilities. First, unlike IOUs, electric cooperatives and municipal utilities do not earn a return on equity. Whereas IOU profitability is driven by the allowed return on the company's assets, the electric cooperatives and municipal utilities request a margin that sufficiently covers the interest on their debt plus a reasonable buffer. Ultimately, all revenues earned by a cooperative or a municipal utility are sent back to or used for the benefit of their members. Second, with respect to rate design, electric cooperatives typically advocate for higher fixed customer charges, which yield more stable income year-round for the cooperatives.

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[7] *Electricity Regulation in the US: A Guide*, Regulatory Assistance Project, p. 55.

Alternative Ratemaking

In order to minimize regulatory lag, promote environmental goals, or achieve other public policy outcomes, states may choose to adjust traditional approaches to ratemaking. These alternative ratemaking approaches generally come in the form of either (1) changes to the actual process of setting rates (*i.e.*, the rate case) or (2) changes to the way utilities recover their costs, which generally focus on how customers pay for service on a month-to-month basis. Collectively, alternative ratemaking policies – also referred to as AFORs or alternative rate plans – are often lumped together. When distinguishing between the two types of changes, however, this document treats changes to process as alternative ratemaking processes, and changes to recovery as alternative rate recovery mechanisms.

Current Alternative Ratemaking Policies at the Public Service Commission

PSC technical staff's March 29, 2019 comments in PC 51 provide a useful summary of ratemaking policy and practice at PSC:

> "[T]he commission has broad jurisdiction over all public service companies in Maryland. In exercising this jurisdiction, the commission, among other things, must set rates that are just and reasonable and consistent with the public good. While the commission has at various points in time relied on a pure HTY as the basis on which rates are determined, over the past several decades the commission has relied extensively on partially forecasted test years during rate cases. Today, the HTY of Maryland public service companies may be filed in full after a company's books are closed for the test year, updated to actuals by a company during the rate case in time for the actuals to be considered in direct testimony by the parties, or, less frequently, filed by the company during the pendency of the rate case with no true consideration due to the timing of the update.

> The vast majority of electric and gas rates applications since the 1990's have been developed based on the use of partially forecasted data. In recent practice, this typically results in the inclusion of two to four months of projected data in the development of rates, provided that the forecasted data is replaced with actual data prior to the hearing phase of the proceeding[8]."

Thus, although PSC has existing authority to approve alternative forms of regulation for electric and gas companies, and has authorized a wide variety of modern or hybrid approaches in authorizing rates, PSC has not elected to undertake a full-scale change in its ratemaking practices on the order contemplated by Senate Bill 572 and House Bill 653 of 2019. The various considerations and approaches set forth in those bills are described in more detail below.

Alternative Ratemaking Processes

Fully Forecasted Test Years

Favored by distribution companies such as Pepco and Washington Gas, a fully forecasted test year allows a utility to forecast its costs and revenues over a future year – typically the first year following a rate case. Maryland typically allows three to four months of forecasted data within a test year. Among other benefits, a fully forecasted test year can mitigate regulatory lag, improve price signals, and allow utilities to better manage risks during periods of rising costs. Forecasted test years may also reduce costs by discouraging the deferment of projects with high initial costs. However, critics maintain that because utilities control and produce the information used in the forecasting process, forecasted test years inhibit the ability of regulators to understand future utility operations and expose ratepayers to overestimated costs and overspending. Finally, although rate cases would theoretically become less frequent, forecasted test years may require significantly more ongoing resources and time for the additional regulatory work inherent in monitoring and truing up rates.

Of note, only seven states with deregulated markets have employed forecasted test years, and of those, a single, widespread solution or approach does not exist. Some deregulated states

[8] Moreover, technical staff notes that "the commission has regularly used AFORs that incorporate the effect of future conditions into base rates. These AFORs include, but are not limited to, allowance of annualized reliability improvements into rate base for improvements that become used and useful through the date of the base rate case hearing, incorporation of Bill Stabilization Adjustments into base rates, inclusion of known and measurable adjustments that will occur during the rate effective period, inclusion of certain utility-specific and statutory surcharges that support activities during the rate effective period, use of Construction Work in Progress ("CWIP"), and alternative rate designs that take into account projected changes in conditions during the rate effective period." (internal citations omitted)

like New York and Pennsylvania that have implemented variations of fully forecasted test years, however, may serve as reasonable comparisons.

Formula Rates

Favored by BGE, formula rates allow a utility to make yearly prospective rate adjustments under a formula established in an initial base rate case. Typically, a utility may earn a rate of return within a specified range. Like other alternative rate plans, formula rates may reduce the frequency of rate cases, and are often considered the most efficient at reducing regulatory lag. Because the formulas are based on exogenous financial metrics, utilities face less financial risk, and less forecasting is necessary, reducing the amount of informational asymmetry[9] relative to other alternative rate plans. Some informational asymmetry will still exist, however, and unless a regulator imposes performance metrics, utilities may have little incentive not to spend enough to earn a rate of return at the top of their authorized range.

Formula rates also shift the financial risks inherent in exogenous economic factors to customers, which may point to a need for revenue sharing mechanisms that reward customers as well as utilities. It is also worth noting that, unlike most states that use formula rates to address the exogenous cost of energy, as a deregulated state, Maryland does not face this particular issue. Other variable costs, such as usage and inflation, remain. Thus, for example, if PSC were to allow a Maryland utility to employ formula rates, the utility might enjoy less risk of under-earning as a result of inflation or decreases in usage, and it might be appropriate to reflect these factors in a lower return on equity.

Alabama, Illinois, and Louisiana along with several other states and FERC in a limited fashion, employ formula rates in various ways. PSC technical staff has suggested that if Maryland at some point were to adopt formula rates, PSC should decide how specific or narrow to make rates of return, how to reduce utility over-investment, how long rates should remain in effect, and the level of ongoing monitoring necessary between rate cases. In FERC cases, for example, there is robust participation by interested parties in both the initial and ongoing monitoring processes.

Multiyear Rate Plans

Although the House amended MRPs out of House Bill 653, the Senate did not make a decision on them. An MRP sets rates for several years into the future, often using a formula or index, or with specific future year changes based on forecasts. Regulators typically may base MRPs on historical, future, or hybrid test years, and must establish a duration. Regulators may also choose to include other features to ensure that the plans operate in the public interest, including performance standards, ROE caps, or earnings sharing.

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[9] Informational asymmetry refers to decisions where one party has more information than the other. In the context of rate setting, the utilities providing information will naturally have more information than regulators and other parties, although this can be mitigated through information sharing and other mechanisms that boost transparency.

MRPs reduce regulatory lag and rate case frequency, but unlike future test years, MRPs are not frontloaded. Rather, MRP rates change over time as forecasted conditions occur, providing a more gradual increase in rates. MRPs also provide more transparency than formula rates, as they provide certainty about when and by how much rates will change. Conversely, like forecasted test years, MRPs rely heavily on information from utilities and as a result come with significant informational asymmetry, which MRPs may exacerbate by employing predictions about conditions several years in advance.

Very few states have established fully functioning, classic MRPs as described above; however, several states, including Maryland, have implemented plans that bear a close resemblance. PSC technical staff has recommended that if Maryland would adopt classic MRPs, it should consider how to reduce informational asymmetries, and how other alternative rate mechanisms – such as cost trackers, STRIDE charges, and regulatory assets and liabilities – fit within a scheme that also allows utilities to recover costs without a rate case.

Performance Based Ratemaking

As its name suggests, performance based ratemaking (PBR) aims to encourage better utility performance more effectively than traditional ratemaking. Under PBR, a regulator typically uses metrics to reward utility performance with increased profits and to punish poor performance with lower profits or penalties. In contrast to fully forecasted test years, MRPs, and formula rates, PBR is not a firm methodology; rather, a regulator may integrate elements of PBR into any form of ratemaking. Although PBR may increase risk for utilities, which are traditionally risk averse, establishing incentives for certain behaviors may lead to more innovative practices. PBR also reduces regulatory lag by giving utilities more control over their return, and establishes clear procedural milestones for future rate proceedings. On the other hand, in Maryland, utilities already have a duty to provide safe, reliable service in accordance with a variety of State environmental, safety, reliability, and other laws. PBR also involves informational asymmetries, carries significant regulatory costs, and if not properly designed or monitored, may lead to disproportionate results. PBR may also reduce traditional regulatory authority over cost relative to performance.

Several states use PBR, with mixed results; the United Kingdom uses PBR extensively. Before adopting PBR, Maryland may wish to consider whether its current ratemaking practices are already producing satisfactory results, the amount of additional regulatory costs, and how to reduce asymmetries of information.

Alternative Rate Recovery Mechanisms

Residential distribution rates in Maryland usually include two principal components: a customer charge reflecting the fixed costs of delivering energy and an energy charge based on volumetric usage. Some customers – especially commercial and industrial customers – also often pay demand charges designed to reflect the higher cost of using energy during peak usage periods.

A variety of "alternative" methodologies may alter or supplement these components in order to achieve certain policy outcomes.

Higher Customer Charges

As favored by electric cooperatives such as SMECO and Choptank, the ability to establish higher customer charges – potentially without direct PSC approval – allows utilities to recover all or more of their fixed costs, thereby sending more accurate price signals to consumers relative to their usage and simplifying the complexity of and need for frequent rate setting in general. Utilities with higher fixed charges have a greater incentive to encourage conservation because variable rate revenue is no longer necessary to cover fixed costs. Moreover, higher fixed costs reduce subsidies to net metering customers, who generate their own power and often pay little or no volumetric charges. The corollary to this, however, is that higher fixed costs reduce the incentive to install residential solar. Higher fixed charges may also adversely impact low-usage customers, discourage energy conservation, and duplicate existing rate stabilization mechanisms like bill stabilization adjustments (BSAs), discussed below. Impacts on conservation may be more muted, however, because fixed charges only have an impact on distribution rates.

Minimum Bills

Like higher fixed costs, minimum bills attempt to ensure that all ratepayers pay to maintain the distribution system by imposing a threshold charge that customers must pay if they do not use a certain amount of energy. As a practical matter, the charge only applies to customers who use a minimal amount of energy, such as net metering customers; thus, most customers receive no charge. As a result, minimum bills may better align utility revenues and costs without impacting the energy conservation efforts of the vast majority of ratepayers. Although some advocates express concerns about impacts on low-income households, correlations between low incomes and very low usage are disputed. Like higher customer charges, minimum bills could, however, lessen incentives for the installation of residential solar.

Tiered Rates

Tiered rates establish various price blocks based on a customer's energy usage during the relevant period, typically a billing period. Depending on how they are structured, tiered rates can be used to facilitate a range of policy outcomes. For example, in order to encourage the recovery of fixed costs, a regulator could approve declining block rates that decrease in rate as usage increases. Alternatively, to encourage conservation, a regulator could approve increasing block rates that increase in rate as usage increases. In Maryland, as in other states, regulators have recently favored rates that encourage or at least do not discourage conservation.

Time-of-use Rates

Time-of-use rates charge customers more during times when energy is more expensive to deliver, and typically when energy has a greater environmental impact. With the advent of smart meters that can track periodic energy usage, PSC has been working to increase the use of time-of-use rates[10] for both Standard Offer Service customers and customers of competitive suppliers. PSC has authorized, and working groups are actively working on implementing, pilot programs that would allow companies to price – and customers to tailor their energy use – in accordance with certain periods of the day when energy delivery is more or less expensive. PSC has also directed each IOU to develop time-of-use rates to implement incentives for electric vehicle owners to charge their vehicles during off-peak hours.

Residential Demand Charges

As with time-of-use rates, demand charges encourage the efficient use of energy, but have not yet been widely used for residential customers. A customer pays a demand charge on the basis of energy used during a certain time period during a monthly billing cycle, typically 15 minutes to 1 hour. With smart meters, demand charges may be applied to residential customers more widely. Demand charges, however, may work more effectively for customers – like businesses – that have a strong incentive and ability to monitor high usage at certain periods, and less effectively for smaller use customers with less incentive and ability to monitor peak pricing signals.

Revenue Decoupling

Revenue decoupling separates or weakens the connection between revenue and energy sales, reducing or eliminating disincentives for utilities to encourage energy conservation. Under revenue decoupling, PSC has for several years approved rate adjustments that respond to changes in sales. Revenue decoupling is also a key component of the EmPOWER Maryland energy efficiency program, to ensure that utilities promote energy efficiency without penalty and in an effective manner. Decoupling also allows electric companies to account for unanticipated changes in usage due to severe weather and customer response to supply price increases.

In Maryland, decoupling is practically accomplished through a bill rider known as BSA, which is a lagged addition to or reduction from a customer's monthly bill that aligns actual revenues with expected revenues set in rate cases. For example, if a utility receives higher-than-expected revenue in one month, a reduction is applied to a subsequent billing period. Similarly, if a utility receives lower-than-expected revenue in one month, an increase is applied to a subsequent billing period.

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[10] PSC has previously authorized time-of-use rates for certain BGE customers and certain electric vehicle pilot programs established by statute, but neither program has been particularly significant in scope.

Other Trackers, Surcharges, and Adjustment Clauses

There are several other ways to allow for utilities to recover their costs more quickly outside of a formal rate case. A regulator may approve provisions in a utility's tariff that allow cost recovery for infrastructure spending, energy use, energy conservation programs, taxes, and other items. For example, as mentioned above, in Maryland, most electric utilities collect a monthly surcharge for their administration of the EmPOWER Maryland energy efficiency program, and most gas customers pay a monthly STRIDE program surcharge for accelerated gas pipeline safety work.

Return on Equity

Many alternative ratemaking processes and rate recovery mechanisms carry the benefit of reducing the risk that a utility may not recover certain revenues. As discussed above, regulatory risk is typically a component that regulators consider when setting a utility's ROE, because utilities that are considered more risky require a higher ROE to attract capital, which results in a higher rate of return and revenue requirement. As a result, many state regulatory agencies – including, for example, Maryland with STRIDE and New York with fully forecasted test years – will, when determining ROEs, consider any reductions in risk that utilities face for cost recovery. Although House Bill 653 and Senate Bill 572 were introduced with a provision prohibiting PSC from adjusting a utility's ROE in connection with an alternative form of regulation, the House struck that provision in House Bill 653. The Senate did not make a decision on that provision. PSC maintains the discretion to make adjustments for regulatory risk under any MRP it approves under the new approach to ratemaking it develops as result of PC 51 and Case No. 9618.

Maryland Public Service Commission Authorized Multiyear Rate Plans

In Order No. 89226, endorsing the implementation of MRPs of up to three years based on a historic test year, PSC acknowledged several "perceived drawbacks" associated with traditional ratemaking, including regulatory lag, limited opportunity to reach policy goals, less cost monitoring, and unequal risk distribution. Citing a slew of State policy goals, PSC noted that with deregulation, it lacks the level of insight into utility planning processes it once had with integrated resource planning, and that a stronger move toward alternative ratemaking processes would bolster transparency and allow PSC to more effectively encourage utility investments that serve the State's policy goals.

PSC declined to endorse formula rates, noting that they do not effectively address regulatory lag and require extensive ongoing regulatory work, among other shortcomings. Instead, PSC noted its successful experience with MRPs in a previous case, which may also allow PSC staff to implement MRPs more efficiently. PSC further noted that MRPs may alleviate rate shock by spreading changes over a longer period of time, lessen regulatory work, provide more price predictability, and reduce regulatory lag. PSC also found that MRPs allowed for adjustments to reflect a changing business environment instead of revenues and costs, along with minimal risks to ratepayers. Finally, PSC also emphasized that MRPs provide increased transparency and annual true-ups, and, in sum, they combine the stability of historic test years with the ability to respond to changes in energy markets.

Going forward, PSC noted that it would draw on the experience of other states to ensure that it realizes more transparency in and oversight of utility distribution planning processes, and that "stay-out provisions" featured by MRPs would prevent utilities from filing for new rates for the duration of their MRP, which could last for up to three years under PSC's decision. To those ends, PSC ordered its Public Utility Law Division to assign a Public Utility Law Judge to lead a working group of interested parties in developing and submitting a detailed implementation report by December 20, 2019[11]. PSC committed to try to issue a ruling with further implementation guidance by January 30, 2020, and contemplated utilities beginning to file MRPs on or after February 1, 2020.

PSC also found it prudent to investigate incorporating performance based ratemaking into future MRPs. PSC determined that PBRs could meet the important goal of aligning State policies with utility rate increases, and that although requiring incentives and metrics would take additional time, the working group should, after submission of the initial implementation report, begin considering appropriate areas for metrics and report to PSC by April 1, 2020, after which PSC may provide additional guidance on the list of appropriate metrics and how to set them.

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[11] PSC required the working group to address the following issues: (1) details regarding the forecasts that must be filed for subsequent years after the initial historic base year, including capital expenditures; (2) a complete list of the proposed reporting requirements, measures, and timelines; (3) proposals for staggering filings to prevent overburdening PSC staff resources; (4) identifying ways to make the utilities' planning process more transparent and open to the commission and ratepayers; (5) recommendations on requirements to decrease information asymmetries between the utility and the affected parties; (6) identifying ways to ensure that the burden of proof remains with the utilities to show that a proposed rate change is just and reasonable; (7) proposals for an annual true-up mechanism; (8) proposals for stay-out provisions; (9) proposed revisions to regulations for filing MRPs; (10) recommendations to ensure that existing regulatory metrics (such as those for service reliability, customer calls, stray voltage, and vegetation management) are not eroded and remain intact through AFOR adoption; and (11) advice on whether additional conditions for filing an AFOR need to be developed for utility companies on an individual basis and, if so, what approach would be most efficient.

Sources

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