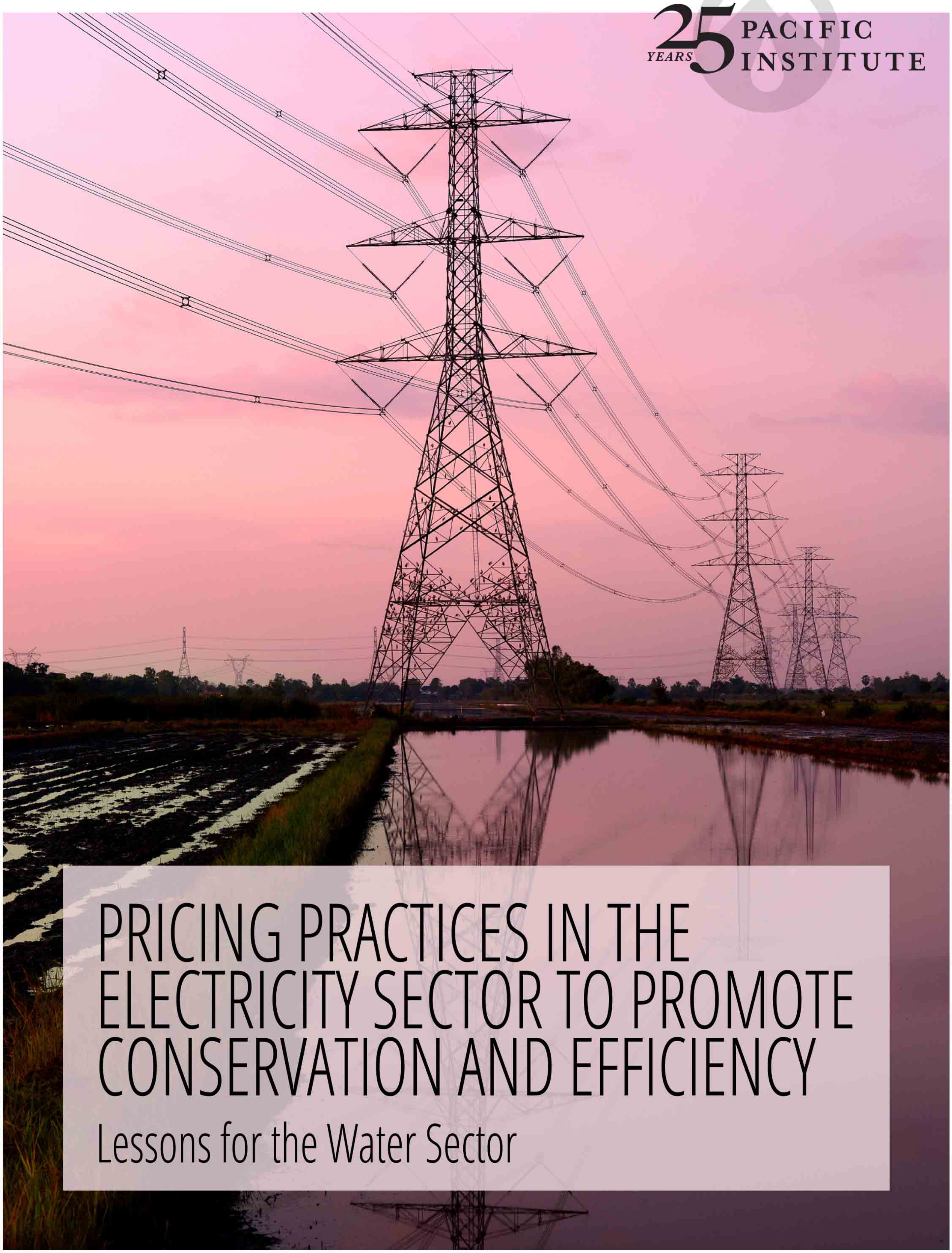

PRICING PRACTICES IN THE ELECTRICITY SECTOR TO PROMOTE CONSERVATION AND EFFICIENCY

Lessons for the Water Sector

25 YEARS PACIFIC INSTITUTE

Pricing Practices in the Electricity Sector to Promote Conservation and Efficiency

Lessons for the Water Sector

September 2013

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About this **Series**

In 2012, the Pacific Institute launched a major initiative and series of reports on key issues related to water pricing practices and policies in California.[1] The first paper in this series, *An Overview of the "New Normal" and Water Rate Basics*, examines how many water utilities are facing higher water costs and lower water demands. The second paper, *Assessing Water Affordability: A Pilot Study in Two Regions of California*, was developed in partnership with Community Water Center and Fresno State University and evaluates the affordability of water in the Sacramento metropolitan area and the Tulare Lake Basin. This paper, the third in the series, explores how California energy utilities have been able to balance a commitment to energy conservation and efficiency with fiscal solvency over the last several decades.

[1] All reports and related materials are available on the Pacific Institute website at www.pacinst.org.

Table of **Contents**

Acronyms

CEC	California Energy Commission
CPP	Critical Peak Pricing
CPUC	California Public Utilities Commission
EAP	Energy Action Plan
ERAM	Electric Revenue Adjustment Mechanism
ERRA	Energy Resource Recovery Account
GRC	General Rate Case
IOU	Investor Owned Utility
LADWP	Los Angeles Department of Water and Power
LRAM	Lost Revenue Adjustment Mechanism
MCBA	Modified Cost Balancing Account
OPA	Office of Public Accountability
PG&E	Pacific Gas and Electric Company
POU	Publicly Owned Utility
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric Company
SFV	Straight fixed-variable
SMUD	Sacramento Municipal Utility District
TOU	Time of Use
WRAM	Water Revenue Adjustment Mechanism

1 Introduction

Per capita water demand in California has been stagnant or decreasing for the past several decades (Gleick 2000). Because water utilities are dependent on the sale of water to recoup costs, reduced sales can result in deficits (Donnelly and Christian-Smith 2013). Other public utilities, including electricity, have confronted these same challenges and found ways to prevent or manage fiscal instability that can result from decreasing demand. In order to understand how some of these practices might be relevant to the water sector, we examine a range of electricity pricing practices and policies that California electric utilities use to remain financially stable even when demand is decreasing. This paper is intended to inform discussions currently taking place across California at the local, regional, and state level about water pricing in light of recent and future reductions in water demand.

It is important to note that there are major differences between the water and electricity sectors that can impact the applicability of certain policies and practices. **Table 1** reviews some of the ways that the water and electricity sectors differ nationwide and many of these differences hold true in California. For example, the major electric utilities in California are privately owned and the state provides a regulatory framework that clearly defines how these utilities must calculate customer rates. By contrast, the majority of water utilities are public entities subject to state and local regulations, and whose rates must be approved by a local, publicly-elected board.

Table 1. National Comparison of Water and Energy Sectors

Characteristic	Water	Electricity
Number	52,000	Over 3,000
Size and service	400 make up nearly 50% of sales	145 make up 75% of sales
Dominant ownership	Public	Private
State regulation	Drinking water quality	Rates and profits
Rate setting	Local or regional boards	State PUC approved
Revenues	$42 billion	$368 billion
Approach to efficiency	Best practices (mostly voluntary)	Resource standards (mostly mandatory)

Source: Adapted from Dyballa (2013)

In addition, water and electricity differ in how cost of service changes according to demand. Water providers typically perceive their cost profile as being heavily weighted toward fixed costs, such as infrastructure upgrades, which are independent of demand.[2] This assumption is reasonable for water utilities that do not pay or pay very little for their water supply. Water retailers that purchase supplies from a wholesaler, however, may have a more variable cost profile. Electric utilities, on the other hand, have costs that are accrued differently. Privately-owned electric utilities in California were encouraged to divest themselves of their generation assets, and, as a result, most own limited generation facilities and must sign short- and long-term agreements to purchase energy (CBO 2001). In 2012, fuel and purchased power alone accounted for 45% of the total costs for three of California's largest privately-owned electric utilities (CPUC 2013a). This suggests that, compared to water suppliers, California electric utility cost profiles may be more heavily weighted toward variable costs. Despite these differences, we conclude that there are several electricity pricing practices that may provide valuable lessons for the water sector. Below, we describe these practices in detail and consider how these practices could be implemented, or further implemented, in the water sector.

[2] The distinction between fixed and variable costs changes depending on the time horizon. Most costs that are considered fixed in the short run theoretically become variable in the long run as the scale of production is much more mutable over longer time periods.

2 California's Regulatory and Rate-Setting Processes

Understanding the relevance of electric utility pricing policies and practices to the water sector requires an understanding of how the utilities are structured. Rate-setting processes for electric utilities are subject to rules and regulations that differ from those that govern the process for water utilities. This section describes how electric and water utilities are structured and how the rate-setting process differs as a result.

Electric Utilities

Ownership is one major factor impacting how electric rates are set. California has both publicly- and privately-owned electric utilities. In 2012, privately-owned electric utilities – also referred to as investor-owned utilities (IOUs) – provided nearly 65% of total electricity demand in the state. California has six electric IOUs, the largest of which are Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric Company (SDG&E). Within these IOU's territories, 20 electric service providers offer direct access electric service to customers (CPUC 2013b). On the other hand, California's 45 publicly-owned utilities (POUs) together provided 24% of the state's electricity demand in 2012. The two largest POUs – the Los Angeles Department of Water and Power (LADWP) and the Sacramento Municipal Utility District (SMUD) – accounted for nearly 13% of electricity demand in 2012. In addition, California has two Native American utilities as well as four electricity cooperatives, which are private, independent, nonprofit utilities that are owned by the customers they serve (CEC 2013).

Whether a utility is publicly or privately owned impacts how it is regulated. IOUs are governed by a board of directors elected by the company's shareholders and are regulated under the State Constitution by the California Public Utilities Commission (CPUC) (CPUC 2010). POUs, by contrast, are governed by publicly-elected boards and city councils and are subject to laws and regulations established by state and local governments. In addition, both POUs and IOUs are subject to regulations promulgated by the State legislature, the California Energy Commission (CEC), and other state and federal agencies.

As a result, the rate-setting process varies among POUs and IOUs. In California, the rate-setting process for IOUs is established by the CPUC (CPUC 2010). While each IOU has a slightly different approach for setting rates, the overall process is quite similar. California POUs, on the other hand, do not have a standardized approach to rate-setting. While a full analysis of POU rate-setting practices is beyond the scope of this report, we discuss LADWP's process and include limited examples from other POUs to inform the discussion.

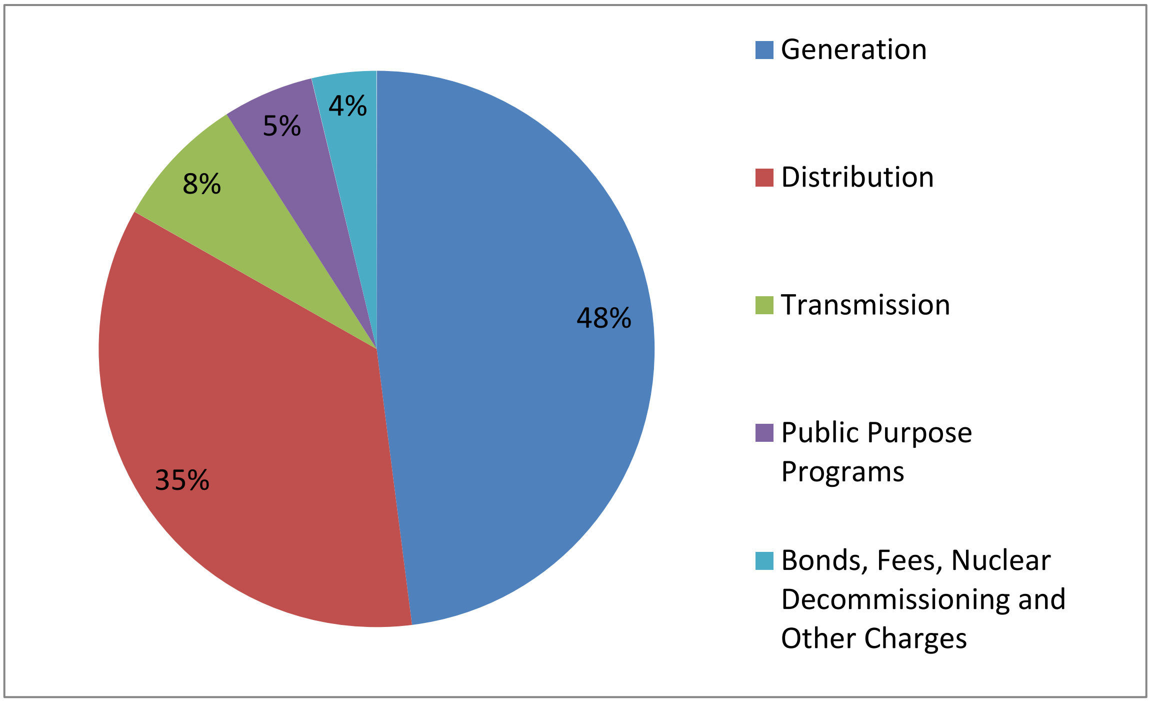

Figure 1. Revenue Requirement for California IOUs
Note: Percentages shown in the figure approximate the 2012 revenue requirements for PG&E, SCE, and SDG&E.
Source: Adapted from CPUC 2013a

Investor-Owned Utilities

Establishing rates requires an estimate of the total cost to provide utility service to customers. The amount of money needed for an IOU to operate and maintain facilities, cover capital expenses, and provide an opportunity to earn a profit is referred to as the revenue requirement. In order to calculate the revenue requirement for electric service and, ultimately, determine how customers are charged, utility costs are categorized into generation, distribution, customer access, transmission, and other program costs (e.g. the public goods charge and nuclear decommissioning fees) (**Figure 1**).

The CPUC authorizes nearly all decisions regarding the collection of revenue.[3] These decisions are made through formal courtroom proceedings where participants present testimony and evidence and may be subject to questioning. Within these proceedings, the utility makes a proposal to change customer rates (CPUC n.d.). This proposal is then reviewed by the Division of Ratepayer Advocates, a state agency required by law to represent ratepayers in almost every CPUC proceeding. State agencies, customers, advocacy organizations, and other groups may also formally intervene in the case, reviewing the utility's proposal and submitting testimony in response.

The majority of an IOU's revenue requirement is approved through two CPUC proceedings: Energy Resource Recovery Account (ERRA) and General Rate Case (GRC) proceedings. ERRA proceedings approve fuel and purchased power costs, which are then passed on to customers without profit. GRC proceedings establish the base generation, distribution, and customer cost of service, and, ultimately, the base electricity

[3] Transmission costs are determined by the Federal Energy Regulatory Commission through their own rate-setting process.

rates. A GRC takes about 18 months and is broken into two phases. During the first phase, the utility determines its total revenue requirement by forecasting costs based on near-term sales forecasts.[4] The first year of the cycle is known as the test year, and revenue requirements for subsequent years are set according to an attrition rate to adjust for anticipated inflation. Separate proceedings are then conducted to allocate costs to customers and set base electricity rates for the next three-to-four years; these proceedings are referred to as "Phase 2" of the GRC.[5] While GRC proceedings are conducted every three-to-four years, ERRA proceedings take place annually because the cost of fuel is much more variable over time than those costs included in the GRCs (CPUC 2013a).

Publicly-Owned Utilities

Although rate-setting processes vary among the POUs, some common factors exist. Each POU typically has a publicly-elected board or city council that is responsible for approving the utility's rates. In addition, California law requires the general manager of a municipal utility district, such as SMUD, to submit a report and recommendation to the governing board prior to making any changes to rates. The report must include the most recent annual report; past financial statements; and forecasts of future sales volumes, sources and dispositions of funds, capital expenditures, and expenses. The utility is also required to describe the basis for revenue allocation among customer classes (Public Utilities Code 14401-14403.5). While state law does not specify how this should be done, a voter-approved initiative passed in 1996, Proposition 218, requires there to be a "significant nexus" between cost-of-service and the prices customers pay.[6] In addition, Proposition 218 requires public notification of all potential rate changes and an opportunity to protest.

The process LADWP uses to determine the revenue requirement differs somewhat from that used by California IOUs. To calculate the utility's revenue requirement, LADWP uses the "cash-needs approach" (LADWP 2012). This approach groups the revenue requirement into categories similar to those used by the IOUs, including operation and maintenance, fuel and purchased power, and efficiency program costs. Unlike with IOUs, the capital component includes costs for debt service, cash reserves, and transfers into other municipal funds and excludes a return on investment. In addition, the revenue requirement must meet several financial goals that have been formally established by the utility, e.g., maintaining an "AA-" bond rating, a debt service coverage ratio of 2.25, full obligation coverage of 1.50, a capitalization ratio not exceeding 68%, an unrestricted operating cash balance target of $300 million, and net income of at least $50 million (PA Consulting Group 2012). LADWP currently allocates these costs using its existing rate ordinance, although an independent ratepayer advocate group established by city voters in 2011, the Office of Public Accountability (OPA), recommended that LADWP conduct a formal cost-of-service study to prepare for future rate restructuring (PA Consulting Group 2012). The newly created OPA provides public independent analysis of the department's actions associated with water and electricity rates.

[4] Long-term demand forecasting is addressed in a separate proceeding and is used to establish long-term generation needs.

[5] The utility establishes rates for different types of customers according to the cost to provide service to that customer. While the utilities generally use residential, commercial, institutional, industrial, and agricultural customer classes, there are often several sub-groups of customers within each class to allow for more targeted calculations.

[6] While there is little case law to indicate how courts will analyze whether a "significant nexus" exists, Proposition 218 has served to bring POUs' water rate-setting practices under further scrutiny.

Water Utilities

As mentioned previously, the majority of water suppliers in California is publicly-owned and governed by publicly-elected boards. Unlike the CPUC, which has legal proceedings overseen by administrative law judges with significant experience in utility finance issues, publicly-elected water boards may have little-to-no background in these areas. In addition, publicly-elected boards may be subject to voter backlash and therefore may be more influenced by political pressure (Donnelly and Christian-Smith 2013).

According to staff at the California Public Health Department, there are more than 1,000 water suppliers in California, operating at multiple scales (from large metropolitan areas to mobile home parks), with different cost profiles. As with electricity, this diversity leads to varied water rate-setting processes. However, Proposition 218 (which applies to the public sector only) imposed new procedural and substantive requirements for public utilities, as briefly described above. Specifically, public water utilities must mail information regarding any changes to water rates to all property owners and must provide a mail-in ballot for the property owner to indicate his or her approval or disapproval of the rate change. After mailing the notices, the public water utility must hold a public hearing and tabulate the ballots. The rate change can be rejected if more than half of customers disapprove (LAO 1996).

These procedural requirements have brought new scrutiny to water rate changes. In addition, the language of Proposition 218 requires that there be a "significant nexus" between the cost-of-service and customer prices. While there is little case law to describe how the courts will interpret this language, it has brought greater attention to the need for cost-of-service studies and more clearly articulated revenue requirements and cost allocation practices.

In the water industry, there are two generally accepted methods for calculating revenue requirements, as approved by the American Water Works Association: the cash needs method and the utility basis method.[7] The cash needs method is commonly used by public water utilities (Denver Water 2008). Under the cash needs method, all of the utility's cash expenditures are included in the calculation of the revenue requirement from water rates pursuant to the following equation (Denver Water 2008):

$$RR = O\&M + DS + CAPEX$$

Where:
RR = Revenue Requirements
O&M = Operation and Maintenance Expenses
DS = Debt Service Payments
CAPEX = Capital Expenditures Financed by Water Rates

Interestingly, revenue requirements in the electricity sector include an "inherent commodity cost" for electricity generation. Water revenue requirements, by contrast, typically do not include inherent commodity costs (that might reflect, for instance, the costs associated with diverting that unit of water from the natural environment). Several water utilities have begun to incorporate inherent commodity costs into their revenue requirements and have passed them along to customers through additional fees. For instance, the Metropolitan Water District of Southern California established the Water Stewardship Rate, which charges customers $41/acre-foot to recover the cost of Metropolitan's financial commitment to conservation, water recycling, groundwater clean-up and other local resource management programs (Metropolitan 2013).

[7] See the American Water Works Association's M1 Manual: Principles of Water Rates, Fees, and Charges for more information about these pricing approaches.

3 Pricing Mechanisms to Promote Conservation and Efficiency

California's electric utilities have adopted various pricing mechanisms that have facilitated conservation and efficiency. This section describes some of the mechanisms, including marginal, tiered, and time-variant pricing, and provides a valuable starting point for discussions about rate design within the water sector. Within each section, we include a discussion about how they are, or can be, applied by water utilities.

Marginal Pricing

California electric IOUs use marginal cost pricing principles to allocate most of the revenue requirement to their customers. The marginal cost is the change in total cost that occurs with the next increment (or decrement) of demand. According to marginal cost pricing theory, setting customer rates at a level that reflects marginal costs sends a price signal that can help customers make efficient decisions about use. The goal of marginal cost pricing is to allocate goods in an economically efficient manner that serves to alert customers about the cost of using (or not using) an additional unit of water, so that usage can be adjusted accordingly. In theory, marginal pricing means that customers do not over- or under-utilizes the service (PG&E 2013a).

The marginal cost revenue is the theoretical amount of revenue that the utility would collect if all customers were charged rates equal to the marginal cost. Marginal cost revenue, however, may not be sufficient to cover the utility's current revenue requirements, and as a result, setting rates equal to marginal costs may not ensure full recovery of the approved revenue. To address this issue, the electric IOUs use each customer class' relative contribution to the total marginal cost revenue to allocate the revenue requirement among the various customer classes. These allocations are then used to establish the average rates for each customer class by dividing the allocated revenue by forecasted sales (PG&E 2013b).

Traditional water sector ratemaking is founded on cost-of-service principles that include distinguishing the cost drivers of a utility's revenue requirement and then allocating the total revenue requirement among customer classes in a way that customer costs are proportional to the amount their usage contributes to the utility's cost drivers. Thus, cost-of-service is essentially a historical accounting approach that does not accurately estimate future costs (Celebi and Hanser 2010). Understanding the marginal costs of service can reveal locations and times when the existing average historical cost-based rates diverge significantly from the cost of providing the next unit of water or energy. In the energy sector, it is well known that peak demand is a key cost driver that can result in much higher marginal costs at particular times. In the water sector, the costs associated with the next unit of water supply can vary based on a variety of factors including the water source (e.g., locally-owned water supplies, purchased water supplies, or desalinated water), the season of use, and the location of use. In addition, the marginal costs of water increase substantially when new water delivery or treatment infrastructure is required to satisfy the next unit of demand.

In the water sector, there are two main approaches to calculating marginal costs, as described in the M1 Manual: Principles of Water Rates, Fees, and Charges (AWWA 2000). The avoided cost approach calculates marginal costs through cost savings from avoided new capacity and the average incremental cost approach estimates annual payments of new capacity additions. The California Urban Water Conservation Council's Direct Utility Avoided Cost Model is a valuable tool for water utilities and is available as a free download from their website. The spreadsheet-based tool uses data already collected by most public water utilities in their Urban Water Management Plans and other financial documents to estimate short-run and long-run marginal costs. Despite the accessibility of the Direct Utility Avoided Cost Model, it remains unclear how many California water utilities have actually incorporated marginal cost pricing as there are no standard reporting requirements.

Tiered Pricing

Tiered pricing structures charge customers different rates according to the amount of electricity consumed. All California IOUs have adopted tiered pricing for residential customers, with four-to-five tiers. The rates for each tier are unique to each IOU. The breaks between tiers will vary by service area, customer class, and, in some cases, by individual customer. The first tiers, also referred to as the baseline tier, was established by the Warren-Miller Energy Lifeline Act of 1976, which required IOUs to designate a baseline quantity of electricity that would supply a significant portion of the reasonable energy needs of the average residential customer. This baseline is set at 50-70% of the average customer's use and is adjusted according to the type of fuel used for space heating (gas, electric, or other), climate, and season.[8] Subsequent tiers are based on a percent increase above the baseline (see Table 2).[9] During the 2001 California energy crisis, the Legislature prohibited the CPUC from approving rate increases for the first two tiers (ABx1 1, Keeley, Chapter 4, Statutes of 2001). Since this freeze was enacted, rising energy costs have been disproportionally borne by customers in the upper tiers. In 2009, however, the California Legislature passed SB 695, which allows for a gradual rate increase for the lower tiers until 2018.

Table 2. PG&E Residential Electricity Rate Tiers

Tier	Description
Tier 1	Electricity usage up to the Baseline amount
Tier 2	Electricity usage from 101% to 130% of Baseline
Tier 3	Electricity usage from 131% to 200% of Baseline
Tier 4	Electricity usage from 201% to 300% of Baseline
Tier 5	Electricity usage in excess of 300% of Baseline

Note: The baseline is determined by the amount of energy required to supply a significant portion of the reasonable energy needs of the average residential customer. SCE and SDG&E have only four tiers, with the fourth tier including all usage above 200% of Baseline. PG&E is currently applying to reduce the number of tiers from five to four.
Source: PG&E 2013c

[8] As required by the Act, a higher energy baseline is provided for residential customers with special medical needs.
[9] Pricing structures attempt to balance a number of societal objectives including equity, efficiency, and affordability. Caps on energy rates in tiers 1 and 2 have led to some concerns about over-collection of revenue from the higher tiers. This issue is currently being addressed in the CPUC's investigation regarding residential rate design, R.12-06-013.

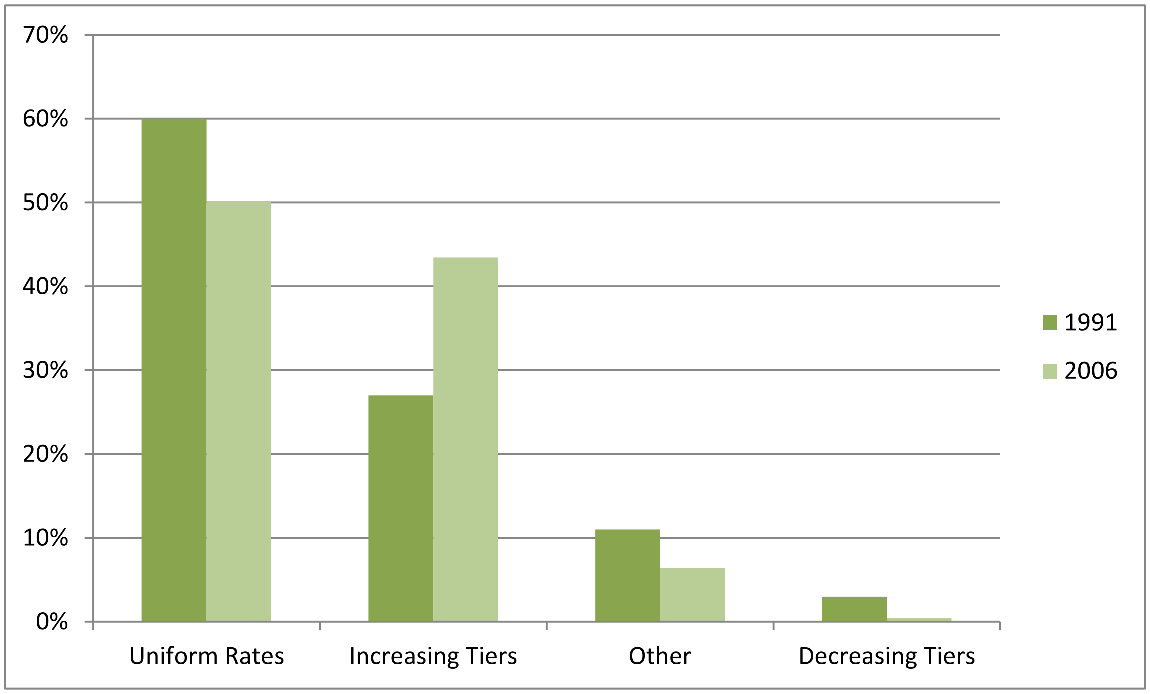

Figure 2. Trends in water rate structures between 1991 and 2006 (Black & Veatch 1991, 2006)

Tiered pricing is also widely used by California water utilities. Black & Veatch has conducted several surveys of California urban water prices and rate structures (Black & Veatch 1991, 2006). Since Black & Veatch began its survey in 1991, to its most recent survey in 2006, water rate structures have shifted away from uniform prices and decreasing tiered rate structures towards increasing tiered rates (**Figure 2**). Only 27% of surveyed urban water suppliers used increasing tiered rates in 1991, while 43% did so in 2006.

Time-Variant Pricing

Time-variant pricing is used to account for the fact that energy use is subject to significant temporal variation. Demand varies throughout the day: electricity use peaks in the morning and evening, with most customers using only modest amounts of energy at night. Additionally, electricity use in California peaks during the summer months when customers are more likely to operate energy-intensive air conditioners. Because electricity cannot be easily or cheaply stored for later use, electricity production must meet demand in real time. This means that meeting demand requires a mix of fuel types and generation facilities, each with different ramp-up and ramp-down times, operational costs, construction costs, and capacity limitations. Plant operators typically minimize costs by operating the least expensive fuels continuously and using the more expensive fuels to meet peak demand. These factors tend to result in marginal costs that increase during peak periods (Joskow and Wolfram 2012, Braithwaith et al. 2007).

The implications of high demand and expanded capacity have encouraged utilities to find various approaches to manage demand. One way is by using pricing structures that signal customers when it is more expensive to generate electricity. Since most retail consumers are charged a single rate throughout the day, daily and seasonal variability in the cost of electricity is not passed on to customers. Therefore, existing pricing structures alone do not adequately represent the cost of service as the rate. Customer rates, however, can be structured to reflect the temporal variation in costs, providing the customer with an incentive to avoid consumption when marginal costs are relatively high. This type of rate structure is typically referred to as "time-variant" pricing. Some time-variant prices are dynamic, with price changes that occur on short notice according to system conditions (CPUC 2013c). Smart meter technology has enabled transition to dynamic pricing schemes by simultaneously allowing utilities and customers to monitor their energy use in real time. Although these kinds of pricing structures have not been shown to reduce overall demand, they have been shown to shift demand to off-peak periods (Levin 2012).

Several policies have been adopted in California to encourage the use of time-variant pricing. In 2003, the California Energy Commission and the CPUC adopted the first Energy Action Plan (EAP), which included key actions to implement dynamic pricing schemes and make them available to all customers. The EAP set a goal that, by 2007, price response from consumers would reduce peak demand by 5%. To further promote time-variant pricing, SB 695 of 2009 established guidance to transition IOU residential customers onto time-variant rates. Some POUs are also implementing time-variant pricing. For example, SMUD plans to have all users on time-variant rates by 2018 (SMUD 2013).

The CPUC uses two approaches for time-variant pricing. Time-of-use (TOU) rates vary according to five established usage periods according to season and time of day. Critical Peak Pricing (CPP), on the other hand, allows a short-term price increase when demand is particularly high. IOUs in California typically call 5-15 CPP days per year (CPUC 2013c). Both TOU rates and CPP use price to encourage customers to reduce or shift their demand during peak periods, however, CPP is dynamic whereas TOU rates are not (Faruqui and Hledik 2007; CPUC 2013c).[10] CPP rates are also more aligned with the true cost of service, since the charges increase during system peaks, rather than individual customer peaks. California IOUs have implemented mandatory TOU rates and default CPP for large agricultural, commercial, and industrial customers. Small and medium commercial and industrial customers will have made the same transition by 2016. TOU rates and CPP remain optional for residential customers and have seen very little implementation; as of this writing, less than 1% of residential customers have opted in (CPUC 2013c).

Some water utilities are implementing rates that vary according to time of use. These are generally associated with seasonal weather patterns and/or droughts. For instance, a water utility may charge higher rates during the summer months in response to expected increased water demand and/or reduced supply. In addition, water utilities may charge higher rates during a drought or other water supply constraint. For example, East Bay Municipal Utility District implemented drought rates in May 2008 in response to a water supply shortage. These rates ended in July the following year when the drought emergency was lifted (EBMUD 2009). More utilities should consider adopting rates that promote conservation and efficiency when water supplies are limited, such as during a drought or during the summer months.

Demand Response Contracts

Demand response programs financially reward customers who reduce electricity consumption during specific time periods and can be considered a form of time-variant pricing. One interesting type of demand response program is a demand response contract. These contracts are

[10] CPP prices are dynamic because they are called on short notice; however, the price change is predetermined.

between an electricity utility and a third-party that is responsible for aggregating decentralized opportunities to reduce demand and manage programs to reward customers who conserve energy. Customers enter into individual contractual arrangements with the third-party to stipulate the energy savings that will be achieved and the incentive payments that will be provided to the customer. From a utility's standpoint, demand response contracts can provide a level of certainty around demand reduction and its impact on revenues.

In 2006, the CPUC required electric utilities to implement demand response contracts (CPUC 2012). PG&E, for example, currently has designated five aggregators who are responsible for designing demand response programs as well as customer acquisition, marketing, sales, retention, support, and event notification tactics (PG&E 2013d). Although PG&E's program did not meet the CPUC's cost effectiveness criteria, it has been revised and approved until 2014 (CPUC 2012).

Some water providers are also using demand response contracts to manage their energy demands. For example, North America Power Partners currently has a multi-year demand response contract with Orange County Water District to reduce peak loads related to their wastewater recycling program (NAPP 2010). However, there has been little application of demand response contracts to help customers reduce water demand during peak periods, such as during droughts or hotter months. Demand response contracts could provide a water utility the opportunity to incorporate pre-determined demand reductions into their demand forecasts and revenue calculations.

4 Strategies for Lost Revenue Recovery

Electricity rates are set to recoup the utility's revenue requirements. However, rates are based on utility service forecasts, which can vary from actual levels of service and thus impact the amount of revenue that is actually recovered. Several factors can impact expected sales, including new distributed generation, energy efficiency improvements, economic activity, weather, customer behavior, and changing demographics. Rate-setting processes evaluate factors that affect costs and sales in order to set rates that minimize the difference between the approved revenue requirement and the actual revenue from customers.

However, reduction in expected sales does not have a direct reduction in overall costs. Cost of service can be thought of in terms of fixed and variable costs. Fixed costs do not change in the short-run according to the amount of electricity sold. By contrast, variable costs, such as the cost of fuel and purchased power, can vary according to electricity sales. Reductions in demand from efficiency improvements or any other factor can result in an under-collection of revenue necessary for utility operation. There are a number of ways utilities may recover revenue losses that result from demand reductions. In this section, we discuss some of these options, including decoupling, and lost revenue adjustment mechanisms, rate stabilization funds, and straight fixed-variable pricing.

Decoupling

A return on investment is included as part of the calculation of an IOU's revenue requirement; however, the level of return is only determined after all other costs have been covered. Thus, the portion of an IOU's revenue requirement that is most at risk from reductions in sales is the "margin," or the rate of return. Investors view utilities that do not provide adequate returns as riskier or less desirable investments and will therefore expect a higher rate of return, increasing the utility's overall costs (Shirley et al. 2008). The incentive to sell more of a product in order to increase profits is known as the "throughput incentive." This incentive is believed to discourage utilities from pursuing efficiency and conservation, as reductions in sales have a disproportionate impact on the margin. While POUs do not earn a profit, marginal revenue covers the cost of debt, ensures sufficient debt service coverage, and is sometimes transferred into other city funds (National Action Plan for Energy Efficiency 2007).

Revenue decoupling mechanisms allow the utility to be reimbursed when there is a difference between expected and actual revenue and can therefore remove the throughput incentive by breaking the link between profits and sales. To implement decoupling, utilities can use a "true-up" mechanism, which adjusts rates periodically in order to address differences between actual and expected revenue, or balancing accounts that store excess revenue or track revenue shortfalls.

The CPUC first introduced the Electric Revenue Adjustment Mechanism (ERAM) for California's electric utilities in 1982. The ERAM was abandoned in 1996 following the deregulation of the electricity market, but forms of this mechanism were reinstated in 2001 after the California energy crisis. The ERAM is designed to recoup lost revenues approved in the General Rate Cases. When there is an over- or under-collection of base rate revenue, the ERAM annually adjusts the rates so that over-collections are refunded to the ratepayer and under-collections are recouped from ratepayers. In this way, the utility recovers its authorized revenue, regardless of sales. Fuel- and transmission-related costs are not addressed in the ERAM true-up, although other balancing accounts exist to recover these costs. Between 2002 and 2005, each of California's IOUs set up their own decoupling mechanism through their GRC by creating balancing accounts that are used for annual true-ups (Kushler et al. 2006; Weber et al. 2006).

There are some criticisms of decoupling mechanisms. One criticism is that it keeps revenues stable regardless of the reason for the difference in approved and actual revenue. This shifts the financial risk from the utility to the customer and provides a disincentive for utilities to effectively manage costs (ELCON 2007). In addition, while decoupling addresses the throughput incentive, it does not provide a direct incentive for investments in conservation or efficiency (NARUC 2007). Decoupling may actually undermine the price incentive for customers to invest in energy efficiency when efficiency results in higher rates (ELCON 2007). Furthermore, if the rate of return is larger than the cost of capital, the utility will still have an incentive to support large supply-side investments, regardless of whether there is a decoupling mechanism in place (Kihm 2009). In addition, the Electricity Consumers Resource Council (2007) has argued that decoupling effectively protects the company's earnings from natural sales fluctuations, which can promote mediocrity and indifference.

Lost Revenue Adjustment Mechanisms

The lost revenue adjustment mechanism (LRAM) provides another way for utilities to capture the difference between expected and actual revenue. While decoupling allows the utility to recover all revenue associated with reductions in demand, the LRAM only allows the utility to recover revenue that is lost as a result of specific factors (NARUC 2007). These mechanisms can be used to recover revenue that is lost by energy conservation and efficiency programs, thereby addressing the disincentive utilities would have to invest in these programs. Because utilities will not collect revenue lost as a result of factors not specifically included in the LRAM, however, these mechanisms do not completely sever the link between revenue and sales, and so do not completely remove the throughput incentive.

LRAMs can be difficult to implement for a number of reasons. LRAMs require the ability to calculate the lost sales attributed to demand or conservation management, rather than from other factors such as changes to the weather or economy.[11] Methods used for calculating lost revenue must be precise and well established in order to avoid contentious rate cases with real or perceived gaming by utilities in an attempt to maximize cost recovery. Moreover, when these mechanisms are used to recover revenue lost through improvements in energy efficiency, the utility can only calculate the energy savings from programs that are known to or sponsored by the utility. Any improvements that fall outside of these programs would potentially underestimate the actual amount of revenue lost through

[11] This is usually accomplished by multiplying the customer rate by the estimated savings, which can be evaluated using ex-ante or ex-post impact evaluation studies.

efficiency improvements. Moreover, this could result in a bias towards utility-sponsored programs over other means, such as standards and codes, regardless of what is most cost effective (Shirley et al 2008).

The CPUC authorizes the use of balancing accounts to recover the cost of fuel, purchased-power, demand-side management programs, and other costs. These accounts track the difference in expected and actual costs; annual adjustments are made to the rates to "balance" these accounts and recover costs or distribute over collections to customers. The CPUC authorized PG&E to use more than 20 balancing accounts in 2012; together, these required approximately $302 million in revenue adjustments (PG&E 2012).[12] LADWP currently utilizes an LRAM for energy efficiency as part of the Energy Cost Adjustment Factor, which adjusts rates quarterly to recoup revenue losses from conservation and efficiency programs (LADWP 2008). The ECAF is also responsible for recovering other lost revenue, including fuel and purchased power (PA Consulting Group 2010).

As in the energy sector, water rates are based on estimates of future demand, which can vary from actual levels of service and affect actual revenue. Here too, the throughput incentive impacts a utility's willingness to implement conservation and efficiency programs. The CPUC has attempted to decouple water sales from revenues for investor-owned water utilities. In 2008, as part of its Water Action Plan, the CPUC adopted two decoupling mechanisms for water IOUs: the Water Revenue Adjustment Mechanism (WRAM) and Modified Cost Balancing Account (MCBA). The WRAM enables utilities to collect any revenue shortfalls that result from water conservation by calculating the difference between actual and adopted quantity charge revenues. The MCBA allows utilities to recoup lost revenue from purchased power, purchased water, and pump taxes.

By 2009, the ten largest water IOUs (which serve the majority of water customers regulated by the CPUC) had decoupling policies in place. The adoption of the decoupling policies, however, coincided with a global recession and several wet years. At the time, revenue forecasts that were based on historical water sales drastically over-estimated actual sales. In 2010, a wet year, 31 of 35 water utilities under-collected revenue and, in the following year, 33 of 34 under-collected. Indeed, three utilities under-collected revenue by 26-27% of expected, representing major budget shortfalls (Kahlon 2012). Nonetheless, the structure of the CPUC decoupling agreement allowed these IOUs to avoid budget impacts as lost revenues were recovered through customer surcharges authorized by WRAMs. The Division of Ratepayer Advocates has argued that customers should not have to reimburse IOUs for budget shortfalls unrelated to water conservation for which the decoupling program was specifically adopted, claiming that much of the reduction in water sales did not result from conservation but were associated with the economic slowdown and climatic conditions (DRA 2012).

Rate Stabilization Funds

Another mechanism to recover lost revenues is through rate stabilization funds. These funds use surcharges to collect extra revenue to establish a reserve that can be used to mitigate unexpected increases in energy costs. Money can be collected through volumetric or fixed charges. These funds can also help shore-up bond ratings, thereby keeping the cost of capital low. LADWP, for example, utilizes a rate stabilization account to handle unanticipated costs, such as legal fees, variable bond rates, and lost revenue from uncollectable customer bills. SMUD has a hydro rate stabilization fund that offsets higher energy

[12] This figure does not include fuel and purchased power costs, which are collected through separate ERRA proceedings.

costs during dry years when less hydropower is available.

Rate stabilization funds must be carefully structured in order to be effective. The utility should establish clear policies about how and when the funds will be used and create a process for regular review so that the fund does not over- or under-collect from ratepayers. Some customers have criticized because they perceive rate increases as unfair or unnecessary when the utility maintains a large reserve. Another issue is that rate stabilization funds, if used regularly to mitigate increases in customer rates, can preserve rates that do not fully recoup revenue, and can ultimately result in much larger rate changes.

While rate stabilization funds have been used in the water sector, the methods used to implement them could be improved. The Board and utility staff are not always provided with specific policies or guidance on how rate stabilization funds are to be set up or operated. A rate-stabilization reserve fund policy would state how the fund should be managed, for instance, to limit rate increases associated with the construction of new water supply infrastructure. Setting quantitative targets for when to withdraw reserve funds and how to apply them can establish clear expectations for their use and avoid potential customer concerns over the existence of such a reserve. Examples of water utilities with clear financial policies to guide rate stabilization fund use are provided in the Need to Know: Water Rates series brief on *Conservation and Revenue Stability*.

Straight Fixed-Variable (SFV) Pricing

Some have suggested using straight-fixed variable pricing as a means to recover costs and promote revenue stability. Straight fixed-variable (SFV) pricing imposes a fixed charge on customers to recover all of the fixed costs. An SFV rate design allows utilities to reliably recover all costs that do not vary with sales. While IOUs in California generally have some charges that are fixed, they are not permitted to collect all of their fixed costs through these charges under the current rate structures. Instead, all IOUs and many POUs in California collect revenue through charges that are almost entirely variable. However, SDG&E is proposing to collect more revenue through fixed charges for some customers (SDG&E 2012).

SFV rates, however, have several shortcomings that would apply to both water and energy utilities. First, SFV will disproportionally increase costs for small users that use less than the average amount of energy or water. Moreover, SFV distributes the cost of peaking capacity such that rates are not set according to how customers impact costs. Additionally, conversion from a volumetric to a SFV rate design could weaken the strength of the conservation price signal to customers (National Action Plan for Energy Efficiency 2007; Shirley et al. 2008). Indeed, any rate structure must take into account a variety of societal objectives, including: sending a conservation signal, distributing costs equitably, and being easy to understand. While SFV rates may stabilize revenue, they do little to respond to these other socially-defined priorities.

5 Conclusions

California's energy sector has implemented many pricing policies that seek to balance a commitment to energy conservation with utility financial health. In this paper we reviewed marginal, tiered, and time-variant pricing, as well as different methods for lost revenue recovery. For water service providers, there are important lessons to be learned. While there are important differences between the water and energy sectors, there is a number of promising electricity pricing practices that could be implemented, or further implemented, in the water sector.

Some of the electricity pricing practices that have contributed to conservation while also maintaining financial stability include: time variant pricing such as seasonal rates, along with innovative tools such as demand response contracts; and lost revenue recovery mechanisms such as rate stabilization funds. Some of these practices are already common in the water sector (e.g., tiered rates), some are becoming more wide-spread (e.g., seasonal rates, rate stabilization funds), while others have not been widely applied to water (e.g., demand response contracts and the calculation of an inherent commodity cost for water in the utility's revenue requirement). In the case of marginal cost pricing, there is little known about the extent of adoption in the water sector as there is no single, standard approach to marginal cost pricing or reporting.

Over the coming years, California water utilities are required to reduce per capita water demand by 20% (see Senate Bill x7-7: The Water Conservation Act of 2009). Thus, the "new normal" or an era of declining demand and rising costs is a trend that is likely to continue. Both water and energy utilities are coping with similar financial challenges related to demand reductions and stand to benefit from a greater exchange of information and lessons learned.

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