CAREC Energy Reform Atlas

Tariff Reform Toolkit

November 2021

This document, the Tariff Reform Toolkit, reviews the principles and objectives that are critical to consider when pursuing tariff reforms. The Toolkit also offers policymakers an approach to implementing and regularly reviewing cost-reflective tariffs in their respective countries. The Toolkit is accompanied by a separate Case Studies Report, which exemplifies the range of tariff design approaches that are in place around the world through three case studies:

- ***Georgia, United States ("US"): an example of cost of service ("COS") ratemaking;***
- ***Colombia: an example of standard performance-based ratemaking ("PBR"); and***
- ***the United Kingdom ("UK"): an example of next generation PBR.***

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List of acronyms

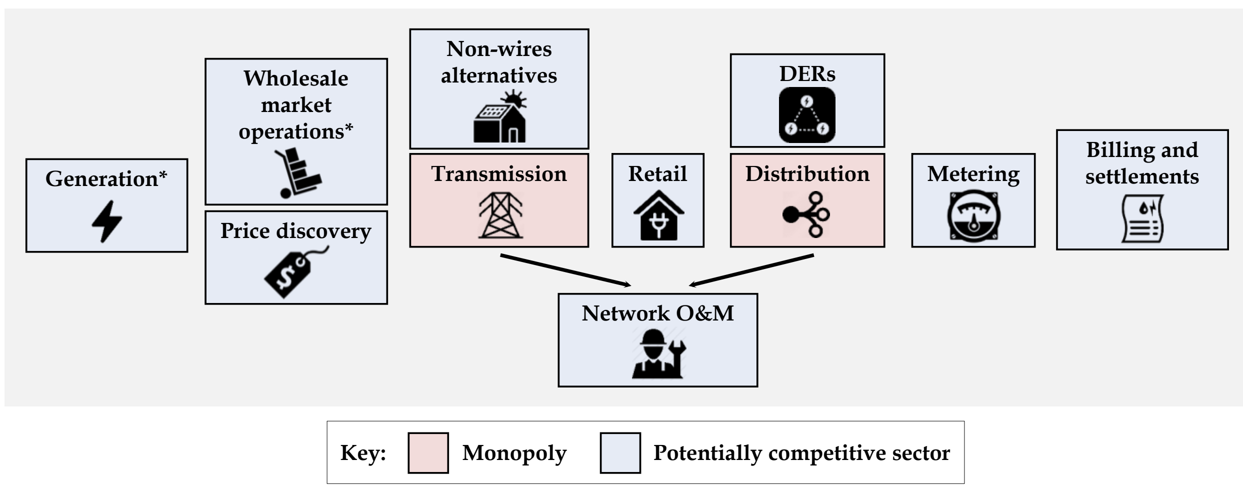
ADB	Asian Development Bank
CAIDI	Customer Average Interruption Duration Index
capex	Capital expenditures
CAPM	Capital asset pricing model

CAREC	Central Asia Regional Economic Cooperation
COS	Cost of service
COSS	Cost of service study
DCF	Discounted cash flow
DER	Distributed energy resource
EDR	Economic development rate
ERP	Equity risk premium
ESM	Earnings sharing mechanism
GAAP	Generally Accepted Accounting Principles
ISO	Independent system operator
kW	kilowatt
kWh	kilowatt-hour
O&M	Operation and maintenance
PBR	Performance-based ratemaking
RFP	Request for proposal
RIIO	**R**evenue = **I**ncentives + **I**nnovation + **O**utputs
ROA	Return on assets
ROE	Return on equity
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TFP	Total factor productivity
UK	United Kingdom
WACC	Weighted average cost of capital

1 Executive summary

To begin understanding tariff design, it is important to distinguish between aspects of the electricity value chain that are competitive, meaning prices are set by market forces, and which aspects are regulated, with prices set according to procedures established by regulatory bodies. Typically, while all value chain segments are regulated from the perspective of health, safety, environmental impact, and consumer protection, only some have prices subject to regulatory approval. Figure 1 provides an illustration of the electricity supply value chain, differentiating between aspects of the value chain that could be considered natural monopolies (highlighted in red), with those that could be competitive (in blue).

Figure 1. The electricity supply value chain



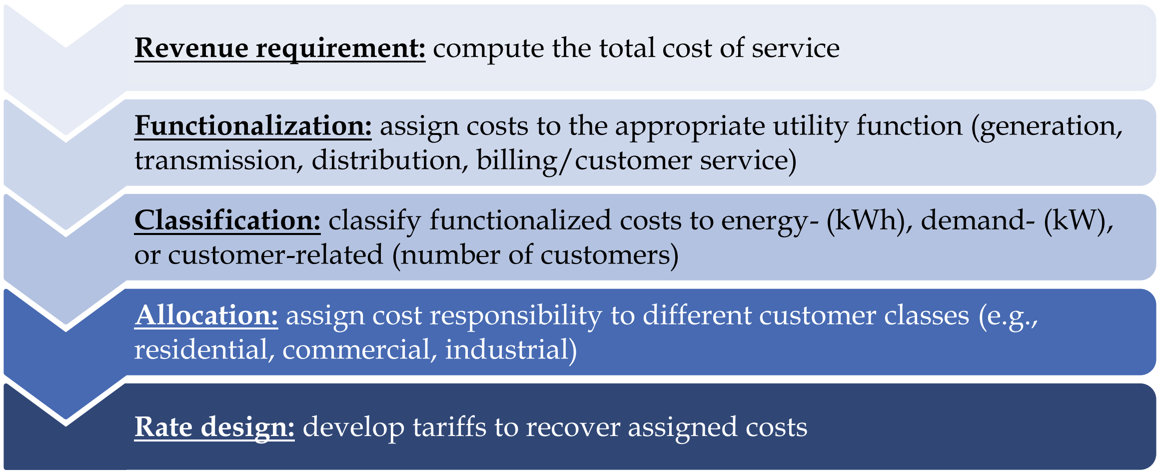
* Independent system operator ("ISO") may be deployed.

Note: DERs – distributed energy resources; O&M – operation and maintenance.

For vertically integrated electric utilities (i.e., those that own assets across the value chain, including generation, transmission, and distribution), as well as for the natural monopoly activities of unbundled entities, the basis for setting rates is what is known as ***cost of service*** ("COS"). Simplistically, a utility adds up all of its costs (the total of which is referred to as its ***revenue requirement***) and allocates them across its customers, who are sometimes referred to as ratepayers. Figure 2 illustrates a high-level summary of the COS ratemaking methodology.

A utility's costs include capital costs associated with the construction of generating stations, transformers, wires, poles, and associated infrastructure (collectively, the ***rate base***), divided by the number of years of expected service; operating costs, which are largely related to the cost of employees; and the cost of capital, which is the return on ratebase and compensates lenders and shareholders of the utility. Some costs are charged on a per unit (usually a kilowatt-hour ("kWh")) basis, meaning customers only pay based on what they use; some are charged based on ***peak demand*** (per kilowatt, or "kW"); while some other costs are charged on a per customer basis, meaning a portion of the customer's bill is not impacted by usage. Rates may be based on forecast or historical costs; in either case, a true up to actual costs may be necessary periodically.

Figure 2. Cost-of-service methodology



An approach that is typically viewed as an alternative to traditional cost of service regulation is ***performance-based ratemaking*** ("PBR"), which shifts the balance of the ratemaking process away from one that investigates costs, to one that sets a partly pre-determined (formulaic) path for rate growth.

The following **Tariff Reform Toolkit** ("the Toolkit") reviews both of these rate setting approaches (i.e., COS and PBR) in detail, providing policymakers and interested stakeholders with a comprehensive document to inform the tariff reform process. As such, the Toolkit is structured as follows:

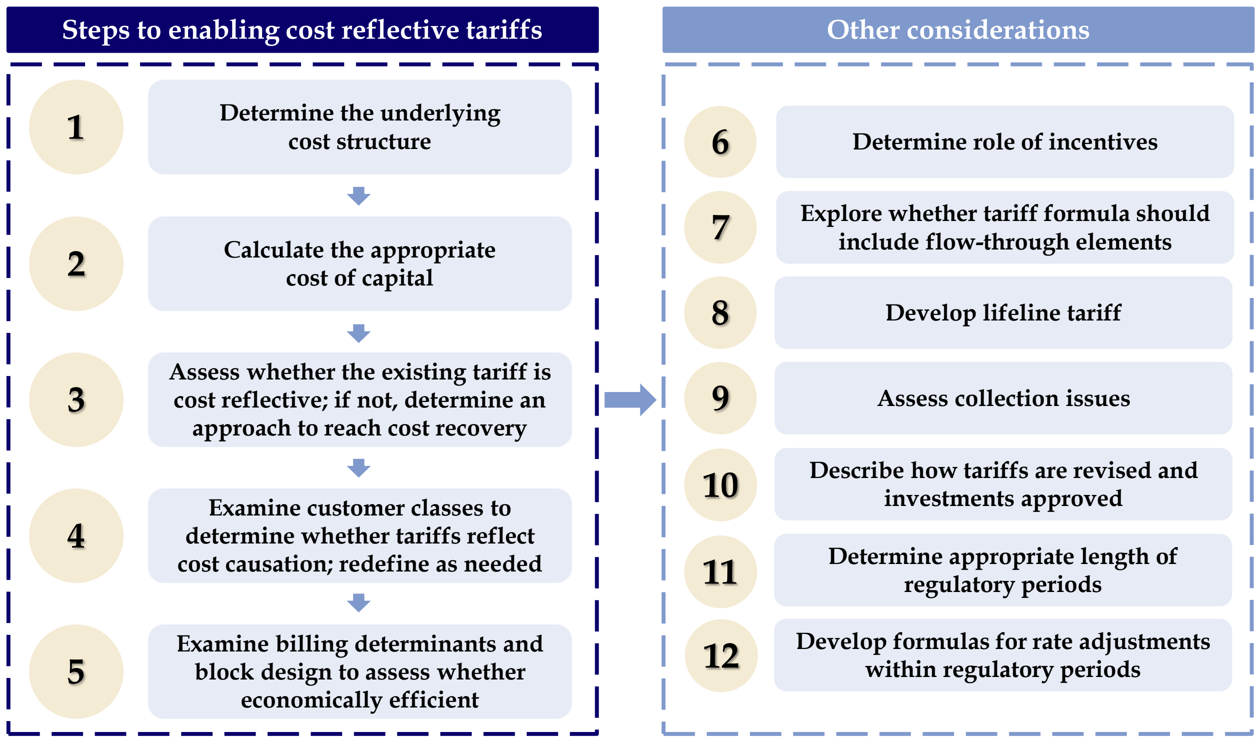
- **tariff design basics** (Section 2): the opening chapter of the Toolkit presents the foundational principles of tariff design, as identified by academics such as James C. Bonbright. These principles guide policymakers to ensure that rates achieve and support the following goals: (1) economic efficiency and performance, (2) customer focus and bill impacts, (3) stability of the sector, (4) evolving the utility structure to facilitate innovation, and (5) regulatory simplicity. The chapter also reviews the basics of COS and PBR, including what each approach involves, how they differ from one another, and the perceived advantages and disadvantages associated with each regime; and
- **tariff reform implementation approach** (Section 3): this chapter proposes a 12-step approach to enforcing practical tariff reforms, which policymakers can use as a guide for: (1) reaching cost reflective tariffs, and (2) enabling the regular review of tariffs once implemented. Each step in the 12-step approach is illustrated in Figure 3, and builds on the knowledge and principles introduced in the opening chapter.

The Toolkit is also accompanied by a separate **Case Studies Report**, which looks to jurisdictions across the world to survey the various rate design approaches that have been implemented to date. Specifically, the Case Studies Report focuses on three informative case studies:

- **Georgia, United States ("US"):** an example of cost of service ratemaking;
- **Colombia:** an example of standard performance-based ratemaking; and
- **the United Kingdom ("UK"):** an example of next generation PBR.

We refer to these three case studies throughout the Toolkit, using textboxes to highlight examples of how certain steps in the rate design process are tackled in the US, Colombia, and the UK, where appropriate. Further details regarding the ratemaking approach used in each jurisdiction are available in the separate Case Studies Report, which also includes an overview of the electricity market in each country to provide further context.

Figure 3. Overview of the tariff reform implementation approach



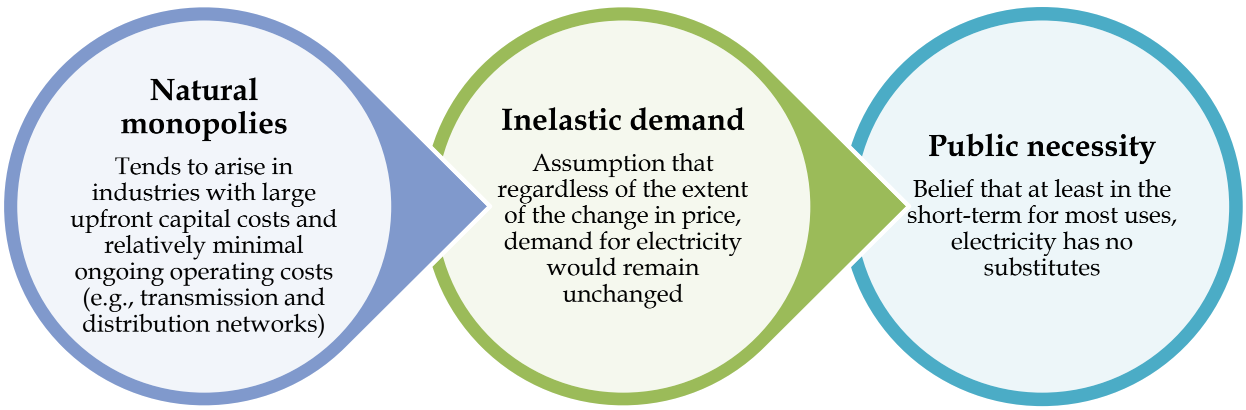
To assist in reading the Toolkit, we also review key energy sector terminology in a glossary (see Section 5). These terms are used throughout the Toolkit, and are highlighted in ***bold italics.***

2 Tariff design basics

2.1 Guiding principles

Traditionally, electricity has been considered a special type of commodity. This view is rooted in the physical properties of electricity, how the industry evolved, and the utility that electricity supply provides to ultimate consumers. Essentially, early electric utilities developed as vertically integrated companies, and they were assumed to be natural monopolies. In addition, because devices that store electricity have historically been expensive (though the technology is improving in this regard), electricity generally must be consumed when it is produced; this means that demand for electricity is largely inelastic. Finally, electricity has become a public necessity.

Figure 4. Fundamental assumptions about the electricity sector



Given these fundamental assumptions (as illustrated in Figure 4), it has been a long-held view that electricity supply needs to be monitored, reliability maintained, and consumers "protected" in a manner which applies to almost no other commodity. The nature of regulated rates for electricity implies that rates are set in advance of a utility incurring the costs associated with producing and delivering electricity, which means that the process is subject to forecast errors, bias, and political machinations.

To minimize the potential for these negative consequences of regulatory practice, and to improve the outcomes (i.e., ensuring reasonably profitable utilities and satisfied customers), a number of guiding principles have been put forward. The textbox below outlines examples of the key rate design principles taken from the *Principles of Public Utility Rates* by Bonbright *et al*. According to these foundational principles identified by Bonbright, first published in 1961, rates should have practical attributes including "simplicity, understandability, public acceptability, and feasibility of an application."[1] Specifically, the goal of protecting the interests of consumers may be linked to the principles of non-discrimination, cost causation, and avoidance of cross-subsidies, while the goal of promoting economic efficiency and cost effectiveness is consistent with the principles of financial stability and ensuring a fair rate of return.

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[1] Bonbright, James C., Principles of Public Utility Rates, Columbia University Press, New York NY, 1961.

Sample of ratemaking principles identified by Bonbright

Financial stability and fair rate of return: rates must be set at a level which enables the utility to meet its statutory obligations to serve, while earning a commercially reasonable return and generating sufficient cash flow to support necessary investment.

Non-discrimination: similarly situated customers should face similar terms and conditions. Whereas competition, in theory, will assure that customers with similar tastes and preferences face a similar set of choices, in a regulated environment such an outcome is assured only through enforcing non-discrimination in rate design.

Incentives compatibility: rate design should, where possible, provide appropriate incentives to both the utility and consumer – namely (1) encouraging utilities to reduce costs, while ensuring reliable, safe, and quality service for customers, and (2) discouraging inefficient consumption on the part of customers. Thus, rates should largely align the interests of the utility and its ratepayers.

Cost causation and avoidance of cross-subsidies: one of the most fundamental principles of utility rate design is that the customer that causes a cost to be incurred should pay that cost. If cost causation could be perfectly identified, cross subsidies (either between or within customer classes) could be avoided.

Administrative simplicity and transparency: rates should be straightforward for customers to understand. Complex rate designs increase costs to consumers, and may result in more time being spent proving that the rate design is indeed fair to all customers. Ratemaking mechanisms should also be appropriate for the jurisdiction in which they are applied – complex rates in regions with poor data and understaffed regulators may be impossible to administer.

Source: Bonbright, James C., Principles of Public Utility Rates, Columbia University Press, New York NY, 1961.

Incorporating the principles and considerations discussed above, guiding principles of ratemaking may be grouped into five broad categories, as illustrated in Figure 5 and described in further detail below:

1. **economic efficiency and performance**: rates should provide sufficient funding to maintain reliability consistent with customer expectations, while recognizing that such preferences are increasingly varied. Rate design should also encourage productivity enhancement in remaining natural monopoly portions of the business;
2. **customer focus and bill impacts**: rates should encourage the pursuit of opportunities for better cost containment, and to the extent possible, cross-subsidies must be avoided;
3. **stability of the sector**: rates should send investment signals that are proportional to the associated risk and market returns; remuneration should take into account the impact on debt service coverage ratios and associated parameters for maintaining an efficient capital structure;
4. **evolving utility structure to facilitate innovation**: the rate framework must balance incumbent opportunities against market participation, reducing barriers to the third-

party providers of services. In addition, capital expenditure (“capex”), ownership, and technology biases should be eliminated to emphasize the focus on a long-run, least-cost approach for determining solutions to identified system and customer needs; and

5. **regulatory simplicity**: ratemaking must balance appropriate oversight with administrative simplicity to avoid an overly burdensome process for all parties. Moreover, the framework must have built-in decision and evaluation criteria to increase accountability and advance strong stakeholder support.

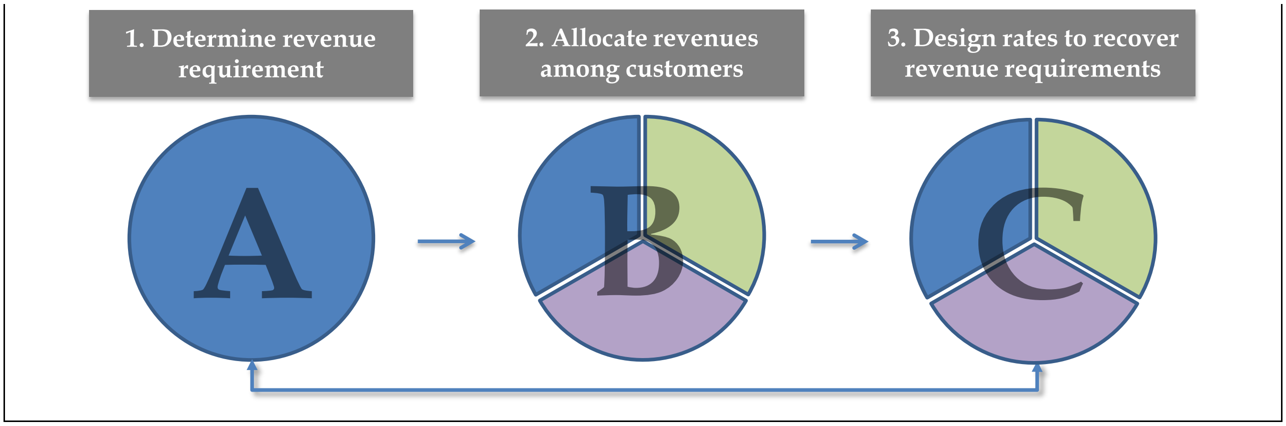
Figure 5. Broadly accepted principles of ratemaking

While the belief that electricity is “special” was always somewhat exaggerated, advances in technology across the value chain are further calling into question the justification for treating electricity, and the networks that transport it, differently from other commodities and transport networks. In the following subsections, we will explore the key elements of traditional ratemaking approaches (i.e., cost of service) as well as more advanced forms (i.e., performance-based ratemaking). However, regardless of the ratemaking regime in question, the basic stages in establishing electricity rates are the same (see Figure 6):

1. **determine the revenues** that the utility requires to cover the cost of producing and delivering electricity to consumers (i.e., the revenue requirement);
2. **allocate revenues** among customers, primarily through ***customer classes***; and
3. **calculate the rates** applicable to customers (primarily by customer class or category) that produce the required revenues.

As illustrated in Figure 6, so long as Pie C (i.e., revenues derived from customers using the designed rates) is equal to Pie A (i.e., the utility’s revenue requirement to cover the cost of operating its business and earning a reasonable return for investors), the ratemaking process has achieved its main objective.

Figure 6. Regulatory ratemaking process



The chief distinction between the traditional and more advanced forms of ratemaking lies in how the revenue requirement is determined. However, while other stages are common and similar to both ratemaking approaches, they are not 100% identical.[2] Section 2.2 discusses the major features of cost of service ratemaking (with a brief overview of each stage outlined above), while Section 2.3 covers the reasons why performance-based ratemaking emerged, as well as the main features of this approach.

2.2 Cost of service ratemaking

As the name implies, cost of service ratemaking involves determining electricity rates based on the cost of operating the utility business, which for vertically integrated utilities, includes the costs associated with generating, transmitting, and delivering electricity to ultimate consumers.

This ratemaking regime stems from the evolution of the so-called ***regulatory compact*** between the utility, regulator, ratepayers, and investors (see Figure 7). The regulatory compact is an agreement whereby the utility takes on an obligation to serve in return for a guarantee of cost recovery, including the cost of capital. Provided the resulting rates are just and reasonable, the utility is able to pass through all appropriate costs to customers. This compact or agreement means that:

(1) **utilities** have the confidence to be able to invest in new plant and equipment (because they know how their investment will be recovered); and

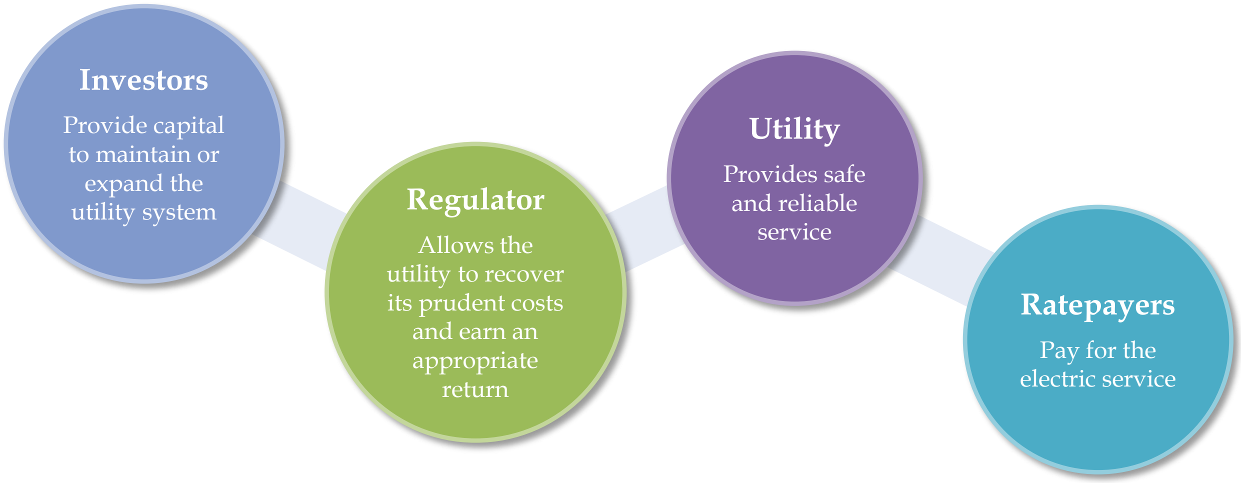
(2) **customers** have confidence that when electric service is required, their business or place of residence will be connected, and that once connected, they can expect reliable service.

It is only when these fundamental principles (i.e., recovery of investment and reliable service in return) are well established that more sophisticated ratemaking regimes should be considered. The economic losses from unpredictable electricity supply are great; by focusing on the fundamentals, and then adding in improvements in incentive compatibility after the sector is

[2] The differences in Steps 2 and 3 are derivative of and complementary to the approach taken in Step 1, whether the revenue requirement is determined as cost-based or incentive-based.

established on a full cost recovery basis, policymakers can assure that the sector can be sustainable over time.

Figure 7. The regulatory compact



Source: S&P Global Market Intelligence. *RRA Regulatory Focus – The rate case process: a conduit to enlightenment.* June 15, 2020.

2.2.1 Determining the revenue requirement

Cost of service rate design rests on a deceptively simple set of calculations. In its most basic form, the ***revenue requirement*** is representative of the totality of costs of operating an enterprise to provide electricity service and is formulaically reflected in Figure 8.[3]

Figure 8. Revenue requirement formula

$$Revenue\ requirement = (\,Rate\ base \times Rate\ of\ return\,) + Operating\ expenses$$

Rate base

The ***rate base*** is the total of all of the utility's long-lived investments, net of accumulated depreciation. Such investments include power plants, the transmission and distribution network, buildings, and other similar assets. The rate base also includes adjustments for working capital, deferred costs (known as ***regulatory assets*** – such as environmental costs, extraordinary weather damages, losses on asset retirements, among others), and deferred taxes (see Figure 9).

The eligibility requirements for investments to be included in the rate base are that they must be:

- **used** in providing services (e.g., a facility that is actually providing electric service);
- **useful** in providing services (such that without the facility, costs would be higher, or service quality would be lower); and

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[3] The Regulatory Assistance Project. Electricity Regulation in the US: A Guide (Second Edition). 2016.

- **prudently incurred** (i.e., a project that was chosen and constructed in an economic manner).

Figure 9. Rate base formula

	Total plant in service at original cost
-	Accumulated depreciation
=	***Net plant in service***
+	Working capital
-	Accumulated deferred taxes
+/-	Other regulated assets approved by the regulator
=	***Rate base***

Rate of return

The **rate of return** needs to be fair to investors and reasonable from the customer's perspective. There are different methods to establish a reasonable rate of return – a commonly applied litmus test is to determine if the rate of return allows the utility to attract additional capital to pay for its investment needs, without reaching levels of return that are expected by speculative, high-risk investors. Regulators typically allow different rates of return depending on the source of funding:

- a higher rate of return for **equity** capital; and
- a lower rate of return for **debt** funding, as debtholders take precedent over equity investors and, thus, face lower risk.

A utility with a simple funding structure (equity plus debt) will have a cost of capital that is equal to the weighted average cost of both sources of funding (i.e., the ***weighted average cost of capital***, or "WACC") – see Figure 10.

Figure 10. Weighted average cost of capital formula

$$WACC = (\, Equity\ percent \times Cost\ of\ equity\,) + (\, Debt\ percent \times Cost\ of\ debt\,)$$

Notably, when the regulator calculates the allowed rate of return, the percent of actual debt funding used (i.e., the debt leverage) is not necessarily the same as in the formula. The formula instead relies on the imputed (approved) debt ratio, which is often based on prevailing funding practices and expert input.

The often-contentious aspect of determining the revenue requirement is agreeing on the appropriate rate of return for equity capital. Typically, regulators will consider different methods or approaches to arrive at various values for the return on equity investment, and then select a fair rate based on circumstances related to the utility specifically and the economy in general. These methods are summarized in Figure 11.

Figure 11. Financial models used to determine an appropriate return on equity

Discounted Cash Flow	Equity Risk Premium	Capital Asset Pricing Model
Based on the present value of the returns an investor may earn in an equivalent company over a long period of time	Based on considering the risk premium investors would seek over the low-risk or risk-free assets (e.g., government bonds)	Uses statistical regression analysis to establish the risk of investing in a utility versus the risk-free assets

The cost of debt is relatively easier to establish as the regulator can review the actual cost of debt carried by the utility. However, for long-term rate determinations, the regulator may need to estimate the cost of debt in the future, using a combination of market-based benchmarks or expert opinion.

Operating expenses

Finally, the operating expenses comprise of costs related to labor, materials, depreciation, and tax, among others. In order to be included in the revenue requirement, these expenses must be necessary and prudent.[4]

Labor refers to the fully loaded costs (i.e., including bonuses, benefits, pensions, etc.) associated with hiring and retaining employees.

Materials represents the costs of items that are used quickly after purchase (i.e., those that are not capitalized for use over several years).

Depreciation reflects the annual charge for use of capitalized equipment (i.e., equipment that is expected to provide service for more than one year). This represents the **return of** capital, or the payback of contributed funds.[5] Depreciation schedules are established for all long-lived assets, accounting for each asset's acquisition value, its estimated service life, and the pattern of expiration of the asset cost over its service life. The estimated service life must take into account physical factors (such as ordinary wear and tear from use, chemical action such as rust, etc.) and functional factors (such as obsolescence). The pattern of expiration is often, but not always, on a straight-line basis, which divides the acquisition cost equally by the estimated service life. Alternative measures are a sum of digits approach, and accelerated depreciation.

Tax includes charges imposed on the utility by government agencies, including industry regulators, and the tax code other than a tax on corporate profits.

2.2.2 Revenue allocation

Once the revenue requirement is established, the next task is to determine which customer pays what portion of these revenue requirements. The ideal approach would be to equitably and proportionately allocate the revenue among all individual customers. However, this approach is

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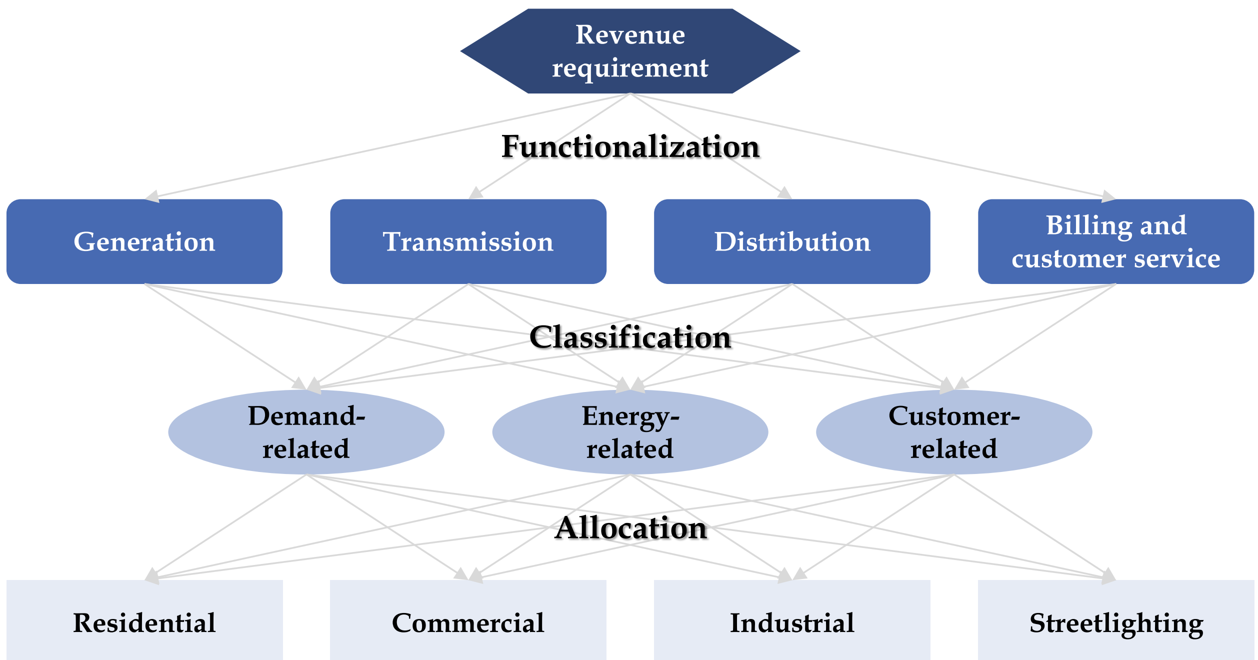
[4] Ibid.

[5] This is in contrast to the WACC, which accounts for a **return on** capital.

rarely feasible or desirable, and as such, the utility needs to establish customers classes that appropriately reflect its customer base, while also allowing the efficient collection of the required revenues.

The parameters on which customer classifications are based can be **usage patterns** (e.g., streetlight versus restaurant), **geographic locations** (e.g., rural versus urban), **type** (e.g., private residence versus industry), **volume of use** (e.g., large industrial versus small industrial), or any other number of parameters that are deemed appropriate. While there is no limit to the number of parameters used to establish customer classes, the most commonly used metrices are the number of customers, peak demand utilized (in kW), and the total energy consumed (in kWh).

Figure 12. Illustrative cost allocation process



Source: Regulatory Assistance Project. *Modern Cost Allocation and Rate Design.* April 17, 2020.

The utility will often commission different ***cost allocation*** studies to inform its decision in allocating costs across customer classes. A typical cost allocation study focuses on three dimensions (as illustrated in Figure 12):

- **functionalization:** what purpose does each cost item (i.e., rate base and expenses) serve for the utility? Is it used in/responsible for the production of electricity, or the transmission or distribution of power? Or is it general overhead?
- **classification:** involves dividing the costs into various components – demand (fixed costs), energy (variable costs), and customer components (directly related to the number of customers); and
- **allocation:** directly assigns the costs to customer classes if wholly attributable, or allocates the costs among customers based on an approach that balances numerous objectives (e.g., upholding the principle of cost causation, matching usage patterns, resulting in stable

revenues for the utility, easily understandable by customers, and acceptable to the regulator).

2.2.3 Rate development

Once cost allocation is completed, the regulator needs to determine the rates that are applicable to each customer class. As suggested in Section 2.2.2, there are three main ways that rates can be charged: based on the number of customers (i.e., per customer costs), per kW of peak demand used, and per kWh of energy consumed. There is no "one size fits all" solution of what rates should be per customer, per kW, or per kWh, as the rates ultimately need to reflect the utility's own circumstances – including the specifics of its customer base, its position in the investment cycle, and/or any policy-imposed objectives that require significant investments.

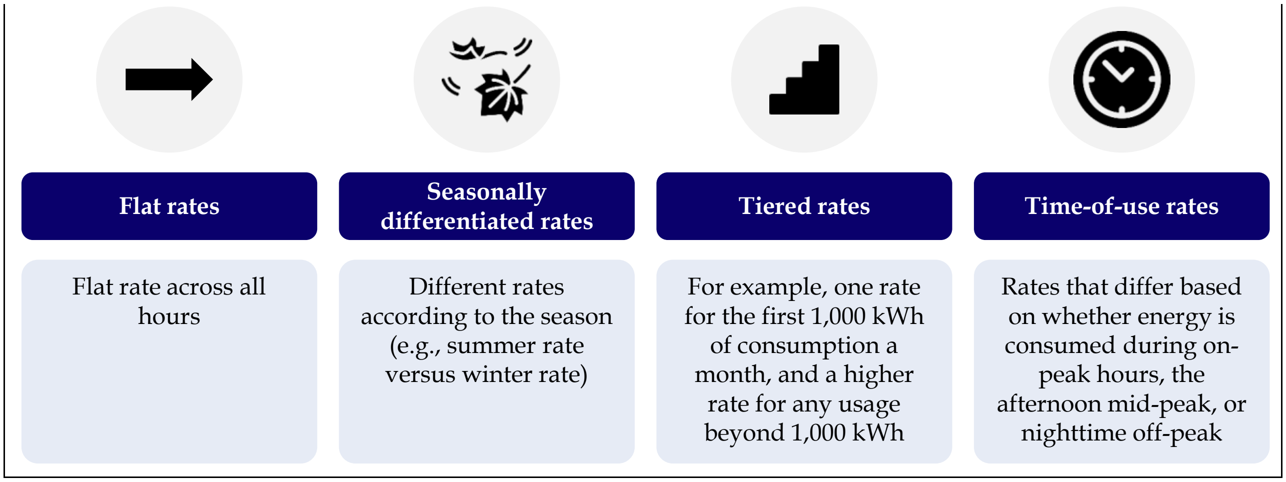
Additionally, each customer class typically has different interests in the final design of rates. For example, in the US, residential customers account for approximately 90% of customer accounts, represent about 50% of peak demand, and consume about 40% of energy.[6] If cost allocation was based strictly on the number of customers, then the burden would disproportionately fall on residential customers. If allocation was instead based on peak demand, then residential and small commercial customers would bear the brunt of costs. In contrast, the energy-based allocation would, by definition, allocate costs proportionately according to usage. Owing to these characteristics, advocates of residential customers in regulatory proceedings usually argue for a greater proportion of revenues to be recovered based on energy usage, while large industrial users generally seek greater weighting on the bases of the number of customers and peak demand use.

Other considerations for rate design may include policy objectives, such as minimizing the burden on vulnerable customers (e.g., low-income households). These objectives should be carefully considered, as cross-subsidization may introduce negative incentives.

Finally, within the rate components for each customer class, there is a range of options as well. For example, as illustrated in Figure 13, variable energy charges may take the form of **flat rates**, **seasonally differentiated rates**, **tiered rates**, or **time-of-use rates**.

Figure 13. Rate design options for the energy charge

[6] Ibid.



The separate Case Studies Report highlights the cost of service ratemaking approach in practice, using the US state of Georgia as an example. The textbox below briefly summarizes the state's electric rate design, and discusses the various rate options that are offered to customers of the state's only rate regulated electric utility, Georgia Power Company (US).

Case study example: cost of service ratemaking in Georgia, US

Under Georgia Code §46-2-23, the Georgia Public Service Commission ("PSC") in the US has exclusive authority to determine rates to be charged by all regulated entities under its jurisdiction. The only electric utility in the US state that is fully regulated by the PSC is Georgia Power Company ("GPC"), a vertically integrated utility that serves approximately 2.6 million customers in 155 of Georgia's 159 counties.

GPC is regulated under a COS regime, whereby the PSC authorizes GPC to recover certain expenses and a set return on equity ("ROE") through the rates charged to its customers. Through this process, the PSC aims to set rates that are just and reasonable, while also providing GPC with enough revenue to provide safe, reliable service and remain financially viable.

As part of the rate setting process, GPC conducts and files a COS study with the PSC. The aim of the COS study is to separate GPC's investments, expenses, and revenues among its jurisdictions (retail and wholesale), and then further among rate groups or classes within each jurisdiction. This study helps to determine GPC's revenue requirement and ascertain how well GPC's costs are being recovered from each jurisdiction (retail and wholesale) and customer group. Based on the COS study, GPC proposes modifications to its rates to help make tariffs more cost reflective. The PSC reviews GPC's rate request, and then reaches a final decision on tariffs.

GPC offers customers several non-traditional pricing options, including:

- **time-of-use rates:** residential customers can apply for the Nights & Weekends rate plan, which bills customers a basic service charge, along with variable energy charges that differ by time of day (i.e., on-peak or off-peak);
- **flat billing:** allows customers to pay a fixed amount per month, regardless of their usage; and
- **pre-payment options:** under the PrePay rate plan, customers add money to their account, which is reduced based on their electricity usage and days of use.

2.2.4 Drawbacks of cost of service ratemaking

The traditional framework of cost of service ratemaking was adopted early on as a reasonably simple tool to regulate a monopoly business. However, the success and effectiveness of this form of regulation predicates on the ability of the regulator to ensure prudent investment decisions by the utility. Yet, there exists an **information asymmetry** between the two entities, as it is only the utility that can be certain of its needs and associated costs.

The way in which cost of service ratemaking is structured also means that utilities are incentivized to increase their capital base in order to increase their profits – leading to ***gold-plated networks*** and over capacity. Similarly, operating expenses can also balloon as approved costs are passed on and recovered from customers under the cost of service approach. While the regulator does review and approve these costs, the regulator's staff may not always be able to examine all costs in detail, in order to correctly identify any exaggerated estimates.

In addition, as utilities need to demonstrate the need for capital investments in rate reviews, their increased investments (in order to increase profits) also necessitates greater utilization of the growing rate base. This means that utilities have an incentive to **promote greater consumption** by customers. At the same time, any increase in sales for a given rate base increases the profits as well (so long as marginal variable costs are lower than the marginal revenues) – this is known as a ***throughput incentive***.

Another drawback of cost of service ratemaking stems from the certainty provided to the utility of receiving a return on its capital investments. This leads to **risk-aversion** on the part of the utility's management, where uncertain returns for innovation or any radical changes means that they are deemed to be too risky compared to the status quo.

Finally, there is an unavoidable ***regulatory lag*** between the moment when costs change for a utility and the time the regulator approves a change in the utility's rates. This lag may work against the utility's bottom line, but it also may result in excess profits if costs decline (or do not increase as fast as anticipated) before rates are revised to reflect this.

Figure 14. Drawbacks of cost of service ratemaking

There is a range of different measures that can be employed to reduce the drawbacks identified above (see Figure 14 for a summary of drawbacks) – these include:

- **revenue decoupling**: where rates are established following the traditional cost of service ratemaking approach, but they are adjusted periodically to account for changes in sales, so that the revenues recovered are as originally intended and allowed. This eliminates the occurrence of the throughput incentive, and also removes the incentive to encourage consumer usage (thereby creating an opportunity for energy efficiency);
- **competitive power supply**: where the requirement to procure power supply through competitive processes (such as auctions) reduces the utility's incentive to gold plate the electric system;
- **unbundling**: where the regulator (with appropriate legislative authority) may force utilities to divest their generation and/or retail operations (i.e., supply business), thus removing the incentive for gold plating; and/or
- **performance-based ratemaking**: an alternative ratemaking approach where the rate of return is not tied to costs, but rather to other metrices that encourage efficient investment decisions and operations. This approach also shifts the balance of the ratemaking process away from one that investigates costs, to one that sets a partly pre-determined (formulaic) path for rate growth.

In the following section, we discuss the main characteristics and principles of performance-based ratemaking.

2.3 Performance-based ratemaking

2.3.1 Overview of PBR and comparison to cost of service ratemaking

Performance-based ratemaking ("PBR") is a regulatory approach that aims to provide incentives for regulated utilities to improve efficiency. PBR seeks to mimic competitive pressures in a natural monopoly environment, providing incentives for utilities to meet a given level of service at the lowest/most efficient cost. In so doing, PBR regulation strives to determine an "optimal price" for monopoly services. Rather than examining individual costs in detail, it allows utilities to make decisions regarding costs and inputs themselves to both:

i. **maximize output** relative to a given level of inputs; and

ii. ensure the most **efficient allocation** of competing inputs.

PBR is typically viewed as an alternative to traditional cost of service ratemaking.

As discussed earlier, under traditional cost of service regulation, rates charged to customers are a function of the revenue requirement, which in turn is a function of the costs incurred by the utility and a return on capital. In contrast, PBR addresses the drawbacks of traditional rate design by minimizing the direct linkage between costs and rates, and instead tying rates primarily to the ***inflation rate*** (or the ***I factor***, which is outside the control of the utility) and ***productivity*** (or the ***X factor***, which is controllable by the utility, though with limitations).

The formulas shown in Figure 15 succinctly demonstrate the fundamental differences between the COS and PBR approaches; it is important to note that the formulas use simplified representations – a full PBR formula showing other key components is introduced later in Section

2.3.2. Generally, under a PBR regime, the rates in the current year (**$Rates_n$**) are based on last year's rates (**$Rates_{n-1}$**) that are:

i. grown by an appropriate measure for the inflation rate affecting the cost of inputs (e.g., labor and materials);

ii. reduced for productivity gains that the utility is expected to make; and

iii. adjusted for other predictable changes in costs or circumstances that are outside the control of the utility (or the ***Z factor***).

Figure 15. Cost of service versus PBR formulas

Cost of service ratemaking:

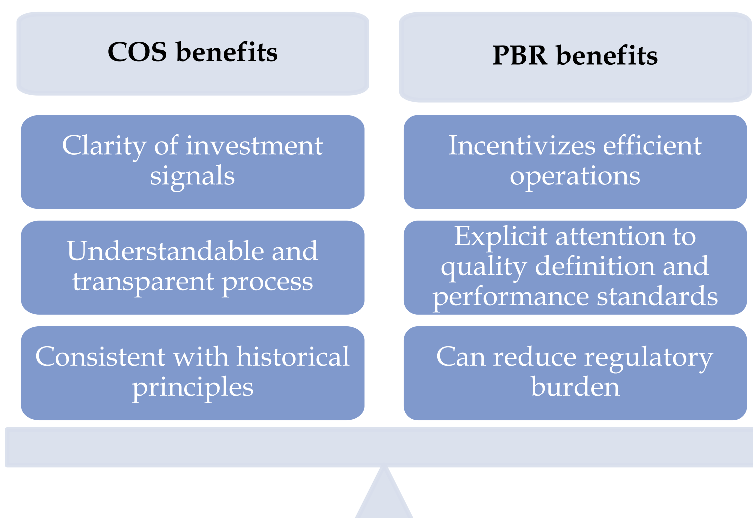
$$Rates = \frac{(\,Rate\ base \times Rate\ of\ return\,) + Operating\ expenses}{Sales}$$

PBR regime:

$$Rates_n = Rates_{n-1}\ x\ Inflation - \ Productivity\ \pm\ Z\ factor$$

The formulaic approach to determining rates under PBR removes the incentive for utilities to increase sales, and instead promotes prudent investment decisions and efficient operations. Figure 16 compares the perceived advantages of PBR versus COS regimes. In general, if properly designed, PBR should create lower rates for customers than a COS regime in the long-run, while also bringing commercial success to those utilities where management is willing to strive for and exceed industry expectations on productivity. PBR is also typically described as a regulatory framework that can, in principle, reduce the regulatory burden on both utilities and regulators, by decreasing the need for frequent regulatory hearings.

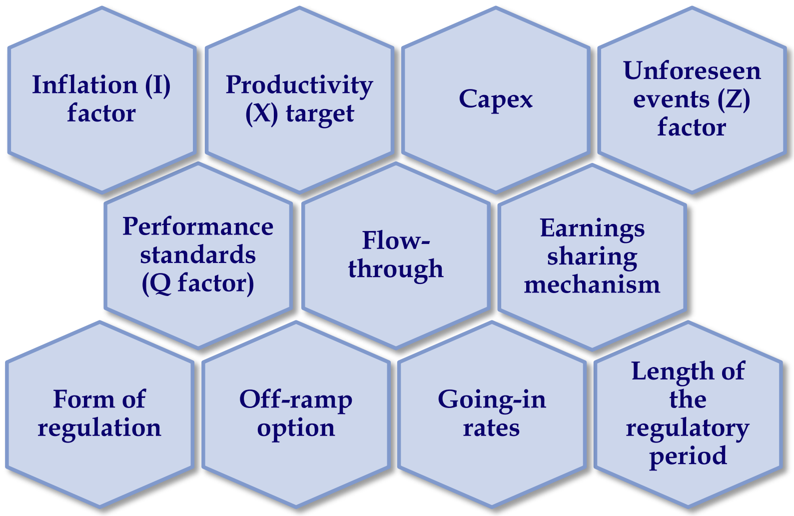
Figure 16. Comparison of COS and PBR benefits



2.3.2 Developing the PBR formula

PBR regimes are not just about selecting an inflation parameter and productivity factor. PBR mechanisms need to include a comprehensive set of components in order to fully address regulation. For example, a typical PBR "formula" may include ***performance standards***, ***earnings sharing mechanisms***, the treatment of (certain) ***capital expenditures*** ("capex"), among others (see Figure 17).

Figure 17. Potential components of the PBR formula



Performance standards

Typically, the PBR framework necessitates a focus on the bottom line, which can lead utility management to pursue imprudent cost savings, thus negatively impacting reliability and service quality. To address these concerns, regulators usually impose a set of conditions and requirements designed to tie the allowed rate of return to ***reliability and service quality indicators*** (or the ***Q factor***) – see Section 3.7.2 for further details.

Earnings sharing mechanisms

A step further in the PBR formula involves adding an ***earnings sharing mechanism*** ("ESM"), where excess returns (or alternatively a shortfall in returns) is shared between the utility shareholders and customers. The specifics of the sharing mechanism may include **symmetrical sharing** (e.g., excess earnings are split 50/50 in the form of an extra return to shareholders, and a rate reduction to customers), or it may be **asymmetrical** (e.g., customers may not be responsible at all or for only a small share of a shortfall in earnings, yet they may benefit from excess earnings).

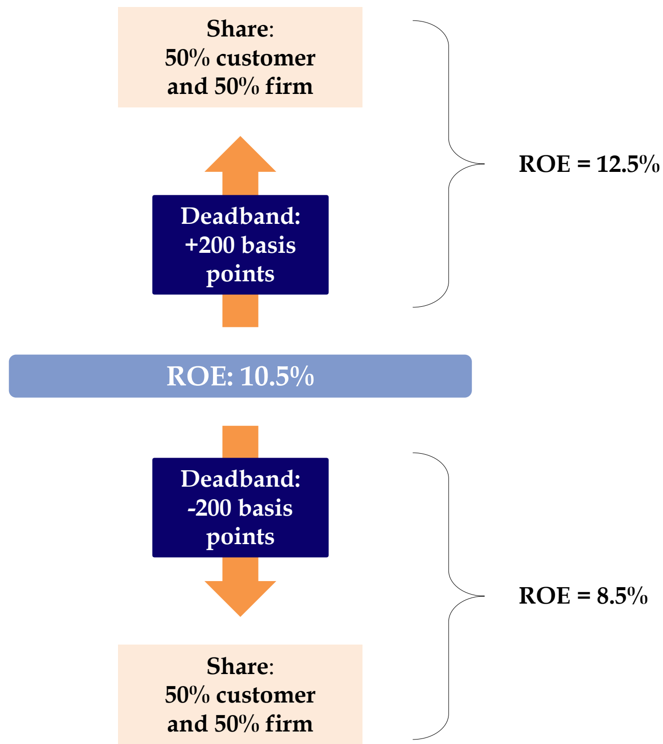
Generally, ESMs comprise of three elements:

1. a **target return on equity** ("ROE"), which is the regulator-approved return for the utility;
2. a **deadband** around the ROE in which no sharing takes place. The deadband allows customers to participate in gains without requiring extensive regulator involvement; and

3. a **share of gains or losses**, which dictates the percentage sharing split between customers and the utility for amounts that are outside of the deadband.

Figure 18 illustrates these design elements through an illustrative example of a symmetrical sharing mechanism.

Figure 18. Example of symmetrical sharing



The separate Case Studies Report showcases how an ESM can be added to the ratemaking regime, even under COS regulation. This is the case in the US state of Georgia, where although the state's only vertically integrated utility has its rates determined on a COS basis, customers are able to share in its excess earnings through an ESM (summarized briefly in the textbox below).

Case study example: Georgia Power Company's (US) earnings sharing mechanism

GPC's rates have been determined on a COS basis since its inception. Under this regime, GPC is allowed to recoup its capital and operating costs from consumers and earn a set ROE. However, the ratemaking regime also includes an ESM, which motivates GPC's management to improve efficiency, and helps avoid the possibility of unscheduled regulatory interventions due to windfall profits.

Through GPC's most recent rate case (for rates covering the 2020-2022 period), the ESM is structured as follows: the PSC authorized an ROE of 10.5%, with an earnings band set between 9.5% and 12%. If actual earnings rise above 12% ROE, GPC will refund 40% of earnings above that level to customers. Another 40% of excess earnings will be applied to regulatory assets (an accounting mechanism that allows utilities to defer costs related to various authorized matters, such as extreme weather), and the remaining 20% will be retained by GPC.

Capital expenditures

In terms of the underlying mechanics of implementing a PBR regime, there are certain features that are similar to traditional cost of service ratemaking. Before rates can be established for the current period, initial rates for the previous year need to be developed – these are known as ***test year rates***. Test year rates are based on a revenue requirement, which is derived in the same way as under a cost of service approach (see Section 2.2.1). Some utilities may require capital investments in excess of those incurred during an ordinary course of business (e.g., investment cycle related to the replacement of utility poles). These investments can be accommodated for in the PBR framework as an additional factor in the formula, known as the ***K factor***.

Overall, the PBR formula needs to be viewed holistically – parameter choices cannot be made independently of one another. For example, the choice of an inflation factor influences whether the productivity factor needs to include only "incremental" sector efficiency gains above that achieved economy-wide (as an inflation index using macroeconomic output-based measures will take into account some level of productivity gains). In addition, higher productivity factors and the assumption of greater risk by a utility (e.g., for certain macroeconomic risks), should ideally be linked to a higher allowed return on equity. Ultimately, data availability is also a critical consideration in developing a PBR formula. Figure 19 exemplifies the PBR formula that is seen in practice, while the table below it summarizes the purpose of each individual component.

Typically, determining the appropriate productivity or X factor is one of the most contentious issues in the PBR regulatory process. The productivity factor in the context of PBR refers not to the actual productivity of the utility, but rather to the changes in its productivity or gains in productivity. Economists have identified a number of ways in which historical productivity changes can be quantified:

- **Total Factor Productivity** ("TFP") analysis: measures the changes in outputs relative to the changes in inputs, thus determining whether the business is delivering more or less output for the given amount of inputs across a time series;
- **Econometric Cost Function** analysis: considers historical cost data to estimate the predicted cost value and compares it with the actual costs to establish the productivity performance at a specific point in time;
- **Stochastic Frontier Analysis**: a technique to estimate TFP that seeks to establish the most optimal production frontier and measures the utility's performance against the **efficiency frontier** – discussed in further detail later in Section 3.7.1; and
- **Data Envelopment Analysis**: another technique to estimate TFP that seeks to estimate the relative efficiencies between different utilities.

Each approach has its own advantages and limitations that direct the selection in specific circumstances (e.g., the number of years for which data is available, number of comparable utilities, and so on). Once the historical productivity gains are estimated, the next challenge is to select the appropriate future performance that the utility must accomplish in order to realize the promised rate of return. Regulators typically consider the opinions and reasoning of technical experts when selecting an appropriate productivity improvement target.

Figure 19. The "full" PBR formula and its components

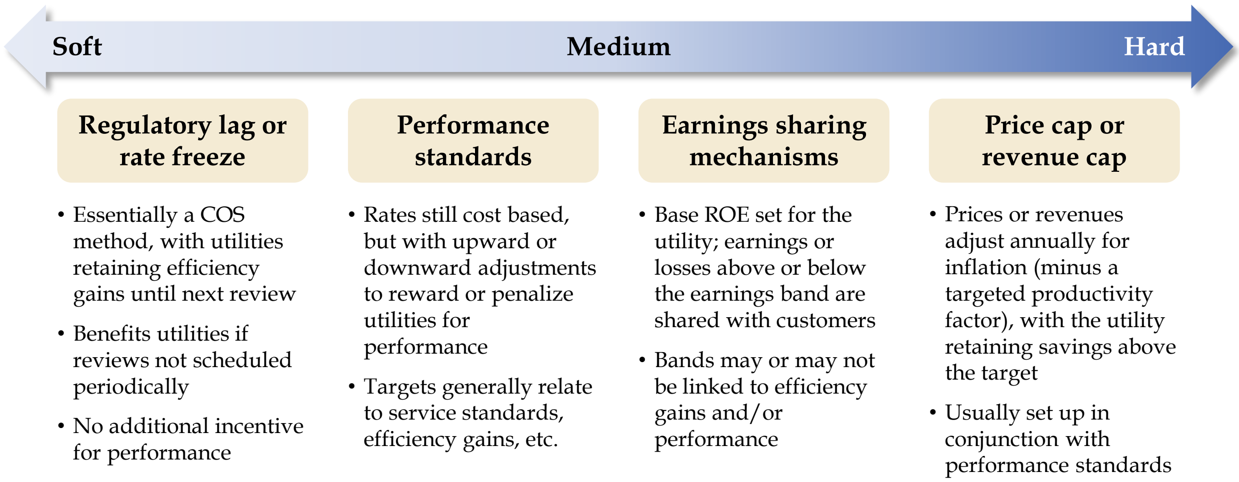
Price/revenue cap = Going-in rates x {Inflation (I) factor - Productivity (X) target} + Capex + Performance quality adjustment + ESM + Unforeseen events (Z) factor + Flow through

Components	Purpose
Going-in rates	Starting point of the PBR regulatory term. Rates usually determined through a COS filing (or rebasing). The PBR annual adjustment (I – X) is subsequently applied to those rates during the regulatory period.
Regulatory period	Scheduled time lag between two major reviews of the underlying components of the ratemaking regime.
Inflation (I) factor	Annual adjustment to the utility's revenue or rates reflecting the level of inflation, usually reflecting the actual inflation rate in the previous year.
Productivity (X) factor	Annual adjustment to revenue or rates reflecting expected changes in terms of productivity. May be based on the utility's historical performance or an external benchmark. May include a firm-specific target, or stretch factor.
Capex (K) factor	Annual adjustment to the utility's revenue or rates reflecting forecasted capex needs or *ex post* approval of capex spending in the previous year.
Performance standards (Q) factor	Contingent adjustment to revenue or rates for rewards/penalties linked to the achievement or failure to reach specified performance targets, usually in terms of service quality, as well as reliability and quality of supply.
Earnings sharing mechanism	Mechanism through which a specified portion of a utility's profits in excess of/below the approved return on equity/forecasted level of expenditures is returned to customers.
Unforeseen events (Z) factor	Contingent adjustment to revenue or rates in order to recover extraordinary costs that are outside of the company's ability to control or predict, usually above a materiality threshold.
Off-ramp option	Mechanism allowing for the trigger, under specified circumstances, of a review of the ratemaking regime in place before the end of the regulatory period. The process may lead to the overhaul or the termination of the regime.
Flow-through factor	Contingent adjustment to revenue or rates reflecting certain pre-approved costs that are automatically passed through to customers as they arise, without having to be approved by the regulator.

2.3.3 Types of PBR frameworks

PBR regulation is best conceptualized as a continuum, ranging from "soft" to "hard" mechanisms as depicted in Figure 20, rather than as a single type of regulatory regime. "Soft" mechanisms include relatively minor adaptations to the traditional COS framework, such as ***regulatory lags*** (where rates may be fixed for a period of time) and efficiency audits and reviews. In contrast, ***price caps*** and ***revenue caps*** (where prices or revenues adjust annually for inflation minus targeted productivity improvements) are "harder" forms of PBR. ***Performance standards*** and ***earnings sharing mechanisms***, between customers and the regulated utility, lie in the middle of the continuum.

Figure 20. Continuum of PBR regulation from "soft" to "hard" mechanisms



"Soft" mechanisms

In terms of "soft" mechanisms, options available to regulators include either a ***regulatory lag*** or a ***rate freeze***. A regulatory lag essentially allows for a delay in introducing new rates. The lag provides the utility a longer horizon to plan, operate and keep the benefits of the incentives provided in PBR. Likewise, through a rate freeze, the utility's rates are held constant during the PBR term. Such mechanisms give strong incentives to reduce or control operating costs. Rate freezes are also commonly used to protect consumers during the transition to a PBR regime. However, without inflation adjustments, lengthy terms can impose risks on the utility, particularly if substantial capital expenditure is required.

"Medium" mechanisms

As for "medium" mechanisms, options include ***performance standards***, as well as ***ESMs*** – both of which were discussed previously in Section 2.3.2.

"Hard" mechanisms

Finally, in terms of "hard" mechanisms, options include either a ***price cap*** or a ***revenue cap*** (both of which are examples of ***rate caps***). The critical difference between price and revenue cap regimes is related to what the PBR formula applies to – rates in the case of price cap regimes, and revenue requirements in the case of revenue cap regimes.

Under a price cap, the regulator approves a formula that determines how fast rates can increase. The regulator sets an **initial price**, and the rates are adjusted for each year, taking changes in inflation and productivity into account. A price cap provides incentives for cost efficiency and an increase in sales. These incentives arise because the tariff is fixed for the regulatory period and does not vary with changes in electricity sales within the term. Another advantage of a price cap is that it provides greater rate predictability for customers. A price cap regime is best suited for utilities in an environment with stable or increasing demand, as it provides incentives for them to operate cost-effectively while meeting the growing demand.

On the other hand, the revenue cap regulates the maximum allowable revenue that a utility can earn. Under a revenue cap, the ***revenue requirement*** in a given year is established according to the previous year's revenue requirement and adjusted based on a predetermined formula, which considers changes in inflation and productivity. Under a revenue cap, there is no incentive for utilities to maximize sales, but there is still an incentive to minimize overall costs, making it arguably more compatible with utilities that are facing substantial demand response programs or energy efficiency reductions in consumer demand. Revenue cap regimes provide more pricing flexibility and are preferable when costs do not vary significantly with sales volumes.

The separate Case Studies Report highlights the revenue cap mechanism in practice, using Colombia as an example. The textbox below briefly summarizes the revenue cap methodology used by Colombia's regulator to set tariffs for electricity transmission and distribution entities.

Case study example: revenue cap ratemaking in Colombia

Pursuant to Laws 142 and 143 of 1994, the Commission of Energy and Gas Regulation ("CREG" or *Comisión de Regulación de Energía y Gas*) is responsible for setting tariffs for the provision of electricity service to regulated users in Colombia (i.e., residential and small commercial customers that have their prices administratively set by CREG). Customers are charged a unified cost of service tariff by retailers, which aggregates costs from each step of the electricity value chain (generation – which is mostly competitively set, as well as transmission, distribution, marketing/retail, and other costs). Of these cost components, transmission and distribution have been regulated under a revenue cap mechanism since 1999 and 2018, respectively.

At a high level, under the revenue cap mechanism, a maximum revenue per utility is established. This maximum revenue is adjusted by an inflation factor (RPI), less an efficiency factor (X), also known as an RPI-X mechanism. A benchmarking exercise is undertaken to determine the X factor. Tariff levels change based on the regulator's methodology, not in response to changes in a transmission or distribution utility's actual cost of service. Therefore, utilities that are able to achieve productivity or efficiency gains are rewarded, whereas utilities that are unable to achieve efficiency targets are penalized. While there are slight differences in the tariff methodology for transmission and distribution, this high-level approach is common to both segments.

Outcomes-based PBR

It is important to note that the PBR framework continues to evolve beyond these mechanisms to address existing and new challenges. The "next generation" of PBR is the so-called ***outcomes-based PBR*** approach, where the focus is on the outcomes rather than on the inputs to the revenue requirement. The utility under this approach is expected to achieve the outputs that are set during the PBR filing (or before the implementation of PBR), which can generally be grouped into categories such as reliability and availability, operational effectiveness, safety, public policy responsiveness, customer satisfaction, financial performance, and environmental impact, to name a few.

One particular iteration of this PBR framework emerged in the United Kingdom ("UK"), and is known as the RIIO regime, where **R**evenue = **I**ncentives + **I**nnovation + **O**utputs. Under the RIIO model, transmission and distribution utilities are encouraged to meet investment and innovation needs to deliver a sustainable energy network. The textbox below summarizes the RIIO model, with further details available in the separate Case Studies Report.

Case study example: outcomes-based PBR in the UK

The UK electricity market is a mature competitive market, having been among the first movers in power sector restructuring. The transmission and distribution sectors have operated under evolving PBR mechanisms for almost two decades, which were adapted over time to meet changing circumstances. These price controls are implemented by the Office of Gas and Electricity Markets ("Ofgem"), which is the executive arm and the independent economic regulatory body of the gas and electricity markets in the UK. Ofgem is responsible for protecting consumers by promoting competition and regulating monopoly companies. Ofgem derives its regulatory powers from the Gas Act 1986, the Electricity Act 1989, the Competition Act 1998, the Utilities Act 2000, and the Enterprise Act 2002.

Since 2013 (for transmission services) and 2015 (for electricity distribution services), Ofgem has implemented the RIIO model to better meet future investment and innovation needs. Simplistically, the RIIO model measures the performance of transmission and distribution operators on a variety of key delivery outputs, including customer engagement, quality of service, efficient cost of service, efficient financing, managing uncertainty, and emissions reductions. Several of these incentives are linked to the percentage of allowed revenue, where the allowed revenue is based on forward-looking revenue requirements of each regulated utility over the term of the price controls. In this way, companies that deliver on these outputs are able to earn a higher return.

2.3.4 Implementation process for a PBR regime

Moving from a traditional COS regime to PBR can be an intimidating task for both the regulator and the utility. It involves a significant amount of regulatory work and requires lengthy stakeholdering efforts to determine the appropriate PBR mechanism to implement and to allow more in-depth analysis of sectoral and technical issues, discussions of which are not always present or as thoroughly dissected during a COS deliberation. Figure 21 illustrates the major stages that the regulator, utility, and other stakeholders must undergo when transitioning to a PBR regime.

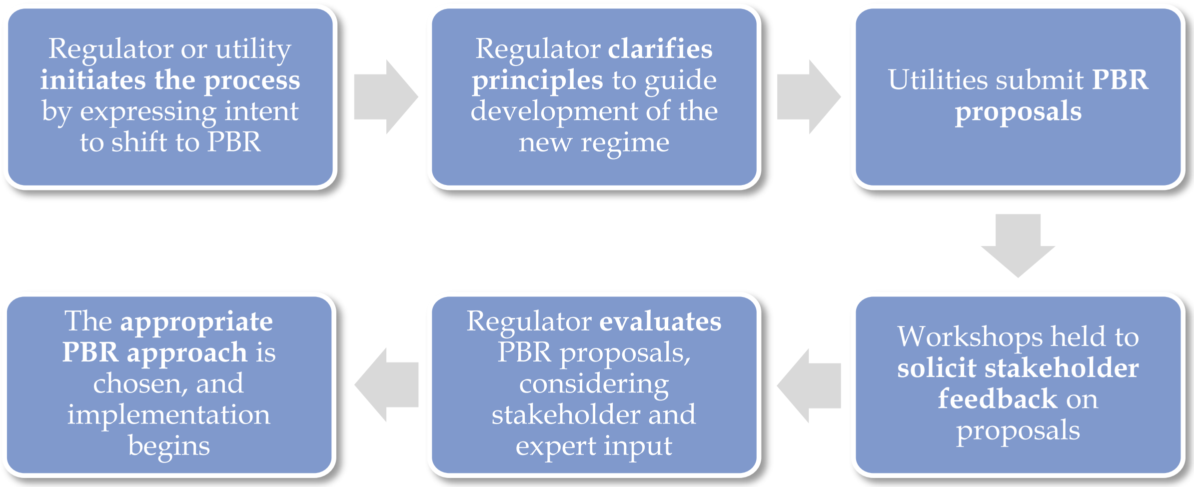
The first "formal" stage in the PBR process is when the regulator (or sometimes, the utility) expresses its intent to implement a shift. At this stage, the regulator is expected to explain the objectives clearly to all stakeholders as it embarks on the process. Experience and best practices dictate that the shift to a PBR mechanism requires establishing principles that should guide the stakeholders (particularly the utility) in the development and implementation process. The principles will assist the regulator in the evaluation of and deliberation on the PBR proposals. Such principles should also guide the utility in developing the most responsive and relevant proposals.

The move to PBR may also involve hiring an economic consultant to assist in determining the appropriate PBR approach, identifying the appropriate components for PBR (such as incentives and magnitude of rewards or penalties for the performance standards), reviewing what data is currently available, or providing a study of historical and forecasts of inflation and productivity trends. It is also crucial that the regulator communicate regularly with stakeholders, to ensure they are on the same level of understanding. Workshops and technical conferences are generally conducted to familiarize stakeholders with the proposed PBR approach and to solicit feedback.

Lastly, data availability is a critical element in the development of a PBR regime and will improve the functionality of PBR regulation over time. The need for good data cannot be understated;

incentive design could be significantly weakened by poor data. More "comprehensive" forms of PBR require collating and employing multi-period information and data samples covering multiple firms. Over time, availability of reliable, comparable, and accurate data for the industry as a whole and the utilization of "best practice" forecasting tools can improve the functionality of the PBR process, thereby facilitating analysis and negotiations of parameters for PBR factors, as well as benchmarking actual productivity achieved against prior targets.

Figure 21. Stages involved in transitioning from COS to PBR

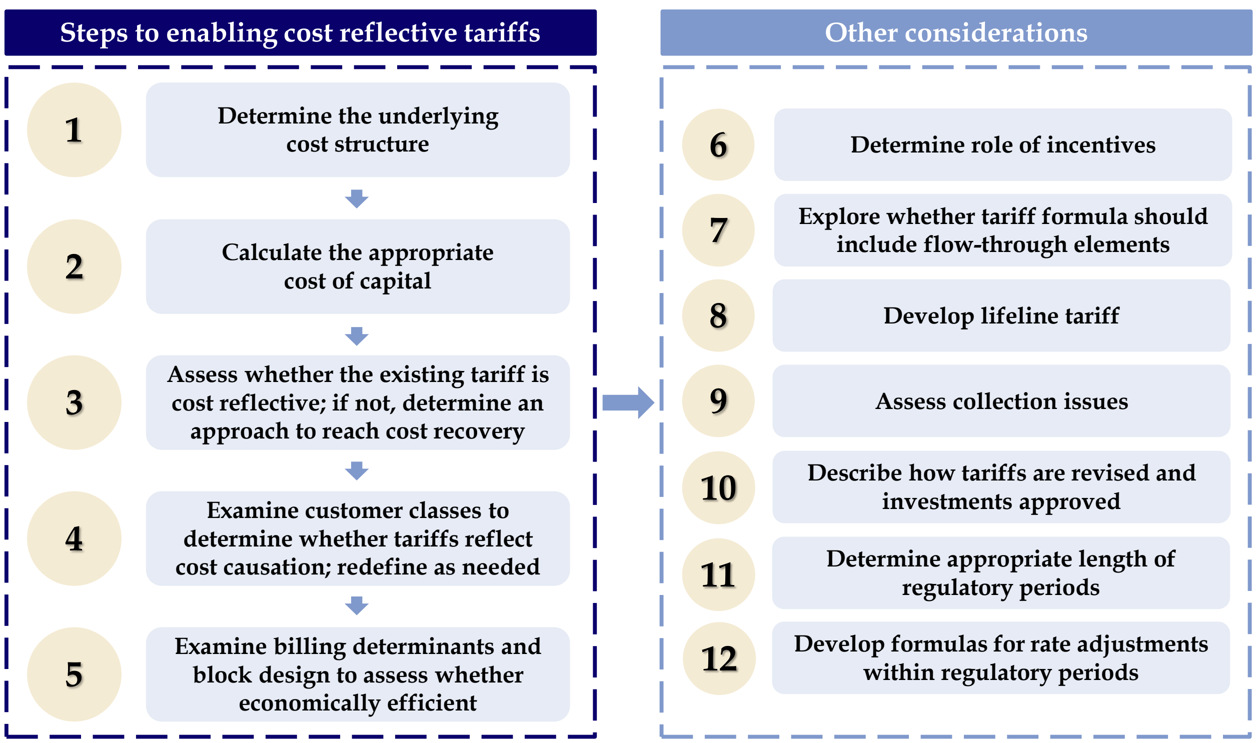


3 Tariff reform implementation approach

3.1 Overview

The following chapter outlines a 12-step approach to enforcing practical tariff reforms. At a high level, Steps 1-5 explore the steps necessary to evolve existing tariffs to become cost reflective, and to bring them in line with the aforementioned principles of cost causation and economic efficiency. Steps 6-12 deal with additional considerations that policymakers and regulators may wish to assess as part of their tariff reform efforts (such as the role of incentives, the development of lifeline tariffs, among other issues). Figure 22 illustrates the 12-step approach, which will be described in detail in the sections that follow.

Figure 22. Overview of the tariff reform implementation approach



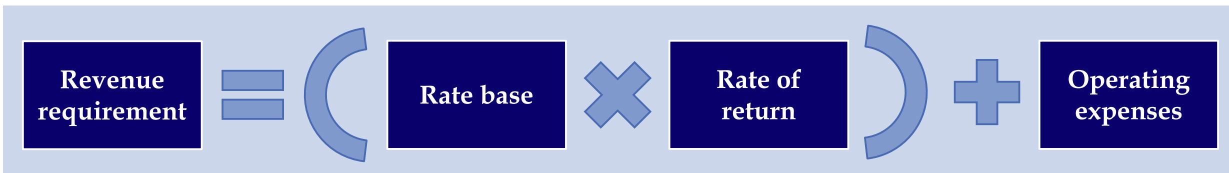
It is important to note that the proposed 12-step tariff reform implementation approach builds on the concepts and knowledge introduced previously in Section 2. Where there are any overlaps in concepts, the following chapter keeps discussion concise – we refer the reader to Section 2 for a more thorough overview of the basics of tariff design.

However, to enhance readability of the Toolkit, the following chapter is also designed to allow readers to be able to review the tariff reform implementation approach in isolation, if they so wish. As such, concepts are covered in enough detail to allow readers to fully grasp the scope of the steps needed to reach cost reflective tariffs.

3.2 Step 1: Determine the underlying cost structure

The first step in implementing tariff reform involves determining the total cost to the utility of providing electric service, also known as its ***revenue requirement***. As discussed in Section 2.2.1, the revenue requirement is a central construct of traditional cost of service ratemaking and is necessary for establishing cost-reflective prices for utility service. Essentially, the revenue requirement identifies the expected amount of revenue that the utility requires to cover its costs and earn a reasonable return on equity for its shareholders. The basic formula for computing the revenue requirement is represented arithmetically again in Figure 23.

Figure 23. Revenue requirement formula



This representation makes clear that there are three core components of the revenue requirement that must be estimated: (1) **rate base**; (2) **allowed return** on rate base; and (3) **operating expenses**. Generally, each component is estimated based on data from either a historical or a forecast ***test year***; a historical test year examines the utility's actual revenues and expenses for a prior 12-month period, whereas a forecast test year examines the utility's projected revenues and expenses for a future 12-month period. We cover the calculation of the rate base and operating expenses briefly in the subsections below, but leave the discussion of calculating the rate of return later to Section 3.3 (i.e., Step 2 in the tariff reform implementation approach).

3.2.1 Calculate the rate base

The rate base (introduced in Section 2.2.1) can be thought of in two different but quantitatively equivalent ways. With respect to physical assets, it represents the value of the plant, equipment, and other assets employed by a utility to provide service to its customers (e.g., utility-owned generation facilities, buildings, poles, wires, transformers, meters, vehicles, computers).

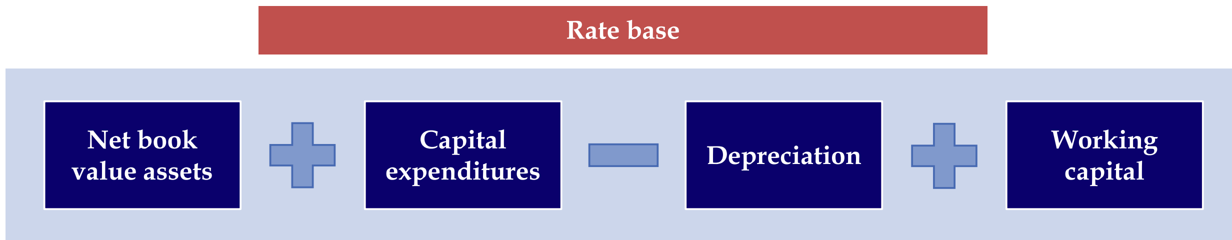
Conversely, with respect to the financing of the investment required to purchase and maintain these assets, the rate base reflects the money provided to the utility by investors expecting a return on their investment. Accordingly, material increases in the rate base due to additional capital investment can result in a significant increase in the utility's overall revenue requirement. Figure 24 demonstrates the rate base formula.

Rate base is normally calculated based on historical cost accounting, using accounts prepared regularly in accordance with generally accepted accounting principles ("GAAP"). However, in some cases, such accounts may not exist. For example, if the utility has operated as a government department, records of historical costs may not be available. In such cases, the starting point for determining the value of the utility's assets consists of two parts:

1. determining the **replacement cost** of the assets, and then adjusting for age; and

2. performing a **condition assessment** to identify whether the assets are able to operate in a manner that is consistent with their age. If not, an additional discount to the asset value may be warranted.

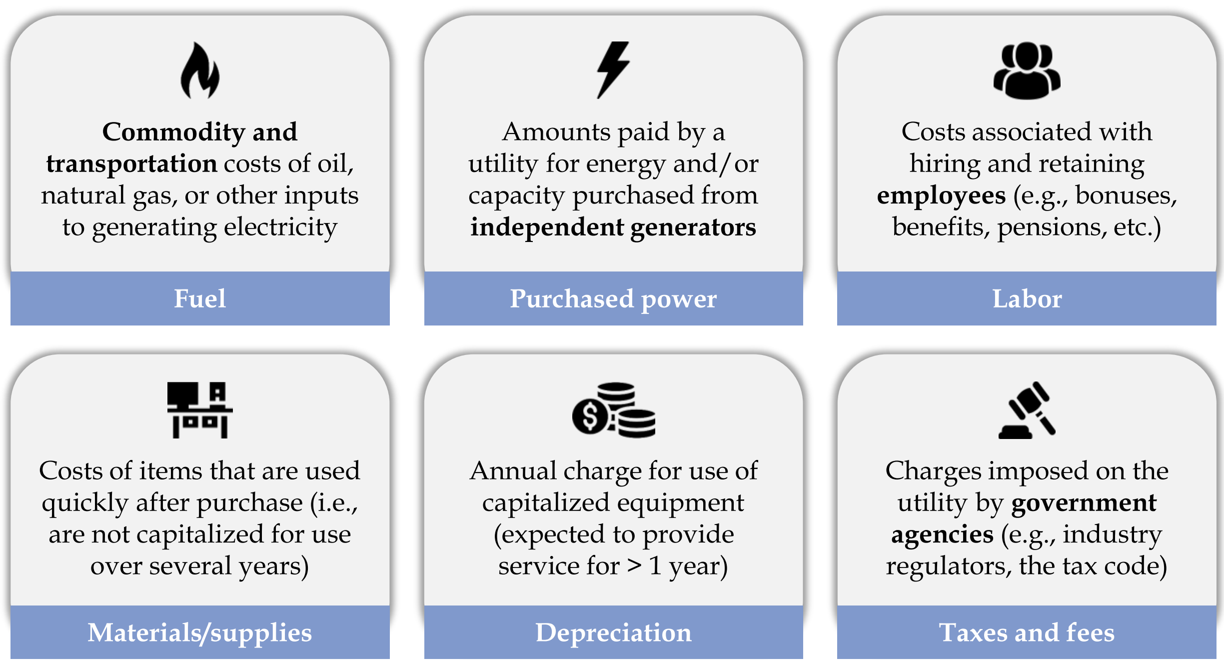
Figure 24. Rate base formula



3.2.2 Calculate the operating expenses

Another component of the revenue requirement is the utility's operating expenses. Operating expenses are the ongoing costs related to operating and maintaining the utility's equipment for providing service. These expenses do not include capital outlays, and the utility does not earn returns on them. Core expense items typically include fuel, purchased power, labor, materials and supplies, depreciation, and taxes, as described in Figure 25 (and discussed in Section 2.2.1).

Figure 25. Components of operating costs



3.3 Step 2: Calculate the appropriate cost of capital

The third and final core component of the revenue requirement is calculating the cost of capital, or the allowed rate of return. This is expressed as a percentage and essentially represents the amount of return that investors will receive on their investment, the rate base (discussed previously in Section 3.2.1).

Setting the allowed rate of return requires balancing two equally important objectives:

1. incentivizing continued **investment** in the power sector; and
2. ensuring that customers pay **just and reasonable rates**.

Thus, the challenge in specifying the allowed rate of return is anticipating the return investors require for contributing capital to the utility. Paying less than this required return puts the utility at risk of being unable to attract capital. Paying more than this required return imposes a charge on customers with no corresponding benefit.

The predominant method for setting the allowed rate of return is to use the utility's ***weighted average cost of capital*** ("WACC") – as discussed in Section 2.2.1.[7] WACC is the total cost, in percentage terms, of financing the utility's assets, and is used across the world in both COS and PBR regimes.[8] Figure 26 demonstrates the formula for calculating the post-tax WACC, which relies on the following inputs: the cost of debt, the cost of equity, and the capital structure to be used. The first two components (cost of debt and cost of equity) take risk factors into consideration and are described in more detail in Sections 3.3.1 and 3.3.2 below.

Figure 26. Formula for calculating the post-tax WACC

$$\boldsymbol{WACC = [\, D \; x \; R_D \,] + [\, (\, 1 - D \,) \; x \; R_E \,]}$$

where D = the ratio of debt to assets; R_D = the post-tax cost of debt; and R_E = the cost of equity.

The WACC is often based on deemed values for the capital structure and the cost of debt and equity. Although in theory the amount of debt in the capital structure should make no difference to the WACC, as more debt means greater risk to debt holders who thus would charge more to lend to the company, in practice debt is normally less expensive than equity. Typically, utilities can be deemed to have as much as 60% debt in their capital structure, given the generally stable revenue streams they garner. While the WACC is based on an assumed capital structure, the company is free to have more or less debt based on what it feels is optimal. However, rates to customers do not change if the company chooses a different capital structure.

3.3.1 Calculate the cost of debt

The cost of debt is a simple summation of the **risk-free rate** (i.e., the rate that creditworthy governments can borrow at) and the **debt premium** for the utility, where the debt premium takes risk factors into consideration. The debt premium is the premium charged for a company with a similar risk profile to the electric utility, relative to the risk-free rate. Generally, debt receives a lower rate of return than equity, as debt holders bear less risk than investors – for instance, debt

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[7] Other methods include using historical rates, or an "a priori" (model-based) approach.

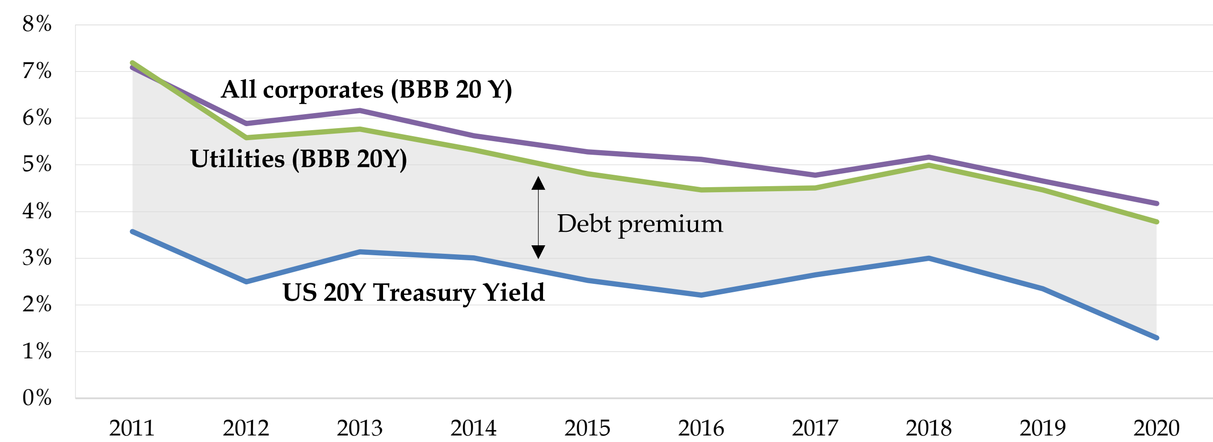
[8] For example, in Australia (which is a PBR regime), the Australian Energy Regulator applies a permitted WACC to regulate the return. In Hong Kong (which is a COS regime), the return on assets ("ROA") employed can be considered a form of WACC.

holders have the first call on the utility's revenues and assets after operating expenses are paid, and before investors receive any dividends or return of capital.[9]

In addition, the cost of debt for utilities can be more easily observed in the market than the cost of equity. Regulators may take into account the company's actual experience in raising debt, or examine recent debt costs for other utilities with similar credit ratings issuing debt of similar maturities. As better credit ratings can facilitate raising capital, regulators may want to consider setting capitalization ratios and rates in a manner which allows the utility to maintain an investment grade rating.

Generally, debt costs for utilities will be above the risk-free rate but below those of many other corporate borrowers. Figure 27 exemplifies this trend using US data, where the cost of debt for utilities (i.e., those with BBB credit ratings issuing debt with a 20-year maturity) has historically been between the lower risk-free rate (measured as the 20-year Treasury rate), and the higher yield for corporate borrowers (i.e., those with the same BBB credit rating issuing debt with a 20-year maturity).

Figure 27. Historical US yields for the 20-year Treasury, corporate, and utility bonds



Source: S&P Capital IQ.

3.3.2 Calculate the cost of equity

On the other hand, the cost of equity is generally calculated according to the capital asset pricing model ("CAPM"). Other methods to estimate the cost of equity typically include the discounted cash flow ("DCF") and equity risk premium ("ERP") approaches – see Section 2.2.1 for more details. The CAPM approach consists of the already calculated risk-free rate (discussed in Section 3.3.1), as well as the **equity risk premium** and the **equity beta** (see Figure 28).

Figure 28. Cost of equity under the CAPM approach

[9] The Regulatory Assistance Project. *Electricity Regulation in the US: A Guide (Second Edition).* 2016.

$$R_E = R_f + (\,ERP\ x\ b_e\,)$$

where R_E = the cost of equity; R_f = the risk-free rate; ERP = the equity risk premium; and b_e = the equity beta.

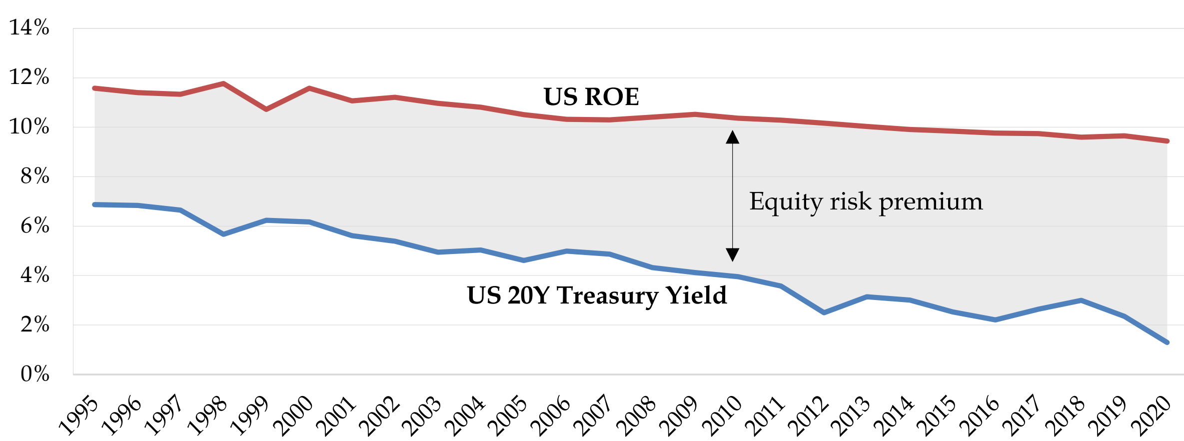
The risk-free rate and equity risk premium rely on market-level data, reflecting macroeconomic conditions, while the equity beta is associated directly with the utility. Determination of the risk-free rate depends on the jurisdiction. A local long-term government bond can be used; if so, any country risk premium would already be embedded in the local government bond rate. By contrast, if a US, European, or Asian sovereign bond is used as the risk-free rate, a separate country risk premium may need to be added.

Likewise, determining the appropriate equity beta depends on the selection of an appropriate market. Local markets may lack long-term data, and the utility itself may make up a disproportionate amount of the market's capitalization. The choice of risk-free rate needs to match the choice of market benchmark. If using global benchmarks, such as US utility betas relative to US market benchmarks, an additional local equity market premium may be necessary, as the country risk premium reflects only the difference in sovereign risk.

The equity risk premium is defined as the rate by which equity market returns have historically exceeded the risk-free rate; however, this is not related to a particular firm's risk profile. The equity beta measures the correlation of the firm's returns with returns in the overall market. This reflects the systemic risk associated with investment in the firm or, in other words, the risk that cannot be eliminated through portfolio diversification. The equity beta is the risk that investors must be compensated for, and from the perspective of the utility, is the core driver of the cost of equity.

As an example, Figure 29 tracks annual US data for the 1995-2020 period, plotting the average equity returns authorized for electric utilities versus the 20-year Treasury rate (where the difference between the two equals the equity risk premium).

Figure 29. Historical US equity returns versus the 20-year US Treasury yield (1995-2020)

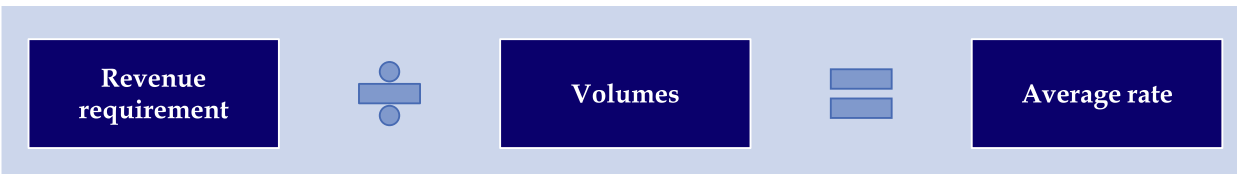


Sources: S&P Global Market Intelligence; S&P Capital IQ.

3.4 Step 3: Assess whether the existing tariff is cost reflective; if not cost reflective, determine an approach to reach cost recovery

Once the three core components of the revenue requirement are calculated (i.e., the rate base, rate of return, and operating expenses – see Sections 3.2 and 3.3), the utility's revenue requirement can be estimated. Again, this represents the total revenues that a utility requires to cover the costs it incurs in providing electric service. To assess whether the existing tariff is cost reflective, it is useful to compare the product of the average rate (i.e., the average of the existing rates charged across different customer classes) and the total volumes delivered by the utility, against the estimated revenue requirement (see Figure 30). Simplistically, if the average revenues earned by the utility are not equal to the estimated revenue requirement, then the existing tariff may be deemed to not be cost reflective.

Figure 30. Converting the revenue requirement into rates



Note: Conversion into rates is complicated by the breakdown into customer classes, and between fixed charges (customer or connection based) and volumetric charges (per kWh).

As discussed previously in Section 2.1, establishing prices that are cost reflective is a core principle of tariff design. This is because tariffs that are not cost reflective can cause several issues, including inducing inefficient behaviors, non-optimal investments, inadequate revenue recovery, increased risk and higher costs of capital, as well as intra-class subsidies.[10]

In contrast, cost reflective tariffs enable two major benefits:

- **promoting efficient behavior among customers:** prices provide a very important signaling function to customers. In this sense, prices can serve as a form of communication for the utility to its customers, conveying the cost of delivering a particular service (e.g., providing a meter, delivering a unit of electricity, extending the network into a remote area, etc.). Thus, a cost reflective tariff provides accurate information to customers from which they can base their consumption decisions – i.e., if customers are to make economically efficient decisions that advance not only their own self-interest but also the efficiency of the broader economy (by contributing to the efficient allocation of scarce resources), then they will need to know the cost; and
- **improving the financial stability of the utility:** when prices accurately reflect costs, this increases the likelihood that a utility will be financially sustaining – more specifically, that it will be able to continually recover the costs it incurs, including the costs of the financial capital required to finance system maintenance and expansion, and other forms of capital investment.

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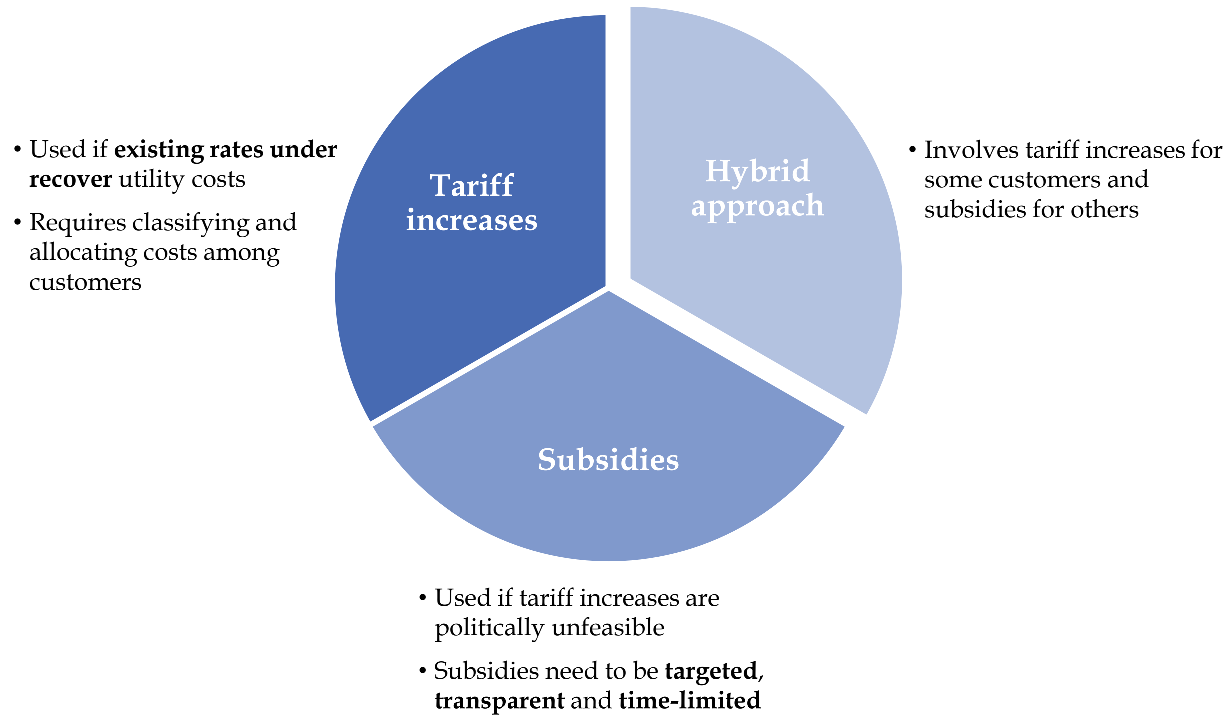
[10] Ahmad Faruqui. *Best Practices in Tariff Design.* June 1, 2016.

Figure 31. Approaches to reach cost reflective tariffs



If the existing tariff is determined not to be cost reflective, an approach will need to be selected to reach cost recovery. Policymakers can choose from several approaches to evolve the tariff design to become more reflective of underlying costs (see Figure 31) – the following approaches will be described in further detail throughout the remaining sections of this chapter:

- **tariff increases:** if existing rates under recover the utility's costs of providing electric service, tariff increases may be required to improve the utility's financial stability. Sections 3.5 and 3.6 (i.e., Steps 4 and 5 in the tariff reform implementation approach) explore how costs can be classified and allocated among customers to reflect cost causation and enhance economic efficiency;

- **subsidies:** if increasing tariffs is politically unfeasible, direct payments from the government may make up the difference in cost of service. Such subsidies need to be transparent, and only cover the shortfall in efficient costs as approved by the regulator.

  Subsidies may be linked to particular customer classes, such as low-income residential, or to particular industries. Regardless, customer bills should clearly show the full cost of power, and the amounts paid by the government on their behalf.

  To maintain the fiscal health of the utility, subsidies need to be paid in full on a predictable schedule; it is not the utility itself that is being subsidized, but rather the utility's customers. Governments should have a strategy for minimizing, and ultimately phasing out, subsidies which is communicated to all stakeholders. At the same time, the regulator needs to assure the utility's costs are appropriately scrutinized, so that when rates increase as subsidies are reduced, it is not due to waste on the part of utility management; or

- **a hybrid approach:** policymakers may choose to adopt a hybrid approach to reach cost recovery, where the rates for some customer classes are increased, while the rates for others are subsidized.

3.5 Step 4: Examine customer classes to determine whether tariffs reflect cost causation; redefine customer classes as needed

Rate design refers to the itemized pricing structure reflected in customers' monthly electric bills, including the underlying mechanism used to derive the rates.[11] Rate design begins with calculating the revenue requirement of the utility (see Sections 3.2 and 3.3), and then involves allocating the cost components to different customer classes (e.g., residential, commercial, industrial, others) while upholding the principle of ***cost causation***.

As discussed previously in Section 2.1, cost causation is a key principle of rate design, whereby the rates that customers pay should reflect the costs that their usage imposes on the system. In a situation where cost causation can be perfectly identified, cross-subsidies (both within and between customer classes) can be avoided. Therefore, it is important, where possible, for the utility to examine its current definition of customer classes and determine whether existing tariffs reflect cost causation. If this principle is not upheld in the current rate design, the customer classes should be redefined, and cost recovery should be reallocated. Below, we discuss the key factors to consider when creating customer classes that align with the principle of cost causation.

Key considerations in customer class creation

Customer classes are employed to identify groups of customers that have similar consumption characteristics (and, by extension, impose costs on the system in similar ways). The challenge in constructing classes of customers is to identify groups that share similar characteristics with respect to the key cost drivers for the utility. The goal is to have – with respect to these key drivers – little variability within a group, and significant variability between groups.

The entire power system (generating stations and transmission and distribution facilities) needs to be built so as to instantaneously meet potential peak demand, plus a reserve margin in case portions of the system are unavailable at peak times. Thus, in allocating costs to customer classes, the key issue relates to the relative contribution of each customer class to this peak load/demand. Based on cost causation, customers that contribute disproportionately to peak load are charged higher rates than those that do not. In this sense, load profile characteristics comprise the key factor that should drive the development of, and the relative prices imposed on, customer classes. Figure 32 shows the types of customer classes that are typically used, which can be further broken down into subclasses as needed (e.g., broken down by the voltage at which they receive service).

Figure 32. Common customer classes

[11] Regulatory Assistance Project. *Smart Rate Design for a Smart Future.* July 2015.

Notes: Agriculture primarily includes irrigation pumping; municipal lighting includes streetlights and traffic signals.

Source: The Regulatory Assistance Project. *Electricity Regulation in the US: A Guide (Second Edition).* 2016.

Utilities often segment their customers into industrial, commercial, and residential load, and charge different rates to each. Residential customers often pay the highest rate because they consume a higher proportion of their load at peak times. By contrast, industrial rates are often lowest because many industrial customers display more uniform consumption throughout the day, and some may not be connected at a distribution voltage, thus using less of the system.

Typically, cost components are allocated to different customer classes after conducting a class ***COS study ("COSS")*** (as discussed in Section 2.2.2). Simplistically, under an embedded cost study, each cost that makes up the revenue requirement is divided among the various customer classes, so that the total equals the revenue requirement.[12] Rates are then designed within each customer class (see Section 3.6 – i.e., Step 5 in the tariff implementation approach) to produce the revenues allocated to each class.

3.6 Step 5: Examine billing determinants and block design to assess whether economically efficient; evolve if necessary

The intent of rate design is to incent efficient use of the system, while also providing utilities a fair opportunity to recover their costs. Once costs have been allocated to the various customer classes (see Section 3.5), the next step in the rate design process is to specify a structure for retail tariffs by defining ***billing determinants***. Typically, billing determinants allocate a portion of the customer class revenue requirement between **volumetric energy charges** (per kWh, based on each customer's usage), **customer charges** (per customer, regardless of usage), and sometimes also **capacity/demand charges** (based on the maximum kW a customer uses in a particular period).

Figure 33. Billing determinants

[12] The Regulatory Assistance Project. *Electricity Regulation in the US: A Guide (Second Edition).* 2016.

Energy charge (per kWh)	**Customer charge** (per customer)	**Demand charge** (per kW)
Accounts for the **cost of generating and delivering energy** to a customer (based on volumetric energy usage) These charges are often flat, but could also be designed in a variety of forms (e.g., inclining or declining block rates, seasonal rates, or time-varying rates)	Used to recover **costs related to billing and metering**, outside of the generation and delivery of electricity These charges apply to all customer classes, regardless of usage levels	Typically used to recover the costs of generating and delivering electricity to **large commercial and industrial users** Traditionally, these charges are based on the customer's peak demand

These tariff components, summarized in Figure 33, are described in further detail below:

- ***volumetric energy charge* (per kWh):** charged based on the amount of electricity consumed, the volumetric energy charge can be **flat**, whereby all units of consumption are priced the same, or alternatively, **blocks** of consumption can be defined and priced at different levels. There are two basic block tariff structures – declining and inclining:
    - **declining block rate:** establishes progressively decreasing rates for larger blocks of consumption, and thereby provides a lower average price for large users. The rationale for this approach is that because large users tend to have flatter load profiles, their ratio of capacity requirements to consumption, and therefore their average cost per kWh, is lower than for small users. As such, this approach enables cost reflective tariffs; or
    - **inclining block rate:** establishes progressively increasing rates for larger blocks of consumption, thereby providing a higher average price for large users. This approach is the most common form for residential rates worldwide,[13] largely due to two key reasons. First, an imposition of higher prices for increased consumption serves to motivate energy conservation. Second, because small users tend to have lower incomes than larger users, an inclining block rate structure provides a mechanism for cross-subsidization that is relatively easy to administer.
- ***customer charge* (per customer):** accounts for costs incurred by the utility that are independent of electricity usage, such as costs related to metering, billing, and collection. This charge applies to all customer classes regardless of their usage levels; and
- ***capacity/demand charge* (per kW):** charged based on the individual customer's highest peak demand – this is typically only charged to large commercial and industrial customers.

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[13] The Regulatory Assistance Project. *Smart Rate Design for a Smart Future, Appendix B – Rate Design for Vertically Integrated Utilities: A Brief Overview.* 2015.

The separate Case Studies Report highlights these typical tariff components in practice – the textbox below summarizes the line items included on energy bills for the customers of Georgia Power Company (US).

Case study example: tariff components for Georgia Power Company (US)

Generally, GPC's rates comprise of three components:

- a ***basic service charge*** to recover costs that are independent of the demand or energy use of a customer (including costs related to the generation, transmission, and distribution of electricity from power plants to homes and businesses);
- a set of ***tariff riders*** that are charged to all customers, which are described in detail below; and
- a ***variable energy charge*** (per kWh), to recover energy-related expenses.

Some commercial and industrial customers also pay a ***demand charge*** (per kW) to recover demand-related expenses.

The tariff riders paid by all of GPC's customers include those for: Environmental Compliance Cost Recovery ("ECCR"), Nuclear Construction Cost Recovery ("NCCR"), Demand-Side Management ("DSM"), Municipal Franchise Fees ("MFF"), and Fuel Cost Recovery ("FCR"). ***ECCR charges*** recover the costs of installing and operating mandated environmental controls. ***NCCR charges*** recover financing costs related to the construction of two new nuclear units at Plant Vogtle. ***DSM charges*** recover costs related to administering demand-side management programs. ***MFF charges*** recover fees paid to the cities for allowing GPC to conduct business within their city limits and on their rights-of-way. ***FCR charges*** recover costs related to GPC's use of fuels in its generating plants and energy purchased on an economic dispatch basis. All charges and fees are presented to the PSC for review, feedback, and approval before they are added to customer bills.

Many utilities incorporate both a ***fixed*** (customer based) and ***variable*** (per kWh) charge within their rate structures. The split between the two is determined based on the extent to which individual cost items do or do not vary in accordance with changes in consumption levels. As summarized in Figure 34, there are arguments in favor of both fixed and variable/volumetric charges.

Figure 34. Fixed versus volumetric rate regimes

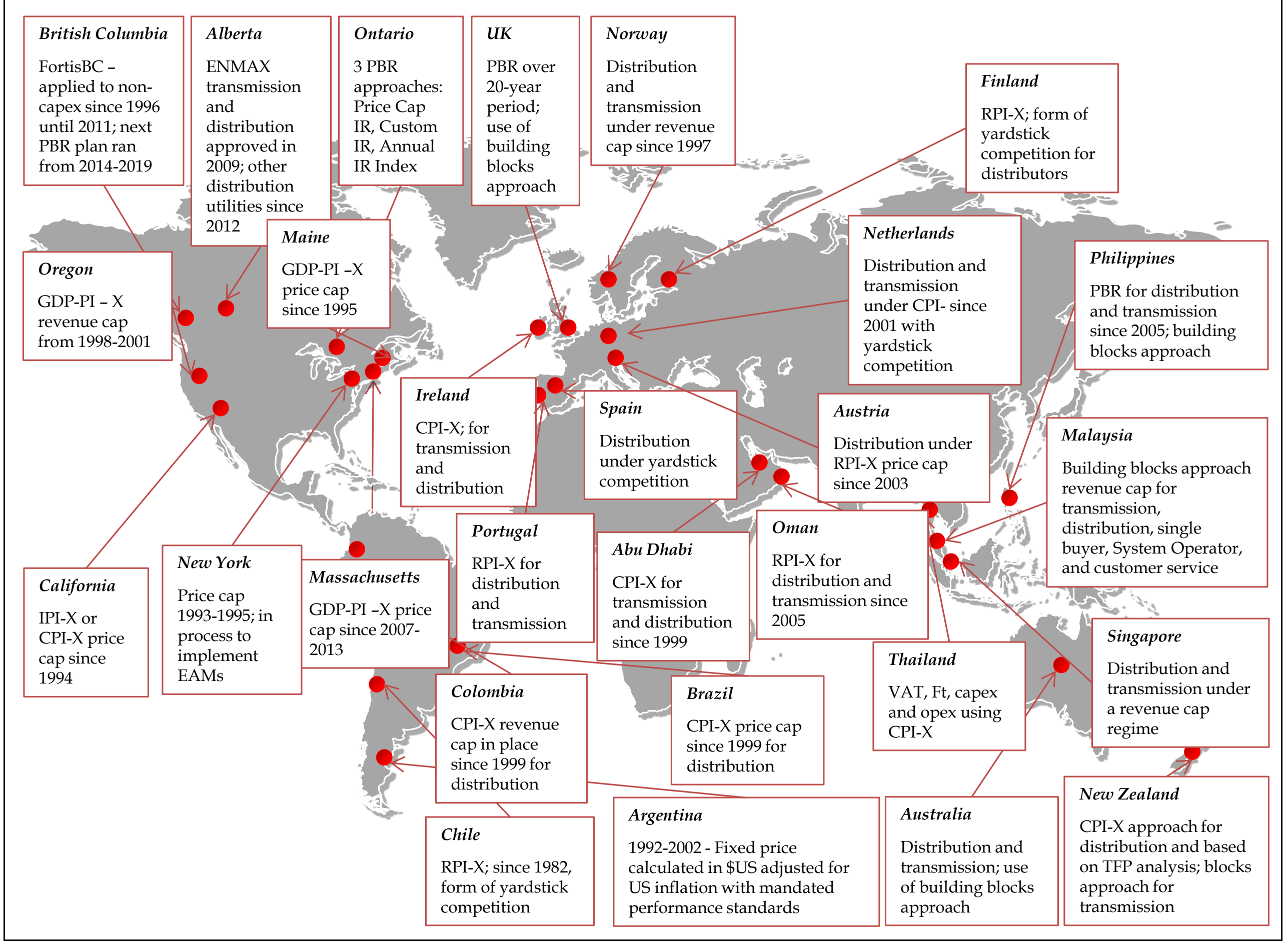
Benefits of a mainly fixed rate regime	Benefits of a mainly volumetric rate regime
Affordability for **vulnerable customers** when external events lead to increased usage	Can be more consistent with **cost causation** – those who use more, pay more
Decouples utility's profits from volume, increasing incentive for **energy efficiency**	Puts the **customer in control**, and can encourage greater demand management
Financial sustainability – utility's revenues less vulnerable to changes in economic conditions and weather	More consistent with **long-run marginal cost pricing** (which signals optimal provision of a good/service)

Volumetric charges ensure that customers who consume more are allocated a correspondingly higher portion of overall costs, and they also provide stronger incentives for conservation. Fixed charges provide a more stable cash flow for utilities and greater certainty to consumers about required payments, and also reduce the incentive for utilities to increase revenues and profits by motivating customers to consume more.

3.7 Step 6: Determine role of incentives

While cost of service is the foundation for rate-setting in many parts of the world, many jurisdictions have been experimenting with ways to incorporate better incentives for utilities into rates (see Figure 35). The implementation of performance-based ratemaking ("PBR"), coupled with specific service quality standards, is seen in some jurisdictions as a way to encourage efficiency while guiding utilities to focus on areas of greatest priority to policymakers. Under PBR, utilities that meet efficiency or other objectives are allowed to earn a bit more than the target cost of capital, while ratepayers benefit from rates that may increase more slowly due to the associated efficiency gains – see Section 2.3 for a detailed overview of the PBR approach.

Figure 35. Examples of jurisdictions that have used, are currently using, or plan to move to PBR



The following subsections focus on three types of incentives: (i) **productivity/efficiency incentives**, (ii) **performance standards**, and (iii) **line loss provisions**. However, policymakers and regulators can identify additional behaviors that they may wish to incentivize through rates. For example, the separate Case Studies Report highlights the range of outcomes which the regulator in the UK prioritizes (see the textbox below for a summary).

Case study example: output categories tracked under the RIIO model

Key components under the RIIO-T2 price control (i.e., the second generation price control for the transmission sector) include:

- **customer engagement** – companies are required to establish Consumer Engagement Groups (for distribution network operators) and User Groups (for transmission operators);
- **service quality** – companies are required to meet service level and performance level outputs;
- **efficient cost of service** – transmission operators are expected to achieve annual efficiency improvements of 1.2%;
- **efficient financing** – Ofgem authorized an ROE of only 4.30%;
- **managing uncertainty** – uncertainty mechanisms are in place, such as pass-through mechanisms (for limited control costs) and use-it-or-lose-it allowances (for items where a need is identified, but the costs are not certain yet – e.g., cybersecurity); and
- **emissions reductions** – in June 2019, the UK set a legally binding target to reduce emissions to net-zero by 2050.

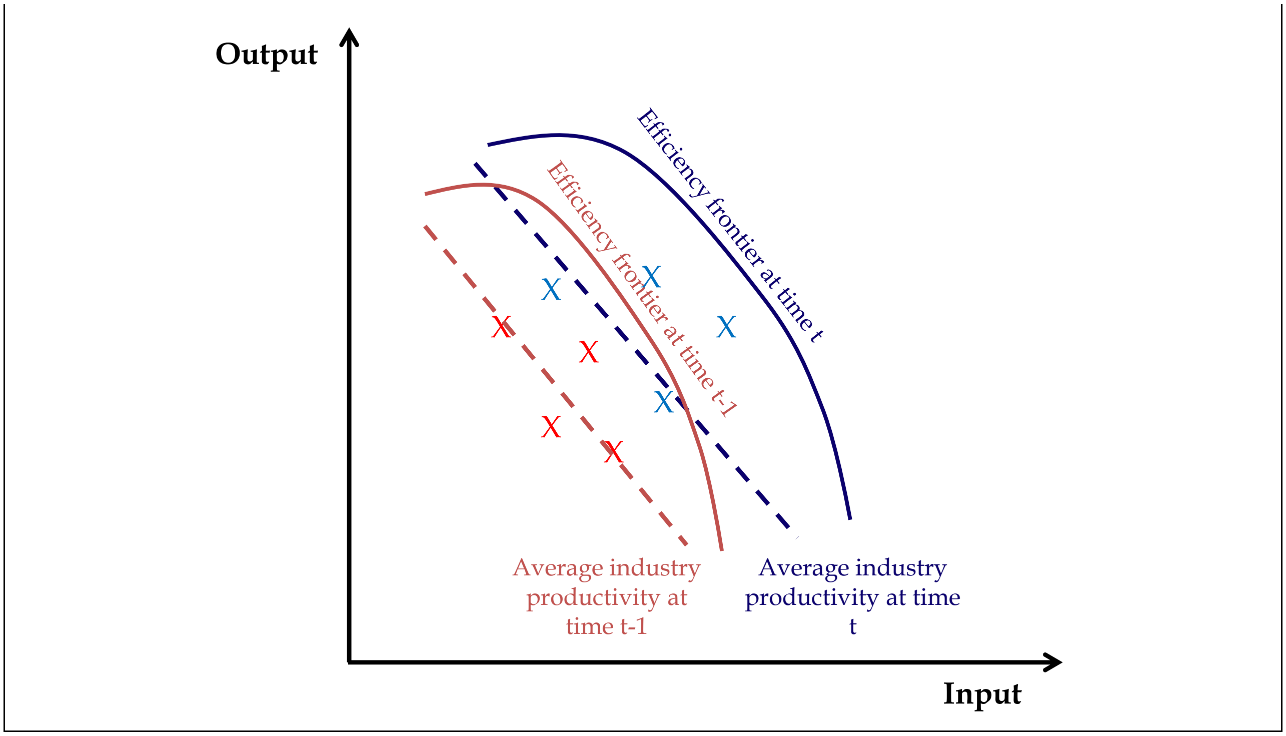
3.7.1 Role of productivity/efficiency incentives

Changes in utility productivity tend to be relatively slow, reflecting the fact that the industry is well-established and has evolved over more than one hundred years. However, the extent of achievable productivity gains may vary greatly from utility to utility, depending on how it is organized, the regulatory regime under which it operates, its position in the investment cycle, and other factors. A well-run utility may be operating close to the **efficiency frontier**, and thus be capable of making few efficiency gains; a less well-run entity may be able to show greater gains both by "catching up" to the frontier and through the movement of the frontier itself. Figure 36 illustrates this efficiency frontier, which represents the optimal output level given a set of inputs.

As such, **productivity/efficiency incentives** seek to incentivize the utility to pursue these efficiency improvements by tying its profits to performance relative to expectations. Thus, if the utility is not able to meet expectations, it will make less than it would have under the traditional cost of service approach. Conversely, if the utility performs better than expected, it will be more profitable than it otherwise would have been.

While regulators sometimes rely on international benchmarks to set expectations, doing so may put the utility at a disadvantage, since it may face different operating conditions than its international peers. In the initial stages of an incentive regime, it may be more appropriate to put in place mechanisms to appropriately assess the utility's own productivity performance, and then use that performance to set future productivity targets.

Figure 36. Efficiency frontier for setting productivity targets



3.7.2 Role of performance standards

Performance standards are often used concurrently with efficiency incentives, to ensure any cost reductions implemented by the utility do not lead to deteriorating service quality. Performance standards can be beneficial to both customers and the utility (i.e., utility service improves, and the utility is rewarded financially), and should be designed to meet numerous objectives:

- **protect customers** from hidden cost increases and degraded service quality;
- **align incentives**, such that as the utility's service level improves (if such improvement is desired by customers), it is rewarded financially. Therefore, performance standards should be well designed to reward utilities for good performance and punish utilities if performance deteriorates. If penalties exist, they should be set at a level which commands the attention of utility management, and incentivizes the utility to fix the underlying problem in performance rather than pay the fine;
- be objectively **measurable**, requiring relevant and accurate data for monitoring performance; and
- be **attainable** – the utility and regulator should cooperate to design challenging, yet realistic standards.

Generally, performance standards can usefully supplement any incentive-based tariff system by indicating very clearly to a utility the range of issues that are of concern to customers and the regulator. Worldwide, the measures of reliability and service that are tracked depend greatly on the specific concerns that arise in particular jurisdictions.

Typically, **reliability** is tracked by measuring the number and frequency of outages, and **customer service** is tracked through an examination of how well the utility manages the various points of interaction with its customers. Additional issues that are often addressed through the establishment of standards, particularly in developing countries, include **system expansion**, **collections**, and **theft**. Figure 37 lists common indicators used to measure utility performance in various areas of interest.

Once a set of performance indicators is selected, the associated metrics must be consistently measured. There are numerous ways in which such ongoing measurement can be incorporated within the broader regulatory regime and tariff-setting mechanics. At one extreme, performance over time can simply be tracked and be made available to the regulator and the general public for purely informational purposes. At the other extreme, benchmarks for performance relative to one or more of the indicators can be established, with the utility being rewarded and/or penalized for over- or under-performance through appropriate adjustments to the annual revenue requirement.

Figure 37. Common performance indicators by category

Category	Common performance indicators
Technical reliability	• System Average Interruption Duration Index ("SAIDI") • System Average Interruption Frequency Index ("SAIFI") • Customer Average Interruption Duration Index ("CAIDI")
Customer service	• Percentage of population served • Percentage increase in domestic connections over the year • Reduced or delayed connections to low-income households • Availability of electricity (hours per day) • Customer complaints
Asset condition	• Percentage planned and unplanned maintenance • Maintenance costs as a percentage of total operating costs • Percentage of meters replaced per year • Rate of capital replacement
Operating efficiency	• Generation capacity utilization • Staff per 1,000 connections • Staff per 1,000 MW of electricity delivered • Training costs as a percentage of total payroll • Percentage days lost due to accidents • Revenue collection efficiency • Average debtor days • Percentage of customers metered • Debt service ratio • Current liquidity ratio

The separate Case Studies Report highlights the range of performance standards that are incorporated in Colombia's revenue cap methodologies for transmission and distribution entities (summarized in the textbox below).

Case study example: Colombia's use of performance standards

In Colombia, the revenue cap methodologies used to set transmission and distribution rates have evolved over time to address deficiencies identified under previous tariff regimes, especially in terms of service quality.

In the case of transmission operators, a maximum number of hours per year for which equipment may be out of service is established. If this number of hours is exceeded, the required compensation to customers is deducted from the maximum revenues authorized for the transmission operator.

As for distribution entities, service quality is incentivized using indicators such as SAIDI and SAIFI (which track the duration and frequency of service interruptions, respectively). CREG establishes targets for both of these metrics, and the distribution operator reports its performance on an annual basis. Based on its performance, its allowed revenues may be increased or decreased. The distribution operator must also compensate the worst-served users. CREG's targets evolve over time, to incentivize continuous service improvements – CREG plans to reduce the levels of SAIDI and SAIFI by 8% each year, until SAIDI reaches 2 hours/year and SAIFI reaches 9 times/year.

3.7.3 Necessity of line loss provisions

Line losses reflect a genuine and, to some extent, unavoidable cost of performing a transmission and distribution service that must be recognized in the revenue requirement. There are generally two types of loss categories:

- **technical losses** reflect basic physical limitations of the equipment with respect to the services being performed. For electricity transmission and distribution, technical losses are comprised of electricity lost during transport due to the naturally occurring effects of heat and resistance along electrical wires; and
- **commercial losses**, which generally occur only at the distribution level, reflect dysfunctions in the relationship between service providers and their customers. The three categories of commercial losses are: (i) **theft**; (ii) **metering inaccuracies**; and (iii) **billing inaccuracies**.

Line loss provisions can be implemented if electricity transmission and distribution line losses are deemed to be at unacceptably high levels. These provisions can specify a multi-year price schedule of allowed levels of (technical and commercial) losses, where the utility is provided the opportunity to earn additional profits if it exceeds expectations with respect to loss reduction, and is exposed to the threat of financial losses if it is unable to meet the expectations.

3.8 Step 7: Explore whether tariff formula should include flow-through elements

Under a PBR tariff formula (see Section 2.3.2 for an example), ***flow-through (or pass-through) elements*** can be incorporated to account for uncontrollable costs incurred by the utility that arise during the normal course of business. In most cases, expense items are estimated with the expectation of being fixed throughout the tariff period, subject to true-up procedures. But there are some circumstances where one or more expense items are provided pass-through treatment. This is appropriate when the expense item has three characteristics:

- mostly beyond the ability of utility management to control;

- volatile, and therefore difficult to forecast; and
- comprising a significant portion of the utility's revenue requirement.

Flow-through elements are primarily fuel-related, such as fuel costs or purchased power. The flow-through component of the tariff formula is a contingent adjustment to revenues or rates for cost events that are passed through to customers as they arise, without necessitating the regulator's approval. In this sense, pass-through treatment applies price adjustments in an ad-hoc manner in response to evolving conditions. However, allowances can be set for exceptional reviews when market prices move outside of a pre-defined range. This helps to balance competing interests of protecting the utility's financial integrity, with the customer's preference for stable prices.

3.9 Step 8: Develop lifeline tariff

The ratemaking process is one that constantly requires the balancing of trade-offs. While the regulator should primarily be concerned with establishing prices that reflect the utility's costs of service, it will sometimes be necessary to make concessions for the sake of equity. For instance, governments often want to ensure a minimum level of electric service is offered to the entire population at affordable rates.

Subsidized tariffs for low-income consumers, commonly referred to as ***lifeline tariffs***, are applied in many parts of the world.[14] When developing these approaches to make electricity more affordable, there are two main questions to be addressed:

(i) **what** is the mechanism by which financial support will be provided? and

(ii) **who** will pay for the support?

Generally, the two basic approaches for providing assistance to low-income customers are either through tariffs or through direct payments (see Figure 38 for a summary).

Tariff solutions entail discounting charges relative to the cost of service. The structure of tariff solutions can vary extensively, including: providing a certain minimum amount of electricity supply for free each month (usually based on the monthly usage needed to meet a basic standard of living);[15] waiving the basic monthly charge; or applying overt discounts to all energy consumed. Some jurisdictions constrain the provision of subsidies to specific seasons, while others supplement the subsidy scheme with an incentive for conservation.

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[14] Governments may at times wish to design special rates for industry, for example to attract new businesses or to retain existing ones. These are often referred to as ***economic development rates*** and involve a discount to eligible customers on a utility's standard tariff rates or terms. While economic development rates can lead to benefits such as job creation, these special rates should be approached with caution, because if they deviate from economic principles, they can cause distortions.

[15] For example, in Johannesburg, South Africa, customers must consume less than 1,150 kWh and earn less than R800 per month to qualify for the lifeline tariff, which entails no service charge, free 50 kWh of electricity per month, and a reduced energy charge.

In contrast, the **direct payment approach** is typically implemented as part of a broader social safety net program that helps low-income individuals and households access a minimum level of what are deemed to be essential services. While the direct payment approach is financed by the government (and, ultimately, by taxpayers), subsidies implemented through tariffs can be financed either through a direct subsidy from the government or through cross-subsidies (i.e., where some customers subsidize others by paying higher rates to fund the discount).

Figure 38. Lifeline tariff options

What is the mechanism for providing financial support?	**Tariff solutions** (e.g., tariff discounts or free service below a certain threshold)	**Direct payments** to qualifying low-income customers
Who will pay for the financial support?	The **government** or **other customers** (through cross-subsidies)	The **government**

3.10 Step 9: Assess collection issues

The extent of **collection issues** (i.e., unpaid bills) should be assessed, and mechanisms should be put in place to address poor cash collections. Collections are crucial from both the utility and customer perspective. From the utility's perspective, low collections result in lost revenues, are a worry for private investors, and as a result can threaten the financial viability of the sector. From the customers' perspective, the burden of nonpayment is usually covered by paying utility customers, in the form of excess charges on tariffs in subsequent regulatory periods.

Several methods can be adopted to reduce collection issues:

- **penalties** can be implemented for non-payment. Importantly, penalties should be greater than the interest rate charged on late payments, so that customers are motivated to pay their energy bills on time;
- implement **service disconnections** for customers that have unpaid bills that are overdue for longer than a specified threshold. Notably, if the utility issues a notice of pending disconnection of service to the customer, the utility must adhere to the stated deadlines;
- create **social tariffs** (i.e., reduced rates) for essential services (e.g., hospitals) and low-income customers;
- do not allow for governmental influence for non-paying customers; and/or
- establish **pre-payment schemes**, where some customers with poor payment history are required to pay for power before they use it.

Collection also relies on the rule of law and the ability to enforce contracts. If a utility is unable to implement disconnection policies for fear of the physical safety of its staff, or judges will not enforce collection orders, utilities have limited tools to improve collections.

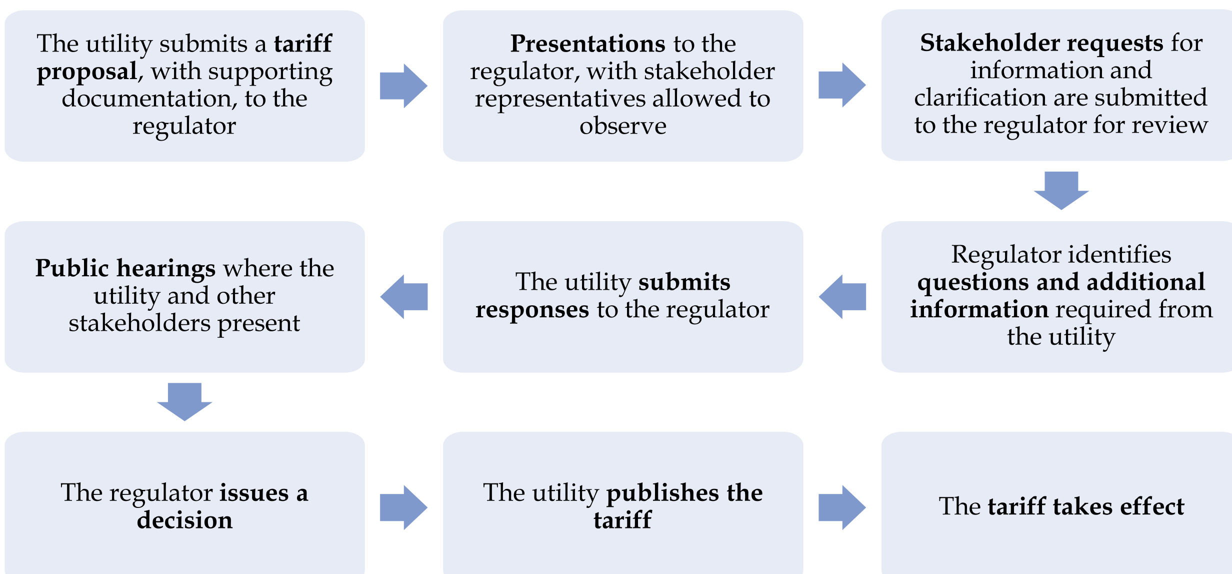
3.11 Step 10: Describe how tariffs are revised and investments approved

Tariff reform efforts will also require policymakers and the regulator to establish procedures for (i) how tariffs are revised, and (ii) how future investments are approved. The subsections below explore each of these issues in turn.

3.11.1 Tariff revision process

Under a COS approach, the basic procedural methodology typically involves the utility and the regulator formally interacting, in accordance with defined protocols and schedules, to specify prices. Figure 39 presents an illustrative schedule to highlight the types of activities that can occur during this process.

Figure 39. Illustrative schedule for the tariff review process



In these proceedings, the utility's primary responsibility is to provide data and supporting materials, in formats to be specified by the regulator. The regulator's responsibilities are to: (i) define the format for reporting information; (ii) review the quality and accuracy of the data and, as necessary, request additional information; and (iii) compute tariffs in accordance with defined and documented methods. In addition, interested stakeholders (e.g., large customers, representatives of residential customers, economists, etc.) should be provided an opportunity to present testimony during the proceedings.

However, this process is generally not administratively efficient. A great deal of data collection and analysis is often required, and both the regulator and the utility must sometimes devote substantial resources to perform the required tasks and reconcile differences in opinion. In particular, the process by which the regulator reviews the utility's costs, and perhaps challenges its expenses and/or investments as imprudent, is particularly difficult and contentious. The regulator will need to balance on the one hand, protecting consumers from the consequences of ineffective management and, on the other hand, allowing investors to recoup their required return.

In contrast, a PBR regime automatically adjusts rates or revenues annually during the ***term*** (discussed later in Section 3.12) based on a pre-specified formula. The use of this automatic adjustment mechanism can reduce the frequency and scope of regulatory intervention, depending on the complexity of the PBR formula. However, it is important to note that effective implementation of a PBR scheme first requires mastery of the basic mechanics of COS ratemaking.

3.11.2 Treatment of future capital expenditures

A key issue faced in certain regions, particularly in growing economies, is how to support continuing investment in energy infrastructure. In particular, the issue centers on how to provide the relevant incentives for ensuring sufficient investments today and in the future to prevent shortages in service provision, while discouraging unnecessary and inefficient spending.

This conflict is often resolved by the utility detailing their long-term capital expenditure plans, which are then subject to review by the regulator (and potentially, at the regulator's discretion, independent experts). These reviews typically occur ex-ante, with approved capital expenditures incorporated in rates for the forthcoming regulatory period. There is also an ex-post review of performance related to capital expenditures from the previous period, with compensation to customers and a reduction in the total revenue requirement if capital expenditures for the previous period is not spent. Furthermore, to ensure competition in investment procurement processes in monopoly-related areas, such as transmission, this mechanism for approval of future capital expenditures is often combined with a request for proposal ("RFP") process for new builds.

3.12 Step 11: Determine the appropriate length of regulatory periods

A ***regulatory period*** typically refers to the time between a major review of the underlying components of a determined rate regime (such as the allowed rate of return, the efficiency factor, performance standards, etc.) and the subsequent review. Separate regulatory periods can also be devised to account for timing to establish new institutions and to ease the transition to a new type of regulatory structure.

Ultimately, there is no unambiguously optimal time period. Determining the appropriate length of the regulatory period requires balancing competing pressures; factors that influence the selection include the stability (or predictability) of the underlying economic and financial factors, as well as the administrative costs associated with regulatory oversight. Generally, most regulatory periods throughout the world range between three and five years – regulatory periods that are relatively longer or shorter than this are associated with their own risks, as highlighted in Figure 40. Notably, these considerations are more apparent under a PBR regime, where prices are set in accordance with a pre-specified formula.

Figure 40. Factors to consider when determining the length of regulatory periods

If regulatory period is shorter than 3 years	If regulatory period is between 3-5 years	If regulatory period is longer than 5 years
• The utility **may not have sufficient time** to achieve target productivity or performance results • Will **not match the planning horizon** for a capital-intensive industry with long-lived assets	• Provides **sufficient certainty regarding regulatory treatment** that the utility feels comfortable engaging in long-term investment programs • Provides the utility with **more flexibility** to manage capital replacement	• The utility's **longer-term financial position may be compromised** if it cannot change 'unachievable' performance target levels • **Hinders the regulator's ability to act** on changing circumstances in a timely fashion

A longer regulatory period provides, all else equal, a stronger incentive for the utility to perform exceptionally, but also increases the risk to both the utility and its customers that prices will fall too far out of line with actual costs.

However, frequent reviews or resets may negatively affect the utility's investment planning. By contrast, a longer regulatory period may provide the utility with a longer-term planning horizon, increasing confidence about regulatory treatment of its investment decisions. This is particularly important in a capital-intensive business such as energy, which relies upon long-lived assets. When developing investment programs, the utility needs to know when efficiency gains are expected to bear fruit, and whether the regulatory period is sufficiently long to allow the utility to capture these gains. In this sense, the utility will be reluctant to invest in operational changes which improve efficiency only after the regulatory period has ended.

3.13 Step 12: Develop formulas for rate adjustments within regulatory periods

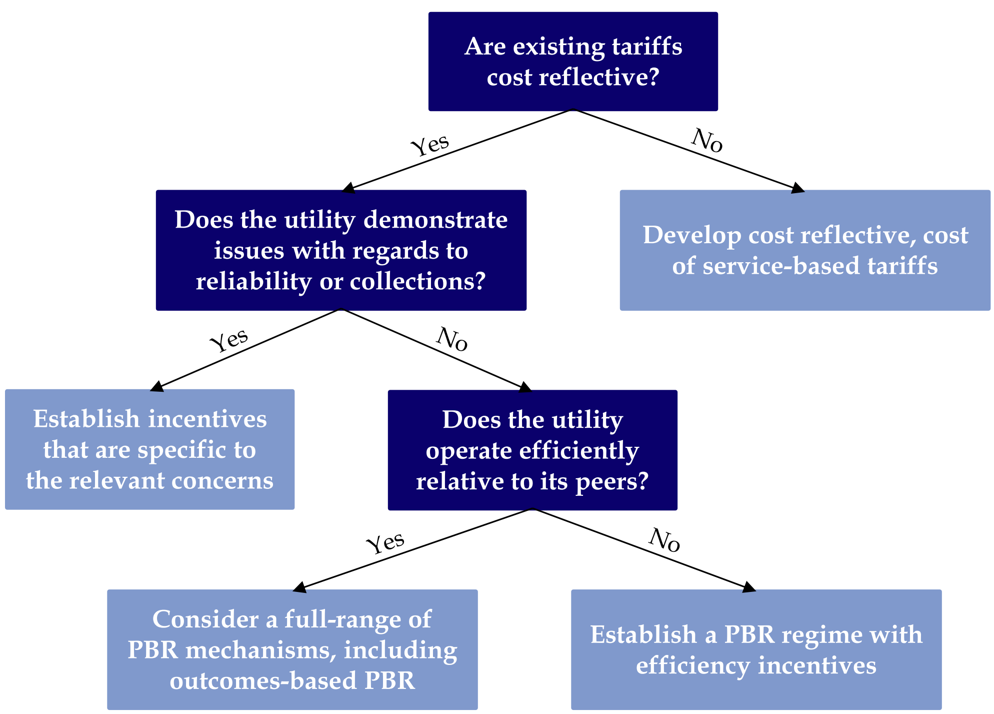
Under a price cap or revenue cap approach (discussed in Section 2.3.3), rather than adjusting prices each year on the basis of the latest available data on actual costs incurred by the utility, average price (in the former case) or the annual revenue requirement (in the latter) is adjusted throughout the regulatory period in accordance with a pre-specified formula. This formula incorporates several parameters understood to reflect the costs of providing utility service – the two most common parameters are an ***inflation factor*** (reflecting trends in the overall economic price level) and a so-called ***X factor*** (reflecting improvements over time in technology and efficiency). With this type of approach, expectations about efficiency improvements throughout the defined period are 'built-in' to a multi-year pricing/revenue trend.

4 Concluding remarks

The Tariff Reform Toolkit has presented two broad ratemaking approaches which policymakers and regulators may wish to implement in order to reach cost reflective tariffs. The first approach, ***cost of service ratemaking***, involves a utility adding up all of its costs (the total of which is its revenue requirement) and allocating these costs among its customers, while upholding the principle of cost causation. The second approach, ***performance-based ratemaking*** moves away from a regime that investigates costs, to one that sets a partly pre-determined (or formulaic) path for rate growth. Within PBR regulation itself, there are numerous mechanisms which can be utilized, ranging from "soft" mechanisms such as rate freezes, to "hard" mechanisms such as rate caps (which typically take the form of either price caps or revenue caps).

However, it is important to note that policymakers and regulators should avoid equating complexity with best practice; stated differently, a more complex ratemaking regime is not necessarily a better regime. Instead, the first step in implementing tariff reform should be to ensure that rates reflect the cost of providing electric service. It is only once this objective is achieved that the ratemaking regime can evolve, where incentives can be added over time to improve utility performance in specific areas of concern (e.g., line losses, collection issues). Figure 41 outlines an illustrative decision tree that can be used to narrow down the choice of ratemaking mechanisms based on the state of play. Key questions that stakeholders may wish to consider during the decision-making process are shaded in dark blue in the figure, with appropriate ratemaking mechanisms in response to each question shown in light blue.

Figure 41. Rate design decision tree



Regardless of the ratemaking regime that is ultimately implemented, the following are some key considerations to keep in mind when pursuing tariff reform:

- **there is no one size fits all approach:** although the Toolkit lays the foundation for COS and PBR regimes, elements of either approach can be combined to address the particular concerns of the jurisdiction and/or utility in question. In this sense, there is no one size fits all approach that will meet the needs of all jurisdictions – ratemaking regimes will need to be adapted to the local context;
- **appropriate mechanisms can change over time:** the ratemaking regime will inevitably evolve with time, as the regulator, utility, and other stakeholders build the knowledge and capabilities needed to implement cost reflective rates;
- **cost of service helps to quickly mobilize investment, while PBR is more suited to a system which has reached steady state:** cost of service ratemaking incentivizes utilities to grow their capital base in order to increase their profits, this can be especially effective in regions that require a build out or expansion of electricity infrastructure;
- **costs to consumers are more easily managed in systems where load is growing:** where load is growing, fixed costs can be allocated across a growing customer base. It is when load is shrinking that rates are especially at risk of increasing, as the fixed costs of providing electric service are allocated among a shrinking customer base;
- **all regulatory systems represent a balancing act among key principles, particularly simplicity versus precision of cost allocation and incentives:** key ratemaking principles include financial stability and a fair rate of return, non-discrimination, incentives compatibility, cost causation and avoidance of cross subsidies, and administrative simplicity. Policymakers need to determine which principles they prioritize most when developing the ratemaking approach; and
- **sector costs do not disappear because they aren't charged, and suppressing power prices can lead to larger problems in the future:** the under recovery of costs incurred by a utility can threaten the financial viability of the sector. If subsidies are pursued to protect vulnerable customers from high electricity rates, those subsidies should be targeted, transparent, and time-limited.

5 Glossary

Billing determinants: various measures of consumption that are used to calculate a customer's energy bill, or to determine the aggregate revenues from rates from all customers.

Capex (K) factor: annual adjustment to the utility's revenue or rates reflecting forecasted capital expenditure (capex) or growth in customers.

Cost allocation: the assignment of a utility's costs among its customers.

Cost causation: a ratemaking principle that posits that the customer that causes a cost to be incurred should pay that cost. Or stated differently, that the rates that customers pay should reflect the costs that their usage imposes on the system.

Cost of service ("COS") ratemaking: traditional form of utility regulation under which changes in the rates approved by regulators are linked to an evolution in underlying costs.

Cost of service study: usually performed in the context of a rate case, this is an analysis that allocates a utility's allowed costs to provide service among its various customer classes.

Customer charge: a fixed charge on a customer's energy bill, which typically covers the costs to a utility associated with metering, meter reading, and billing (which do not vary with customer size or usage).

Customer class: a group of customers that share common usage patterns or other characteristics – typically classified as residential, commercial, and industrial customers, among others. Generally, all customers within the same class are charged the same rates.

Demand charge: a charge on a customer's energy bill paid based on metered demand, typically for the highest hour during a billing period.

Earnings sharing mechanism ("ESM"): a mechanism through which a specified portion of a utility's profits in excess of/below the approved return on equity/forecasted level of expenditures is returned to customers.

Energy charge: a charge on a customer's energy bill based on the amount of energy consumed.

Fixed charge: any charge that does not vary with electricity consumption.

Flow-through element: a contingent adjustment to revenues or rates reflecting certain pre-approved costs that are automatically passed through to customers as they arise, without having to be approved by the regulator.

Gold-plated networks: relates to one criticism of cost of service ratemaking, where the incentives for cost-efficiency are weak, and as such the utility is more likely to over-invest in (or gold-plate) its system.

Inflation (I) factor: an annual adjustment to the utility's revenues or rates reflecting the level of inflation, usually reflecting the actual inflation rate in the previous year.

Lifeline tariff: reduced electricity rates for low-income households that are unable to afford to pay for their basic electricity needs.

Off-ramp: a mechanism allowing triggering, under specified circumstances, a review of the ratemaking regime in place before the end of the regulatory period. The process may lead to the overhaul or the termination of the regime.

Outcomes-based PBR: a comprehensive PBR regime that focuses on the outputs or outcomes of the PBR plan, rather than the inputs/activities, which is generally the emphasis of the traditional rate filing. Under outcomes-based PBR, the utility's revenue requirement for the next regulatory term is adjusted according to its performance based on achievement of outcomes.

Peak demand: the maximum demand either by (i) a single customer, (ii) a group of customers located on a portion of the electric system, (iii) all the customers in a particular customer class, or (iv) all of a utility's customers during a specific period of time.

Performance standards (Q factor): a contingent adjustment to revenues or rates for rewards/penalties linked to the achievement or failure to reach specified performance targets, usually in terms of service quality as well as reliability and quality of supply.

Performance-based ratemaking ("PBR"): a form of utility regulation which, by decoupling changes in rates and costs, aims to strengthen the financial incentive to lower costs. It usually also contains other targets in order to enhance other non-price performance.

Price cap: a mechanism under which the rates charged by a utility are allowed to increase following a formula consisting of several factors, such as inflation, productivity, quality performance, etc.

Productivity (X) factor: an annual adjustment to revenues or rates reflecting expected changes in terms of productivity. May be based on the utility's historical performance or on an external benchmark.

Rate base: the net investment of a utility in property that is used to serve the public.

Rate design: the specification of prices for each component of a rate schedule for each class of customers, which are calculated to produce the revenue requirement allocated to the class.

Rate freeze: where a utility's rates are held constant during the PBR term – rate freezes are commonly used to protect customers during a transition.

Regulatory assets: an accounting mechanism unique to utilities, regulatory assets are usually authorized by regulators to allow utilities to defer costs related to various matters (e.g., extreme weather) for future recovery.

Regulatory compact: the implicit agreement between a utility and the regulator, whereby the utility accepts an obligation to serve in return for rates that compensate the utility fully for the costs it incurs to meet that obligation.

Regulatory lag: the lapse of time between when costs are incurred by a utility and when those costs are allowed to be recovered from customers.

Regulatory period: time lag between two major reviews of the underlying components of the ratemaking regime.

Revenue cap: a mechanism under which the revenues earned by a utility are allowed to increase following a formula consisting of several factors, such as inflation, productivity, quality performance, etc.

Revenue requirement: the annual revenues that a utility is entitled to collect.

Test year: a specific period chosen to demonstrate a utility's need for a rate increase, which can either be historical or forecasted.

Throughput incentive: occurs in the short-run – if a utility's variable costs rise or fall more slowly than its revenues from a change in sales, it will earn more if sales increase and less if sales decrease.

Unforeseen events (Z) factor: a contingent adjustment to revenues or rates in order to recover extraordinary costs that are outside of the utility's ability to control or predict.

Weighted average cost of capital ("WACC"): the total cost, in percentage terms, of financing a utility's assets. The predominant method for setting the allowed rate of return is to use the utility's WACC, suggesting that the utility is being compensated for its capital costs.

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