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Cost of Service Regulation of Electricity Distribution Services in the U.S.[1]

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1. Introduction

This chapter discusses the application of "cost of service" (COSR) or "rate of return (ROR) regulatory mechanisms (COSR) in practice by U.S. public utility commissions to set allowed revenues, profitability, and "retail tariffs" that specify the prices that end-users pay for regulated distribution services provided by investor-owned distribution utilities (IOUs). IOUs serve almost three-quarters of retail consumers in the U.S.[2] COSR principles are used to establish prices for both distribution and transmission services offered by IOUs. However, regulatory responsibility is split between the states, which regulate distribution rates and rates for bundled transmission service for a utility's retail customers (their so-called native load), and the federal government, with the Federal Energy Regulatory Commission (FERC) responsible for regulating interstate transmission services.

In this chapter we focus on the regulation of distribution and certain bundled transmission services by state public utility commissions. On average across states, distribution services account for 26% of the average customer bill and transmission services another 12%.[3] That is, total delivery services account for just under 40% of the average electricity bill. This share is expected to increase in the future as investment in distribution and transmission networks increases to support growing demand for electricity as customers switch to electric vehicles, heat pumps, and other electric appliances and equipment to meet decarbonization goals as well as to replace aging equipment.

Essentially the same COSR principles apply to IOUs that have been restructured to separate generation services from delivery services and offer unbundled distribution services and well as to

[1] This chapter draws heavily on Joskow (2007, 2014, and 2024), Joskow and Schmalensee (1986), and Schmalensee (1979). To be published as Chapter 3 in *Handbook on Electricity Regulation,* Jan-Michel Glachant, Micheal Pollitt, and Paul Joskow, Editors. Edward Elgar Press.

[2] https://www.transportation.gov/rural/ev/toolkit/ev-partnership-opportunities/electric-utilities.

[3] Energy Information Administration, *Electricity Explained*, https://www.eia.gov/energyexplained/electricity/prices-and-factors-affecting-prices.php

IOUs that continue to be partially or fully vertically integrated into generation and transmission and supply bundled services to their retail customers. Finally, COSR is also the foundation for setting the regulated prices for unbundled interstate transmission service by the FERC, which is discussed in detail in Chapter 4. We focus here on the application of COSR to set the overall level of revenues that a regulated firm is allowed to earn ---its revenue requirements. We also discuss briefly rate design --- the design of the actual prices schedules or tariffs that define how individual types of customers are charged for electricity. Chapter 10 discusses U.S. rate design in detail.

This chapter proceeds as follows. We begin with a brief overview of the organizational structure of the U.S. electric power industry today. There is considerable diversity in the structure of IOUs and their regulation as a consequence of the different approaches that the states took to restructuring over the last 25 years. Section 3 then reviews the "natural monopoly" rationale for continuing economic regulation of distribution networks even as competition among decentralized suppliers of generation has become a dominant organizational paradigm. Section 4 discusses the choice of regulation by independent state commissions rather than alternative governance arrangements. Section 5 presents an overview of COSR as used in formal rate reviews by state public utility commissions. Section 6 provides a brief discussion of the performance of COSR in practice. The final section contains a brief discussion of the gradual diffusion of performance-based regulation (PBR) to U.S. distribution companies as a complement to traditional COSR, mainly as a response to new obligations being placed on distribution companies.

2. The U.S. Electric Power Sector Today

The structure of the U.S. electric power industry, especially the IOU sector, has changed considerably in the last two decades. Among other changes are the vertical restructuring of many IOUs to separate generation (potentially competitive) from transmission and distribution that largely continue to be subject to COSR, the creation of independent non-profit entities that manage organized wholesale electricity markets and have responsibilities for system reliability and transmission planning, and the unbundling of retail energy supply (potentially competitive) from regulated distribution or delivery services in some parts of the country. Despite all of these changes, the distribution of electricity by IOUs everywhere continues to be subject to price, entry, and services obligation and quality regulation by state regulatory commissions. Moreover, in those states that have expanded the application of performance based regulatory mechanisms, COSR remains an important complement to these new regulatory regimes (Joskow 2024). Accordingly, it is important to understand the details of COSR regulation as it is applied both in theory and in practice to the distribution of electricity.

Today, IOUs fall into two categories. In the first category are utilities that have been fully restructured vertically, provide distribution and (typically) transmission service, and acquire electricity through various competitive market arrangements from independent generators. Distribution utilities that fall into this category are typically also members of non-profit Independent System Operator (ISO) or Regional Transmission Operator (RTO) organizations. (Differences between these two sorts of organizations are minor.) These organizations manage organized competitive wholesale markets for generation services, manage a regional open access transmission tariff, including rules governing interconnection of new generators, manage bulk power system reliability, and plan for transmission upgrades. Thirteen states, mostly in the Northeast plus Texas, Ohio and Illinois, and the District of Columbia have also unbundled competitive retail electricity supply from the delivery of electricity for all retail consumers.[4] Competitive retail electricity suppliers operate pursuant to rules and regulations established by state statutes and administrative regulations, but are not subject to price or profit regulation. For utilities that fall into this "full restructuring" category, unbundled distribution service prices are regulated by state public utilities commissions. Prices for unbundled interstate transmission service, as well as rules governing transmission access, the details of organized wholesale markets managed by ISO/RTOs, and transmission planning protocols adopted by ISO/RTOs are regulated primarily by the FERC. We focus here on state COSR regulation of distribution services and the next chapter focuses on FERC regulation of transmission, though the COSR principles applied are very similar in both cases.[5]

IOUs in the second category remain fully or partially vertical integrated into generation, transmission, and distribution. These utilities lie primarily in the South, the West and the Midwest. Some of these utilities are also members of ISO/RTOs, buy and sell electricity in their organized

[4] https://www.cnet.com/home/energy-and-utilities/energy-deregulation/. Another five states have limited retail competition.

[5] As discussed in Chapter 4, FERC's regulatory responsibilities cover interstate transmission service. Where utilities have fully unbundled transmission service, FERC has full regulatory responsibility. For utilities that have not fully unbundled transmission service, regulatory responsibility for transmission service dedicated to the utilities' retail or "native load" customers lies with the states. In the latter cases, both FERC and state regulators have some responsibility for the economic regulation of transmission service.

wholesale markets, and are subject to open-access transmission rules, transmission pricing, and many aspects of transmission planning. However, state cost-of-service regulation now governs distribution services, bundled transmission services designated as serving the utility's retail customers, and the net revenues the utility can earn on the generating plants they own and operate. There is no retail competition in these states. The basic COSR principles that we discuss in this chapter apply to these utilities as well, now covering the generating plants that they own as well as distribution and intrastate bundled transmission serving their retail customers. The mix of regulatory responsibilities between state commissions and FERC is discussed in Chapter 4.

While academic and policy discussions focus on restructured utilities that fall into the first category, fully and partially vertically integrated utilities still comprise a significant fraction of the IOU segment of the industry.[6] About 36% of the energy delivered to retail customers is provided by IOU generators and about 45% is generated by unregulated independent power producers (IPPs). (The remainder is provided by a heterogeneous set of government- and cooperatively-owned utilities.) However, vertical integration by IOUs into generation continues to decline as regulated thermal plants retire and entry of independent wind and solar generating capacity grows. Generation by independent power producers has increased by 19% in the last ten years while total utility generation (IOUs + all others) has declined by nearly 5% and by more for IOUs.

3. Rationale and Goals for Regulation of Electricity Prices

The standard normative rationale for regulating electricity prices has been that providing electricity is a natural monopoly, so that geographic monopolies can in theory provide services at the lowest cost,[7] but that actual geographic monopoly would lead unregulated electricity suppliers to have significant market power allowing them to raise prices far above costs. Moreover, long-lived sunk costs represent a large fraction of total costs (Joskow 2007, Schmalensee 1978, 1979). Under these conditions, (a) a single firm operating efficiently can in principal provide services in a specific geographic area at a lower cost than two or more firms serving the same area, (b) a single incumbent firm, whether it emerged "naturally" or received a de facto exclusive contract from a

[6] This paragraph is based on https://www.eia.gov/electricity/annual/ and https://www.eei.org/resources-and-media/industry-data.

[7] Technically this means that the cost function for providing electricity, $C(X)$, where X is a non-negative vector of location-specific sales, is *subadditive*. The function C is strictly subadditive if for any non-negative sales vectors X and Y, $C(X+Y) < C(X)+C(Y)$, so that it is always cheaper to have one firm meet demand than to have two or more firms do so.

government entity, would have significant market power enabling it to charge prices that are significantly above its costs, (c) a single incumbent firm would be able to deter entry profitably, and (d) if entry did occur it would lead to a failure to capture all economies of scale and scope. Designating a single regulated firm to provide service to a defined geographic area may reflect public policy goals other than cost minimization, such as universal service, income redistribution, and/or other sorts of taxation by regulation (Posner 1971).

Until the 1980s, it was widely believed by academics and policymakers that natural monopoly characteristics over specific geographic areas extended to all segments of the industry; generation, transmission, distribution, and retail supply. In addition, it was assumed that there were also economies associated with vertical integration between these segments. The evolution of the electric power sector in the U.S. and many other countries over the last 25 years or so demonstrates how much thinking about these matters has changed. It is now widely recognized that economies of scale at the generation level within most geographic areas are limited and that moving to a competitive generation segment would not sacrifice economies of scale while potentially yielding cost savings by relying on competition rather than regulation to provide stronger incentives for efficiency. And any vertical economies between generation and transmission/distribution can be reasonably well achieved through decentralized market mechanisms, open transmission access rules, and regional transmission planning, all managed by independent regional system operators (ISO/RTOs) with geographic footprints substantially larger than those of the incumbent vertically integrated utilities.

At the distribution level there continues to be diverse views on whether vertical economies between the physical distribution of electricity and the procurement and sale of electric power to retail customers are important. As noted above, a few states and the District of Columbia have unbundled delivery services from energy procurement and adopted full competitive retail supply of energy, while the bulk of states have continued to bundle delivery and energy supply.

The one remaining common feature of all electric distribution utilities is the assumption that the physical distribution and transmission of electricity continues to have geographic natural monopoly characteristics. Indeed, over the last few decades, mergers between utilities have led to distribution utilities with larger geographic footprints.[8] Giving transmission operating and planning authority to regional ISO/RTOs actually expands the geographic scope of management of the transmission network, while regulation of transmission service prices controls the monopoly power that transmission owners would otherwise have. And, while there are ongoing experiments with expanding competitive opportunities to own certain distribution facilities, the primary governance arrangement is to rely on geographic distribution monopolies subject primarily to cost of service regulation. This leaves the distribution function as the primary target of state commission regulation in states that rely on wholesale markets to provide generation services and have fully unbundled transmission.

Whether one accepts the normative, natural monopoly rationale for the regulation of distribution companies or not, the reality is that most IOU distribution companies operate with de facto exclusive geographic franchises. The goals of regulation include the mitigation of the potential monopoly power associated with a geographic monopoly, protection of investors in the regulated enterprise from ex post expropriation of the associated long-lived assets in order to preserve investment incentives, and efficient production of and investment in the regulated services. There is a large literature on efficient pricing of public utility services in the presence of perfect information,[9] but its prescriptions have had very little influence on regulatory practice. In practice, regulated firms have better information than their regulators, interest group politics plays a significant role even where regulators are legally independent, and regulators have limited human and financial resources to meet their responsibilities.

4. Public Utility Commissions and Governance Alternatives

In the earliest days of the electric power industry in the U.S., municipalities exerted governance by requiring competitive bidding for exclusive local franchises. Three different structures have replaced this approach. During the 1920s and 1930s, many cities acquired the distribution assets that served their residents and regulated the resulting municipal utilities directly (Schap 1986). The largest municipal utility is the Los Angeles Department of Water and Power, which has about 1.6 million electricity customers. Beginning around 1930, the federal government

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[8] The Edison Electric Institute reports that there were 123 mergers and acquisitions of IOUs between 1995 and 2022. https://www.eei.org/-/media/Project/EEI/Documents/Issues-and-Policy/Finance-And-Tax/Financial_Review/FinancialReview_2022.pdf

[9] See, for instance, Braeutigam (1989), Brown and Silbey (1986), and Joskow (2007).

became an important producer of hydroelectric power, which it sold at wholesale on favorable terms to municipal utilities and cooperatives, which are owned and governed directly by their customers (Schmalensee 2016). This provided incentives to form utilities of both sorts. Most cooperatives are relatively small, but the Pedernales Electric Cooperative serves over 250,000 customers. In 2017 cooperatives served 13% of U.S. customers, and municipal and other publicly owned utilities served 16%.[10]

The most important governance structure and the one on which we focus here emerged beginning in 1905 (Phillips 1993): the regulation of IOUs by an independent regulatory agency in which decision-making authority is vested in 3-7 "public utility commissioners". In 2017, IOUs regulated by independent agencies served 71% of U.S. customers. These agencies have a quasi-judicial structure and apply statutory authority and more detailed administrative procedures to establish prices and profitability, to review investment and financing plans, and to specify and monitor other terms and conditions of service. Typically, public utility commissioners are appointed by the governor and approved by the legislature (or appointed by the President with consent of the Senate for FERC), though in ten states they are elected by popular vote.[11] Their terms are limited by statute. The last state to turn to regulation of the electric power industry by an independent state commission was Texas in 1975.[12] Prior to the creation of the Public Utility Commission of Texas, regulation of IOUs there was the responsibility of municipal governments via the terms of franchise agreements.

State commissions typically have responsibility for multiple industries, not just electric utilities. For example, the California Public Utilities Commission has a variety of regulatory responsibilities for electricity, natural gas distribution and intra-state pipelines, intra-state telecommunications, water, and intra-state rail transportation.[13]

The commissions have staff composed of professionals with training in engineering, accounting, law, finance, and economics. For example, Joskow (2024) surveyed 14 states and found that the size of state public utility staffs varied from 27 (Vermont) to 1,218 (California).

10 https://www.eia.gov/todayinenergy/detail.php?id=40913#:~:text=IOUs%20are%20most%20prevalent%20in,Company%2C%20with%205.07%20million%20customers.

11 https://ballotpedia.org/Public_Service_Commissioner_(state_executive_office)

12 The New Orleans City Council has regulatory authority over the distribution utility serving the City (Entergy New Orleans), though regulatory responsibility for the rest of Louisiana is with the Louisiana Public Service Commission. https://www.all4energy.org/cno.html

13 https://www.cpuc.ca.gov/about-cpuc/cpuc-overview/about-us

Thus, commissions have resource constraints of varying stringency, though the implications of these constraints have not been studied. Some commissions have administrative law judges who conduct public hearings and make preliminary rulings which are then considered by the commissioners for final decision. At the end of general rate cases, which are described below, commission decisions may be hundreds of pages long.

IOUs must file a lot of financial and operating data pursuant to a *uniform system of accounts* administered by FERC and additional data requirements specified by the Energy Information Administration (EIA).[14] Pursuant to the Clean Air Act, the Environmental Protection Agency (EPA) collects and reports environmental data drawn from continuous emissions monitors installed on most fossil fuel generating plants. The Nuclear Regulatory Commission (NRC) oversees permitting and safety of nuclear power plants. State commissions may require that additional information be reported by the firms they regulate.

Most of the data collected by these agencies are publicly available and help reduce the information asymmetry between the regulators and the firms that they regulate (see Chapter 2). It should be recognized, however, that more and better reporting of historical data cannot fully mitigate the asymmetric information problem faced by regulators. Regulators cannot measure managerial effort, and they cannot fully understand all the myriad factors that affect observed performance.

Regulators can "disallow" costs that they determine are unreasonable through, for example, independent assessments of firm behavior and comparisons with other firms. Costly nuclear plants have often been the target of large disallowances. For example, in 2023 the Georgia Public Service Commission disallowed $3.3 billion of costs incurred to build the third and fourth units of the Vogtle nuclear plants.[15] The arguments between the utility, regulators, and stakeholder intervenors about cost recovery gives real substance to the asymmetric information challenge that U.S. regulators face.

As we discuss in more detail below, regulated prices typically are not adjusted continuously to assure that revenues and costs are exactly in balance. There are sometimes lengthy periods of "regulatory lag" between rate cases during which prices are basically constant, though

[14] https://www.ferc.gov/general-information-0/electric-industry-forms/form-1-electric-utility-annual-report; https://www.eia.gov/electricity/data/eia861

[15] https://psc.ga.gov/search/facts-document/?documentId=205571

changes in some costs that are beyond the utility's control are typically passed through automatically to prices.[16] Some jurisdictions have now implemented multi-year rate plans that have more comprehensive mechanisms to adjust prices between formal rates cases.

The decisions of state and federal regulatory agencies are bound by a variety of legal constraints. Their decisions must be based on a reasonable assessment of the relevant facts in light of the agency's statutory responsibilities. Following the 1944 *Hope* decision, regulated prices must also be "just, reasonable and not unduly discriminatory," ensuring that consumers are charged no more than necessary to give the regulated firms a reasonable opportunity to recover efficiently incurred costs, including a fair rate of return of and on their investments.[17]

Finally, in practice, regulatory agencies are not completely independent of the influence of interest groups and the political system. The commissioners are typically political appointees and commissions are subject to oversight by legislatures and depend on legislatures to allocate funds to support their operations (Weingast and Moran (1983)). Commissioners and senior staff may have career ambitions that may benefit from supporting actions involving particular firms or industries (Laffont and Tirole (1993), Ch. 16). Political pressure and economic conditions may lead commissions to make decisions that allow rates to get too high or, at the other extreme, to fail to protect utilities' sunk investments from regulatory expropriation (Joskow (1974), Kolbe and Tye (1991), Sidak and Spulber (1997)).

5. Cost of Service Regulation in Practice

5.1. Overview of Formal Rate Cases

As noted, electricity distribution service rates are set by state regulatory commissions through a public adjudicatory process. Typically, the utility proposes a set of new rates and (perhaps) a new mechanism that operates "automatically" between formal regulatory review for adjusting those rates over time. A formal rate case may also specify and expand the regulatory firm's service obligations and define performance metrics. Depending on the state, a consumer advocacy agency, often under the state's attorney general, may be responsible for representing the public in these proceedings. Interest groups may participate in formal regulatory proceedings as "intervenors." Intervenors may include consumer advocacy groups, environmental groups, and

[16] Examples of such costs are fuel costs and costs of electricity procured on wholesale markets.
[17] *Federal Power Commission v. Hope Natural Gas* 320 U.S. 591 (1944).

organizations representing specific groups of consumers (e.g., large industrial consumers). Individual consumers may represent themselves, but the cost of doing so typically means that the "individuals" are very large electricity consumers (e.g., the U.S. General Services Administration). There are typically public hearings where the distribution company, the commission staff, and intervenors can file testimony with relevant evidence. Oral hearings may or may not be held, although anecdotally, "paper hearings" with only written testimony are used frequently.

Formal general rate cases are time consuming, paper-intensive and use substantial staff and intervenor resources. The regulatory agency ultimately issues a decision and its justification for it based on the evidence presented and relevant statutory requirements and case precedents. The utility can appeal to the courts for relief if it feels that the Commission's decision does not give it a reasonable opportunity to recover its prudently incurred costs. Intervenors can appeal if they feel the Commission has been too generous to the utility or has been unfair to their constituents. Increasingly, commission decisions are based on settlement agreements between some or all of the parties to the proceeding, which reduces the time, costs, and uncertainty of fully litigating the rate case.[18]

Once the commission issues its decision, new rates go into effect and stay in effect (except for automatic pass-through of some exogenously determined costs) until the next regulatory proceeding. The commission decision may also include a multi-year rate plan (MYRP), a comprehensive mechanism to adjust rates between rate cases. Even in the absence of such plans, formal rate cases do not take place every year, for a variety of reasons including administrative costs and risks to the utility and other stakeholders of unfavorable outcomes. Sometimes many years have elapsed between formal rate reviews, and the prices and price adjustment provisions from the most recent rate case remain into effect until a new rate case is triggered, typically by the regulated firm.

Formal rate cases begin with the choice of a "test year." The test year defines the time period for which data are used for evaluating the "reasonableness" of the existing rates and the

[18] A settlement of a rate case refers to the frequent use of negotiations between key stakeholders and the affected utility to resolve issues before the regulatory commission renders its own final decision. When a sufficient number of stakeholders reach an agreement with the utility subject to formal regulatory review or other regulatory action, a document specifying the terms and conditions to which the stakeholders have agreed is presented to the commission for its approval. If the settlement agreement is approved by the commission, its terms and conditions are included in the commission's final decision and order. A settlement may resolve only some or all issues raised in a formal proceeding. If only some issues are resolved by the settlement, any remaining issues are litigated and a decision made rendered by the regulatory agency.

request to adjust them. The test year is typically either the most recent full year of utility's operations adjusted for known changes when the rates go into effect or a future test year incorporating estimates of costs and quantities during the period when the new rates will ultimately go into effect. Based on the data for the test year chosen, the first component of a formal regulatory review is the "Revenue Requirements" phase in which the utility's aggregate allowed revenue or aggregate allowed "cost of service" is establish by the regulatory commission. A regulated firm's revenue requirements or cost of service has numerous individual components that can be grouped into a few major categories:

a. Operating expenses (e.g. fuel, labor, materials and supplies, maintenance expenses, and income taxes) --- *O&M*

b. Capital-related costs that define the effective rental price for capital used to provide services. These capital related costs are a function of:

i. the value of the firm's "regulatory asset base" or its "rate base" -- *RAB*

ii. the annual amount of depreciation on the regulatory asset base -- *D*

iii. the allowed rate of return on the regulatory asset base -- *r*

c. Other costs (e.g. property taxes, franchise fees) --- *F*

The utility's total revenue requirements or cost of service in year t, R_t, is then given by

$$R_t = O\&M_t + D_t + r_t RAB_t + F_t \qquad (1)$$

After the test year is chosen, the regulatory agency determines the allowable operating and maintenance costs. These include labor costs, materials and supply costs, capital items that are expensed under accounting rules, purchased power costs from third parties, property taxes, depreciation, income taxes,[19] and, for utilities that are vertically integrated into generation, fuel costs. The company will propose adjustments to the test year O&M expenses, and the staff and intervenors will propose their own adjustments, including rejecting utility adjustments they argue are unreasonable.

The next step in a formal rate case is to determine the utility's "rate base" and associated annual depreciation charges. In the U.S., state regulators and FERC generally calculate the rate base as the original cost of allowable investments in utility assets less the accumulated straight-line depreciation of those assets. The current year's depreciation becomes a non-cash operating cost included in the revenue requirement.

[19] The treatment of income taxes and deferred income taxes is very complicated and we will not discuss it here.

The formal rate case then proceeds to determine the allowed rate of return on the rate base. The regulator specifies the fraction of the firm's financing that it determines should be allocated to debt, preferred stock, and common equity capital. The cost of debt is measured as the weighted average coupon rate on the bonds that the utility has issued in the past, referred to as the embedded cost of debt. Similarly, the cost of preferred stock is derived from the coupon rate preferred stock issued in the past. The cost of equity must be estimated, and this is typically a source of controversy in a rate hearing. With an estimate of the cost of equity capital in hand, the allowed rate of return is calculated as the weighted average cost of debt, preferred stock and equity capital. The allowed rate of return is then multiplied by the allowed rate base to yield the allowed capital charge component of the annual regulated revenue requirement. Per equation (1), allowed O&M costs are then added to the allowed return on the rate base and depreciation to arrive at the allowed total revenue requirement for the test year.

The second phase of a formal rate case is the "Rate Design" phase, in which the commission allocates the aggregate Revenue Requirement among different customer classes (residential, commercial, small industrial, large industrial, agricultural, street lighting, etc.). It then determines the structure of the rates within each class. Traditionally, particularly for residential and small commercial customers, regulated rates have involved constant charges per kilowatt-hour of electric energy consumed, plus a small monthly fixed charge. Assumptions about the test year quantities have been or will be sold in each rate category are applied so that the revenues estimated to be produced aggregate up to the allowed aggregate revenue requirement, also referred to as the aggregate cost of service. Once test year rates and any automatic mechanisms to adjust them (including automatic pass-through of certain costs) are set, they remain in force until they are adjusted in a subsequent rate case.

5.2. Revenue Requirements in More Detail

The utility's operating and investment costs are initially drawn from the regulated firm's books and records based on the uniform system of accounts and any additional information required by the regulator. The hearing process then turns to evidence presented by the company, staff, intervenors and the public advocate regarding the "reasonableness" of these costs. The regulatory agency may rely on its own staff's evaluations to identify costs that were unreasonable or unrepresentative of a typical year, or the regulator may also rely on studies presented by third-party intervenors in the rate case (Joskow (1972)). As noted above, costs that the regulatory agency determines are unreasonable are then disallowed and deducted from the regulated firm's cost of service.

How can regulatory agencies determine whether the costs presented by the firm are "reasonable"? One approach is to apply a statistical "yardstick" method in which a particular firm's costs are compared to the costs of comparable firms, and significant deviations may trigger disallowance (see, e.g., Haney and Pollitt (2011), Jamasb and Pollitt (2001, 2003), Carrington, Coeli and Groom (2002), Schleifer (1985)). Since there are about 135 IOU distribution companies in the U.S. reporting abundant data using the same Uniform System of Accounts, one might think that this would be a widely used method for evaluating utility costs and performance. While this method has been used from time to time to evaluate fuel costs, labor productivity, wages, executive compensation, construction costs, and some other costs, it is not used as frequently as it probably should be in the U.S. This situation is gradually changing as a growing number of state regulators have introduced PBR mechanisms.

Rather than relying on statistical yardstick analyses, state commission and intervenors can hire outside experts to review the firm's expenditures in specific areas and present assessments of whether costs and performance have been reasonably efficient given industry norms. Regulators may also examine assumptions about future demand, future wage growth, the timing of replacements of capital equipment, and other factors. Finally, the regulator's accounting staff and intervenors may go through the regulated firm's accounting reports to search for expenditures that are either prohibited (e.g., Red Sox tickets for the CEO's family) or that may be of questionable value to the regulated firm's customers (e.g., a fleet of corporate jets). However, no matter how hard the regulator and intervenors explore the evidence of the firm's costs and behavior, we must assume that regulated firm always knows more about its own cost opportunities, expenditures, and managerial effort than does the regulator, consistent with the importance of conceptualizing public utility regulation from an asymmetric information perspective.

Once the reasonableness of the firms operating costs and investments have been determined, the rate review turns to the valuation of the firm's rabe base, depreciation rules, and the allowed rate of return on the rate base (Sharfman (1928), Phillips (1993), Bonbright (1961), Clemens (1950)). As noted earlier, since 1944 the basic legal principle that governs price regulation in the U.S. is that regulated prices must be set at levels that give the regulated firm a reasonable opportunity to recover the costs of the investments it makes efficiently to meet its service obligations but to earn no more than is necessary to do so in order to protect consumers from the exercise of monopoly power.[20]

One way of operationalizing this legal principle is to reduce it to the rule that the present discounted net present value (NPV) of expected future cash flows that flow back to investors in the firm (holders of equity, debt, and preferred stock) should be at least equal to the "reasonable" cost of the capital facilities in which the firm has invested, where the discount rate is the firm's risk adjusted cost of capital. If a regulated firm expects to recover its operating and capital costs over time, including a return on its investment greater than or equal to its opportunity cost of capital, the firm should be willing to make the investments since it will cover its costs. If the relationship holds with equality, then consumers are asked to pay no more than is necessary to attract investments in assets required to provide services efficiently.

The earliest efforts to develop capital valuation and pricing principles focused on "fair value" approaches, in which the regulated firm's assets would be regularly revalued based on the consideration of "reproduction cost" and other methods, including giving some consideration to "original cost" (Troxel (1947, Chs. 12 and 13), Clemens (1950, Ch. 7), Kahn (1970, pp. 35-45)). Implementing these concepts in practice turned out to be very difficult with rapid technological change and widely varying rates of inflation over time. Moreover, "fair market value" rules led regulated firms to engage in "daisy chains" in which they would trade assets back and forth at inflated prices and then seek to increase the value of their rate bases accordingly. Many regulated firm asset valuation cases were litigated in court. The guidance given by the courts was far from crystal clear (Troxel (1947, Ch. 12)). And, of course, there was a fundamental circularity: the value of any asset is the discounted value of the future earnings it will generate, but the purpose of regulation is to determine those earnings.

Beginning in the early 1920s, alternatives to the "fair value" concept began to be promoted. In an influential dissenting Supreme Court opinion in 1923,[21] Justice Louis Brandeis proposed a formula based on what he called the "prudent investment" standard. Regulators would first determine whether an investment and its associated costs reflected "prudent" or reasonable decisions by the regulated firm. If they did, investors were to be permitted to earn a return of and

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[20] *Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 602 (1944).*
[21] *Southwestern Bell Telephone Company v. Public Service Commission of Missouri* 262 U.S. 276 (1923).

on the original cost of this investment. The formula for determining the trajectory of capital-related charges specified that regulators should use straight-line depreciation of the original cost of the investment, value the regulatory asset base at any time as the original cost of plant and equipment prudently incurred less the accumulated depreciation associated with it, and apply an allowed rate of return equal to the firm's nominal cost of capital. Brandeis argued that this approach would make it possible for regulators and the courts to "avoid the 'delusive' calculations, 'shifting theories,' and varying estimates that the engineers use as they measure the reproduction costs and present values of utility properties" while providing regulated firms with a fair return on the prudent cost of investments that they have made to support the provisions of regulated services (Troxel (1947, p. 271).

The Brandeis formula is quite straightforward, and it does satisfy the NPV criterion: it provides an expected return that is high enough to attract investment, but not so high that it yields prices significantly higher than necessary to attract investment (Schmalensee 1989). The present discounted value of cash flows calculated using the Brandeis formula, including an allowed rate of return that is equal to the regulated firm's nominal cost of capital, is exactly equal to the original cost of the investment; investors get a return of their investment and a return on their investment equal to their opportunity cost of capital. As Brandeis suggested, his formula provides a simple and consistent method for compensating investors for capital costs and eliminates the uncertainties and opportunities for manipulation that characterized the earlier application of "fair valuation" concepts.

Beginning in the 1930s, regulators began to adopt and the courts began to accept the Brandeis formula, and by the end of World War II it became the primary method for determining the capital charge component of regulated prices. In the *Hope* decision in 1944, the Supreme Court concluded that from a Constitutional perspective it was the result that mattered rather than the choice of a particular method, thus freeing the courts from evaluating the constitutionality of the detailed regulatory formulas chosen by state and federal regulators. "Under the statutory standard of 'just and reasonable it is the result reached not the method employed which is controlling."[22] "Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risk assumed certainly cannot be condemned

[22] *Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 602 (1944)*

as invalid, even though they might produce only a meager return on the so-called 'fair value' rate base."[23]

While the Brandeis formula does satisfy the NPV criterion, and may have other attractive properties, it also has some peculiar implications. These can be seen most clearly for a single asset utility (e.g. a pipeline) with a "one horse shay" physical depreciation profile: no change in the asset during a lifetime of T years, after which it is valueless and must be replaced. Equation (1) above then shows that with $O\&M_t$ constant over time by the no-change assumption and D_t constant because of straight-line depreciation, the regulated firm's revenue requirement falls steadily as its depreciated rate base, RAB_t, declines. This implies, all else equal, that the utility's regulated prices would decline as its single asset aged, even though if it were selling in a competitive market there would be no reason for it to change its prices.

If the asset is replaced at the start of year $T+1$, the utility's rate base would discontinuously increase, and its revenue requirement and regulated prices would also jump and then again decline over time for the following T years. For a single asset company, when this asset is replaced, the application of the Brandeis formula typically leads to a sudden large price increase (known as "rate shock"), which creates both consumption distortions and political problems for regulators. More generally, using the Brandeis formula, otherwise identical firms may be treated very differently under regulation simply because the ages of their assets happen to be different even if their market values are the same. An old gas-fueled plan may have a much higher market value than a new coal-fired power plant, but the prices charged to consumers of the regulated firm with the old gas plant will be low while those of the utility with the new coal-fired plant may be high.

Finally, when assets are carried at values reflecting initial costs that are significantly greater than their market values, there may be incentives for inefficient entry as well as transition problems when competition is introduced into formerly regulated industries. When competition in generation replaces regulated monopoly, who pays for the undepreciated portion of the new gas plant that has a low competitive market value, and who gets the benefits from deregulating the old coal plant whose market value is much higher than its RAB? These so-called "stranded cost" and "stranded benefit" attributes of the Brandeis formula have plagued the transitions to competition in telecommunications as well as in electric power.

[23] Ibid at 605.

It turns out that any formula for calculating the annual capital or rental charge component of regulated prices that has the properties that (a) the firm earns its cost of capital each period on a rate base equal to the depreciated original cost of its investments and (b) earns the book depreciation deducted from the rate base in each period, satisfies the NPV and investment attraction properties of the Brandeis formula (Schmalensee (1989)). So, in principle, the Brandeis formula could be modified to take account of physical depreciation, technological change and inflation to better match both the capital attraction goals and the efficient pricing goals of good regulation.

The final component of the computation of the capital charges that are to be included in regulated prices involves the calculation of the allowed rate of return on investment, r_t in equation (1) above. Regulatory practice is to set a "fair rate of return" that reflects the firm's nominal cost of capital. Regulated firms are typically financed with a combination of debt, equity and preferred stock (Spiegel and Spulber (1994), Myers (1972a, 1972b)). The allowed rate of return is typically calculated as the weighted average of the interest rates on debt and preferred stock and an estimate of the firm's opportunity cost of equity capital,[24] taking into account the tax treatment of interest payments and the taxability of net income that flows to equity investors.

To illustrate, consider a regulated firm with the following capital structure:

Instrument	average coupon rate	fraction of capitalization
Debt	8.0%	50%
Preferred stock	6.0%	10%
Equity	N/A	40%

Then the firm's weighted average cost of capital (net of taxes) is given by

$$r = 8.0*0.5 + 6.0*0.1 + r_e*0.4 \qquad (2)$$

where r_e is the firm's opportunity cost of equity capital, which must then be estimated. Rate cases focus primarily on estimating the firm's opportunity cost of equity capital and, to a lesser degree, determining the appropriate mix of debt, preferred stock, and equity that comprise the firm's capital structure. A variety of methods have been employed to measure the regulated firm's cost of equity capital (Myers (1972a, 1972b)), including the so-called discounted cash flow model, the

[24] This is not a standard weighted average cost of capital, since it is based on historical (embedded) costs of previously issued debt and preferred stocks rather than current or forecast costs and does not take account of the income tax shield from debt. Income and other taxes are handled separately, because they are complicated, and effectively become an operating expense.

capital asset pricing model, and other "risk premium" approaches (Phillips (1993, pp. 383-412). At least in the U.S., the methods that are typically used to estimate the regulated firm's cost of capital are surprisingly unsophisticated in light of the advances that have been made in theoretical and empirical finance in the last thirty years.

With all of these cost components computed the regulator adds them together to determine the firm's "revenue requirement" or total "cost of service", R_t in equation (1). This is effectively the budget balance constraint used by the regulator to establish the level and structure of prices – the firm's "tariff" – for the services it sells. Figure 4 in the next chapter summarizes the components of the revenue requirements calculation.

5.3. Rate Design or Tariff Structure

The second phase of a formal regulatory proceeding is the determination of the prices or tariffs which define the terms and conditions for charging retail customers for the electricity that they consume, typically on a monthly basis. As noted above, a set of customer classes is specified, e.g. residential, small commercial, farm, municipal lighting, and industrial, and generally each customer class is further divided into sub-groups (e.g. optional residential TOU rates, EV charging rates, industrial rates differentiated by voltage, commercial and industrial customers with self-generation, etc.). For example, United Illuminating, which serves portions of Connecticut had 21 commercial and industrial retail tariffs in 2024.[25] Statutes, administrative rules, and court decisions generally require that prices not be "unduly discriminatory." The general approach to specifying retail tariffs is to allocate a share of the utility's total revenue requirement to each class of customers based on estimates of the costs of serving each class and to establish a tariff that is expected to yield the portion of the revenue requirement allocated to each customer class. Since many of the costs that go into determining the revenue requirement are joint or common costs that contribute to provision of service to more than one class, and inevitably uncertain estimates of anticipated electricity usage for each customer class must be used, there is considerable flexibility associated with the allocation of costs to each customer class. This provides significant flexibility for regulators in designing retail tariffs (Chapter 11 below, Bonbright (1961), Clemens (1950), Salinger (1998)). In addition, in many states special tariffs apply to low-income customers meeting specified criteria, to promote economic development and other policy goals, such as promoting

[25] https://www.uinet.com/account/understandyourbill/pricing

rooftop solar generation. These tariffs are not based on the standard cost allocation principles that the regulators would otherwise rely upon.

Considerations of economic efficiency have traditionally played at most a very limited role in rate design. In practice, rate designs reflect a variety of "public interest" considerations including income distributional impacts, economic development considerations, rate stability considerations, reasonable firm profitability, etc. For example, the Massachusetts Department of Public Utilities states that "… the goals of defining utility rate structure are efficiency and simplicity as well as to ensure continuity of rate, equity and fairness between rate classes, and corporate earnings stability."[26]

Residential and small commercial tariffs are generally quite simple, with a small monthly fixed charge (the customer charge) and a volumetric (per kilowatt-hour) charge. Even though about 72% of all customers and 73% of residential customers now have smart meters that can record electricity consumption over short time intervals,[27] U.S. utilities have experimented with time-varying rates since the 1970s, and a growing number of U.S. utilities are letting customers opt-in to such rates, less than 10% of U.S. customers are served by time-varying rates (Wolak and Hardman 2020, pp. 84-86). Only four states, led by California, are moving to make time-of-use rates the default option, from which customers can opt out.[28] Rate structures that are tied more closely to actual variations in wholesale market prices, so-called "real time" or dynamic rates, are rarely available to most customers, and experience suggests that risk averse residential and small commercial customers are not attracted to them. On the other hand, load control programs where customers receive discounts for agreeing, for example, to allow the utility to cycle their air conditions on a limited number of "peak" days in return for a discount are quite attractive. Tariff schedules for large commercial and industrial customers are more complicated and often include customer charges based on the voltage at which electricity is supplied, demand charges based on the customer's peak demand, and time-varying usage charges. Chapter 10 in this Handbook discusses contemporary rate design developments and issues in much more detail.

As electric power systems and the demand for electricity have evolved, heavy reliance on constant volumetric charges has become increasingly problematic. As wind and solar generation,

[26] https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/15824195, page 404.
[27] https://www.eia.gov/tools/faqs/faq.php?id=108&t=3
[28] The others are Colorado, Hawaii, and Michigan (Kavulla (2023)).

which have zero marginal cost, have become more important, the actual marginal cost of providing electric energy has become more variable over time (Mallapragada et al 2023). Retail prices that don't reflect this variation thus fail to provide appropriate incentives for shifting consumption over time. Time-of-use rates, which vary over time in a pre-announced fashion, provide a relatively attractive mechanism to address this problem (Schittekatte et al 2024). Time-of-use rates, unfortunately, are likely to make a second problem worse. The capacity of distribution systems needs to accommodate instantaneous peak power (kilowatt) demand. Electric vehicle (EV) charging is fairly flexible, and as EV penetration increases, coordinated charging of EVs, either reflecting similar commuting patterns or shifts in charging times to take advantage of cheaper energy under time-of-use pricing, can sharply increase peak power demand and thus require substantial investments in transmission and distribution. Covering transmission and distribution charges through substantial subscription charges for peak power demand, as is common in Europe but not in the U.S., has considerable potential to deal with this problem (Turk et al 2024). Moving to this basic design would enable reducing average per-kwh charges, thus encouraging electrification essential to economy-wide decarbonization (Schittekatte et al 2023).

5.4. Regulatory lag

As noted above, there is a "regulatory lag", which may last for several years, between the time a set of retail rates is established and when those rates are next formally reviewed. In early work on this subject Joskow (1974, Table 3) found that about a third of the utilities had zero formal rate reviews between 1958 and 1972, and another third of the companies had one rate review. Lowry, et al., (2017, Table 2) reports rate case activity for a longer period of time, 1948-1977, with similar patterns of rate case activity. The U.S. Energy Administration (2019) reports the number of electric utility rate cases for each year from 1980 through 2018, and S&P Global (2023) extends the time series to 2022. Overall, the number of annual rate cases varies widely over the 1948-2022 period. The number of formal electric utility rate cases fell to low levels during the 1990s, but rate cases began to increase in 2000, around the time that the restructuring process began in many states. The number of rate cases continued to increase through 2022 due to inflation, rising interest rates, and new obligations being placed on distribution utilities. This is consistent with the recent perception by regulators that the administrative burden of formal rate cases has been growing.

There has been a tendency to treat regulatory lag as a bug in COSR, but Kahn (1971, p. 48) long ago argued that it could be a feature: "The *regulatory lag*… is it to be regarded not as a deplorable imperfection of regulation but as a positive advantage? Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses and offers rewards for the opposites: companies can for a time keep the higher profits they reap from superior performance and suffer the losses from a poor one."[29]

Regulatory lag may be tempered (and administrative costs reduced) by the adoption of multi-year rate plans (MYRP). An MYRP is adopted in a formal rate case and specifies how the level of the rates set in that case will be adjusted until the next formal rate case. Many MYRPs specify the number of years for which the plan will apply, typically 3-5 years, before another formal COSR rate case takes place. Some MYRPs have no defined term and may last indefinitely. For example, the MYRP for Alabama Power was adopted in 1982 and not modified until 2013 (Kirsch and Morey 2016).

There are two polar types of MYRP. One type adjusts price levels according to *external* indices such as wage and input price indices, changes in cost of capital benchmarks, and productivity indices. These plans, which we discuss in Section 7, are typically motivated by performance goals as well as an interest in reducing regulatory costs. The other type of MYRP adjusts prices over time to reflect changes in the *actual* costs incurred by the utility rather than changes in external indices. These plans are typically referred to as formula rate plans. Under such plans the utility's rates are adjusted annually (say) based on realizations of the actual costs it incurs; that is, there are automatic true-ups for the actual operating and capital costs incurred by the utility in order to maintain the allowed rate of return determined in its last rate case. The Alabama MYRP mentioned above is a formula rate plan.

Formula rate plans provide poor incentives; they eliminate the penalties and rewards that Kahn (1971, p. 48) noted are provided by regulatory lag. They are effectively automatic cost-plus mechanisms that reimburse whatever costs the regulated firm incurs without formal regulatory reviews of costs and performance. Some formula rate plans adjust prices only if the earned rate of return falls above or below a specified band. Thus, these plans add a profit-sharing component to what would otherwise be a continuous COSR plan.

[29] See also Joskow (1974).

6. The Performance of COSR in Practice

Until roughly 1970, most of the theoretical research on natural monopoly regulation focused on optimal prices for a natural monopoly subject to a binding budget constraint.[30] The regulator was assumed to seek to set prices to maximize welfare subject to a break-even constraint for the regulated natural monopoly. The natural monopoly in turn was assumed to have a cost function characterized by increasing returns to scale (or, more technically, strict subadditivity),[31] and was assumed to produce output efficiently. The regulator was perfectly informed about costs and demand. Thus, the most important attributes of real utility regulation that motivate much of the more recent incentive regulation literature were ignored: imperfect and asymmetric information, adverse selection, managerial shirking and moral hazard, and rent extraction (see, e.g., Laffont and Tirole (1993) and Chapter 2).

Much has been written about the incentive properties of an idealized version of COSR introduced by Averch and Johnson (1962). In the A-J model, the allowed rate of return is greater than the regulated firm's cost of capital, giving the firm a bias toward the use of capital, the regulatory constraint is binding continuously, and the regulator accepts all of the costs presented to it by the firm. Numerous studies have extended the A-J model in various directions (e.g., Bailey (1973) and Epple and Zelinitz (1979)). In most cases, the A-J capital bias remains, though in other cases it does not (e.g., Bailey and Coleman (1970)).

Policy commentaries on the inefficiencies associated with cost-of-service regulation often refer to the A-J model. However, the A-J model ignores regulatory lag and other important dynamic attributes of regulation and firm behavior. It assumes that the regulator can observe the firm's actual costs perfectly. There is no provision for managerial inefficiencies that can naturally arise when monopolies are sheltered from competition and regulators cannot observe managerial effort. In our view, the most important intellectual contribution of the Averch-Johnson paper is not the capital bias result, but rather that it got economists thinking about the implications of various regulatory mechanisms for the regulated firm's costs.

[30] Braeautigam (1989), Brown and Sibley (1986) and Joskow (2007) provide useful summaries of this literature.
[31] See note 7, above.

Consider regulatory lag first. The A-J model is a static model that, when given a dynamic interpretation, effectively assumes that the regulatory constraint is binding continuously. However, this assumption is valid only for firms that are subject to formula rate plans that automatically and continually pass through to prices all actual cost changes, including changes in the firm's cost of capital. Few such firms, if any, have existed.

Efforts have been made to extend the A-J model to incorporate regulatory lag. See for example Klevorick (1973) and Bailey and Coleman (1971). Klevorick finds that there are situations where the input bias is just the opposite of the A-J capital bias, and Bailey and Coleman find that depending on the length of the lag, the A-J capital bias may be at least partially mitigated. From these papers it should be clear that introducing regulatory lag into the A-J model is not easy but potentially important. Perhaps more importantly, regulatory lag is not random since the "review trigger" tends to be pulled by the regulated firm rather than by the regulator when the firm feels that it can make a case for a profitable change in its rates (Joskow 1973). That is, regulatory lag was not used historically as an instrumental regulatory mechanism; it was a consequence of regulatory institutions that sought to reduce formal regulatory reviews, probably for administrative convenience.

While the regulator can observe a firm's actual operating and capital costs, it is a strong implicit assumption in the A-J model that the regulator cannot observe and penalize expenditure that are inefficient. Regulators, helped by staff and intervenors, can search for and disallow costs that they conclude are excessive. However, disallowances are typically quite small. And asymmetric information is nowhere to be found in the A-J model.

In the A-J model, changes in operating and capital costs are reflected in rates automatically. In practice some operating costs are in fact typically passed through to rates automatically and continuously even when there is no formal rate case triggered and even in the absence of a comprehensive formula rate plan. This is true of fuel costs, purchased power costs, energy efficiency expenditures, and some other operating costs. Under traditional regulatory practice, however, increases in other operating costs, for example increases in labor and materials costs, can only be reflected in rates through a formal rate case. And under traditional regulatory practice, whatever efficiencies that the utility can retain through regulatory lag can be realized through savings on costs that are not automatic pass-throughs.

In the end, we believe that traditional COSR of legal monopolies does lead to inefficiencies, mainly for all of the reasons articulated in the incentive regulation literature. We can see this most clearly in studies that have examined the efficiency consequences of moving generating plants from a regulated regime to a competitive regime with stronger incentives for efficiency, since such moves are quasi-random experiments. They show that there are efficiency gains from deregulation (Fabrizio, Rose and Wolfram 2007, Davis and Wolfram 2012, Cicala 2015, 2022). The inefficiencies are much broader than an excessive capital/operating cost ratio, though a number of studies have tested whether there is a capital bias that can be identified empirically. Some studies find that there is a capital bias (e.g., Spann 1974, Epple and Zelenitz 1979, Cicala 2022) while others do not (e.g. Boyes 1976). All these papers focus either on generation or on vertically integrated electric utilities rather than separately on distribution and transmission.

We believe that it is likely that the capital bias is articulated most importantly as a bias toward owning capital assets rather than buying services from third parties, since the costs of many of these services are treated as cost pass-throughs in the regulatory process, are not impacted by regulatory lag, and provide no profit opportunities. That is, under traditional COSR practice there are no benefits of regulatory lag to the utility associated with costs that are passed through automatically and continuously. Nor does the regulated firm have much of an incentive to procure services whose costs are treated as automatic pass-throughs from third parties even if that would be economical. This is a primary reason why IOUs in the U.S. did not want to dispose of their generating assets through restructuring in anticipation of replacing them by purchasing power from third parties in competitive markets which would be treated for regulatory purposes as automatic pass-throughs with no profit margin.

7. Performance-Based Regulation[32]

Recognizing the inevitable inefficiencies of COSR, academics and policymakers have focused on identifying incentive mechanisms as a complement or substitute for COSR that are expected to improve firm performance and better to achieve public policy goals such as static and dynamic cost minimization. An important step in this process was the development of RPI-X regulation (sometimes called price-cap regulation) and its application to the newly privatized British Telecom beginning in 1983 and thereafter to all regulated network industries in the U.K. (Littlechild (1983), Beesley and Littlechild

[32] This section relies heavily on Joskow (2024).

(1989), Armstrong, Cowan, and Vickers (1994)). Under this system the rate of growth of a weighted average of the regulated firm's prices is constrained not to exceed the rate of growth of the RPI, the main U.K. economy-wide retail price index, minus a constant, X, which could be positive or negatives, set, after negotiation, by the regulator. It was initially hoped that once X had been set, this system could simply run until competition made regulation redundant, but that did not happen. While some early enthusiasts accordingly touted RPI-X as an alternative to COSR, competition has not and likely will not generally take over in electricity distribution. In practice the system came to involve regularly scheduled true-up proceedings in which the regulator evaluated whether the utility's earnings were adequate or excessive and adjusted initial prices and X accordingly. Thus RPI-X regulation for electric distribution companies is properly viewed as a form of COSR, albeit an important and interesting form, not an alternative to it. The RPI-X regulatory formula has been much more successful in the regulation of landline telephone regulation where competition has emerged and reliance on the legacy landline networks has declined significantly (Sappington and Wiseman 2010, Table 2).

There is by now a very extensive and mature theoretical literature on incentive regulation of legal monopolies (see, e.g., Chapter 2, Armstrong and Vickers (1991), Laffont and Tirole (1993), Armstrong and Sappington (2004, 2007), Sappington (2005)). At least some of the teachings of this literature, especially simple price-cap or indexed price regulation a la RPI-X have guided reforms to traditional cost of service regulation in several U.S. industries, regulated telephone service at both the federal and state levels being the most widely cited (Lowry and Kaufman (2002, pp. 408-409); Sappington et al (2001, Table 1); Sappington and Weisman, 2010)). Incentive regulation mechanisms have been applied for many years to the regulation of electric utilities in countries other than the U.S., including Great Britain, Chile, Argentina, Japan, New Zealand, Australia, and Canada. U.S. regulators have not historically played a leading role in the development and deployment of incentive regulation.

The early applications of incentive regulation principles in the electric power sector tended to be very partial (e.g., focused on the performance of generating plants (Joskow and Schmalensee (1986)), quasi-automatic adjustment mechanisms in response to high rates of inflation in the 1970s and early 1980s, or temporary de facto price cap mechanisms (e.g. short-term rate freezes) that emerged as settlements of rate cases. These rate cases often involved vertical and horizontal restructuring, stranded cost recovery, and mergers, especially in the late 1990s and early 2000s as industry restructuring occurred. Administrative convenience rather than clearly articulated performance goals drove many of these experiments.

Since around 2015, the application of incentive regulation mechanisms to electric distribution companies in the United States has accelerated considerably. Incentive regulation mechanisms of some type have now been introduced into the electricity distribution regulatory process in a majority of U.S. states. Comprehensive incentive regulation mechanisms (described below) have been or are now being introduced or evaluated in about a dozen states. These initiatives are never called "incentive regulation" by regulators and policy makers in the U.S. The policy phrases used routinely now are "performance-based regulation" (PBR) or "alternative regulatory mechanisms (ARM)." We use the term PBR and incentive regulation interchangeable in this chapter.

The role of electric distribution companies has expanded considerably in the last two decades, but especially in the last 5 to 10 years, and this has led to increasing interest in PBR mechanisms. The changes have increased the complexity of regulators' objectives, and regulators have accordingly placed additional obligations on regulated distribution utilities and in the process further complicated the task of regulating them.

One major driver of these changes has been utility restructuring. In states that restructured their vertically integrated utilities, electric distribution became the primary target of state regulatory responsibility. It took perhaps a decade for state commissions to manage and adapt to the changes brought about by industry restructuring. Restructuring required significant attention by state regulators in order to put the supporting institutions in place and to respond to teething problems that emerged. State commissions also participated in the transition to ISO/RTOs and competitive wholesale markets in general and played a role in defining and adjusting to FERC's rules for organized wholesale markets, transmission pricing, transmission investment, and transmission planning. (See the discussion of FERC regulation in Chapter 4.)

The second major driver of regulatory change has been the dramatically expanded set of responsibilities with which U.S. electric distribution companies have been saddled. Many of these new responsibilities reflect the central role that the electricity sector is expected to play in meeting state and federal decarbonization commitments and goals and the accompanying technological changes. These responsibilities include energy procurement from independent power producers of carbon-free electricity (wind and solar), integration of rooftop and community solar generation and other distributed energy resources, distribution level storage, building a "smart grid" with enhanced communications, control, and metering capabilities, supporting the development and integration EV charging stations, and designing and implementing energy efficiency programs.

The multi-year PBR plan adopted by Hawaii at the end of 2020 to be applied to Hawaiian Electric is perhaps the most comprehensive PBR plan in the US. [33] Fully comprehensive PBR plans have three basic building blocks.

1. Multi-Year Rate Plans (MYRP) in the spirit of RPI-X regimes that provide cost efficiency incentives by adjusting adjusts prices or revenues based on *external* indices of input costs, productivity, and other performance metrics. Such MYRPs may be accompanied by a profit sharing or sliding scale plan as well as including reopeners for various unanticipated or highly uncertain costs (Whited and Roberto 2019). Massachusetts, Hawaii, Minnesota, Vermont, Rhode Island, and Maryland have adopted MYRPs in the spirit of RPI-X. Other states are considering doing so or are in the process of designing MYRP mechanisms, including. North Carolina, Colorado, Connecticut, Nevada, and Arizona. A few other states have considered MYRPs and decided against them (e.g., Michigan).

2. Performance Incentive Mechanisms (PIMs) targeted at a set of specific performance metrics. PIMs set goals for a range of performance indicia and apply financial penalties or rewards for meeting, exceeding, of falling short of those goals. The performance indicia that have been target by one of more state regulatory commission include the performance of customer energy efficiency communications and incentives; customer service, billing, and satisfaction; outage frequency and duration, power quality; employee safety (e.g. restricted work injury index), distribution network efficiency metrics (e.g. line losses), generator performance metrics for vertically integrated utilities (Joskow and Schmalensee 1986)); load factor and peak load reduction targets. As of 2017 about 16 states had adopted at least some of these PIMs (Brattle (2017, Appendix A-2)).

More recently, even more PIMs are being added to reflect changing regulatory and policy responsibilities. These include targets for expanding distributed generation and storage, targets for the expansion of EV charging stations (utility owned and third party), targets for moving customers to voluntary TOU and critical peak pricing rates, targets for expanding customer demand response capabilities, environmental metrics (e.g. greenhouse gas emissions), targets for "smart grid"

[33] https://puc.hawaii.gov/wp-content/uploads/2020/12/PBR-Phase-2-DO-5-Page-Summary.Final_.12-22-2020.pdf. Similar plans are being developed in Massachusetts, New York, California, and other states.

deployment, and targets for "beneficial electrification" (e.g. heat pump adoption). Adoption of this sort of PIM is becoming more common in states that have adopted aggressive decarbonization and electrification targets. Regulators adopting these types of PIMs include New York, Vermont, District of Columbia, Minnesota, Hawaii, and states in the process of doing so are Connecticut, Maryland, North Carolina, Colorado, Nevada, Illinois and Washington (Rocky Mountain Institute (2022)).

Two challenges faced by regulators in specifying and implementing PIMs are developing appropriate targets or benchmarks for satisfactory performance and devising the best incentives for meeting, exceeding or falling short of the PIM targets. This is challenging due to limited data availability, natural variation from one year to the next, lack of comparability across utilities in different regions of the country, differences between urban areas with significant underground distribution infrastructure and rural areas with primarily above ground infrastructure, and the technical challenges of doing sound benchmarking analyses.

Two approaches are often used to set targets. The first is to benchmark the utility against its own historical performance, challenging the utility to meet or exceed its historical performance. If the utility consistently beats the benchmarks, they can be tightened. (Knowing that this is possible may diminish the utility's incentives to perform well, of course.) The second approach is to use industry benchmarks, trimming the data to take account of variations in exogenous drivers of performance in an effort to identify comparable utilities.

The second design challenge is the specification of rewards and punishments. In many states there are no financial incentives, but performance standards can be set by the regulator, and the utilities must prepare and make public a "scorecard" with their performance metrics. This is sometimes referred to as creating "reputational incentives." Presumably, this information can then be used by the regulatory agency and intervenors in the next formal rate case to adjust allowed returns if there is poor performance. In some states there are financial penalties for falling outside a range of acceptable performance (a dead-band) and for some PIMs, especially energy efficiency PIMs, there are both financial rewards and penalties.

3. Revenue Decoupling Mechanisms, sometimes referred to as lost revenue adjust mechanisms (LRAMs), automatically adjust a firm's net revenues established in the previous formal rate case to compensate for revenue losses associated with the impacts of energy efficiency programs and of the diffusion of rooftop solar systems. The goal is to reduce or eliminate

disincentives regulated firms may have to avoid losing net revenues between formal rate cases because of these programs. Accordingly, during a regulatory lag period, revenues and profits are not affected by variations in quantities resulting from the successful implementation of programs assigned to the regulated firm. While these programs are referred to as revenue decoupling programs, effective implementation to make revenue adjustments that are profit-neutral, the regulator must define the "margin" between prices and short run marginal costs. This can be a complicated (and potentially controversial) set of calculations. About 30 states have now adopted revenue decoupling for at least one of the distribution utilities that they regulate.[34]

In addition to these three standard building blocks, some commissions have introduced additional provisions to give the distribution utilities they regulate incentives to experiment with adapting to state climate policies and changes in the structure of the electric power industry.

We are not aware of any high-quality studies of the effects of PBR plans on the performance of electric distribution companies in the context of their expanded service obligations. Designing and implementing a good assessment program is very challenging, since there are so many differences in the attributes of utilities, the actual applications of COSR across state commissions and utilities, and the differences in the details of the PBR mechanisms being applied. Such studies are a target of opportunity for future research.

8.0 Conclusions

It should be clear that the mechanisms for regulating the prices charged by electric distribution utilities has evolved considerably over time. However, the basic COSR principles are now well established and serve as a complement to the relatively recent introduction of PBR principles. Thus, it continues to be important to understand how COSR works in practice along with its strengths and weaknesses.

[34] Spot for Clean Energy, "State Policy Opportunity Tracker," https://spotforcleanenergy.org/state/wyoming/decoupling-and-dsm-performance-incentives/ accessed March 17, 2024.

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